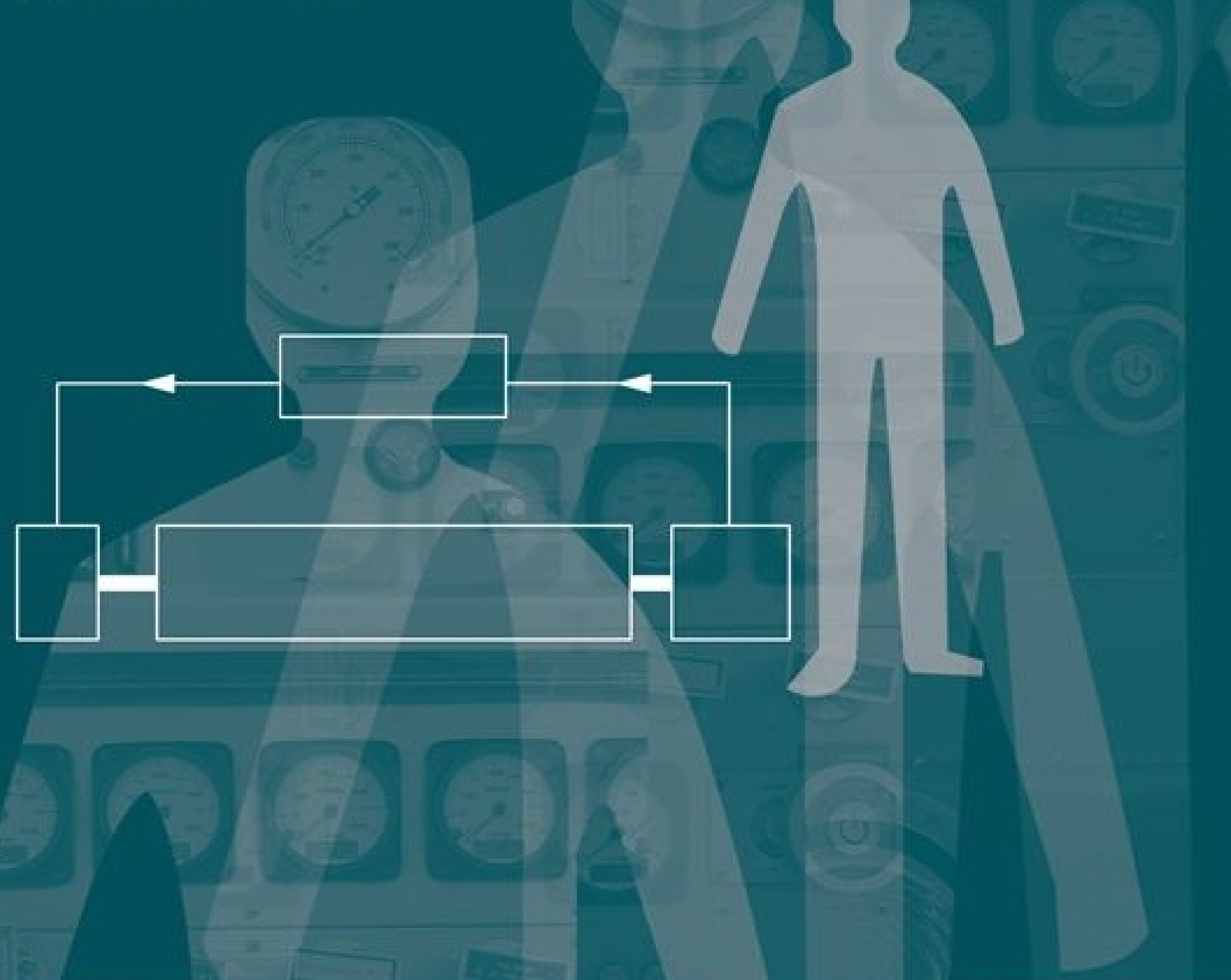
The Condensed Handbook of MEASUREMENT AND CONTROL

3rd Edition

By N.E. Battikha



ISA

Setting the Standard for Automation™

The Condensed Handbook

of Measurement and Control

3rd Edition

N. E. Battikha

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Dedication

This book is dedicated to the pioneers of measurement and control. This technology took its first steps along the Nile Valley about 2600 B.C., when Egyptian engineers began using precise yet simple measuring devices to level the foundation for building the Great Pyramid and employing weirs to measure and distribute irrigation water across the fertile delta. Much more recently, hundreds of dedicated people tinkering in their home and labs, working late at night, and overcoming failures and frustrations, created the powerful computer technology we now rely on.

Without these pioneers, whose first tentative steps thousands of years ago have accelerated into today's full-speed sprint toward on-going advances, the world of measurement and control would not exist and this book would never have been written. And instead of being an I&C engineer, I would have devoted the past three decades to a profession far less interesting and rewarding.

N.B.

About the Author

Nabil (Bill) E. Battikha, P.Eng., has a B.Sc. in mechanical engineering with about 30 years of experience in process measurement and control. He is the president of BergoTech Inc., a firm specializing in process instrumentation and control engineering. Over the course of his career, he has worked for suppliers of control equipment, consultants, and end users and developed experience mainly in engineering, management, and training. He has published two other books with ISA: *The Management of Control Systems* (1992) and *Developing Guidelines for Instrumentation & Control* (1994). He has also written numerous technical articles, co-authored a patent and a commercial software package, and teaches part-time at universities across North America.

PREFACE

This is the third edition of *The Condensed Handbook of Measurement and Control*. Thanks to its readers, the first and second editions were a huge success. In 1997, its first year of publication, the book was awarded ISA's Raymond D. Molloy award as the best-selling book in that year. I sincerely hope that its success will continue—an indication that it is well accepted by the public at large.

The book is directed toward all practitioners in process measurement and control as well as other technical personnel such as project managers, process engineers, and mechanical engineers. I wrote it for specialists in process measurement and control and also to help people with little knowledge of process measurement and control to understand that specialty. Readers can find additional detailed information beyond the level of this book in specialized publications available from ISA, other organizations, and major vendors (whose valuable experience and knowledge is readily available to users).

I wrote this book because I wanted to concentrate the knowledge I learned over the years in a book format and because I felt there is a need for a condensed source that presents information on measurement and control in a clear and concise form. Its condensed format is ideal for everyday use. To the best of my knowledge, there is no other book quite like this one. One of the main difficulties I faced in creating this book was deciding how much detail is required – a task I hope I accomplished successfully. Several books provide a great deal more detail but do not actually provide any more substantial information than this text. Because this is a condensed handbook, readers seeking more information should refer to vendor publications and detailed textbooks (refer to the Bibliography at the end of this handbook).

It may be helpful to describe how the reader can use this book. First, it can be read by anyone seeking to understand the field of process measurement and control, or it can be used as a reference book to be consulted whenever information is required on a certain topic. I have used the content of this book as the basis for teaching courses in these subject areas at a few universities across North America.

I hope that this third edition, like the first two, will guide you in selecting and implementing process measurement and control devices as well as contribute to improving this field of technology. The third edition updates most of the chapters of the first and second editions while adding sections on maintenance, calibration, project implementation and management, consulting, and tools for decision making. In addition, a companion CD is included to facilitate the implementation of this technology.

I have made every effort to ensure that this book is accurate and clear. I would appreciate hearing your comments and suggestions for improving this handbook—they may be used in the next edition.

N. E. Battikha
2006

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CHAPTER 1

INTRODUCTION

What Is Measurement and Control?

Measurement and control is the brain and nervous system of any modern plant. Measurement and control systems monitor and regulate processes that otherwise would be difficult to operate efficiently and safely while meeting the requirements for high quality and low cost.

Process Measurement and Control (also known as *Process Automation*, *Process Instrumentation and Control*, or just *Instrumentation*) is needed in modern industrial processes for a business to remain profitable. It improves product quality, reduces plant emissions, minimizes human error, and reduces operating costs among many other benefits.

The production quantities and requirements define the type of process required to make a certain product. In the process industries, two types are commonly used: continuous process and batch process. Often, a combination of the two processes exists in a typical plant.

The continuous process consists of raw materials entering the process and following a number of operations emerge as a new product. The material throughout the process is in constant movement and each operation performs a specific function.

The batch process consists of raw materials transformed into a new product according to a batch recipe and a sequence. The raw materials typically are fed into reactors or tanks where the reactions occur to produce a new product.

Definitions

automation. A system or method in which many or all of the processes of production, movement, and inspection of parts and materials are automatically performed or controlled by self-operating machinery, electronic devices, and so on.

instrument. Any of various devices for indicating or measuring conditions, performance, position, direction, and the like, or sometimes for controlling operations.

measurement. Extent, quantity, or size as determined by measuring.

Overview

Some measurement and control technologies have evolved rapidly over the past few years, while others have almost disappeared. Instruments presently in use may become obsolete as newer and more efficient measurement techniques are introduced. The emergence of new techniques is driven by the ongoing need for better quality, by the increasing cost of materials, by continuous product changes, by tighter environmental requirements, by better accuracies, by improved plant performance, and by the evolution of the microprocessor-based devices. These technical developments have made possible the measurement of variables judged impossible to measure only a few decades ago.

Effective measurement requires a solid understanding of the process conditions. Selecting the correct measuring and control device is sometimes a challenge even for the most seasoned engineers, technicians, and sales personnel.

This handbook provides the tools to enable users to correctly implement measuring and control systems, which in many cases is an activity not well understood and therefore not successfully implemented. Given the ever-growing demand for measurement and control applications and the wide range of devices on the market, the user must be able to assess different methods of measurement and control and select the most appropriate one. It is not wise to consider only one type of measurement or control since each has its own advantages and disadvantages. The user must compare the different types in terms of which best fits the user's application since many techniques are available for measuring a parameter (such as flow, level, etc.). Making the optimum selection involves considering the requirements of the process, the desired degree of accuracy, the installation, dependability factors, maintenance, and economic factors. Since there is probably no one best method for measuring a specific variable this guide should help the user decide which method is more appropriate for the application.

One final note: when describing the function of instrumentation it is important to ensure that we are using uniform terminology. ANSI/ISA-51.1-1979 (R1993), Process Instrumentation Terminology, includes definitions for many of the specialized terms used in the industrial process industries, such as *accuracy*, *dead band*, *drift*, *hysteresis*, *linearity*, *repeatability*, and *reproducibility.*

Historical Summary

Even a few years ago the scope of process measurement and control was much simpler to define than today. It was referred to simply as "instrumentation." With the advent of software-based functionality and advances in technology in most fields, this specialty has begun to branch out into individual subspecialties.

Process measurement and control, also commonly referred to as "Instrumentation and Control," has evolved from a manual and mechanical technology to, successively, a pneumatic, electronic, and digital technology. This field's exponential growth began after World War II, and its progress toward digitally based systems and devices is still proceeding rapidly today.

We do not know with certainty who invented the field of measurement and control. About 2600 B.C., Egyptian engineers were surely using simple yet precise measuring devices to level the foundation and build the Great Pyramid and to cut its stones to precise dimensions. They also used weirs to measure and distribute irrigation water across the fertile delta. Many centuries later, the Romans built their aqueducts and distributed water using elementary flowmeters.

The pitot tube was invented in the 1600s. The flyball governor for steam engines was invented in 1774 during the Industrial Revolution (with improved versions still in use today). The flyball governer is considered the first application of a feedback controller concept.

In the late 1800s, tin-case and wood-case thermometers and mercury barometers became commercially available. In the early 1900s, pen recorders, pneumatic controllers, and temperature controllers hit the market.

With the advent of World War I, the need for more efficient instruments helped improve and further develop the field of instrumentation. Control rooms were developed, and the concept of proportional, integral, and derivative (PID) control emerged. By the mid-1930s, analyzers, flowmeters, and electronic potentiometers were developed. At that time there were more than 600 companies selling industrial instruments.

In the early 1940s, the Ziegler-Nichols tuning method (still in use today) was developed. World War II was a major influence in moving the field of measurement and control to a new plateau. Pressure transmitters, all-electronic instruments, and force-balance instruments were produced. In the late 1940s and through the 1950s, the process control industry was transformed by the introduction of the transistor. The following also were introduced to the market during this period: pneumatic differential pressure transmitters, electronic controls, and the 4-20 mA DC signal range.

In the 1960s, computers were introduced along with the implementation of direct digital control (DDC) with CRT-based operator interfaces, the programmable logic controllers (PLCs), the vortex meter, and improved control valves. The 1970s brought the microprocessor, distributed control systems (DCSs), fiber-optic transmission, in-situ oxygen analyzers, and the random access memory (RAM) chip.

The 1980s and 1990s saw the advent of the personal computer and the software era, which widened the application of DCSs and PLCs. Neural networks, expert systems, fuzzy logic, smart instruments, and self-tuning controllers were also introduced.

The future of measurement and control is unknown. However, based on present trends, it is expected that the line of demarcation between DCSs and PLCs will continue to disappear, auto-diagnostics and self-repair will increase, artificial intelligence will expand in acceptance and ease of use, and a standard plantwide communication bus system will become the rule. The age of the total integration of digital components—from the measurement to the control system to the final control element—is on the horizon.

Handbook Structure

This handbook is divided into chapters and appendices. Units of measurement are shown in customary U.S. units followed by the SI units in parentheses.

The book is divided into five major parts:

1. Chapters 1 to 14 are for design activities—typically these are the first steps in implementing process control systems.
2. Chapters 15 to 17 deal with the installation, maintenance and calibration of control equipment—these activities typically follow Part 1 above.
3. Chapters 18 and 19 cover project management and decision making tools—an activity that covers both parts 1 and 2.
4. Chapter 20 describes the road to consulting—a subject of interest to experienced practitioners thinking of (or already) providing consulting services.
5. A number of appendices to support all the above chapters.

The following is a further breakdown of each of these parts.

Identification and Symbols

Chapter 2 covers the naming of instruments including the correct functional identification using typical tag numbers. This chapter is based on ISA-5.1-1984 (R1992), Instrumentation Symbols and Identification.

Measurement

Chapters 3 through 7 focus on the measurement of analytical values, flow, level, pressure, and temperature, respectively. Each chapter consists of an overview and a comparison table. These tables provide, in condensed form, the guidance the user needs to select a type of measuring device. For each type of device listed in the tables, a description follows that provides its principle of measurement and related application notes.

Control

Chapters 8 through 12 discuss the control portion of typical control systems. Chapter 8 provides an overview of the different types of control loops, a description of the three elements of a PID controller, and a description of controller settings (i.e., how to tune PID controllers). Chapters 9 through 12 describe, respectively, programmable electronic systems such as DCSs and PLCs, alarms and trip systems, control centers, and enclosures.

Control Valves

Chapter 13 provides an overview of control valves followed by a comparison table that lists the different types of control valves and each valve's different parameters (such as service and rangeability). The chapter includes application notes related to control valves as well as information on valve trim and actuators.

Design and Documentation

Chapter 14 describes the different types of engineering drawings and documents found in a typical instrumentation and control job.

Installation

Chapter 15 covers the installation of instrumentation equipment.

Maintenance

Chapter 16 describes maintenance activities and their management.

Calibration

Chapter 17 covers instrument calibration and its requirements.

Project Implementation and Management

Chapter 18 describes the steps for implementing a project in process instrumentation and controls.

Decision Making Tools

Chapter 19 provides tools and methods to facilitate the decision making process.

Road to Consulting

This last chapter is geared toward practitioners of process instrumentation and controls who are thinking of becoming independent contractors, or who are already working as consultants, and would like to know more about the world of consulting.

Appendices

Unit Conversion Tables

Appendix A provides tables for converting between commonly used SI units and commonly used U.S. units.

Corrosion Resistance Rating Guide

Appendix B will help the user determine the suitability of a particular material when it is in contact with a particular process. The table columns list different materials normally encountered in instruments (e.g., Teflon, neoprene, Hastelloy C, titanium, stainless steel, etc.). The table rows list different fluids (e.g., acetic acid, aluminum chloride, beer, boric acid, etc.).

The Engineering Contractor

Appendix C describes the activities of an engineering contractor on a typical instrumentation and control job.

Packaged Equipment

Appendix D describes the activities of a packaged equipment supplier from the point of view of instrumentation and control.

Typical Scope of Work

Appendix E lists the many engineering activities typically encountered in instrumentation and control work.

Standard Development

Appendix F describes the steps required to develop a set of corporate standards or guidelines.

Typical Job Descriptions

Appendix G provides a set of typical job descriptions for personnel working in the field of process automation.

Sample Audit Protocol and Sample Audit Report

Appendices H and I are related to the auditing activities described in chapter 19.

Selecting Measurement and Control Devices

The instrumentation and control (I&C) designer must first understand the process if he or she is to be able to implement the required control system with the proper instruments. The proper selection of instruments and controls typically involves considering the following:

1. Compliance with all code, statutory, safety, and environmental requirements in effect at the site.
2. Process and plant requirements, including required accuracy and speed of response.
3. Good engineering practice, including acceptable cost, durability, and maintainability.

Selecting instrumentation and control items entails several important aspects other than the specific technology. These include:

- safety
- performance
- equipment location
- air supply
- electrical supply
- grounding
- installation and maintenance

Safety

Safety must be considered a top priority. Improper materials may produce corrosion and material failure that may lead to leakage or major spills. For the same reasons, gasket and seal materials must also be compatible. All measurement and control equipment must be manufactured, installed, and maintained in compliance with the codes when they are located in hazardous areas or in the presence of flammable gases, vapors, liquids, or dusts. ANSI/ISA-12.01.01-1999, Definitions and Information Pertaining to Electrical Apparatus in Hazardous (Classified)

Locations provides a general review of the applicable codes and standards as well as guidance for safe implementation.

Performance

The implementation of measurement and control equipment must meet certain performance requirements as dictated by the user's process needs, such as desired accuracy and turndown capability. A typical measurement and control device has span and zero adjustments capability. The type of output signal required in today's modern devices is either a 4-20 mA output or a bus protocol. In many cases transmitters are specified to be of the indicating type. When indicating transmitters are required, the user should determine whether digital or analog displays are needed, what size the digits should be, and whether to display in percentage or in engineering units.

The accuracy requirement is directly related to the needs of the process. For example, in flow measurement, elbow tap accuracy may reach 10 percent, while on magnetic meters accuracies of ±0.5 percent are common. Thus, two questions arise. What is the accuracy the user requires, and which measuring device can meet this accuracy? It should be noted that this accuracy should be maintained within the process's minimum to maximum operating range (not just at the normal value).

Turndown is the range between the maximum and minimum measurement, an essential parameter when determining which measurement technique to use. For example, flowmeters using orifice plates have a 3:1 turndown, whereas mass flowmeters reach 100:1.

The measurement and control equipment should be capable of handling corrosive environments, both from the process side (e.g., acid fluids) and from the environment side (e.g., sea water spray). In addition, abrasion is caused by solids entrained with the fluid coming into contact with the components of the device. In these environments, the user should choose obstructionless devices or hardened material to reduce such effects.

Additional considerations include the electrical noise, vibration, and shock surrounding the equipment, as well as variations in power supply and their effect on the instrument's performance.

Enclosures must be suitable for the process, for the ambient local conditions, and for the area classification (see chapter 12 for further information).

Equipment Location

All measurement and control equipment should be installed in an easily accessible location (see chapter 15 for further information). In addition, the user must consider both the maximum and minimum ambient temperatures, and the equipment's electronics must be protected from the process temperature. In the case of high process temperature, remote electronics are typically used. The accuracy of the measurement should remain unaffected by temperature variations. For low ambient temperature, winterizing may be required, and the user should assess the potential effects of winterizing failure.

Air Supply

An instrument air system is typically required in most plants. In modern control systems, air is generally used to drive control valves. In most designs, control valves go to their fail-safe positions when the instrument air fails.

There are few cases where, in addition to control valves, measuring devices (i.e., transmitters and controllers) are pneumatic instead of electronic. Their signal range is typically 3-15 psig or

20-100 KPag. Pneumatic control systems are generally used in specially corrosive or hazardous environments and are immune to electrical noise. However, they have a slow system response and have a limited transmission distance. In addition, they cannot communicate directly with computer systems and require air to electronic signal transformation. Their installation cost is relatively high since they cannot be marshaled in groups or networked. In addition, the availability of pneumatic instruments is limited in comparison to their electronic counterparts.

The need for instrument air necessitates some minimum quality requirements. Dirty air will plug the instrument's sensitive pneumatic systems, and moisture can freeze, rendering pneumatic devices inoperable or unreliable. Thus, clean, dry, oil-free instrument air is generally supplied at a minimum pressure of 90 psig (630 kPag) and with a dew point of 20°F (10°C) below the ambient winter design temperature at atmospheric pressure.

An instrument air supply system consists, in most cases, of air generation (i.e, compressors), air drying, and air distribution, which includes an air receiver that protects against the loss of air compression and is independent of any non-instrument air users. This receiver should be sized to provide acceptable hold capacity (e.g., a minimum of 5 minutes) in the event the instrument air supply is lost. Air supply distribution systems generally consist of air headers that have header takeoff points mounted at the headers' top or side to feed the branches.

Air drying is typically done through the use of one of three common types of air dryers:

- refrigerated,
- absorbent (deliquescent desiccant), or
- adsorbent (regenerative desiccant).

A refrigerated air dryer uses mechanical refrigerated cooling. It provides a constant dew point, low maintenance, low operating cost, and is not damaged by oil vapors. However, it has limited dew points. In an absorbent air dryer, a hygroscopic desiccant is consumed and typically requires a pre-filter and after-filter. It has a low initial cost, is simple to use, and has no moving parts. However, its desiccant needs to be replaced periodically, it requires high maintenance, and has a high operating cost. The adsorbent dryer is the most common type used in industrial plants. In this type of dryer, a hygroscopic desiccant is regenerated using alternate flow paths in two towers. This type of dryer also requires a pre-filter and after-filter. The adsorbent dryer has low dew points with a reasonable operating cost. However, it has a high initial cost.

Additional information on instrument air is available from ANSI/ISA-7.0.01-1996, Quality Standard for Instrument air.

Electrical Supply

Electrical power supply is required for all modern control systems. This power supply must conform to the requirements of all regulatory bodies that have jurisdiction at the site.

In most industrial applications, it is particularly important that the quality and integrity of the power supply for process computers and their auxiliary hardware be maintained at a very high level. Such power integrity can be achieved by using properly sized devices such as an on-line uninterruptible power supply (UPS), a ferroresonant isolating transformer, or a surge suppressor. If the process under control would be affected by a power loss of the control system, or if a system outage cannot be tolerated, the user may have to consider a UPS.

UPSs are available in many types and options. The two most common types are on-line and off-line. The on-line type basically converts the incoming AC power to DC and stores it in the batteries—then the battery output is converted back to AC feeding the load. Any power interruption on the incoming side is not felt at the output—in addition, any incoming electrical noise is not passed to the output, thus providing a clean output AC source.

The off-line type charges its batteries and waits until it is required to supply the load, while the control equipment uses incoming raw power. The off-line UPS will power the load when it senses an incoming power failure.

When specifying a UPS, the user needs to ensure that the equipment bears the label of the approval authority (e.g., UL, CSA, etc.). In addition, the user should specify the required discharge rate, discharge time at rated load (e.g., 45 minutes), and recharging time under full load as a percentage of full capacity (e.g., 95%) and at a preset time (e.g., 10 hrs).

Additional features commonly required in industrial UPSs are:

- extra capacity (for future needs),
- the ability to directly use raw on-line power in case the UPS fails,
- local panel displaying incoming AC volts, output indication of AC volts, amps and frequency, and a bypass switch to use raw on-line power,
- remote alarm indication when the UPS fails, when AC is fed from the automatic transfer switch, and when AC is fed from the manual bypass, and
- sealed and maintenance-free batteries to avoid generating hazardous gases emitted by the batteries.

Often, a UPS is installed with two separate service feeders; one feeder for the UPS and the other for the bypass. Where raw power is used (i.e., bypassing the UPS), an isolation transformer is required on the raw power side to reduce the transfer of electrical noise present in the electrical supply system.

For large time-retention capacity, a UPS with a diesel-driven generator is generally provided. This approach avoids having a large number of batteries.

When electronic equipment is connected to a breaker panel (also know as a fuse panel), electromagnetic interference (EMI) noise may travel to sensitive devices. EMI does not easily travel through transformers, hence, isolating transformers are needed to isolate the electronic control equipment from other EMI-generating devices.

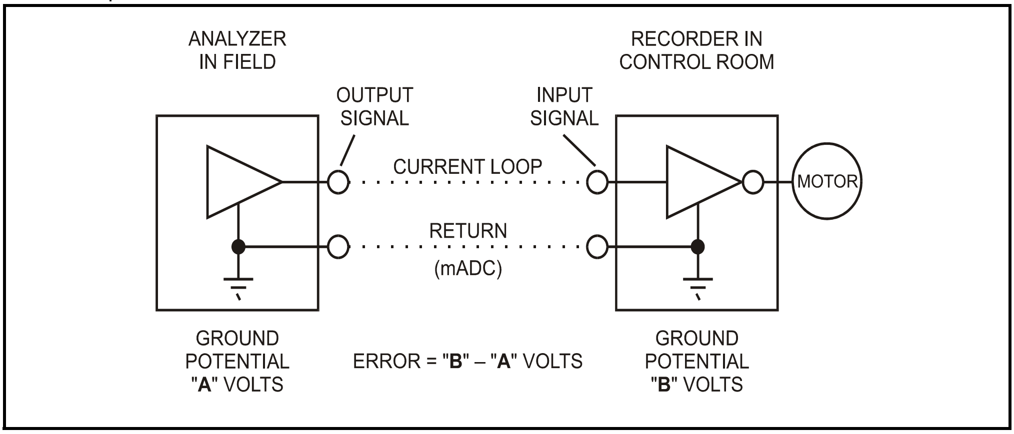
Grounding

Grounding is an essential part of any modern control system. Good grounding requirements help ensure quality installations and trouble-free operations. Users should implement grounding systems in compliance with the code and with the system vendor's recommendations. Many electrical codes accept the use of a conductive rigid conduit to ground equipment. However, electronic equipment necessitates the use of a copper wire conductor to ensure proper operation.

Three grounds need to be considered; power, shield, and signal. Power ground is typically implemented by Electrical Engineering and will not be covered in this book. Proper grounding is vital to the operation of computer-based control systems. Some organizations will involve the control equipment manufacturer in reviewing the detailed grounding drawings to ensure correctness.

When grounding the shield that wraps around a pair of wires carrying the signal, only one end should be grounded. The other end (typically on the field side) should be cut back and taped to prevent accidental grounding. Signal ground should also be grounded at one point only (typically, the point closest to the signal's power source). Multiple signal grounds generally result in ground loops (i.e., grounds at different potentials). Such ground loops add to or subtract from the 4-20 mA signal, introducing an error to the measured signal (see figure 1-1). It may be difficult to eliminate grounds for some devices such as analyzers, grounded thermocouples, and instruments grounded for safety. For these devices, and in situations where more than one ground exists, signal isolators should be used.

Figure 1-1
Ground loop errors.



Installation and Maintenance

The user should determine the capabilities of the plant's in-house maintenance staff when selecting measurement and control devices. Maintenance may need to be done by an outside contractor, in which case the user should determine whether that contractor has the necessary expertise and can reach the site in an acceptable time. Other considerations include the difficulty and frequency of calibration, as well as whether calibration should be done at the site or at the vendor's facilities.

Maintenance is part of the cost of ownership, and the user should consider the cost of high-maintenance items that require specialized equipment and expertise. The frequency of required preventive maintenance should be determined as well as the robustness of the instrument in comparison to its required performance.

Because some installation and maintenance activities require the process to be shut down, it is often necessary to determine whether the measurement and control device can be removed on line and how essential the device is to the ongoing process. In all cases, the measurement and control devices should be accessible from either grade or platform.

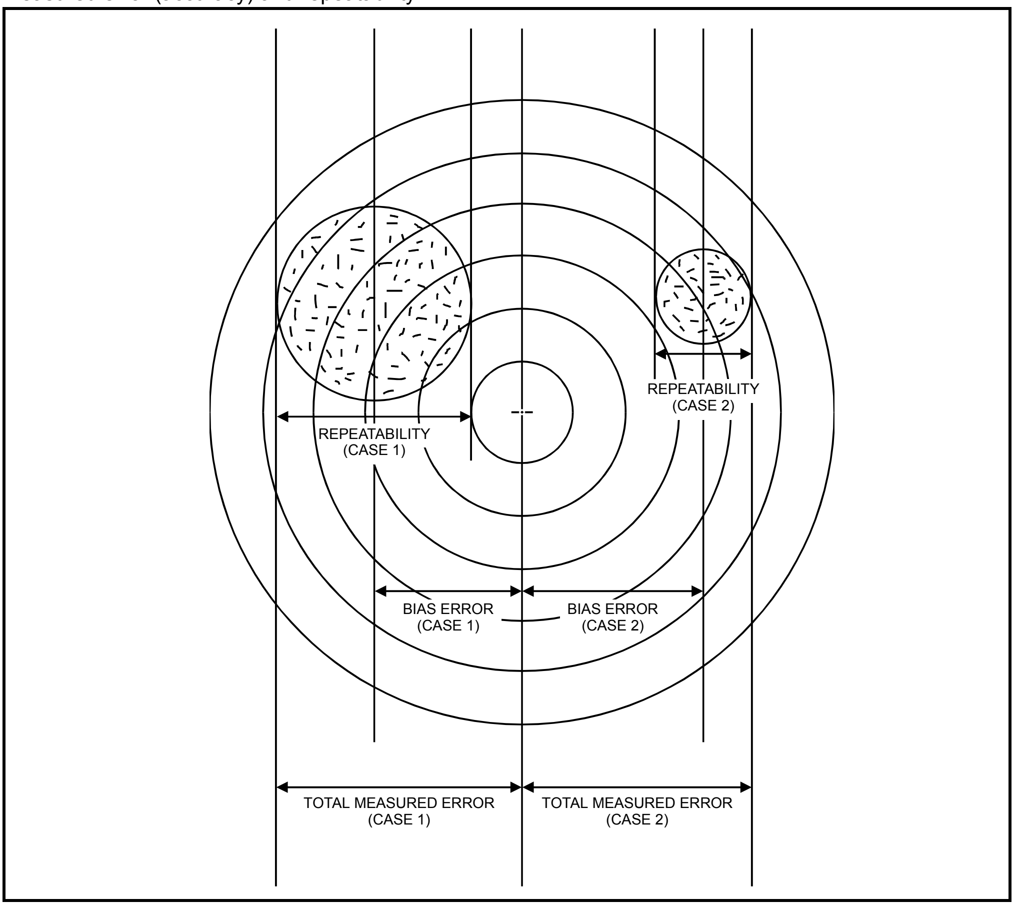
Accuracy and Repeatability

Accuracy and *repeatability* are essential terms in the world of measurement and control. Accuracy (an indication of the measured error) displays the instrument's capability to provide the correct value. Repeatability is the instrument's ability to give the same value every time.

The composite accuracy of a measuring device includes the combined effects of repeatability and accuracy. Unfortunately, this concept is sometimes referred to simply as "accuracy." Yet, without repeatability good accuracy cannot be obtained (see figure 1-2). Where repeatability changes with time or where accuracy is an important factor, good performance will be a direct result of the frequency with which the equipment is calibrated.

It is possible to have good repeatability without good accuracy. The term *repeatability* is an indication of the ability of a measuring device to reproduce a measurement each time a set of conditions is obtained. It does not mean that the measurement is correct, only that the indication is the same each time.

Figure 1-2
Measured error (accuracy) and repeatability.



CHAPTER 2

IDENTIFICATION AND SYMBOLS

Identification

Users of instruments and control systems need some method for identifying equipment so they can manage the engineering, purchasing, installation, and maintenance of such systems. Therefore, one of the key requirements of measurement and control systems is that every device have a unique tag number. An installation's guidelines for these tag numbers should either conform to a company standard or to ISA-5.1-1984 (R1992). Either way, these tag guidelines should be uniform throughout the plant.

The practitioner is advised that, per ISA-5.1-1984 (R1992), identification of instruments is according to function and not construction. Thus, a differential pressure transmitter across an orifice plate in a flow measuring application would be tagged as "FT," not "PDT."

According to the ISA standards, the typical tag number consists of two parts (see figure 2-1): a functional identification and a loop number (e.g., TIC-103). The functional identification consists of a first letter (designating the measured or initiating variable; for example, F for Flow, T for Temperature, etc.) and one or more succeeding letters (identifying the functions performed; for example, I for Indicating, T for Transmitter, C for Controller, V for Valve, etc.). For example, a temperature indicating controller is identified as TIC, a flow transmitter as FT; a temperature recorder as TR, a level controller as LC, and so on.

Figure 2-1
Tag Numbers

		TYPICAL TAG NUMBER
TIC	103	- Instrument Identification or Tag Number
T	103	- Loop Identification
	103	- Loop Number
TIC		- Functional Identification
T		- First-letter
IC		- Succeeding-Letters
		EXPANDED TAG NUMBER
10-PAH-5A		- Tag Number
10		- Optional Prefix
	A	- Optional Suffix

Note: Hyphens are optional as separators

The loop number is unique to each loop and is typically common to all instruments within a loop. For example, if in a loop, a transmitter FT is measuring flow, and a controller FC is controlling a valve FV, then they would all share the same loop number, that is, FT-123, FC-123, and FV-123. See figure 2-4 for further examples.

The total number of letters in a tag number should not exceed four. Identification letters are shown in table 2-1; typical letter combinations are shown in table 2-2. Both tables are based on ISA-5.1-1984 (R1992). For further information, the user should refer to the latest issue of this ISA standard.

Table 2-1
Identification letters.

	FIRST-LETTER (4)		SUCCEEDING-LETTERS (3)		
	MEASURED OR INITIATING VARIABLE	**MODIFIER**	**READOUT OR PASSIVE FUNCTION**	**OUTPUT FUNCTION**	**MODIFIER**
A	Analysis (5,19)		Alarm		
B	Burner, Combustion		User's Choice (1)	User's Choice (1)	User's Choice (1)
C	User's Choice (1)			Control (13)	
D	User's Choice (1)	Differential (4)			
E	Voltage		Sensor (Primary Element)		
F	Flow Rate	Ratio (Fraction) (4)			
G	User's Choice (1)		Glass, Viewing Device (9)		
H	Hand				High (7, 15, 16)
I	Current (Electrical)		Indicate (10)		
J	Power	Scan (7, 24)			
K	Time, Time Schedule	Time Rate of Change (4, 21)		Control Station (22)	
L	Level		Light (11)		Low (7, 15, 16)
M	User's Choice (1)	Momentary (4, 25)			Middle, Intermediate (7,15)
N	User's Choice (1)		User's Choice (1)	User's Choice (1)	User's Choice (1)
O	User's Choice (1)		Orifice, Restriction (23)		
P	Pressure, Vacuum		Point (Test) Connection (26)		
Q	Quantity	Integrate, Totalize (4)			
R	Radiation		Record (17)		
S	Speed, Frequency	Safety (8)		Switch (13)	
T	Temperature			Transmit (18)	
U	Multivariable (6)		Multifunction (12)	Multifunction (12)	Multifunction (12)
V	Vibration, Mechanical Analysis (19)			Valve, Damper, Louver (13)	
W	Weight, Force		Well		
X	Unclassified (2)	X Axis	Unclassified (2)	Unclassified (2)	Unclassified (2)
Y	Event, State or Presence (20)	Y Axis		Relay, Compute, Convert (13, 14, 18)	
Z	Position, Dimension	Z Axis		Driver, Actuator, Unclassified Final Control Element	

NOTE: Numbers in parentheses refer to following explanatory notes.

Notes:

1. To cover unlisted meanings that will be used repetitively. The meanings need be defined only once.
2. To cover unlisted meanings that will be used only once (or used to a limited extent). The meanings must be defined outside the tagging bubble.
3. The grammatical form may be modified as required. Example: “Indicate” may mean “indicator” or “indicating.”
4. A first letter used with a modifier is treated as a first-letter entity. Example: “TDI” for differential temperature.

5. To cover all analysis not described by a "user's choice" letter. The type of analysis must be defined outside the tagging bubble.
6. To be used in lieu of a combination of first letters. Generally used for multipoint recorders/indicators.
7. Using these modifiers is optional. Example: The letters *H* and *L* may be omitted in the undefined case.
8. To cover only emergency protective primary elements, such as a rupture disk (PSE), and emergency protective final control elements, such as a pressure safety valve (PSV).
9. Applies to instruments that provide an uncalibrated view, such as a sight-glass level gage (LG) and television monitors.
10. Normally applies to an analog or digital readout.
11. Used for pilot lights. Example: A running light for a motor may be identified as EL or YL, depending on whether the measured variable is voltage or operating status, respectively. Used also for process indicating light. Example: A high-level light (LLH).
12. Used instead of a combination of other functional letters.
13. Used for hand-actuated switches or on-off controllers. It is incorrect to use the succeeding letters *CV* for anything other than a self-actuated control valve.
14. Used generally for solenoid devices and relays. For other uses, the meaning needs to be defined outside the tagging bubble.
15. These modifying terms correspond to values of the measured variable, not to values of the signal. Example: A high level from a reverse-acting level transmitter should be LAH.
16. The terms *high* and *low* when applied to positions of valves denote open and closed positions, respectively.
17. Applies to any form of permanent storage of information.
18. Used for the term *transmitter*.
19. Used to perform machine analysis (whereas the letter *A* performs more general analyses). Except for vibration, the meaning must be defined outside the tagging bubble.
20. Not to be used when control or monitoring responses are time driven or time/schedule driven.
21. To signify a time rate of change of the measured variable. Example: WKIC means a rate-of-weight-loss indicating controller.
22. Used to designate an operator's control station, such as a manual loading station (HIK), or the operator interface of a distributed control system.
23. Used also to designate a restriction orifice (FO).
24. Used also to designate a temperature-scanning recorder (TJR).
25. Used also to designate a hand momentary switch (HMS).
26. For example, an analysis test point is identified as AP.

These notes are abbreviated. See ISA-5.1-1984 (R1992) for full text.

Table 2-2
Typical letter combinations

First-Letters	Initiating or Measured Variable	Controllers				Readout Devices		Switches and Alarm Devices*			Transmitters			Solenoids, Relays, Computing Devices	Primary Element	Test Point	Well or Probe	Viewing Device, Glass	Safety Device	Final Element
		Recording	Indicating	Blind	Self-Actuated Control Valves	Recording	Indicating	High**	Low	Comb	Recording	Indicating	Blind							
A	Analysis	ARC	AIC	AC		AR	AI	ASH	ASL	ASHL	ART	AIT	AT	AY	AE	AP	AW			AV
B	Burner/Combustion	BRC	BIC	BC		BR	BI	BSH	BSL	BSHL	BRT	BIT	BT	BY	BE		BW	BG		BZ
C	User's Choice																			
D	User's Choice																			
E	Voltage	ERC	EIC	EC		ER	EI	ESH	ESL	ESHL	ERT	EIT	ET	EY	EE					EZ
F	Flow Rate	FRC	FIC	FC	FCV, FICV	FR	FI	FSH	FSL	FSHL	FRT	FIT	FT	FY	FE	FP		FG		FV
FQ	Flow Quantity	FQRC	FQIC			FQR	FQI	FQSH	FQSL			FQIT	FQT	FQY	FQE					FQV
FF	Flow Ratio	FFRC	FFIC	FFC		FFR	FFI	FFSH	FFSL						FE					FFV
G	User's Choice																			
H	Hand		HIC	HC						HS										HV
I	Current	IRC	IIC			IR	II	ISH	ISL	ISHL	IRT	IIT	IT	IY	IE					IZ
J	Power	JRC	JIC			JR	JI	JSH	JSL	JSHL	JRT	JIT	JT	JY	JE					JV
K	Time	KRC	KIC	KC	KCV	KR	KI	KSH	KSL	KSHL	KRT	KIT	KT	KY	KE					KV
L	Level	LRC	LIC	LC	LCV	LR	LI	LSH	LSL	LSHL	LRT	LIT	LT	LY	LE		LW	LG		LV
M	User's Choice																			
N	User's Choice																			
O	User's Choice																			
P	Pressure/ Vacuum	PRC	PIC	PC	PCV	PR	PI	PSH	PSL	PSHL	PRT	PIT	PT	PY	PE	PP			PSV, PSE	PV
PD	Pressure, Differential	PDRC	PDIC	PDC	PDCV	PDR	PDI	PDSH	PDSL		PDRT	PDIT	PDT	PDY	PE	PP				PDV
Q	Quantity	QRC	QIC			QR	QI	QSH	QSL	QSHL	QRT	QIT	QT	QY	QE					QZ
R	Radiation	RRC	RIC	RC		RR	RI	RSH	RSL	RSHL	RRT	RIT	RT	RY	RE		RW			RZ
S	Speed/Frequency	SRC	SIC	SC	SCV	SR	SI	SSH	SSL	SSHL	SRT	SIT	ST	SY	SE					SV
T	Temperature	TRC	TIC	TC	TCV	TR	TI	TSH	TSL	TSHL	TRT	TIT	TT	TY	TE	TP	TW		TSE	TV
TD	Temperature, Differential	TDRC	TDIC	TDC	TDCV	TDR	TDI	TDSH	TDSL		TDRT	TDIT	TDT	TDY	TE	TP	TW			TDV
U	Multivariable					UR	UI							UY						UV
V	Vibration/Machinery Analysis					VR	VI	VSH	VSL	VSHL	VRT	VIT	VT	VY	VE					VZ
W	Weight/Force	WRC	WIC	WC	WCV	WR	WI	WSH	WSL	WSHL	WRT	WIT	WT	WY	WE					WZ
WD	Weight/Force, Differential	WDRC	WDIC	WDC	WDCV	WDR	WDI	WDSH	WDSL		WDRT	WDIT	WDT	WDY	WE					WDZ
X	Unclassified																			
Y	Event/State/Presence		YIC	YC		YR	YI	YSH	YSL				YT	YY	YE					YZ
Z	Position/Dimension	ZRC	ZIC	ZC	ZCV	ZR	ZI	ZSH	ZSL	ZSHL	ZRT	ZIT	ZT	ZY	ZE					ZV
ZD	Gaging/Deviation	ZDRC	ZDIC	ZDC	ZDCV	ZDR	ZDI	ZDSH	ZDSL		ZDRT	ZDIT	ZDT	ZDY	ZDE					ZDV

Note: This table is not all-inclusive.
*A, alarm, the annunciating device, may be used in the same fashion as S, switch, the actuating device.

**The letters H and L may be omitted in the undefined case.

Other Possible Combinations:

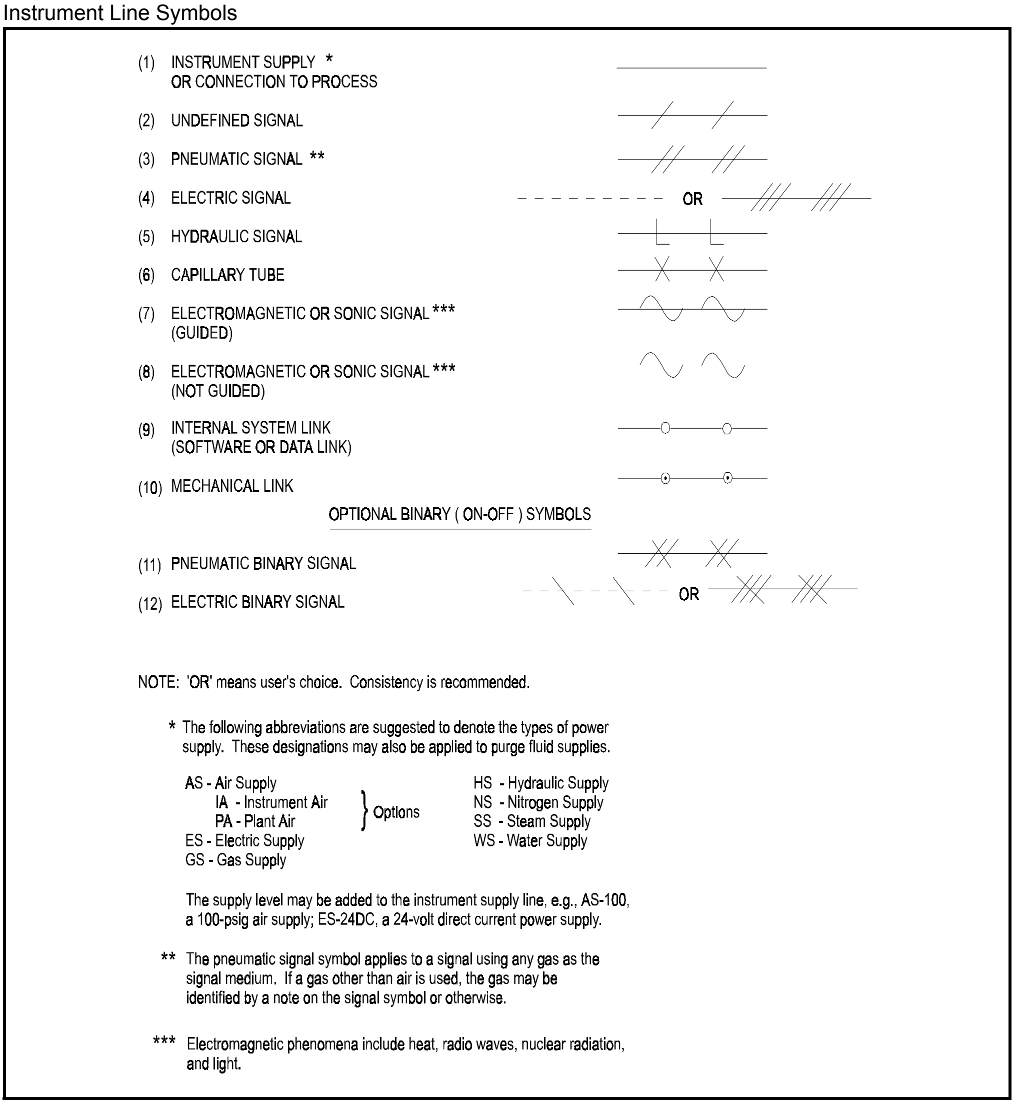
FO	(Restriction Orifice)	PFR	(Ratio)
FRK, HIK	(Control Stations)	KQI	(Running Time Indicator)
FX	(Accessories)	QQI	(Indicating Counter)
TJR	(Scanning Recorder)	WKIC	(Rate-of-Weight-Loss Controller)
LLH	(Pilot Light)	HMS	(Hand Momentary Switch)

Instrument Line Symbols

On any drawing, symbols should remain consistent throughout the drawing to avoid confusion. Typical line symbols are shown with a lighter-weight line than are process lines.

In identifying an electric signal, the user should choose either the dashed-line symbol or the triple cross-hatch symbol and apply it consistently (the author prefers the dashed-line symbol). On any given set of documents internal consistency is strongly recommended. Instrument line symbols are shown in figure 2-2 and are taken from ISA-5.1-1984 (R1992).

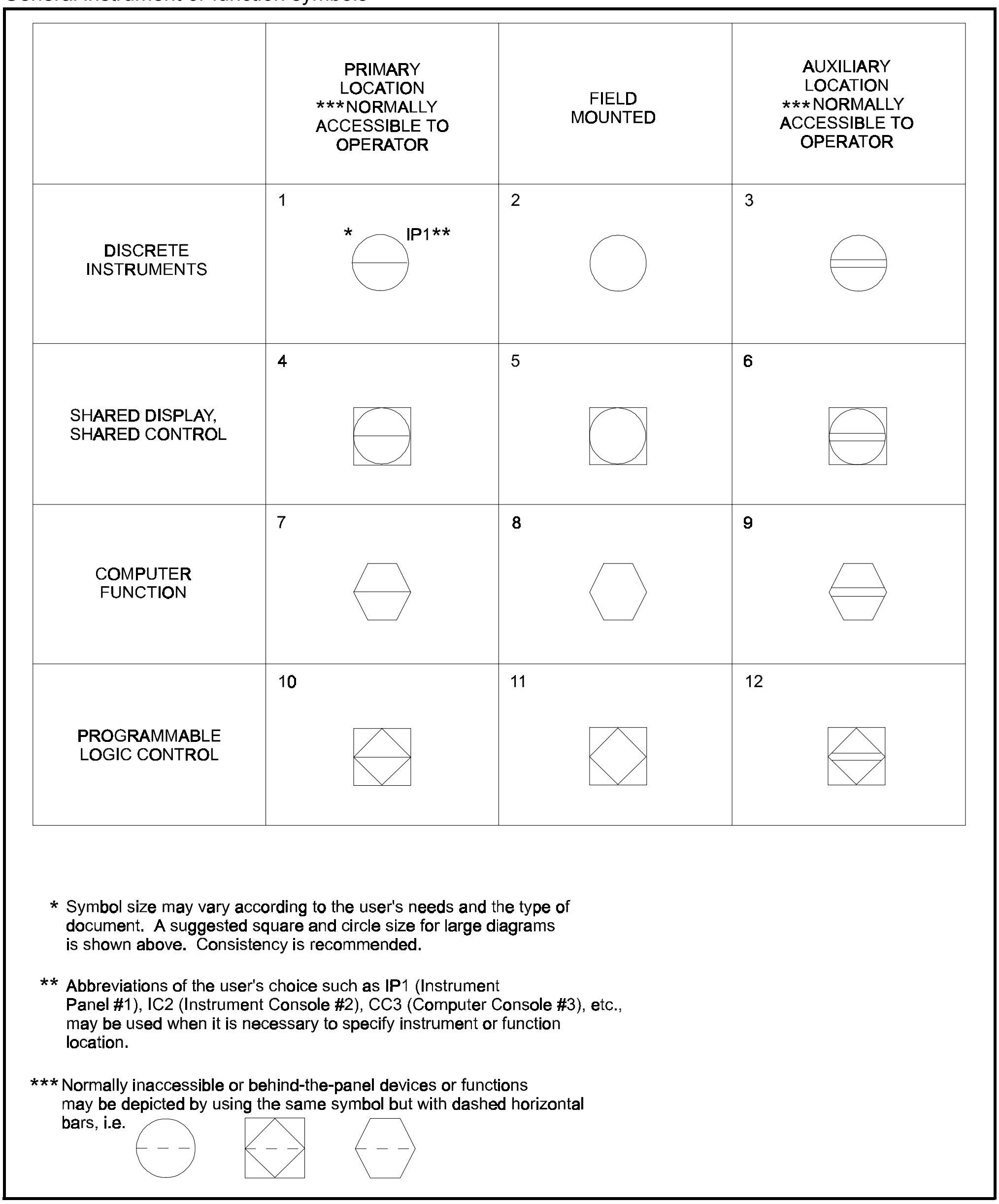
Figure 2-2
Instrument Line Symbols



General Instrument or Function Symbols

General instrument or function symbols identify the location and function of an instrument. They are shown in figure 2-3 and are taken from ISA-5.1-1984 (R1992).

Figure 2-3
General instrument or function symbols



Examples of how symbols should be used are shown in figure 2-4. Figure 2-5 shows the degree of detail typically shown on a diagram.

Figure 2-4a
Examples of symbol usage.

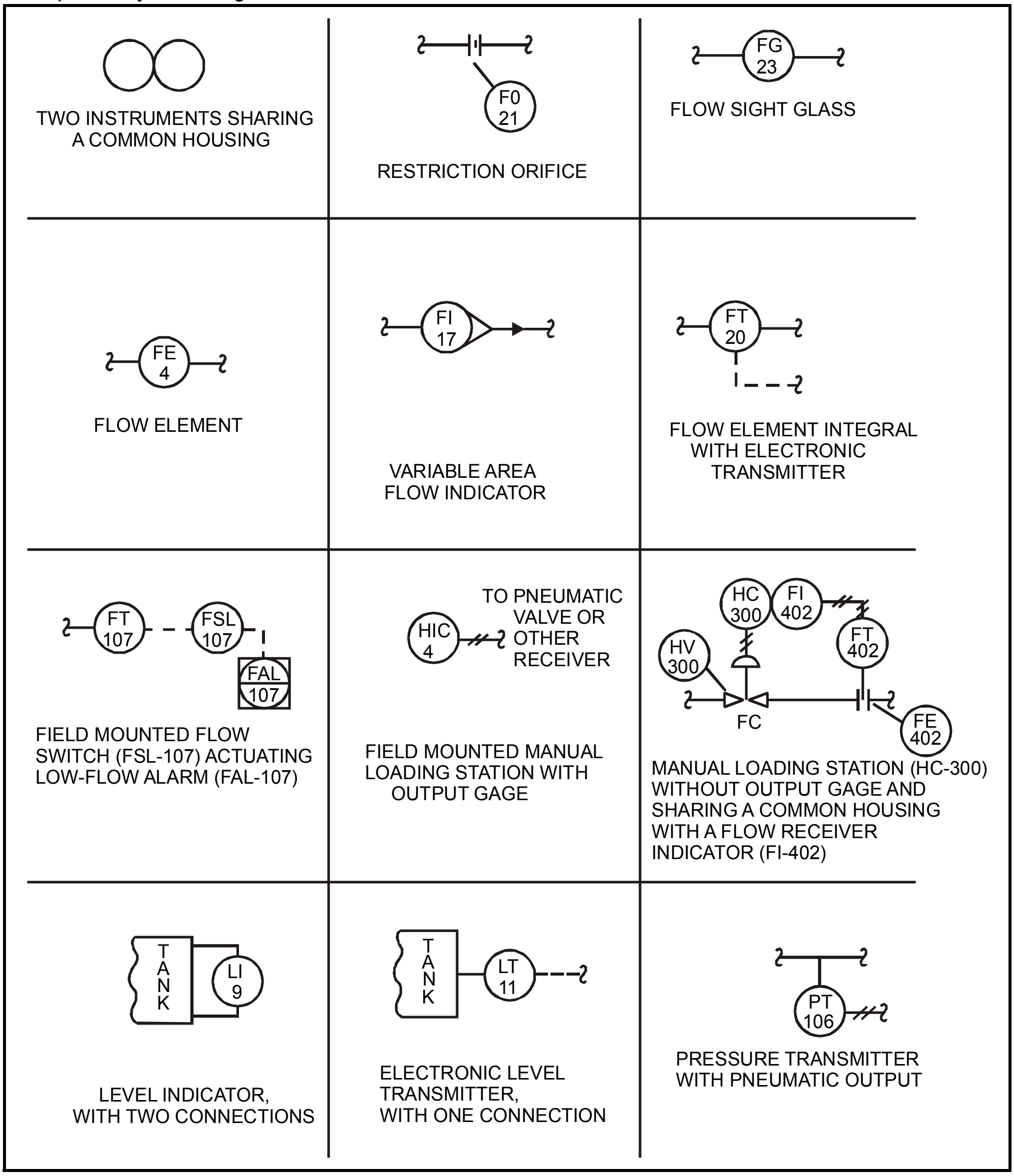


Figure 2-4b
Examples of symbol usage.

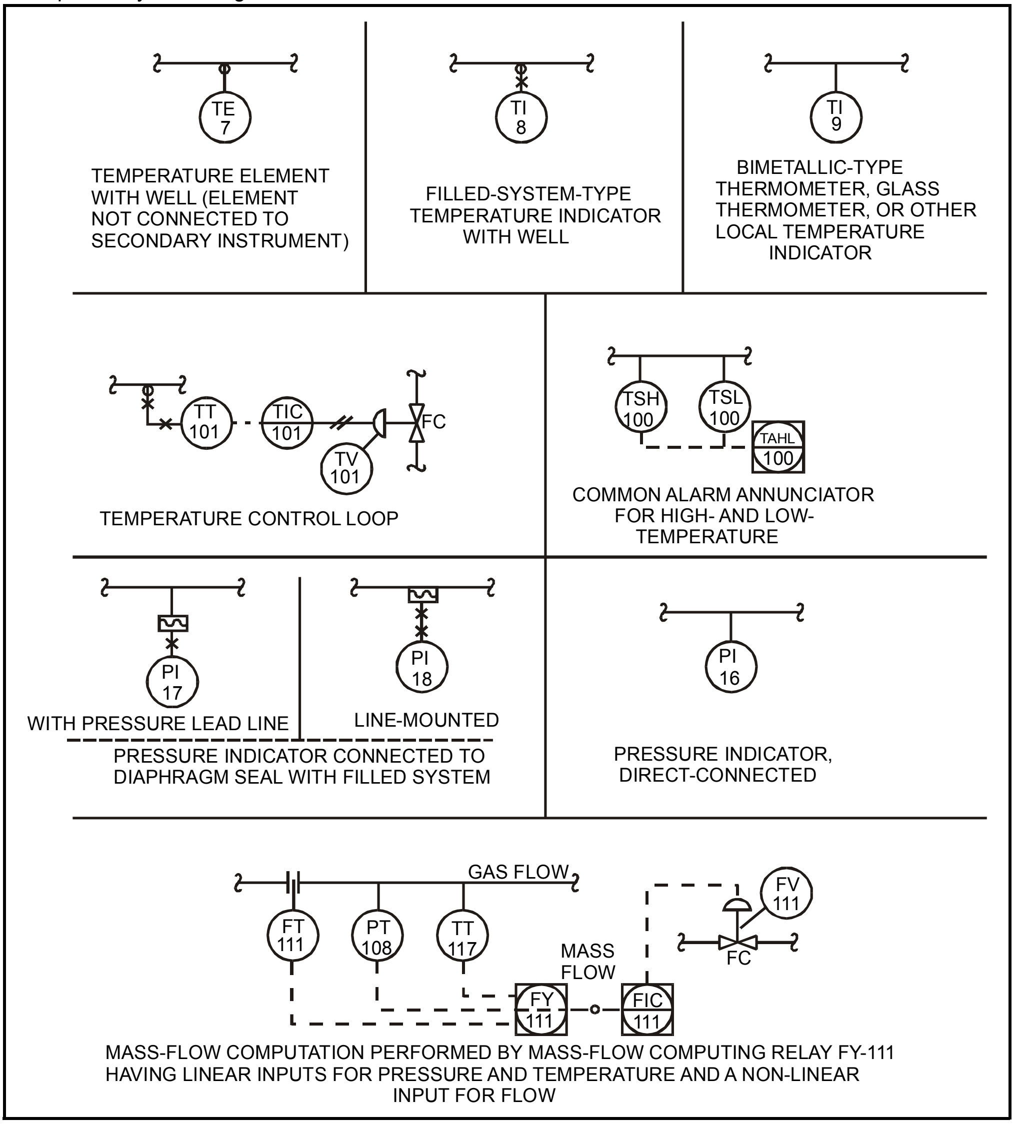


Figure 2-4c
Examples of symbol usage.

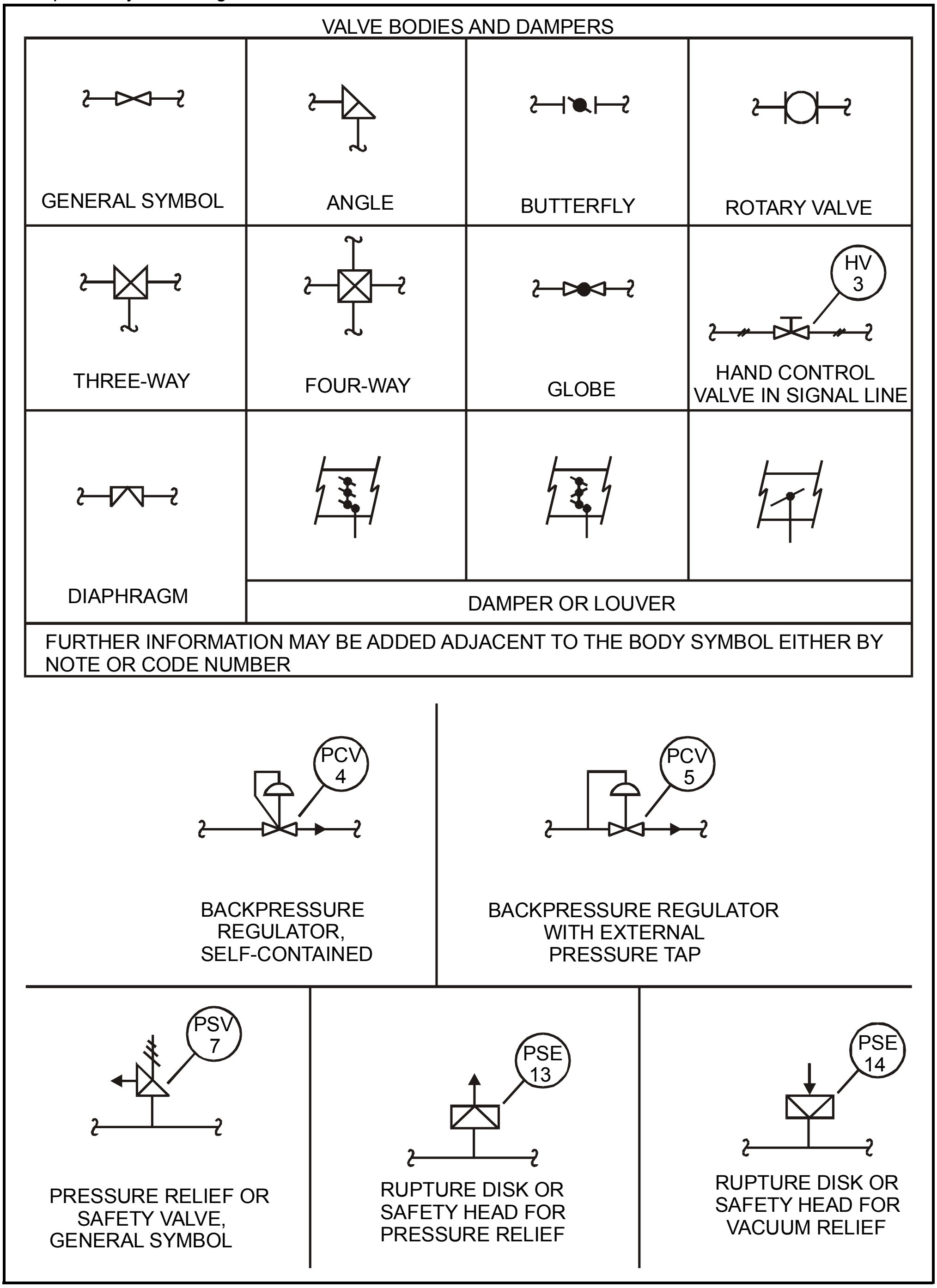
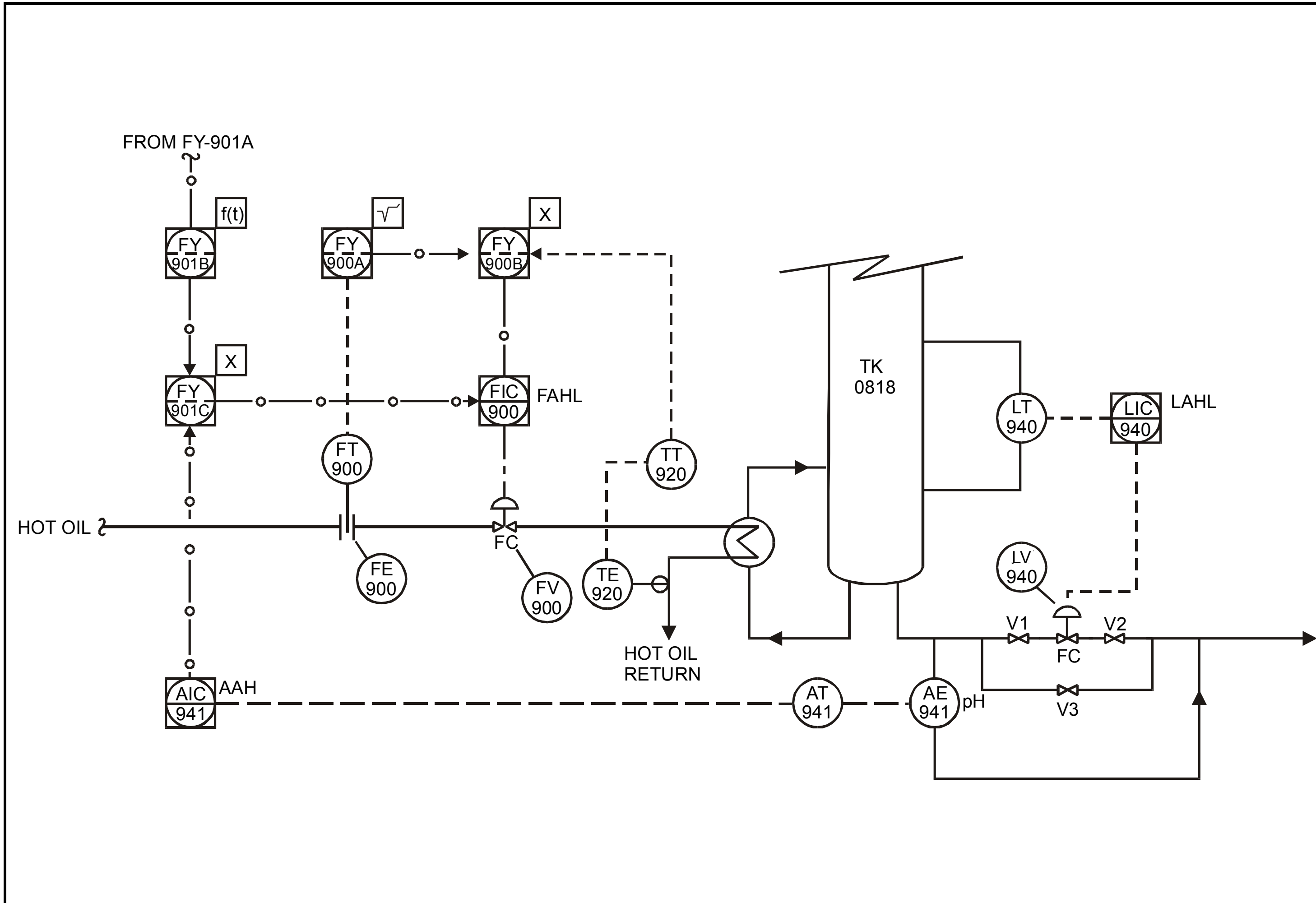


Figure 2-5
Example showing the degree of detail.



CHAPTER 3
ANALYZERS

Overview

Analyzers are used to measure analytical values. The most frequently used analyzers in the process industries are pH and conductivity analyzers. Of all the typical measurements, such as flow, level, pressure, and so on, process analysis tends to be the most difficult, the least understood, the most troublesome, the most expensive, and the most difficult to maintain. It is therefore imperative that the user handles process analysis carefully and gives it the time (and money) required for a successful installation. Laboratory and portable analyzers will not be discussed in this handbook.

When selecting an analyzer, the user should preferably choose a time-proven off-the-shelf device. Custom-built analyzers tend to have debugging problems and lead to difficult and expensive maintenance.

The cost of implementing an analyzer system is typically much higher than the cost of the analyzer itself. An analyzer system may include a sample probe, a sample line, a shelter, sample disposal equipment, and calibration gases. In addition, ongoing maintenance costs includes the cost of maintenance personnel and their training, the replacement of calibration gases, the cost of the calibrating equipment, and utilities.

Location

When deciding upon the location of an analyzer, there are two possibilities: extractive and in-situ. Some analyzers are mounted remotely from the sample point; these are known as "extractive" analyzers. This approach is implemented when the process conditions are severe, when the sample point is practically inaccessible, or when the analyzer's capabilities require it (e.g., it is not built for an industrial environment). Extractive-type analyzer systems draw a sample from a remote location through a sample line to the analyzer. Such systems are also used where many analyzers are sampling a single process, and the sample can therefore be shared by more than one analyzer. Extractive systems typically require a probe, a sample line (sometimes heat traced), a pump, filters, sample line flushing, a means for calibration, and other miscellaneous equipment. The cost of extractive systems is much higher than in-situ systems. They also require more maintenance.

When extractive analyzer systems are implemented, they are typically assembled in a controlled environment by a specialized vendor in a specialized shop. This provides a better-quality final product. These preassembled systems are normally tested before being shipped to site, minimizing startup problems.

Analyzers that are mounted in line are referred to as "in-situ" analyzers. With in-situ types, the instrument analyzing the sample is at the process and does not have to extract a sample. This eliminates all the sampling problems, and measurement can be achieved without the time delay created by sample lines.

Tagging

Tagging is required to identify all parts of an analyzer system, including all components of the sample system, valves, switches, circuit breakers, field connection points, and gas cylinder connection points. The tagging information is typically identified on nameplates that are attached with stainless steel screws or wire (refer to chapter 2 for further details on the tagging of instruments). Attaching the nameplates with adhesive is an acceptable alternative for temperature-controlled environments.

Implementation

It is important that the user prepares a technical specification that covers every component of an analyzer system. This specification should include the system's design, fabrication, supply, installation, and startup. It is generally expected that the system vendor will furnish all the material needed for a complete and workable system.

The user needs to define the following in the technical specification to ensure a good match between the supplied analyzer system and the plant requirements:

- A description of the process and a tag number for the analyzer(s)
- The components to be measured, with the range of measurement and the required accuracy
- The concentration of all other components and contaminants in the sample stream (even if only traces), with their expected range
- The conditions of the process, that is, the minimum, normal, and maximum range for temperature and pressure
- The materials of construction in contact with the sample that can (or cannot) be used
- The physical state of the sample, that is, liquid, gas, and so on.
- The hazards of the sample
- The electrical area classification
- The available power and utilities (such as instrument air)
- The environmental conditions (ambient temperature, corrosive environment, dusts, vibration/shock, etc.)
- The type of measurement, that is, continuous or intermittent—and at what interval?
- The analyzer response time versus the time required by the process
- The warm-up time for the system following a restart, and the frequency that the analyzer is expected to shut down
- The requirements for analyzer output signal (e.g., 4-20 mA, RS232C, etc.) and display (analog or digital? local and/or remote?)
- The need for a sample probe and sample line
- The required analyzer(s)
- The enclosure that will contain the sampling systems, the analyzers, the exhaust system; will it consist of either a climate-controlled walk-in enclosure (known as the shelter) or a cabinet?
- The calibration system (such as gas cylinders with regulators)
- When required, a strip-chart recorder or connection to a data collection system to continuously record the analyzed value(s)

For most analyzer applications, it is good practice for the user to discuss the requirements and implementation with one or more reputable suppliers. Both the plant and vendor must work closely to ensure a successful implementation.

The plant's responsibilities typically encompass the following:

- Specify the process data and system requirements by preparing the technical specification.
- Review all vendor designs. It should be noted here that unless plant personnel are very experienced in the application of analyzer systems, the system vendor must be made

responsible for the design, implementation, and overall suitability of all components for performing the required analysis.
- Witness the testing at the system vendor's facilities.
- Install the enclosure and sample line. The system vendor may connect both ends of the sample line.
- Connect to the structure's grounding.
- Install and terminate all power and signal cables.
- Install and connect all utility piping

The system vendor's responsibilities typically include the following:

- Provide a qualified project engineer who will work closely with the plant engineer for the duration of the project. The system vendor may be required to submit the project engineer's résumé for the plant's approval at the bidding stage. A relationship with the vendor's designated engineer should be maintained until the project's completion.
- Prepare and submit a schedule showing complete detailed activities, starting with the verification of the analyzer specifications and continuing until the field checkout and final acceptance of the system. This schedule should be updated regularly, with the frequency depending on the project's requirements.
- Develop complete installation and electrical drawings showing all material being used, the power source required, wire sizes, terminal designations, wiring by the plant, circuit breaker values, and so on. Drawings should be submitted for the client's review.
- Prepare a bill of material for all equipment, using the names and model numbers of the original manufacturers.
- Finalize the design and submit final drawings.
- Specify and purchase all auxiliary equipment, as applicable, for a complete, fully functional analyzer system. This includes tube fittings, terminal blocks, and the like.
- Expedite all purchases.
- Construct the system.
- Notify the plant in writing when the system is fully operational and ready for testing at the vendor's facility.
- Provide the initial set of cylinders of calibration and consumable gases; they are to remain the property of the plant.
- Conduct a thorough system test, with plant personnel in attendance.
- Arrange and prepare all equipment for shipment.
- Prepare and submit final documentation.
- Make available qualified personnel to supervise the field installation.
- Install the sample probe and connect it to the sample line.
- Make all connections from cylinders to the cabinet and connect the sampling line to the cabinet.
- Prior to startup, do a complete mechanical, loop, and electrical check (with sample line in operation).
- Start up all analyzers and sampling trains.
- Calibrate all instruments and provide the final calibration results to the plant.
- Conduct operation and maintenance training classes at the plant.
- Perform system checkout and startup, with plant personnel in attendance.
- For new plants, provide a qualified person to return to the plant to assist during process startup.

In most applications, the bidders are required to supply, as a minimum, three references that have similar process applications (with a contact name and phone number) as well as a service support plan with expected response time and personnel availability. The plant's personnel should contact these references to confirm the vendor's capability.

Safety

It is imperative that the measurement and control system be installed safely. Therefore, the following steps should be taken:

- Insulate all high-temperature equipment (i.e., sample lines, heat-traced system components, electrical connections, etc.) to protect personnel. Hot lines or analyzers, which cannot be insulated, must have guards placed around them to prevent possible injury.
- Provide a means to flush the sample system components for repair or replacement. Note that there may be no sewer, and the only means of disposal may be a suitable container and/or pump-out system.
- Atmospheric vent lines should be adequately sloped to the vent bulkhead to avoid trapping condensate. This bulkhead should have a drain at its lowest point.
- Design the sampling system to minimize the volume of hazardous gases (toxic or flammable) entering the analyzer enclosure. Suitable flow restrictions should be provided between the analyzer enclosure and the supply source of hazardous gases. This includes the supply of calibration gases.
- Use relief valves (or bursting disks) in cases where the failure of a part could cause an analyzer or sample system component to over pressurize.

Code Compliance

The implemented system, including all design, equipment, and installation, must comply with the statutory and regulatory requirements that are in effect at the site. These requirements may include, for example, the latest edition of the National Electrical Code® (NEC®), Canadian Safety Association (CSA), Environmental Protection Agency (EPA), National Fire Protection Association (NFPA®), and the latest edition of ISA's *Standards Library for Automation and Control*. Typically, it is the vendor's responsibility to ensure that the supplied system meets such requirements. In addition, the installation must also meet the specific requirements of the local authorities. These may include analyzer performance (accuracy, drift, response time, etc.).

All electrically operated instruments, or the electrical components of any instrument, should be approved and bear the approval label (UL, FM, CSA, etc.). The plant's maintenance personnel should remember that any modifications they make to approved equipment may void that approval.

Selection

When selecting an analyzer, the user must assess the effects of power loss and power restart as well as the required startup time. Startup time is defined as the time interval between the moment when the system is switched on (power and sample) and the analyzer(s) generates an output that indicates the analyzed value(s). Switching the system on includes switching on other utilities (such as instrument air) and bringing the sample-handling system and all system components to a working condition within the stated limits of performance. The vendor is expected to advise what the startup time is, and the plant should check that this time conforms with the process requirements.

The analyzer system typically provides output signals to the plant control system to indicate analytical values, to signal alarms, or to initiate the shutdown of the process. When the link to the plant control system is digital, the plant user must ensure that the communication protocol is an off-the-shelf item. Custom software that has never been used before tends to take longer to develop than originally planned and tends to have a longer than anticipated debugging period.

Analyzer outputs are sometimes sent to a chart recorder to conform to environmental regulations that require a continuous and direct link to the analyzer(s). Hardwired alarm contacts for the analyzer system, identifying component failure, should be tied into a common trouble alarm. This common alarm might activate a red beacon located on top of the enclosure and provide a contact that is to be connected to the plant's control system (see the subsection "System Alarm" in the section titled "Enclosures" later in this chapter).

Where the user needs to measure stack flow many methods are available (see chapter 4 on flow measurement). In all cases, the location of the measuring device should be immune to the effects of pulsating or cyclonic flow. Typically, one of the following three methods is used:

- *Differential pressure.* Frequent blowback may be required when using this method to prevent probe plugging. An averaging pitot tube is commonly used. If a single pitot tube is recommended, the bidders and the plant must assess its advantages.
- *Thermal.* When using this method, the system designer should consider the effects of particulate buildup on the sensors, water droplets causing a bias due to evaporation, and acid droplets corroding the probe.
- *Ultrasonic.* In environments where transducers are exposed to the process, buildup on sensors must be avoided. It may be necessary to use blowers to keep the transducers clean.

There are many analyzers on the market today. Different analyzers are capable of measuring the same component. When selecting an analyzer the user must evaluate such parameters as the following:

- The analyzer's individual characteristics
- Its cross sensitivity with other components in the stream or sample
- Its range, accuracy, and speed of response
- Its cost
- The plant's experience with a particular analyzer
- The plant's working relationship with a particular supplier and that supplier's capabilities

Most analyzers can be divided into family type. The most common ones are: physical property, electrochemical, spectrophotometric, and composition.

Physical property analyzers use a measurement technique that provides data correlated to a laboratory measurement. These analyzers include capillary tube, rotating disk, thermal conductivity, and vibrating U-tube.

Electrochemical analyzers typically use electrodes to measure ions, such as pH-measuring hydrogen ions. These analyzers include the following types: amperometric, catalytic, conductivity, polarographic, and zirconia oxide.

Spectrophotometric analyzers are based on the phenomenon whereby molecules in a sample stream absorb light at specific frequencies. These analyzers include the following types: chemiluminescence; infrared absorption, including Fourier transform infrared (FTIR) and nondispersive infrared (NDIR); and ultraviolet (UV).

Composition analyzers are based on the separation and measurement of components in a process stream. These analyzers include flame ionization analyzers, gas chromatographs, and mass spectrometers.

Documentation

Plants need vendor-supplied technical manuals. A minimum of three copies is typically required, one for engineering, one for maintenance, and one to be left at the analyzer enclosure.

The manual's content should cover the technical information for all analyzers, accessories, enclosures, and sampling system, namely:

- A drawing showing the complete analysis system, with a flow schematic of the sample systems and analyzers and a list of all material components (especially the ones that come into contact with the sample fluid)
- Specification sheets and cut sheets for the analyzer(s), the sample system hardware, and all other associated hardware, as well as their limit conditions of operation, storage, and transport
- Installation, operation, and maintenance instructions for each piece of equipment, including calibration and troubleshooting procedures
- Startup, operating, and shutdown instructions
- A description of the logic required to blow back the sample system and calibrate the analyzer
- All wiring schematics
- Factory sample calibration data reports
- A parts list(s) and recommended spare parts list(s), including prices and lead times

Sampling Systems

Sampling systems provide a representative sample from the process to the analyzer(s). They are an essential part of any extractive-type analyzer and typically the most troublesome part when they are implemented improperly. An integral part of the sampling system is the instrumentation necessary to ensure the sampling system's proper functioning or to facilitate maintenance work.

The sampling system extracts a sample, transports it to the analyzer(s), conditions it to the analyzer's capabilities, and finally exhausts the stream to a safe disposal point. A sampling system should not alter the sample, should be leak free, and quite often should maintain the sample within a set temperature and pressure range. Most sampling systems also can do zero and span calibrations of the analyzer they are connected to. The materials used in the sampling system must not react with the sample, absorb components of the sample, or transfer contaminants through osmosis. The sampling system must avoid polymerizing, stratifying, or contaminating the sample.

Depending on the sample to be analyzed, the sampling system must sometimes reduce (or increase) the temperature or pressure of the sample, restrict and/or filter flow, or wash and/or dry the sample. Sometimes, vapor samples are heated to prevent condensation. In other cases, liquid samples are vaporized. A sampling system may remove or alter material that may plug or corrode the analyzer, but it should not alter the variable component to be measured. The composition and the physical state of the fluid in the sample line can only be allowed to change in a predictable way.

To provide good system response, sampling lines must be kept at a minimum length and provide a sufficient flow rate to each analyzer. The volume of the sample system should be kept at a minimum, and the sample flow velocity should be kept high, typically, about 5 to 10 ft/sec (1.5 to 3.5 m/sec). Where possible, the sample system should be provided with the necessary flow, temperature, and pressure indicators to determine whether the sample conditions required by the analyzer system are met. The sampling system must not create an unsafe or flammable condition.

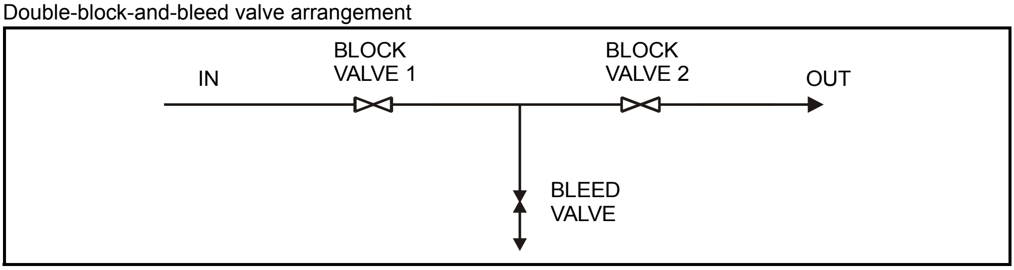
Any sample line that enters an enclosure should be fitted with a fixed restrictor mounted outside the enclosure. The line should be sized to limit the full release flow from a fractured sample line in the enclosure to a calculated safe level matched to the house ventilation flow.

Adjustable valves should not normally be used in place of fixed restrictors since they can be easily modified. Lines that carry hazardous fluid should have automatic isolation valves to shut off the sample line in case the enclosure's ventilation fails.

If required, dilution extractive systems can be used. These systems dilute the sample with an inert fluid at a known ratio. This approach reduces problems with sample handling; however, it increases the complexity of the sampling system and reduces the sample sensitivity (since it is diluted). These systems should be designed to maintain a constant flow, temperature, and pressure for the dilution fluid.

The plant may have to employ automatic switching to share one sample among many analyzers or to have different samples analyzed by one device. Switching is typically accomplished by using solenoid valves. However, these valves may leak. If this is unacceptable, the plant will need to use a double-block-and-bleed valve arrangement (see figure 3-1).

Figure 3-1
Double-block-and-bleed valve arrangement



In most applications, a logic is required in order to blowback and calibrate the system. This is generally supplied by the analyzer system vendor as part of the total analyzer package. In most cases, clean and dry instrument air, typically regulated at a preset pressure, is required for blowback. If instrument air is not available, then the plant may have to use high-quality bottled air or a compressor/dryer combination.

To permit effective isolation, the plant may need to install suitable block valves immediately downstream of the sample take-off point, at the inlet and outlet of the analyzer, and in the sample return line. In addition, the application may require a sample connection for lab checking just upstream of the analyzer. This makes possible direct correlation between the analyzer output and the lab results (an effective and rapid method of analyzer validation and troubleshooting).

Sample Point

The sample point location should be selected so as to provide a sample that is clean, measurable, and representative. Good access for maintenance personnel is a must, and an access platform may have to be provided where needed.

The location for a sample point should be selected so as to prevent plugging and to reduce entrainment in the form of liquid droplets for gaseous streams or gas bubbles in liquid streams. The plant may have to use traps, filters, separators, and even scrubbers to remove harmful or signal-disruptive entrained contaminants. The sample point internal diameter should be large enough to prevent blockage.

The sample point should be immune from the effects of flow stratification. Cross-sectional multi-point extraction, vanes, or baffles may be required. The sample point must be representative of the cross-sectional area being measured, and its location should avoid multi-phase streams.

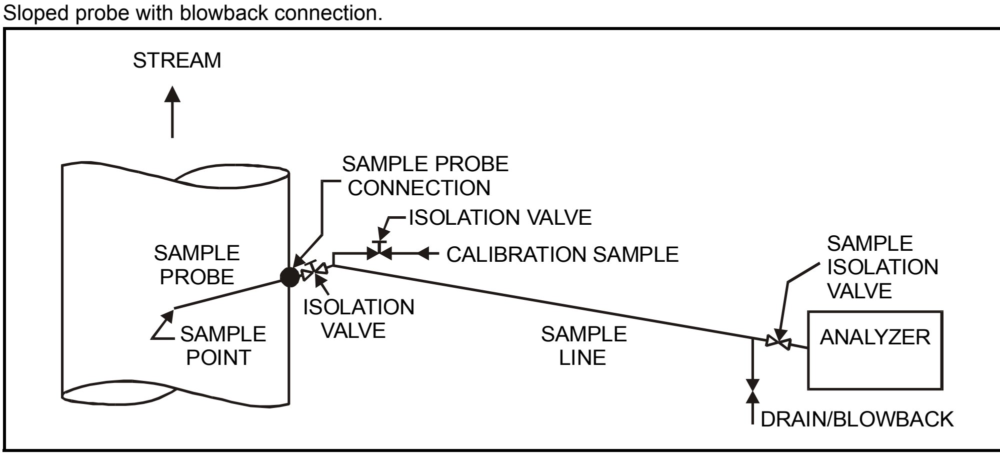
Where a Continuous Emission Monitoring System (CEMS) for a stack is required, the sample point location must conform with local regulations regarding the number of stack diameters upstream and downstream of a sample point. Typically, the sample point is located eight diameters after the inlet breach to ensure good mixing and two diameters below the stack exit to avoid atmospheric contamination.

Sample Probe

Where it is necessary to use a sample probe for the sample stream, a full-bore block valve is generally required for isolation. The probe must be made of a material that will not corrode, be long enough to obtain an accurate sample, be located so as to minimize fouling, and be accessible (i.e., an access platform may be required). It is important to assess whether doors will be needed to allow the insertion, maintenance, and retraction of probes. Most systems are designed to make it possible to calibrate the whole system by introducing the calibration sample at the sample extraction point. This permits the system as a whole to be calibrated.

Particulate matter may cause probes to plug. So, for horizontal installations, the probe should be pointing slightly downward so that condensation can be returned to the process and blowback will be more efficient (see figure 3-2). Blowback is typically used to clean the probe and sample filter.

Figure 3-2
Sloped probe with blowback connection.



In negative pressure systems, leaks will dilute the sample. Probes and the sampling line must be carefully tested to ensure that that are no leaks in the system. Also, very high temperature applications may require the use of water-cooled probes to cool the sample and provide longer probe life.

Sample Line

To avoid lags, the sample line should be as short as possible so the probe is as close as possible to the analyzer. A distance of up to 100 ft. (30 m) from the analyzer is considered acceptable in most applications. If the process fluid is at a high temperature, it must be cooled. A length of plain tubing may provide adequate cooling—however, the plant must be sure this is the case.

The sampling line is typically made of ¼″ to ½″ stainless steel tube, depending on the sample. Since most process streams contain contaminants, the plant should avoid loops or low areas that will trap liquids or particles. Proper support should also be provided where lines enter an enclosure to minimize mechanical stresses on the line and fittings.

Depending on the sample components and on the surrounding climate, the sample line may be heated (and insulated) or unheated. If it is unheated it may be insulated or left bare. Line heating can be performed with steam or electricity. In either case, the plant must assess the controlled temperature range of the heating medium against the sample temperature requirements. Where steam-heated lines are used, line accessories such as traps and temperature controls are required. Steam heating is commonly used where steam is cheaply available or in electrically hazardous areas where electrical sparks may cause an explosion. However, steam heating may be expensive to maintain. In addition, steam leaks could be dangerous to personnel and to sensitive analyzer equipment. The plant should properly insulate the tubing transitions between heated lines and non-heated fittings to minimize heat losses to the surroundings.

Integrally heat-traced-and-insulated sample lines are typically pre-cut at the factory with extra length to allow for errors in measurement. In most cases, the extra length should not be looped since looping may result in line blockage or liquid pockets—both conditions will greatly affect the performance of the analyzer(s). In extreme cases with electric-traced sample lines, looping the sample line on itself can cause the insulation on the sample line to ignite, destroying the heat-traced line and creating a hazard. The plant should install excess length with a continuous downward slope.

Line Accessories

The number of fittings and joints in the sample system must be minimized to avoid leakage points. In addition, the plant should locate a sample isolation block valve outside the analyzer enclosure to allow safe isolation. A catch pot may be required to retain any moisture that may have dropped out during the sample transfer of gaseous samples.

Where pressure boosting is required, plants commonly use leak-free pumps. Note that doubling the pressure doubles the amount of gas in the line. Sample pumps, where required, are typically of the diaphragm type, with all the components that contact the fluid being made of a material that will not react with the fluid being transferred. Pump head and bearings must be capable of operating continuously twenty-four hours per day.

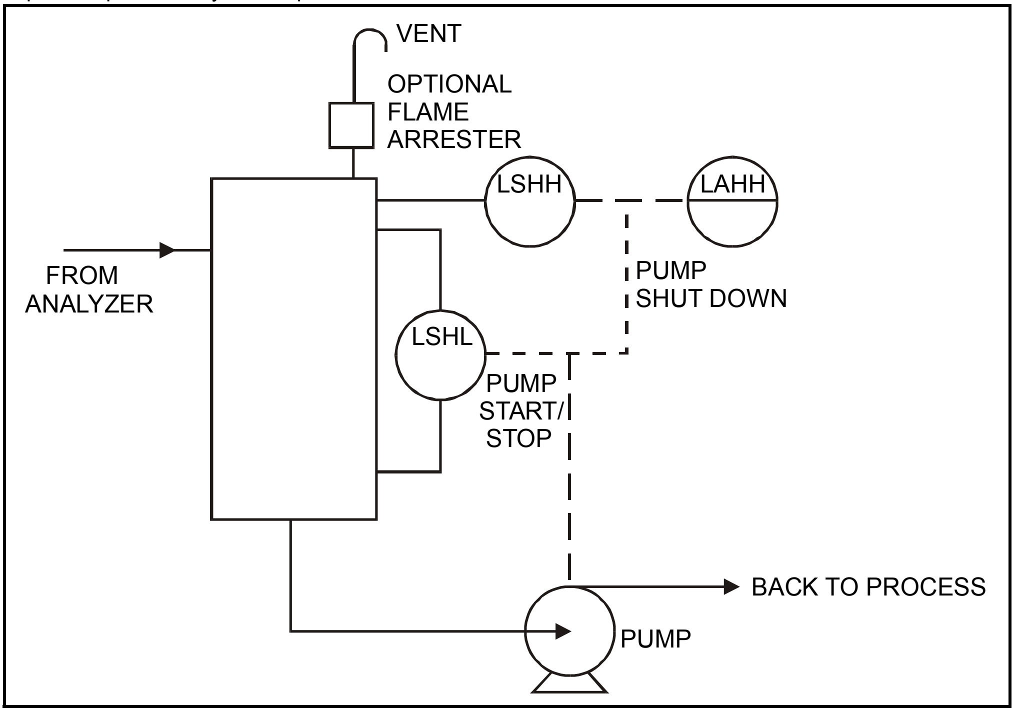
Where the plant requires a pressure reduction of the process fluid, a pressure control valve (PCV) is commonly located at the sample point to keep the high pressure at the process and reduce the dew point. Sometimes, to dry the sample even further, the plant removes the water before the gas pressure is reduced. The plant must assess the effect of removing water on the sample concentration of the gas being analyzed. A safety pressure-relief valve (or bursting disk) may be required downstream of the PCV to guard against sample pressure buildup in the event the pressure regulator fails.

Filtration is generally required on all sampling lines. Filters must be suitable for the physical and chemical composition of the sample. The filter's porosity must be small enough to protect the analyzer yet not too small, otherwise the filter will plug rapidly. Filters must be easy to maintain and replace. Some filters may be of the self-cleaning type (tangential swirl).

Sample Disposal

Once analyzed, the sample should be routed to an acceptable and secure location, preferably back to the process (see figure 3-3). The plant must dispose of safe samples in conformance with all local codes and regulations. Typically, plants assess the following three parameters before deciding about sample disposal: discharge pressure and temperature, maximum concentration of hazardous components, and the flow rate of exhaust stream.

Figure 3-3
Liquid sample recovery and disposal.



The plant must ensure the proper disposal of process samples, the atmospheric vent, the stack vent, and the sample recovery system. The analyzers must be vented in most applications, and it is recommended that the analyzers be vented where there is a minimum of turbulence and where the pressure is constant. Variations in analyzer back pressure will cause significant errors in measurement, and therefore, a back-pressure regulator is sometimes required. A good regulator will maintain a back pressure within +/- 0.5" of water column (WC).

All piping should be routed and designed to prevent condensation from accumulating in line pockets as well as to prevent rain and debris from entering the sample vents. All drains and vents should be installed at a suitable incline toward the discharge.

Enclosures

Extractive analyzers are commonly housed inside enclosures. These enclosures protect the sensitive analyzers and their accessories and also provide a clean and sheltered environment so that the equipment can operate more efficiently and be maintained in all-weather conditions. These enclosures can be wall-mounted cabinets, floor-mounted panels, or self-contained walk-in shelters. In most cases, they are shop-fabricated before they are shipped to the site. Walk-in shelters are shipped on skids. The analyzer enclosure should allow the analyzer to be located safely in the plant, as close as possible to its sample point, and must conform to the electrical code in effect at the site. Additional information on enclosures is provided in chapter 12 of this handbook.

If a plant locates analyzer enclosures in a hazardous area, the inside of the enclosure is commonly designed as a safe area. In the safe area, the plant may have to install an internally located detector(s) with annunciation to a central area, such as a control room. If ventilation stops or if the detector(s) alarms, all electrical power to the analyzer enclosure is cut and all inflow of flammable samples is halted. In addition, analyzers that handle flammable samples are air purged, and failure of the air purge should cause a power interruption. Purging requirements vary with the purge classification, which should be implemented according to the applicable code (also see ISA-RP12.4-1996, Pressurized Enclosures).

All sample lines that carry hazardous fluids and are fitted with flow restrictors should have automatic isolation valves (spring-to-close) located outside the enclosure. These valves shut off the sample lines in the event of purging failure. If such valves are dependent on the enclosure electrical supply, then when the purging fails the resulting electrical supply shutdown to the enclosure will automatically isolate the sample. The startup delay setting should be in compliance with the applicable code (which is typically calculated for ten complete internal air changes of the enclosure).

Construction

The enclosure is generally made of a weather-proof construction and must meet the electrical area classification of its intended location, the ambient temperature and humidity fluctuations, and any other environmental requirements such as earthquakes, rainfall, and wind velocity. In addition, the enclosure should have adequate strength and sealing to withstand internal pressurization to 2" WC (50 mmwc). The enclosure may have to be insulated to reduce heat loss and eliminate condensation without hindering the installation of analyzers and their associated piping and wiring, or it may have to be large enough to dissipate heat buildup.

The enclosure's dimensions depend on the number and type of analyzers and associated equipment as well as the need to provide easy access. At the early stages of implementation, bidders should include preliminary enclosure dimensions in the initial proposal that they submit to the plant engineer for review. If possible, the system should be assembled so that any one analyzer can be removed or serviced without interrupting the operation of any other analyzer in the enclosure.

Some process equipment creates vibration. Such vibration must be properly isolated from the enclosure. Also, the plant must take proper precautions to eliminate the transfer of electrical noise to the analyzer from components such as pumps and solenoid valves.

Walk-in Shelters

Walk-in shelters are used where a cabinet (or panel) is not the preferred enclosure. This occurs when either the cabinet is not large enough or when opening a cabinet will expose the analyzers and their accessories to a harmful environment. Walk-in shelters should be selected so as to provide sufficient clearance around the analyzers and associated equipment for maintenance, removal, and safety. The following minimum clearances are commonly allowed for: about 2 ft (0.7 m) between analyzers, 1 ft (0.3 m) between an analyzer and an adjacent wall, and 3 ft (1 m) in front of an analyzer. In addition, walk-in shelters must provide sufficient space so that the shelter's door can be easily accessed in emergencies. The plant should also consider including space for a desk with storage shelves (for all the maintenance manuals), a chair, an adequate fire extinguisher, and a telephone.

The shelter should be made of a material that is not affected by the environment surrounding it (such as corrosion), and it should be appropriately ventilated from a source that is safe and reliable. The ventilation motor and fan should be easily accessible for maintenance, and an intake filter is typically required. Walk-in shelters are generally prefabricated and made of approved fire-resistant material such as aluminum, with adequately insulated walls and roof. A fully gasketed entrance door should be provided with an opening that is wide enough to allow easy access for equipment and personnel. The door is often supplied with a safety-glass vision panel, an automatic closer, an outside lockable handle, an internal panic bar, and a safety chain that prevents the door from opening such that the hinges are damaged.

The base of the walk-in shelter typically consists of an I-beam or C-channel frame that also serves as the skid for shipping. The base is normally designed to support the enclosure when it is lifted, and it should be flush on all sides with the outside walls of the enclosure. The enclosure is then installed on a concrete pad at the job site by crane. Provisions must be made for suitable lifting lugs and eye bolts for lifting, transporting, and placing the walk-in shelter.

An overhang is commonly provided on one or both sides of the enclosure to provide weather protection of calibration gas cylinders, junction boxes, and other devices mounted outside the enclosure. This overhang is removable for transport and yet should provide a continuity of appearance when installed.

The shelter should be designed such that it is not necessary for field installation personnel to enter it to complete any portion of the installation. Termination for all wiring and tubing should be done outside the shelter through electric junction boxes and tubing manifold ports/bulkheads located under the overhang on the outside walls of the shelter.

To ensure signal integrity, two separate electrical junction boxes should be provided, one for AC power, the other for all low-level signals. Each box should have a minimum of 25 percent spare capacity (for future use) on all terminal strips. A separate clearly labeled junction box is required for Instrinsically Safe (IS) cables, and these cables should be run in their own conduit, away from other wiring, and clearly labeled “IS CABLES.” IS implementation must be done in conformance with local codes.

All junction boxes should be located such that service personnel can gain unobstructed access to them and at a convenient height. A bulkhead gland plate located near the junction boxes is required for the electrical and instrument cables that pass through the wall of the walk-in shelter. Grounding is critical for the successful operation of electronic equipment. Vendor grounding recommendations must be closely followed.

All wiring should be run in conduit, with dedicated conduits for power, analog, and digital signal wiring. These conduits are typically of a 1/2″ minimum thin-wall construction of hot-dipped galvanized steel for noise rejection. The conduit should not interfere with the maintenance or removal of any equipment in the enclosure. In addition, any low point on the conduit systems should have a low-point drain.

The plant must assess whether a mushroom-head emergency-call “HELP” button is required. If so, it should be located about 18 in. (500 mm) from the floor in an accessible position, preferably near the door yet away from accidental triggering. In larger shelters, additional buttons wired in series should be evenly spaced around the perimeter at about one every 9 ft (3 m). Usually, the alarm brought up by these buttons is in the control room, and the emergency response is established by plant procedures.

HVAC Systems

HVAC systems are commonly required for walk-in shelters, not only for the comfort of personnel but also to dissipate excess heat that may be detrimental to sensitive electronics. Plants provide an HVAC unit to control the temperature, humidity, and cleanliness of the air within the enclosure. The system vendor normally provides the unit with the enclosure and selects it for the specified external ambient conditions and with enough spare capacity for possible future analyzers. The system vendor is typically expected to be responsible for calculating the amount of heat to be dissipated inside the enclosure, assuming the simultaneous operation of all equipment. An HVAC system is typically sized so as to provide the minimum air flow required to ensure ten changes of air per hour.

The fresh air intake of the HVAC system should be located away from any possible leaks, combustible gas source, or any other source of contaminated air (such as proximity to the discharge of a relief valve). The HVAC is generally provided with a rain cap, a bug screen, and air filters for intaking fresh air. In certain conditions, a suitable air flow indicator is mounted inside the enclosure. Weighted exhaust louvers are installed so they close when the HVAC unit is not operating. The louvers are typically installed at different wall elevations (one high and one low) so light and heavy potential vapor buildup can be limited.

In some cases, the environment outside the enclosure requires that both ventilation and pressurization be used to maintain a minimum pressure inside the enclosure. The prime safety requirements are air pressure and air flow—therefore, in addition to pressure sensing, the flow of air is also monitored. The plant will typically provide an air-flow switch in the discharge air duct, which is wired into the enclosure's common trouble alarm to warn that ventilation air flow has been lost.

Gas Detection

In locations where hazardous gases are handled, plants may need to provide for combustible and toxic gas detection inside the enclosure. Such gas detection equipment is commonly mounted in the enclosure's ventilation exhaust to ensure accurate sensing. Oxygen monitoring may be required where a nitrogen purge is present.

Where combustible gas detectors are required, the alarm must be set at a point safely below the hazardous limit. When this alarm limit is reached, power is removed from the analyzer enclosure, an alarm is initiated in the control room, and a red beacon that is located outside the enclosure activates. All equipment that need to remain operational when the ventilation fails must be certified for operation in a hazardous environment.

In plants where toxic gas detectors are required, they should also be set at a safe limit. When that limit is reached, all toxic supply lines to the enclosure should automatically shut. Like the combustible gas detector, an alarm is initiated in the control room, and a red beacon located outside the enclosure is activated.

The alarm setting of these combustion and toxic detection analyzers should be adjustable, and the adjustments should be closely controlled by plant procedures. Both combustible and toxic gas-detector alarm points must be manually reset after an alarm condition. If they are not, the shutdown system may cycle on and off if the measured variable is hovering around the set point.

System Alarm

The enclosure should be provided with a common trouble alarm that is wired both to the control room and to a red beacon mounted outside the enclosure. If a walk-in shelter is used, the beacon should be mounted above the door. A warning sign should be attached close to the red beacon to explain what an activated red beacon means.

All alarm contacts tied into this system should normally be open in the unpowered (shelf) position, closed in the powered but inactivated position, and therefore open upon an alarm condition. The intent is to provide a deenergize-to-alarm system.

All the individual alarm contacts from the analyzer system would be connected in series to the enclosure's common trouble alarm. Examples of alarm contacts include high or low temperature in the enclosure via temperature switches mounted inside the enclosure, the loss of air flow in the enclosure, and the loss of instrument air purge (if any) to individual devices.

Inside the enclosure, and if deemed necessary, an annunciator or alarm light box with an audible alarm (with adjustable volume) may be added. Its function is to list all the individual alarm conditions that triggered the common trouble alarm. Each alarm point should be appropriately tagged and should illuminate during an alarm condition. This alarm system should have acknowledge, reset, and test push buttons.

Electrical

The main power source for the enclosure is supplied by the plant. Lower voltages, as required by the analyzer system, are typically provided through a dry type transformer supplied with the analyzer system. If the transformer is located inside the enclosure, it would be protected from the outside conditions but would be generating excessive heat that must be dissipated. Quite often, the transformer is installed on the exterior of the enclosure. Typically, there is a master power disconnect on the primary side of the transformer, a circuit breaker panel board with a main circuit breaker, and 20 percent spare breakers (minimum).

Each of the main system components (i.e., each analyzer, lighting, HVAC system, etc.) should have an individual isolation circuit breaker. In addition, two duplex electrical socket outlets located inside the enclosure should be provided to power computers, tools, and the like.

Wiring and termination should comply with good installation practices—see chapter 12 on enclosures. As a rule, signal types should be adequately segregated to ensure integrity, and splices are not permitted. Correct grounding must be implemented. Poor signal grounding may result in ground loop errors (see figure 1-1 in chapter 1).

Tubing and Piping

Whenever possible, manifolds and replaceable elements (filters, flowmeters, etc.) should be positioned so that personnel can carry out maintenance and routine operational checks on the equipment from a standing position, so they are accessible from the front, and so they can be replaced without disturbing the remainder of the system. A bulkhead plate should be available for all the service gases.

Instrument air tubing and fittings are typically of 316 stainless steel (SS) (or Teflon®). The fittings used should comply with the type used on site. This will facilitate maintenance and the stocking of maintenance components. All sample wetted components must be compatible with the sample and are typically of 316 SS (or Teflon®).

The enclosure should be supplied with an instrument air filter-regulator station if air is required at the enclosure. The function of this station is to reduce the instrument air header pressure, generally supplied at 100 psig (700 Kpag), to a lower usable pressure. In some applications, high-quality bottled air may be required (e.g., for total hydrocarbon analyzers). In such cases, it may be practical and economical to use piped-in instrument air with a "zero-air generator."

Communication

Hand-held transceivers (walkie-talkies) are generally not used in and around the analyzers since they generate electrical noise (RFI) that affects the microprocessor functions of the analyzers. A telephone with a long handset cord should be used instead.

Testing and Startup

Testing

Performing factory acceptance testing (FAT) on the completed system ensures that it is fully functional before it's shipped to the site. It is recommended that these tests be done at the analyzer system assembly shop instead of on site. This makes possible troubleshooting in a controlled environment. On site, time is generally critical, and other field problems demand attention and time.

The completed analyzer system should be accurately calibrated and set up to prove that all equipment is functioning correctly. The analyzers and all their accessories, including the sample system and calibration gases, should be operated on samples supplied by the system vendor or analyzer manufacturer so as to verify correct operation and time constants. All tests should be witnessed by plant personnel. It is expected that the system vendor will supply all required test equipment and test personnel.

The FAT of the analyzer system and its enclosure has succeeded when all the required tests are completed satisfactorily and the plant has approved them. Test personnel should submit all recordings and the results of all calibrations, together with a copy of the test report, to the plant. After the system has been installed on site, the vendor should certify the complete analyzer system on site and test for accuracy, repeatability, and drift.

Startup

Where they are required, gas cylinders equipped with regulators should be supplied with the system. These cylinders are typically manifolded, easily replaceable, and located close to the cabinet (or walk-in shelter).

Depending on the capabilities of maintenance personnel at the site, the system vendor's responsibility may vary from just supplying the equipment to providing full site support. In any case, it is recommended that, following the plant's startup, the plant run a seven-day acceptance test to ensure that the complete system operates without any problems.

Maintenance

Maintenance includes all work that has to be done to maintain the specified operating conditions of an analyzer system, including the sample handling system or any system component. The components of an analyzer system must therefore be easily accessible for testing and repairs. Access to an analyzer system must be restricted to authorized personnel only. Enclosures may be locked and the key subject to a formal logging system.

Calibrating an analyzer typically requires training and specialized equipment. Preferably, the analyzer system should have a built-in automatic calibration capability, set at a predetermined frequency. The calibration time should be a time acceptable to the process operations, since during calibration the analysis is stopped.

Another requirement besides calibrating the analyzer is to perform regular maintenance on all filters. Such filters should be reliable and easy to maintain. They could be placed on the probe or at the flange. If they are placed on the probe, then the plant should ensure that the probe is easy to remove.

At the bidding stage, the system vendor should supply the information necessary to estimate the maintenance requirements. This information should include but is not limited to the following:

- A description of the work that will be carried out by maintenance personnel
- The maintenance frequency for all components
- The material (spare parts, reagents, etc.) that are consumed
- A list of recommended spare parts

Shipment and Delivery

Depending on the plant's capability, the vendor of the analyzer system may need to be responsible for delivering and unloading the equipment at the plant. However, before the equipment is shipped, the vendor should cover all enclosure openings (including tube fittings) to prevent contaminants from entering during the equipment's transit and while it's in storage. In addition, all items subject to movement must be tied down and all water drained to prevent damage from freezing.

In most cases, equipment should be transported via a full air-ride flatbed truck. Therefore, the complete analyzer system must be designed for land transport to the job site.

Comparison Table

Table 3-1 will serve as guide during the process of deciding which analyzer is appropriate. In the table, a *Y* (for *Yes*) indicates an analyzer that can analyze a component. A *<u>Y</u>* indicates where an analyzer is commonly used for a particular component measurement.

Amperometric

Principle of Measurement

The amperometric cell consists of two electrodes immersed in an ion-containing solution (typically, 60 percent calcium bromide). The applied voltage across the electrodes causes the electrodes to become polarized with a hydrogen layer. The presence of an oxidizing gas, such as chlorine, reacts with the ionic solution, liberating elemental bromine and reducing the gas layer. The current flow that results so as to re-establish the polarization equilibrium is proportional to the oxidizing gas concentration (see figure 3-4).

Application Notes

The amperometric cell can handle sample temperature ranges of 32 to 140°F (0 to 60°C) and process pressures up to 10 psig (70 Kpag). It also has an operating range as low as 0 to 20 ppm for chlorine with an accuracy of 0.5 to 5 percent of full scale and a 1 ppb resolution (depending on the measuring range). It requires a sample flow of about 500mL/min and a sample velocity of at least 1 ft/sec (0.3m/sec). The amperometric cell provides a response time of about 10 to 20 seconds. However, it is affected by temperature changes (therefore, temperature compensation is required), by changes in pH (a cell buffering solution is used in the cell to stabilize the cell current), and by variations in dissolved oxygen (at low concentration level).

Capillary Tube

Principle of Measurement

The differential pressure capillary tube analyzer measures viscosity based on the Hagan-Poiseuille equation:

$$\text{Absolute viscosity} = \frac{\text{constant} \times (\text{capillary internal radius})^4 \times (\text{differential pressure across capillary})}{(\text{sample flow}) \times (\text{capillary length})}$$

The analyzer measures differential pressure across a capillary through which a constant flow passes. Since the capillary bore and length are constant, the absolute viscosity is proportional to the differential pressure measured across the capillary (see figure 3-5). All significant components are maintained at a constant temperature. Sometimes multiple parallel capillaries are available to provide different viscosity ranges.

Table 3-1
Analyzer comparison

COMPONENTS TO MEASURE / TYPES OF ANALYZERS	ACID GASES	AIR	AMMONIA	ARGON	BENZENE	CARBON DIOXIDE	CARBON MONOXIDE	CATALYST RESIDUE	CHLORINE	COLOR	COMBUSTIBLE GAS	CONDUCTIVITY	DENSITY	ETHYLENE	FREON	HYDROCARBONS	HYDROGEN GAS	MERCURY	METALS	NITRIC OXIDE	NITROUS OXIDE	NITROGEN GAS	NITROGEN DIOXIDE	NITROGEN OXIDES (NOx)	OXYGEN GAS	ORP	OPACITY	ORGANIC COMPOUNDS	OZONE	pH	PROPANE	SPECIFIC GRAVITY (GAS)	SPECIFIC GRAVITY (LIQUID)	SULPHUR DIOXIDE	SULPHUR OXIDES (SOx)	VISCOSITY	WATER VAPOR (Moisture)
AMPEROMETRIC							Y		Y								Y			Y			Y											Y			
CAPILLARY TUBE																																				Y	
CATALYTIC			Y								Y			Y		$\underline{Y}$								Y	Y						Y						
CHEMILUMINESCENCE			Y																	$\underline{Y}$			Y	$\underline{Y}$					Y					Y			
CONDUCTIVITY												$\underline{Y}$																									
ELECTROCHEMICAL			Y				$\underline{Y}$		Y																$\underline{Y}$	$\underline{Y}$				$\underline{Y}$				Y			Y
FLAME IONIZATION DETECTOR					Y		Y				Y			Y		$\underline{Y}$												Y			Y						
FOURIER TRANSFORM INFRARED			Y		Y	Y	Y							Y	Y	Y				Y	Y		Y	Y				Y			Y			Y			Y
GAS CHROMATOGRAPH	Y	Y	Y	Y	Y	Y	Y		Y					Y	Y	Y	Y			Y	Y	Y	Y	Y	Y			Y	Y		Y			Y	Y		Y
INFRARED ABSORPTION			Y		Y	$\underline{Y}$	$\underline{Y}$							Y	Y	Y				$\underline{Y}$	Y		Y	Y			Y	Y			Y			$\underline{Y}$	Y		Y
MASS SPECTROMETER	Y	Y	Y		Y	$\underline{Y}$	$\underline{Y}$		Y					Y	Y	$\underline{Y}$	$\underline{Y}$			Y	Y	$\underline{Y}$	Y	Y	Y			Y	Y		Y			Y	Y		Y
NON-DISPERSIVE INFRARED			Y		Y	$\underline{Y}$	$\underline{Y}$				Y			Y	Y	Y				$\underline{Y}$	Y		Y	Y				Y			Y			$\underline{Y}$			Y
PAPER TAPE			Y		Y		Y		Y											Y			Y						Y					Y			
PARAMAGNETIC																									$\underline{Y}$												
pH																										$\underline{Y}$				$\underline{Y}$							
POLAROGRAHIC							$\underline{Y}$		Y								Y			Y			Y		$\underline{Y}$				$\underline{Y}$					Y			
RADIATION ABSORPTION													$\underline{Y}$																			Y	Y				Y
ROTATING DISK VISCOMETER																																				$\underline{Y}$	
THERMAL CONDUCTIVITY DETECTOR			Y	Y		$\underline{Y}$	Y		$\underline{Y}$						Y	Y	$\underline{Y}$			Y		Y	Y		Y									Y			Y
ULTRAVIOLET			$\underline{Y}$		Y				Y	Y	Y					Y		$\underline{Y}$		$\underline{Y}$			$\underline{Y}$	$\underline{Y}$				Y	Y					$\underline{Y}$	Y		
VIBRATING U-TUBE													$\underline{Y}$																			Y	Y				
X-RAY FLUORESCENCE								Y										Y	Y																		
ZIRCONIA OXIDE											Y														$\underline{Y}$												

Legend : Acceptable = Y Commonly used = $\underline{Y}$

Figure 3-4
Amperometric cell.

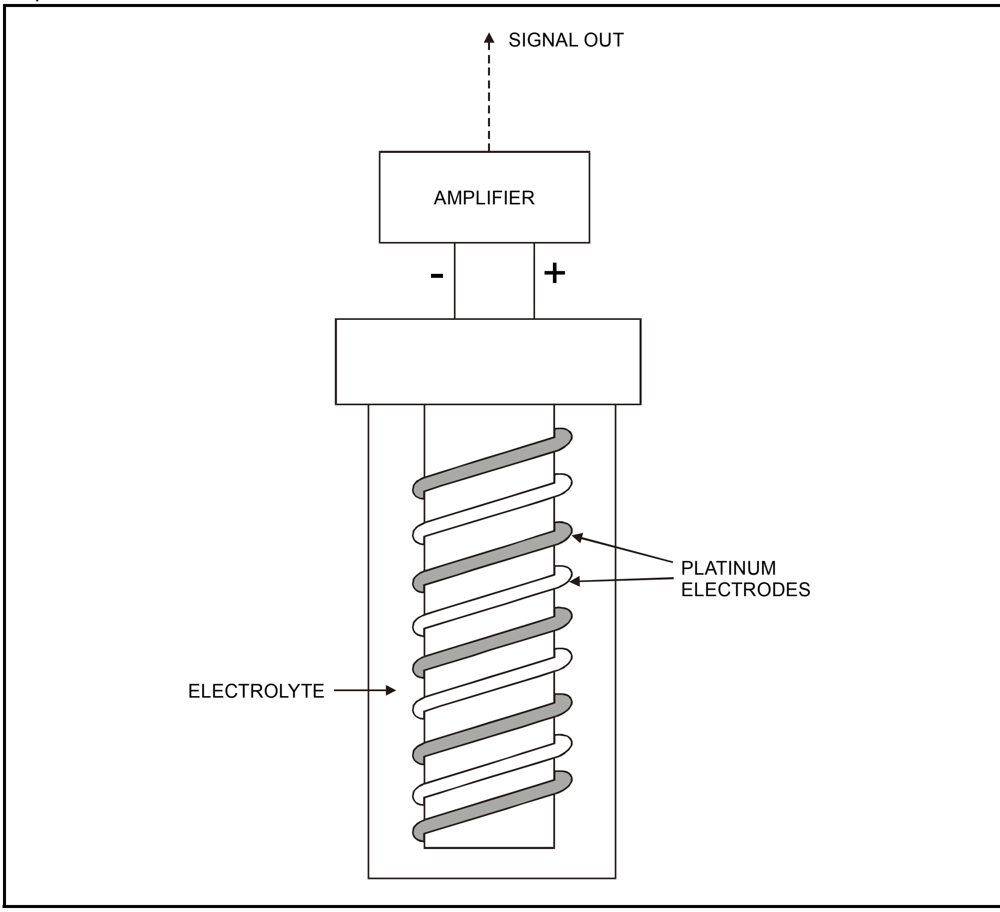
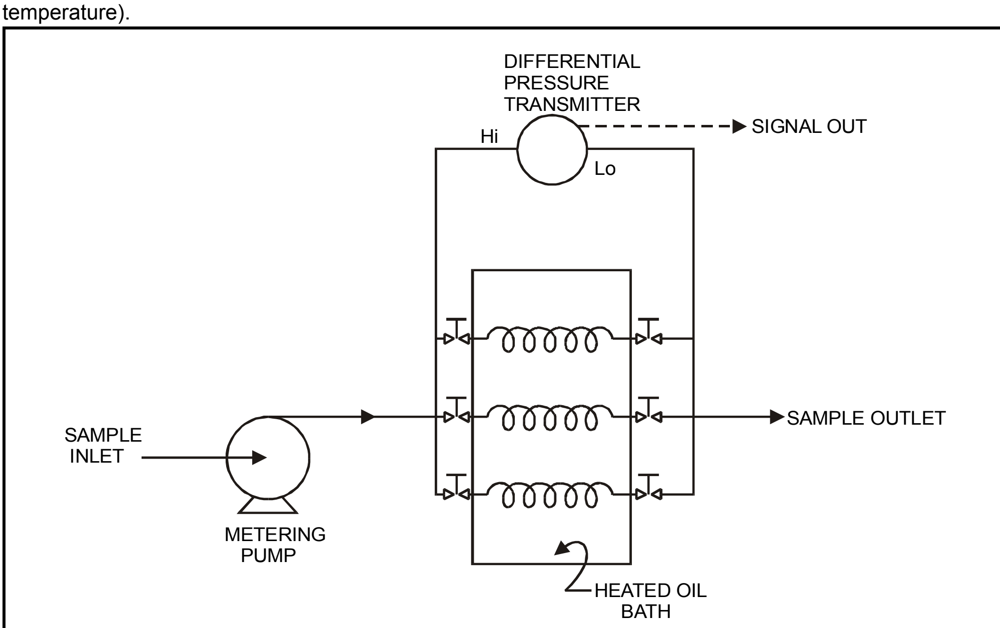


Figure 3-5
Capillary tube viscosimeter (shown with three capillaries immersed in a bath to keep them at a constant temperature).



Application Notes

The capillary tube has a precision of +/- 1 percent of full scale. It requires that the sample be clean and that pressure pulses be avoided. It also requires that its components be maintained at a constant temperature.

Catalytic

Principle of Measurement

The catalytic cell consists of two heated platinum sensors. The first, the active sensor, is treated with a catalyst and is sensitive to all combustibles. The second, the compensator or reference sensor, is not treated with a catalyst and therefore will not respond to combustible gases, but it does have equivalent thermal mass to the active sensor (see figures 3-6 and 3-7). The catalyst allows a normally non-flammable mixture to be burned and allows combustion to occur at a temperature below the ignition temperature of the sample gas. To maintain similar electrical characteristics, the reference sensor has the same construction and mass as the detector, but without catalyst. Its main function is to compensate for variations in ambient conditions.

When combustibles are present, they burn at the first sensor. This raises the sensor's temperature and therefore changes its electrical resistance. The sensors are incorporated in a Wheatstone bridge. The unbalance in the bridge is amplified and produces an output proportional to the measured variable. Combustible gases are diffused through a flame arrestor before reaching the sensors.

Figure 3-6
Explosion-proof catalytic gas detection cell.

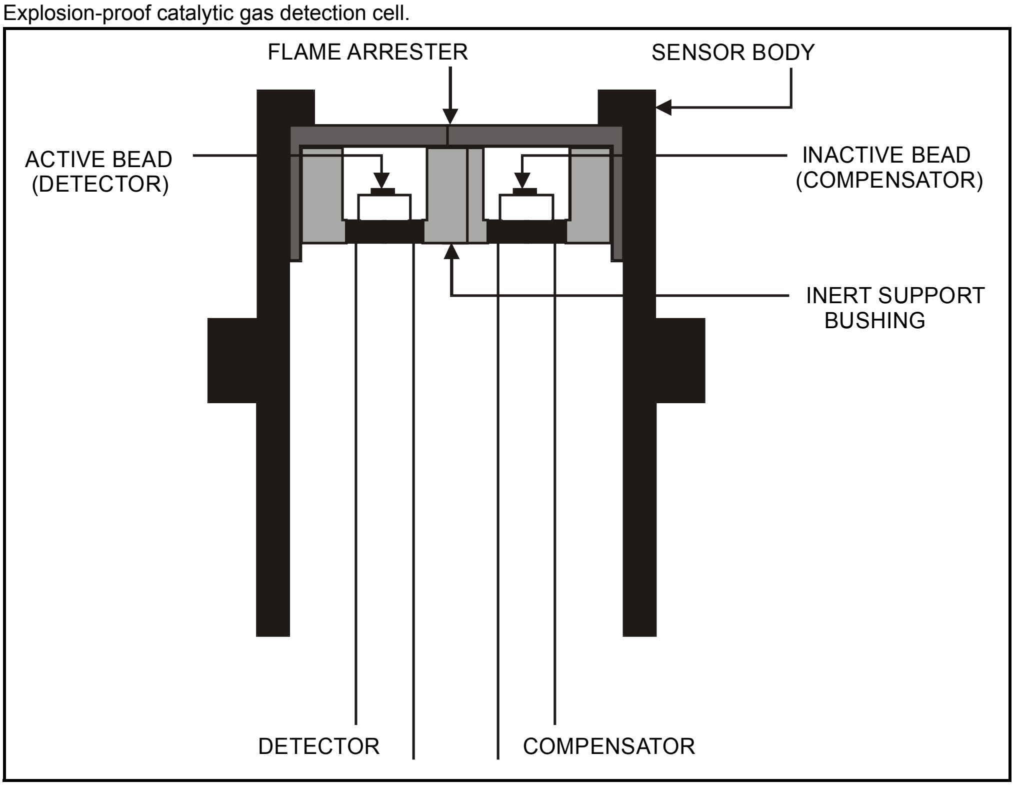
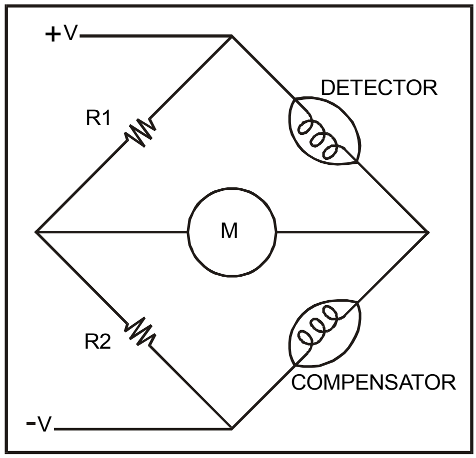


Figure 3-7
Catalytic cell circuit diagram.



Application Notes

The catalytic cell is commonly used to detect combustible gases. It has a typical temperature range of -67 to 212 °F (-55 to 100 °C). However, this range will vary considerably from one design to another. It has an error of +/- 1 to 5 percent, is versatile, small in size, simple in design, and rugged. It has a relatively low cost, responds well to high gas concentrations and to oxygen-deficient atmospheres, and is simple to calibrate and maintain. However, the catalytic cell is typically limited to concentrations above 1000 ppm. It has a life expectancy of less than two years depending on the detector design and on the gas being measured. This unit has four common failure modes: corrosion, poisoning, inlet blockage, and burnout. It is affected by the presence of CO and hydrocarbons. Also, in some models, it is susceptible to H_2S, lead, or silicones poisoning (however, some sensors are poison-resistant). It has a typical warm-up time of about 45 minutes, with a response time of 10 to 30 seconds. The catalytic cell requires oxygen for the oxidation process and constant flow and temperature for the sample (also corrosive gases or vapors, dusts, and entrained liquids should not be present). The catalytic cell is affected by the lack of oxygen, which decreases the burning ability at the active sensor.

Chemiluminescence

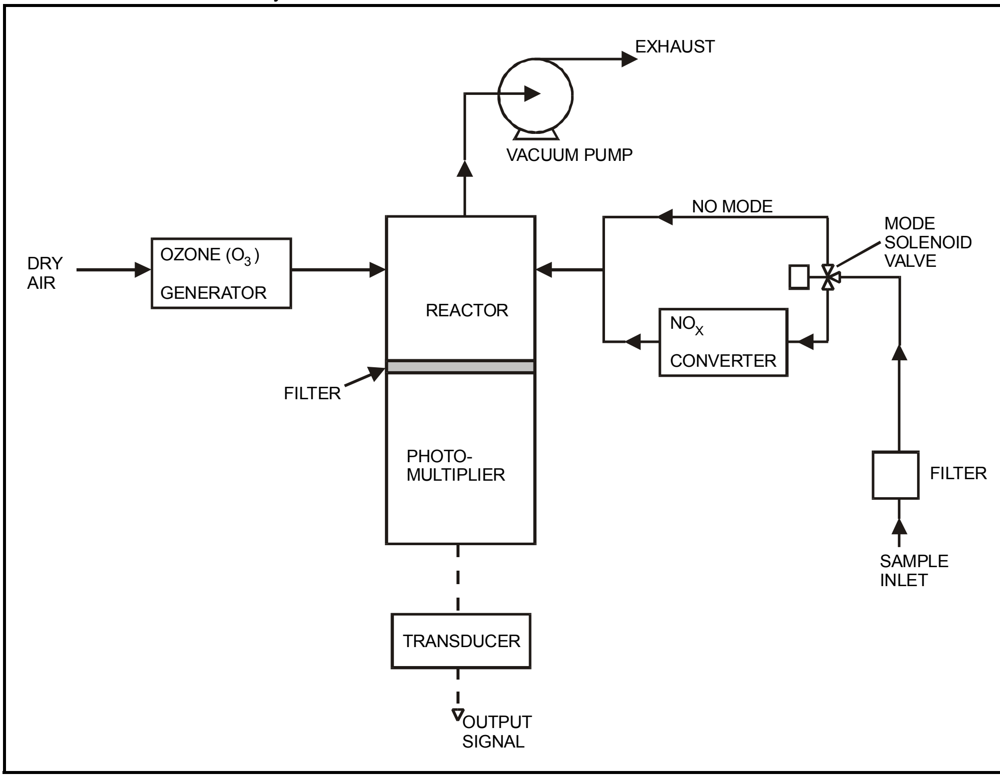
Principle of Measurement

The chemiluminescence technique combines the NO and ozone inside a vacuum chamber. When NO and ozone are combined, they produce NO_2 and light. The light produced is proportional to the NO_2 (and original NO) concentration. The light is then measured and converted into a signal output (see figure 3-8). To measure NO_2, the gas is first converted into NO and then combined with ozone.

Application Notes

The chemiluminescence technique is highly sensitive and easy to maintain. It measures a range from 0.1 ppm to 1 percent, has an accuracy of +/- 1 to 2 percent of full scale, and a drift of about 3 percent per week. The unit is commonly used to measure NOx on a continuous basis. It meets CFR 40 Part 60 (Method 73) when it is measuring NOx, and can handle sample temperature ranges of 32 to 122 °F (0 to 50 °C) and pressures of 0 to 20 psig (0 to 140 Kpag). The chemiluminescence technique has a response speed of 5 to 60 seconds (depending on the analyzer model) and a warm-up time of about an hour. It typically requires a 2 micron sample gas filter. However, this technique is relatively expensive and is affected by the presence of CO_2, O_2, N_2, H_2O, hydrocarbons, and ammonia (NH_3).

Figure 3-8
Chemiluminescent NOx analyzer.



Conductivity

Electrolytic conductivity refers to the ability of a solution to carry an electric current. In general, the more ions there are in a solution, the greater its conductivity. In conductive solids, the flow of electricity is accomplished by the movement of electrons; in solutions, the current is carried by all ions (positive and negative). The conductivity of a solution depends on the ions' mobility and presence. The ions' mobility depends in turn on the dielectric constant of the solution, on the ions' charge and size, and on the solution's temperature. As temperature increases, ion velocity increases, which increases the ions' mobility. Also, as the temperature increases, the solution's viscosity decreases. This reduces the resistance (or drag) on the ions' movement, which also increases their mobility. The conductivity of a solution varies with temperature changes and is a key factor in how accurate a conductivity measurement is. Therefore, such temperature changes must be compensated for.

Conductivity is normally measured in microsiemens/cm. Ultra-pure water has a conductivity of 0.05, distilled water a conductivity of 3.0, milk of 45, and sodium hydroxide (10% weight) of 355,000. Whereas conductivity measures the total ions, pH only responds to the concentration of hydrogen ions. Conductivity measurement is nonspecific, that is, measurements cannot identify one ion from the other.

Principle of Measurement

A conductivity-measuring system consists of the conductivity cell (the source of most difficulties) and the resistance-measuring instrument (the transducer). There are two basic types of conductivity cells: electrode cells and electrodeless induction cells. The electrode type was originally designed for lab applications and consists of two (or four) metal electrodes in an insulating chamber. The electrodes are generally coated with a deposit of spongy black platinum to increase the effective surface. An AC Wheatstone bridge is the most commonly used resistance-measuring instrument because it is sensitive, stable, and accurate. The current is introduced into the system and leaves it through the metallic electrodes. The four-electrode design is commonly used for high-conductivity measurements (up to 1 S/cm) and will work well in dirty solutions. An alternating voltage is applied across the conductivity electrodes (which are in contact with the process). The resulting current is proportional to the solution's conductivity.

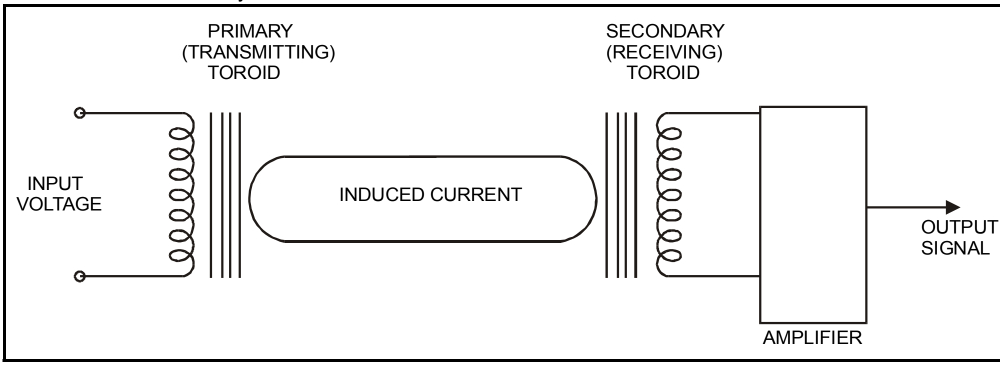
Each cell has a cell constant—this is the distance between the electrodes divided by the electrode area. With a low cell constant (e.g., 0.1/cm) the electrodes are relatively close together, which is suitable for high-resistivity solutions. However, a low cell constant will tend to become plugged from dirty fluids (due to the restricted passage). Cell constants are available from 0.01/cm to 50/cm, but in most industrial applications, the cell constant varies between 0.01/cm and 10/cm The cell must be matched to the solution being measured to provide an accurate measurable range. A cell with a large electrode area will perform better than one with small electrode areas (hence, the spongy platinum deposit). The sensor should be completely immersed in the solution, and the cell should not trap air or collect sediments. The cell location should avoid poor circulation (e.g., dead-end pipe). The velocity should not be too high since this damages the cell physically. If the velocity is low, the flow should enter the open end of the cell.

The electrodeless induction type of cell consists of a pair of toroidal coils mounted so that a stream of solution penetrates both toroidal holes. It is the equivalent electrical circuit of two transformers. The first transformer consists of the input toroid as the primary and the closed loop solution as the secondary (a small current is generated from the ions moving in the conducting loop solution). The second transformer consists of the closed-loop solution as the primary and the output toroid as the secondary (see figure 3-9). The electrodeless induction type of conductivity electrode has many advantages. Because it has no electrodes in contact with the process, it can be used to cope with severe conditions (suspended solids, slurries, abrasive or corrosive materials, very highly conductive materials, etc.). It can also handle up to 390°F (200°C) and 285 psig (2000 KPag) processes. However, it requires that non-conductive piping be used (or a nonconductive liner in a metallic pipe).

Application Notes

The conductivity-measurement system provides continuous measurement and is highly sensitive, with an accuracy of +/- 1 to 2 percent of full scale. Moreover, it is simple in design, has a reasonable cost, and is easy to maintain. It can be simplified by using self-diagnostics, where the transducer can detect and alarm internal circuit malfunctions, shorted or open electrodes, or a fouled cell. The conductivity-measurement unit provides conductivity measuring ranges of 0 to 2 microsiemens/cm up to 0 to 1,000,000 microsiemens/cm and can handle process pressures of up to 500 psig (3500Kpag) and 390°F (200°C). Conductivity measurement is used for liquids and has a response time of 2 to 20 seconds for the electrode type and 20 to 60 seconds for the electrodeless (toroidal) type. When compared to pH, conductivity provides easy installation, low maintenance, high reliability, and relatively low cost. However, the elements should be kept clean and should not be exposed to dirty or oily solutions.

Figure 3-9
Electrodeless conductivity cell.



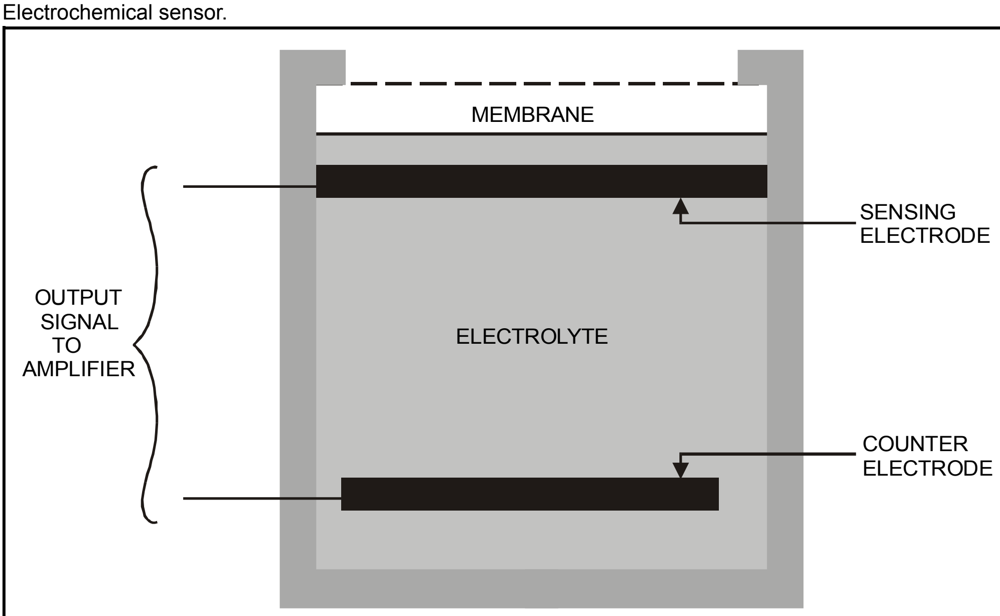
Electrochemical

Principle of Measurement

The electrochemical cell appeared in the 1950s and was primarily used to measure oxygen. In its simplest form, it consists of two metallic electrodes (a sensing electrode and a counter electrode) that are in contact with an electrolyte. pH probes are a type of electrochemical sensor. The electrodes and electrolyte are enclosed behind a membrane. The chemical reaction in the cell produces a voltage output that is proportional to the number of ions diffusing between the electrolyte and the electrode (see figure 3-10). The molecules to be measured permeate the membrane and react with the electrolyte. Drying out the electrolyte will reduce the life and performance of the sensor. Plants typically incorporate a temperature compensation method to compensate for the changes in diffusion rates when the temperature changes.

The fluid to be measured passes through a membrane that limits the flow of fluid entering the sensor. The fluid then reacts with the sensing electrode. Selective reactions are matched with an electrode material, and an electrolyte is selected for the fluid to be measured.

Figure 3-10
Electrochemical sensor.



Application Notes

The electrochemical cell is sensitive and can operate from 23 to 104 °F (-5 to 40°C) and with process pressures of up to 150 psig (1000 Kpag). The unit provides a sensitivity as low as 1 ppb (some units claim to go as low as 0.1 ppb), a range as high as 0 to 1000 ppm, and an accuracy of +/- 2 to 3 percent. The electrochemical cell can detect many gases, offers low cost, is easy to install, and requires little power to operate. It is widely used and has an expected life of one to two years (with a calibration interval of one to eight weeks, depending on the cell and on the application). It is available as a portable instrument, is commonly used to detect toxic gases in ppm ranges, and can provide a response time that varies between 5 and 60 seconds, depending on the selected model, the required accuracy, the selected range, and the measured fluid.

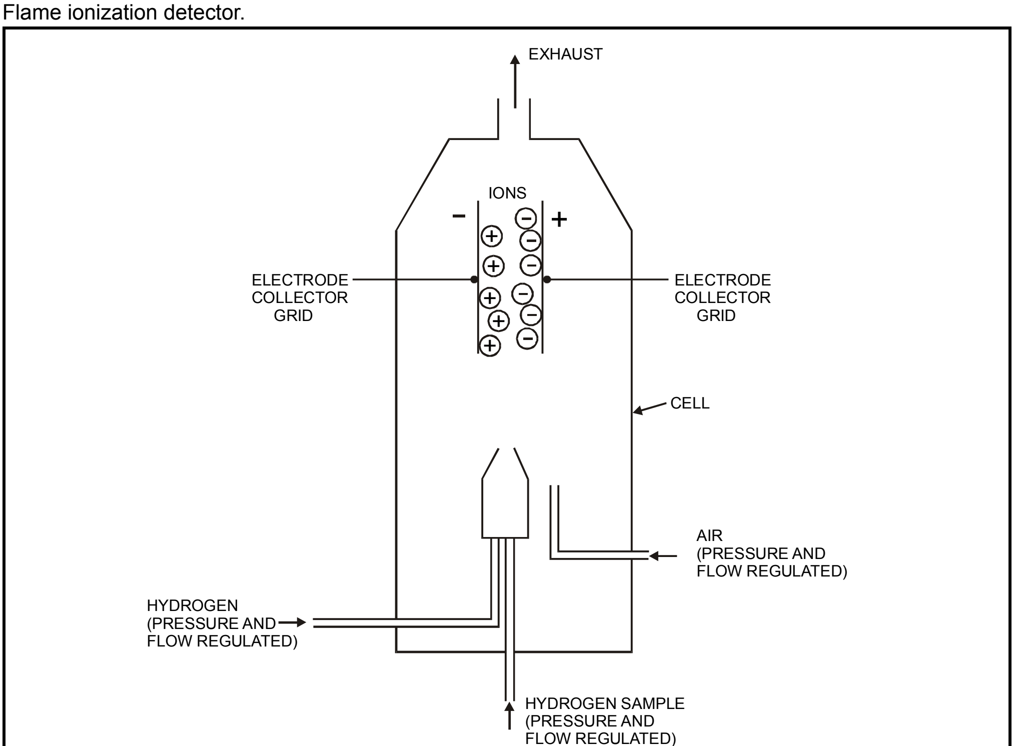
However, the electrochemical cell is typically limited by two factors: the varying pH of the solution being measured and the presence of other ions, which interfere with the measurement of the ion of interest. However, this interference can be minimized by biasing the electrode's potential and by selecting the correct electrode material. In addition, the electrochemical cell is subject to poisoning, cross-interference, and electrolyte leakage and dry out.

Flame Ionization Detector (FID)

Principle of Measurement

The flame ionization detector, which is used in gas chromatography, burns hydrocarbons in a hydrogen/air flame. It is the most common analyzer for measuring total hydrocarbons. Carbon ions released from the combustion are sensed through electrons around an electrode in the flame. The current measured is proportional to the number of carbon atoms in the flame, that is, the concentration of hydrocarbons (see figure 3-11). The detector cell, where the combustion occurs, is regulated at a fixed temperature, typically, 80°C +/- 1°C.

Figure 3-11
Flame ionization detector.



Application Notes

The flame ionization technique is highly sensitive. It has an accuracy of 1 to 2 percent of full scale, provides a wide linear range of response and continuous measurement, and has a typical response time of 1 to 10 seconds (depending on model). It has the ability to measure ranges as low as 0 to 1 ppm with resolutions of 0.01 ppm. Flame ionization units are available at moderate cost and are easy to maintain.

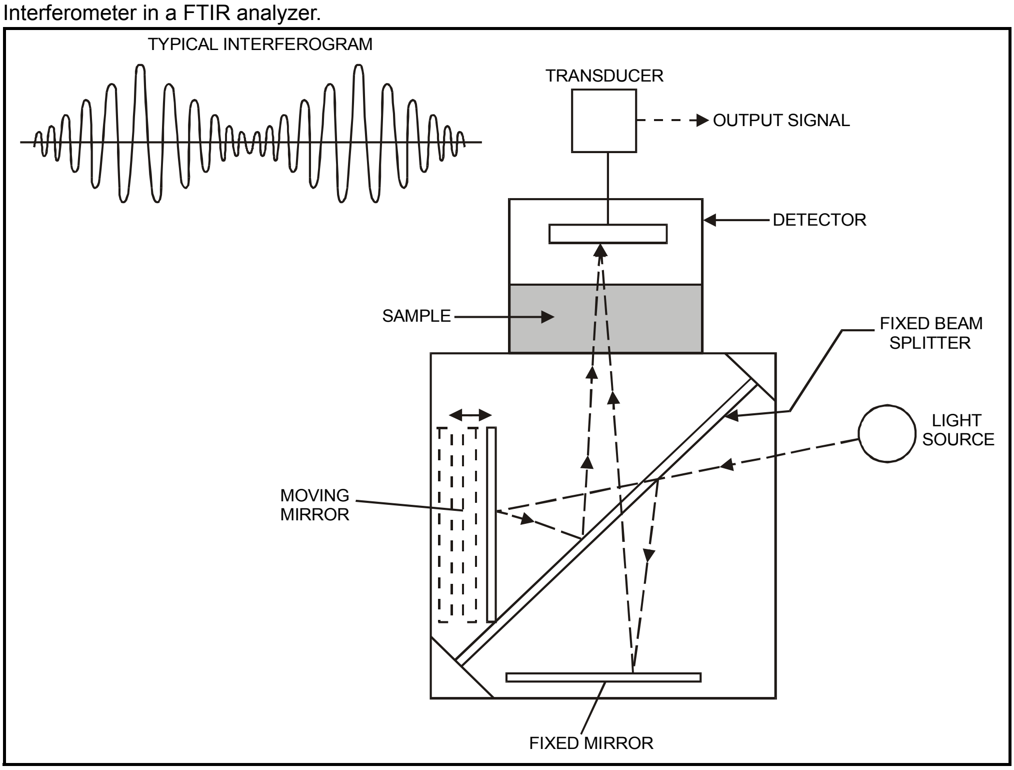
Flame ionization requires a sample flow rate of about 4 L/min, a fuel flow (hydrogen) of about 50 mL/min, and a zero grade (THC < 1ppm) air flow of about 400 cc/min at 25 psig minimum (175 Kpag). Flame ionization units also require a gaseous sample and should be calibrated for each component to be measured. However, these units require absolutely clean (hydrocarbon-free) air to operate correctly and so must be cleaned in environments where samples generate ash or soot in the flame. To prevent flooding of the detector, the unit should be designed so that water produced by the hydrogen flame (from condensation) is swept away from the detector.

Fourier Transform Infrared (FTIR)

Principle of Measurement

The Fourier transform infrared (FTIR) analyzer consists of an infrared source (typically a heated coil of wire), an interferometer, a sample cell, and a detector. The heart of the FTIR system is the interferometer (see figure 3-12). It consists of two mirrors: a fixed mirror and a moveable mirror. The performance of an FTIR is largely dependent on the correct alignment of both mirrors.

Figure 3-12
Interferometer in a FTIR analyzer.



The FTIR analyzer is similar to the non-dispersive infrared detector (NDIR). However, NDIR detectors are dedicated to monitoring a single component, whereas the FTIR detectors can provide analysis of multiple components (see section on NDIR later in this chapter). Most industrial chemicals absorb infrared radiation in a specific manner. This absorption is then measured by the infrared analyzer (including FTIR and NDIR).

The difference is that in the Fourier transform method, a modulation/demodulation process occurs. Typically, an infrared source is collimated and sent to an interferometer, where a beam splitter splits the radiation into a transmitted and a reflected beam. The transmitted beam goes to a moving mirror, and the reflected beam goes to a fixed mirror. Through the mirrors, the beams are recombined to produce an interference pattern. When the beams are exactly identical in length, light frequencies will combine constructively. The moving mirror creates path lengths that are different from the fixed mirror path. As the moving mirror moves at a fixed velocity, cycles of constructive and destructive interference occur because of the path difference, that is, the phase difference, between the two beams on recombination at the splitter. This composite pattern (called an interferogram) is the Fourier transform of the infrared spectrum.

Thus, an FTIR analyzer produces an instantaneous spectrum for all wavelengths in contrast to NDIR analyzers, which produce only a portion of the spectrum covering a narrow wavelength range. Interferometers are single-beam instruments. The specific concentration data is mathematically calculated from the measured spectrum by identifying spectral “fingerprints” rather then individual peaks (see section on infrared absorption later in this chapter). The appearance of affordable computers provided the necessary power to perform the Fourier transform so as to fit the analysis of peaks and spectral fingerprinting. The sensitivity of this analyzer is proportional to the length of the measuring cell, which typically varies between 1 mm to 1 meter for a fixed path length and 1 meter to 100 meters for multiple internal reflection (MIR) cells.

Application Notes

The Fourier transform infrared (FTIR) is more sensitive than infrared (dispersive IR) and NDIR because of the increased infrared energy at the detector. It can measure gases and liquids continuously and can measure solids if they are thin enough (such as moving films). It may also measure thicker solids by reflection from the surface. The FTIR unit is rugged and reliable, has a response speed of 1 second to 5 minutes (but typically around 30 seconds), and has an accuracy (at best) of around +/- 1 percent. The FTIR is easy to maintain, can detect airborne pollutants in an atmospheric open path within a few tens of ppb over distances up to 6 miles (10 km), and can measure multiple components (typically limited to 6 to 15 per stream).

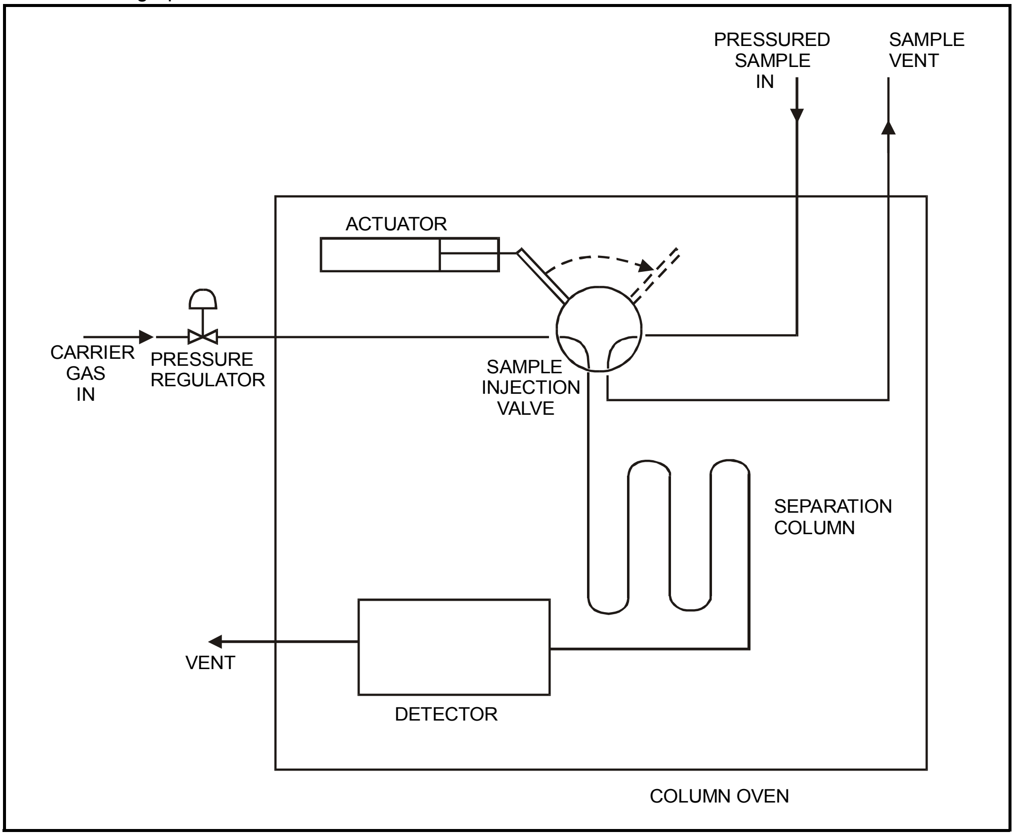
Errors are introduced into FTIR measurements from non-linearities and from noise. The unit requires that extreme precision be exercised when aligning the interferometer in order to maintain the interferometer’s accuracy and field alignment (for units that are not permanently aligned). Thus, calibration could be an expensive maintenance item. FTIR units require accurate data on the spectral signatures of all the components that will be in the sample. Any changes in the sample’s composition will necessitate recalibrating the analyzer. The FTIR’s infrared source must be replaced frequently, typically yearly.

Gas Chromatograph

Principle of Measurement

The gas chromatograph (also sometimes referred to as a “gas liquid chromatograph”) consists of a carrier gas system, a sample injection valve, a separation column, a detector, a column oven, and a controller that provides the method for controlling the analyzer system (see figure 3-13). The gas chromatograph measure the concentration of multi-component mixtures. This method is used for gases and liquids as long as the components to be measured are volatile and do not decompose in the vapor phase. The technique is not continuous. It works by separating the constituents of a mixture from an injected sample, then measuring the concentration of each component as it passes through a detector.

Figure 3-13
Gas chromatograph.



The carrier gas system typically consists of gas bottles containing a high-purity carrier gas (such as nitrogen, helium, or hydrogen), pressure regulators, and flow controllers (such as needle valves). Theoretically, any gas that is pure and inert can be used as a carrier. Care must be taken to ensure that no contaminants are introduced through the carrier gas system.

The sample injection valve injects a fixed sample gas volume into the carrier gas and onto the column on a timed basis. It is a high-precision device that meters a gas sample of 0.1 to 2.0 milliliters.

The separation column separates the sample components based on their boiling point, polarity, or other separation criteria. It consists of a tube that is packed (or coated) with a material that produces a retarding effect on the components passing through it. Different packing materials and column temperatures provide the means for changing the component separation. The components will come out of the column at different times, with all the molecules of a component emerging together in a defined time span. That is, these components are presented to the detector in batches. Corrosive materials or particles in suspension must be avoided to maintain the column's effectiveness.

The detector is a very sensitive device that measures the concentration of the different components emerging from the column. The detector could be a thermal conductivity sensor, flame ionization sensor (which measures down to ppb), or one of many specialized detectors sometimes used for specific applications. The sample is typically measured at a constant temperature and pressure.

The column oven is insulated and temperature controlled. It encloses the sample inject valve, the separation column, and the detector. The column oven provides stability and an optimum temperature of 60 to 200°C for the separation process. The temperature control loop typically uses electrically heated circulated air to maintain the oven temperature to a fraction of a degree.

Application Notes

The gas chromatograph is highly accurate and very versatile. It can measure from parts per billion (ppb) to 100 percent. It is commonly used to measure hydrocarbons but can measure other gases with proper column and detector combinations. The gas chromatograph can measure multiple components and handle process temperature ranges of –20 to 350 °F (-28 to 176 °C) and pressures of 10 to 1200 psig (70 to 8400 Kpag). It is used only where the sample is vaporizable, and it must receive a representative sample. Gas chromatographs are relatively slow to respond.

Gas chromatographs should be positioned away from high-vibration areas and and must be operated by particularly well-trained maintenance personnel. Expensive to purchase and maintain, gas chromatographs are not easy to maintain, requiring about one man-month per year. They produce a cyclical rather than continuous analysis (it is a batch operation). Gas chromatographs are therefore not used on fast loops or where instant analysis is required, but rather as a process check or in trimming control signals. They require a sampling system that consumes a bottled carrier gas.

Infrared Absorption

Principle of Measurement

When infrared radiation impacts a molecule with a frequency that is identical to the molecule's specific vibrational frequency, energy from the infrared beam will be absorbed in the molecule. The operation of the infrared analyzer is related to the Beer-Lambert law: with a constant cell length and a constant absorption coefficient for a compound X at a fixed wavelength, the measured absorbance is directly related to the concentration of compound X.

The concentration of one material can be determined in the presence of another material as long as the wavelength of light chosen is absorbed only by the material under measurement and not by any other material. It is therefore essential to know the concentrations of all the components in a sample. Infrared absorption is based on vibrational frequency, and infrared absorption units are less sensitive than ultraviolet sensors (see section on UV sensors).

The infrared absorption consists of an infrared source, two optical filters (a measure filter and a reference filter), a sample cell, and an infrared detector (see figures 3-14 and 3-15). The infrared source is usually a nichrome element that has been heated to a dull red color. The infrared region of radiant energy has longer wavelengths than those of visible light. As the temperature of a component increases, the wavelength of the emitted radiation decreases. The amount of emitted radiation forms a curve that is a function of wavelength or frequency. The source provides a continuous beam of radiation that represents the portion of the spectrum in which the sample will be absorbed. The measure filter then limits the radiation to the desired wavelength.

The reference filter is selected such that none of the measured components nor the background components can absorb infrared energy. The reference filter compensates for background energy changes. Typically, the beam is mechanically chopped by a chopper wheel on which two filters are mounted. The radiation then passes through the cell, through which the fluid being analyzed is flowing. Cell path lengths vary from 0.025 mm for liquid service to 1 m for high-sensitivity gas applications. The detector compares the received infrared energy with that of a reference wavelength (typically, between 1 to 10 nanometer). It then sends its signal to a transducer. New infrared absorption instrument designs have a single source that is split into a reference beam and a sample beam. This approach eliminates the problem of two sources decaying, over time, at a different rate, thereby causing an error between the two beams.

Two common variations of industrial infrared sensors are the non-dispersive infrared (NDIR) detectors, which are dedicated to monitoring a single component, and the Fourier transform infrared (FTIR) detectors, which can perform multi-component analysis. Refer to the sections on NDIR and FTIR analyzers for further information. Dispersive infrared analyzers are commonly used in protected locations such as a laboratory.

The sensitivity of the infrared absorption analyzer is proportional to the length of the measuring cell (which typically varies between 5 mm to 1 meter for gases and 0.01 to 1 mm for liquids). Solid samples are measured as a thin film or as a powder suspended in an infrared transparent binder (such as mineral oil).

Figure 3-14
Single-beam, single-detector, dual-wavelength IR analyzer.

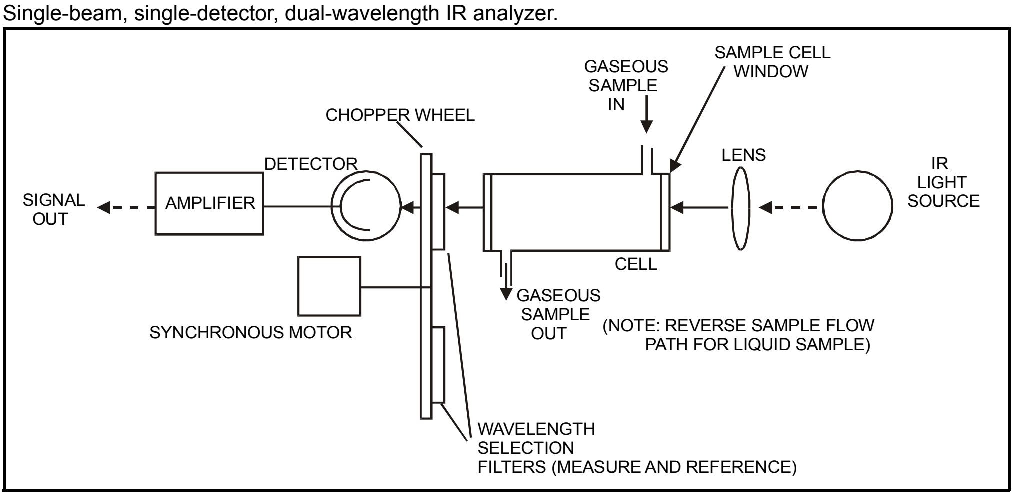
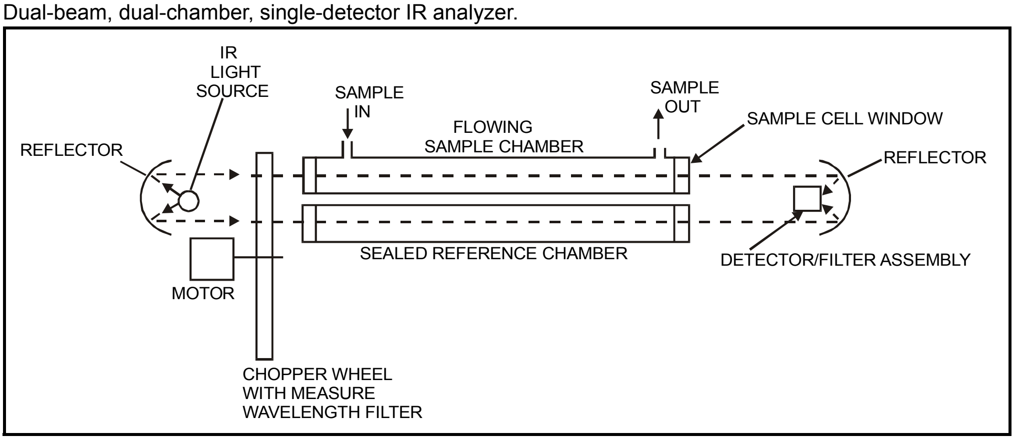


Figure 3-15
Dual-beam, dual-chamber, single-detector IR analyzer.



Application Notes

The infrared absorption detector can, in theory, measure from as low as 0 to 10 ppm, with sensitivities of 0.1 to 1 ppm, and up to 100 percent (v/v). Practically, however, the low range is between 200 and 500 ppm. The infrared absorption detector has a linear response, provides a continuous measurement, will respond within 3 to 5 seconds, and has an accuracy of +/- 0.5

percent of span with a +/- 1 percent drift every 24 hours. It is rugged and can operate, with proper maintenance, for long periods of time. This detector is used for gases, vapors, and liquids (and even for thin-film solids or powders). However, it needs to operate at a constant cell pressure for gases; a 1 percent change in cell pressure will cause a 1 percent measurement error. The infrared absorption detector also requires a sample that is clean, dust free, and without condensate.

The infrared absorption detector is commonly used to measure CO, CO_2, SO_2, NO, and ammonia. It meets CFR 40 Part 60 (method 10) for CO measurement, CFR 40 Part 60 (method 3A) for CO_2 measurement, and CFR 40 Part 60 (method 26) for HCl measurement. Its cost is relatively low and maintenance is easy. The unit requires typically about two man-weeks per year for maintenance.

The infrared absorption detector may have difficulty measuring components that have similar molecular structures since their absorption bands overlap. It will also experience interference as a result of moisture and temperature changes.

Mass Spectrometer

Principle of Measurement

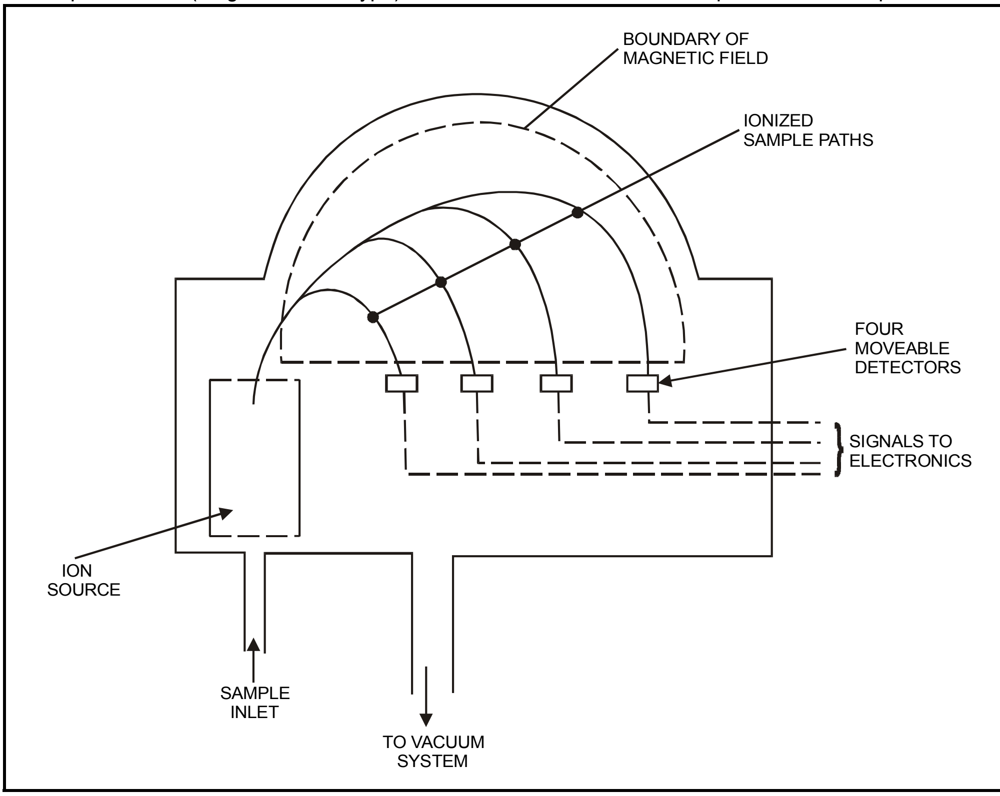
The mass spectrometer consists of six basic components: the inlet system, the ion source, the separator, the detector, the vacuum system, and the electronics/controller (see figure 3-16). It is one of the most powerful and versatile analyzers on the market. Mass spectrometers can analyze most components that can be vaporized and are compatible with the analyzer's operating temperature; it is a universal analyzer.

The mass spectrometer's inlet system introduces a small sample into the ion source by using a flow-by capillary or a membrane. The spectrometer's design must ensure that the introduced sample is a true representation of the fluid; therefore, sample fractionation must be avoided. The spectrometer's inlets are commonly heated to vaporize the liquid samples and to maintain gas samples above their dew points.

The ion source bombards the sample with electrons, forming a gaseous mixture of ionic fragments that drift into the analyzer. Positive ions are measured by injecting them into the separator. The separator separates the ions according to their mass-to-charge ratio. There are two types of separators: the quadrupole and the magnetic sector. In the quadrupole separator, the fragments are separated by a combination of DC electric fields and radio frequency. The magnetic sector separator uses a magnetic field to separate the ion beam, which tends to form a segment of a circular orbit. Each type has its advantages and disadvantages. But typically, the quadrupole is smaller, faster, more reliable, and less expensive then the magnetic sector type. On the other hand, the magnetic sector type is more accurate and more stable and requires less frequent calibration.

The mass spectrometer detector produces a voltage that is proportional to the ion beam that strikes it, which in turn is proportional to the amount of a particular component in the sample. The vacuum system creates a very low pressure in the system so as to avoid the collisions between the ions and gas molecules. This also increases the probability that the ionizing electrons do ionize the sample.

Figure 3-16
Mass spectrometer (magnetic sector type) for the measurement of four components in a sample.



The system's electronics, including a personal computer (PC), identify the results from the detector and compare their fingerprint to a database, thereby identifying the components. The PC controls the analyzer, tunes the system, and calculates the component concentrations.

Application Notes

The mass spectrometer has a fast and linear response. What may take ten minutes to analyze with another method, takes ten seconds with a mass spectrometer. It provides a highly reproducible measurement for a given set of conditions, offers an equal sensitivity to all components, and can measure up to 16 different components from a single stream.

The mass spectrometer provides continuous measurement and is used for gases, vapors, and liquids. The unit measures from ppb (but typically ppm) to 100 percent and has a sensitivity of about 0.01 percent with a measuring error of +/- 1 to 2 percent. However, it requires a sample that can be vaporized (when measuring chlorine or acid gases, the sample should be dry). Typically, it also requires special manifolds and valves for automatic calibration (they are controlled by the PC). The unit may change the form of the sample as a result of the vacuum that is produced. The vacuum may also bring in background gases, which introduce noise into the measured signal.

The analyzer of a mass spectrometer must be tuned every one to two months, and it is essential that maintenance personnel receive extensive training in its maintenance. Maintenance is complex, and the mass spectrometer's initial cost is high.

Non-Dispersive Infrared (NDIR)

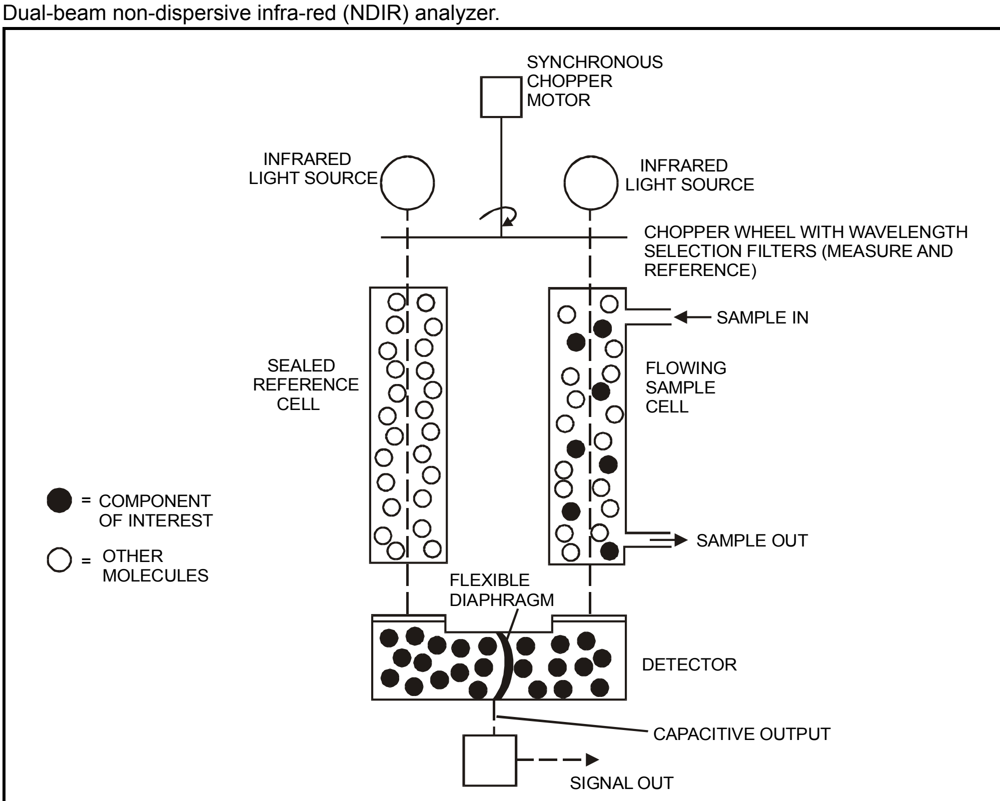
Principle of Measurement

Non-dispersive infrared systems (NDIR) are a type of infrared detector (see the earlier section in this chapter on infrared absorption). In the preferred dual-beam NDIR instrument, the infrared beam is split in two, with one beam passing through a sample cell and the other through a reference cell (see figure 3-17). The component in the sample cell will absorb radiation, whereas the radiation passes through the non-absorbing reference cell. IR radiation is absorbed by the sample molecules, which results in a detector imbalance. This imbalance is sensed by the detector and transmitted to a transducer.

NDIRs are dedicated to monitoring a single component, whereas FTIR detectors can provide multi-component analysis. NDIRs are available in single- or dual-beam types. The dual-beam NDIR has a separate reference cell and is used more frequently then single-beam NDIRs. The single-beam is cheaper, whereas the dual-beam is more sensitive and more stable, but costs more.

The stability of NDIR analyzers can be improved with the use of a single infrared light source, where a curved mirror is used to split the beam equally to the sample and reference cells. The sensitivity of this analyzer is proportional to the length of the measuring cell (which typically varies between 1 mm to 1 meter).

Figure 3-17
Dual-beam non-dispersive infra-red (NDIR) analyzer.



Application Notes

The NDIR detector can have a range of 0 to 5000 ppm (though typically it is 10 – 100 ppm) with a resolution of 0.1 to 10 ppm. It is often used as an open-path detection device for up to

650 feet (200 meters) in hydrocarbon applications or down to 1.5 ft (0.5 meters) for stack installations. The NDIR has a response time of 0.5 to 20 seconds (though typically 2 to 5 sec), with an accuracy of +/- 1 to 3 percent of full scale, depending on the component being measured and on the analyzer. The unit meets 40 CFR 60 and 75 when measuring CO and CO_2. It can measure moisture in a 0 to 95 percent range, with a +/- 0.5 percent accuracy, and typically requires about four hours to calibrate.

Paper Tape

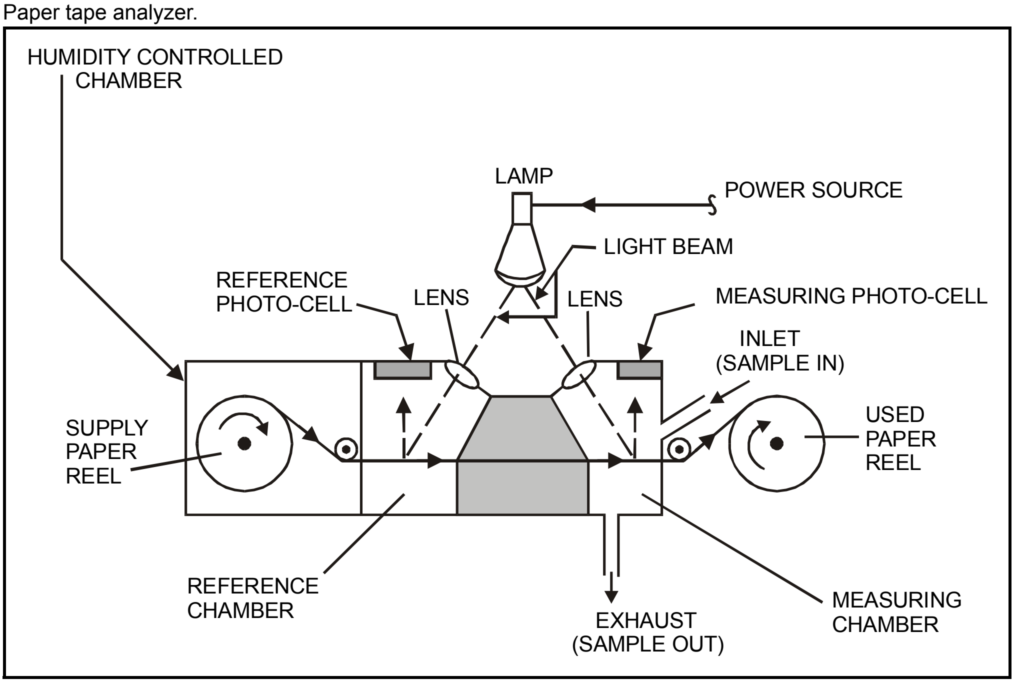
Principle of Measurement

In the paper tape technique, a chemically impregnated tape is drawn mechanically across a sample inlet where it comes into contact with a metered gas flow. If the component to be measured is present, a reaction takes place on the tape, and a colored stain is developed (see figure 3-18). An optical system illuminates the tape, and the reflected light is measured. The intensity of the stain is proportional to the concentration of the metered gas flow.

Application Notes

The paper tape analyzer, which is available as a battery-powered portable unit, can measure down to ppb and is reasonably accurate. It can operate within 32 to 104 °F (0 to 40 °C), is relatively inexpensive, and can be maintained simply and relatively quickly. In addition, it has a response time of 10 to 250 seconds (depending on the gas being measured).

Figure 3-18
Paper tape analyzer.



Paramagnetic

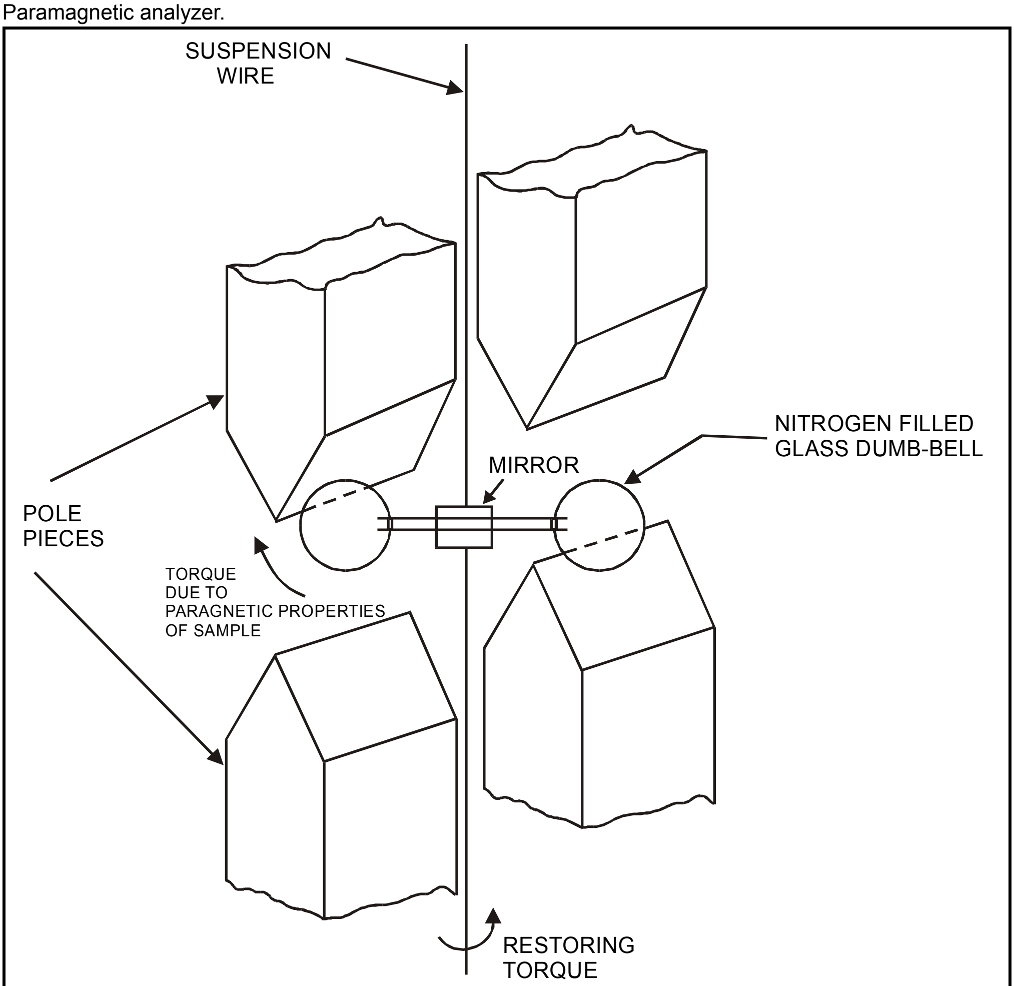
Principle of Measurement

The paramagnetic measurement technique (also known as "magneto dynamic") is dedicated to measuring oxygen. It is based on the physical principle that oxygen atoms are paramagnetic, that is, are attracted into a magnetic field. With some exceptions (see following application notes), most other species of atoms are diamagnetic (i.e., repelled by a magnetic field). In paramagnetic measurement devices, a small mirror is suspended between the poles of a magnet. When the gas containing the oxygen flows through the gap it deflects the mirror, and the degree of deflection is detected optically and amplified to give a direct measurement of oxygen concentration (see figure 3-19).

Application Notes

The paramagnetic detector is reasonably inexpensive and has a response time of 2 to 70 seconds (depending on the selected unit). It has an accuracy of +/-1 to 2 percent of range, a sensitivity of about 0.01 percent, and a sample temperature range that varies from about 32 to 110°F (0 to 44°C). The paramagnetic detector's maintenance requirements are low; it requires about two hours to recalibrate. However, it can only measure oxygen on a dry basis; for the wet measurement of O_2, the zirconia cell should be used. The paramagnetic detector also requires a low sample pressure; 10 psig (70 Kpag) is a typical maximum. The paramagnetic detector will experience measurement interference from NO, so it could therefore be used for measuring NO in the absence of O_2. In addition, the detector is susceptible to the presence of nitric oxide, nitrogen dioxide, chlorine dioxide, carbon monoxide, carbon dioxide, and certain hydrocarbon gases (CH_4, etc.) since these gases are also paramagnetic. For this reason, plants requiring low measuring ranges (2% or less) should be aware that background gases may cause significant errors. The paramagnetic detector also requires a sampling system and is susceptible to vibrations.

Figure 3-19
Paramagnetic analyzer.



pH

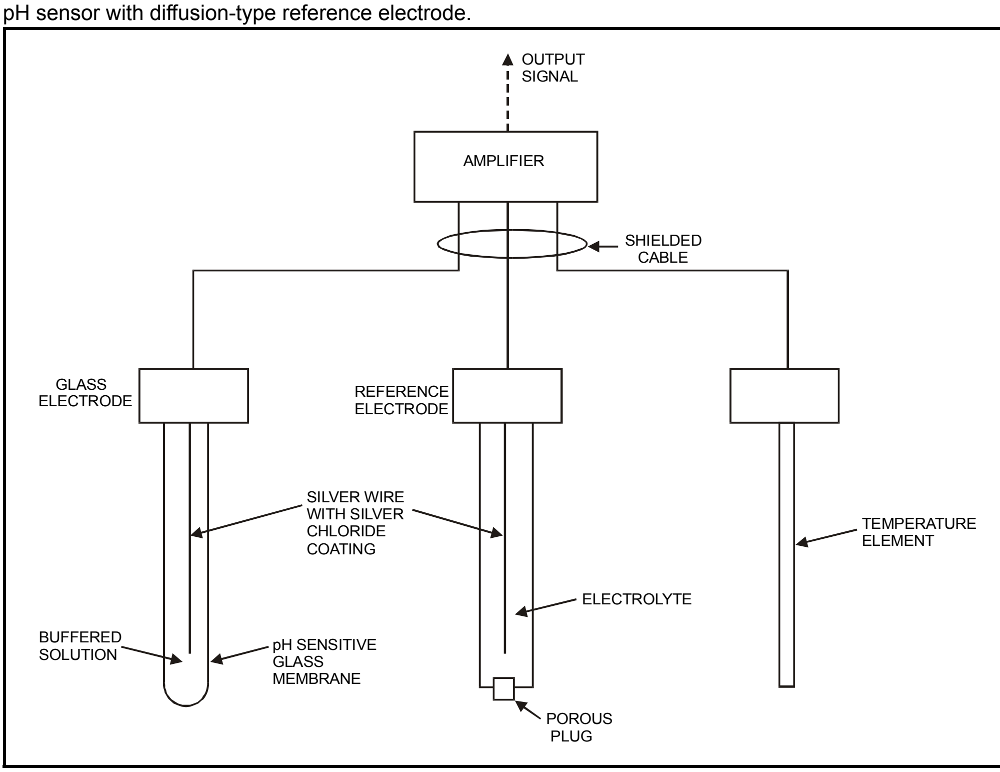
pH measures the concentration of hydrogen ions in a solution and is an indication of the solution's acidity or alkalinity. Therefore, the strength of an acid solution is indicated, through a logarithmic scale, by the number of hydrogen ions available. For example, a pH of 5 means that the hydrogen ion concentration is 0.00001 grams/liter at 25°C. The smaller the pH number, the greater the hydrogen ion concentration and, therefore, the solution's acidity.

The normal pH measuring range is 0 to 14. A pH of 7 at 25°C is for neutral (pure) water. Acidic solutions have a pH < 7, whereas alkaline solutions have a pH > 7 (i.e., a lower hydrogen ion concentration than an acidic solution). A pH of 0 is measured for 3.5 percent hydrochloric acid and a pH of 14 for 4 percent sodium hydroxide. The hydrogen ion concentration will increase ten times when the pH value drops by one. A pH of 7 has ten times the acidity of a pH of 8. So to reduce the pH of a solution from 6 to 5 requires ten times the amount of acid required to reduce the pH from 7 to 6.

Principle of Measurement

In pH measurement, an electrochemical sensor consisting of three electrodes—the glass electrode, the reference electrode, and the temperature electrode—is connected to an amplifier (see figure 3-20).

Figure 3-20
pH sensor with diffusion-type reference electrode.



Glass electrode. The glass electrode provides a potential that is proportional to the hydrogen ion concentration (pH value) of the solution. It consists of a glass membrane that contains a standard solution with a known hydrogen ion concentration in which is inserted an electrical conductor. The glass membrane is a poor conductor (i.e., has high impedance). The glass selected for the membranes of the electrodes must be compatible with the process fluid temperature and its pH value. When immersed in a solution, the potential developed across the glass membrane is measured between the electrode of the glass electrode and the electrode of the reference electrode. Glass electrodes are the most commonly used measuring electrodes. When immersed in a solution, they gradually reach equilibrium with the ions present in the solution and maintain equilibrium as the ionic strength of the solution changes.

The voltage developed between the measured solution and the standard solution in the glass electrode is caused by the difference in the ion concentration between the two solutions. When the glass electrode is immersed in an aqueous solution, a gel layer forms on the glass. That is, the electrode becomes "wetted" (for an alkaline solution, the hydrogen ions diffuse out, and the outer gel layer gets a negative charge, and vice versa for an acidic solution). Minute cracks in the glass membrane, not visible to the naked eye, will cause a constant reading of pH=7, that is, input of 0 mV. The electrode must be conditioned for a 24-hour period before it is used (i.e., left in solution) in order for the gel layer to generate on the surface of the glass. To prevent dehydration, the pH electrode should be stored in a wet environment. Extensive dehydration will ruin the pH electrode. pH probes should preferably be stored in a buffered solution, but if that is not available, tap water will do. The electrode may be preconditioned (memory effect) by exposing it continuously to a solution with a pH >10. As a result, the electrode will not respond well for low pH solutions, so specially formulated electrode membranes should be used.

Reference electrode. The reference electrode provides a constant potential regardless of the solution in which it is immersed. This potential is used as the reference from which to measure the variable potential produced by the glass electrode. The pH reference probe must be a good conductor (i.e., have low impedance) with the solution to be measured. There are two main types of reference electrodes: the diffusion type (where the electrolyte diffuses through a porous area) and the flowing type (where a small amount of electrolyte flows out of the reference electrode). For the flowing-type electrode, positive pressure must be maintained inside the reference electrode. For both types, the electrolyte must be in electric contact with the solution. The reference electrode is affected by coating the porous plug, which results in a gradual drift in calibration until complete plugging occurs. Electrolyte contamination must be avoided. The reference electrode is directly affected by the presence of poisoning ions, which react either with the electrolyte or with the electrode, causing coating. Typical poisoning ions are found in ammonia, chlorine, and sulfur solutions.

Temperature electrode. The temperature electrode is required to compensate for the varying potential at the glass electrode as a result of temperature changes. Temperature affects pH measurement in two ways: on the electrodes and on the solution itself. Employing temperature compensation in pH measurement will correct for the effects on the electrode and not for the changes in the solution's pH (although some transducers have a built-in capability to compensate for that effect as well). Temperature changes cause pH measurement errors in the solution because of the volumetric expansion (or contraction) with temperature, which results in a reduced (or increased) solution concentration.

Combination glass/reference electrodes contain the sensing electrode, reference electrode, and temperature sensor in one unit. They are small and easy to handle. However, the choice of sensing electrodes is limited, and they are more expensive to replace than individual sensing electrodes.

Application Notes

pH measurement is continuous and applies to liquids only. It is highly sensitive when the electrodes are kept clean, is reasonably inexpensive, and maintenance is relatively easy to accomplish. pH loops should be run on a continuous basis (rather than on/off). Typically, pH measurement has an accuracy of +/- 0.01 to 2.0 units and a temperature limitation of 210°F (100°C) max, although some special sensors can reach temperatures 30 to 100 percent higher.

The pressure limitation is 140 psig (1000 KPag) max. Some special units can operate under higher pressures.

In spite of their fragile appearance, glass electrodes are relatively robust, are resistant to most solutions, and have a wide pH and temperature range. Different glass formulations should be used for different process applications. For example, hydrofluoric acid will attack the glass material of the typical glass electrode, so an antimony probe should be used instead. Antimony is hard, brittle, and sensitive to temperature changes. In addition, glass probes will introduce errors when they are used with high alkali concentrations. High-purity water has only traces of contaminants and a very low conductivity, so special high-purity water pH sensors must be used. Sudden (and excessive) temperature changes will create a damaging thermal shock on the pH element.

Amplifiers with self-diagnostics facilitate troubleshooting. They typically monitor sensor breakage, fouling, non-immersion, incorrect operation, and time-in-service for the purposes of probe maintenance. Table 3-2 lists commonly encountered problems in pH measurement and their respective solutions.

Table 3-2
Troubleshooting guide

Problem	Possible Causes	Solution
None or only slight pH response	Broken pH electrode Heavily coated electrode Broken lead to probe	Replace Clean/replace Replace
Elongated span	Calibration Incorrect; manual temperature compensator set too low, automatic temperature compensator in error	Recalibrate Correct temperature compensation
pH offset	Reference junction fouled Reference solution contaminated	Clean/replace Replace
Noisy	Solution ground open Intermittent cell contact to sample Improper reference junction Reference junction fouled Air bubble in salt bridge Broken or shorted lead	Repair Ensure cell immersion and absence of air bubbles Replace Clean/replace Remove bubble Replace
Slow response	Dehydrated glass membrane Coated or dirty membrane Improper cell placement	Soak in weak salt solution for 2-3 h Clean/replace Place cell in area of uninterrupted flow

It is good practice to locate the electrodes where they are immersed at all times and where the proper flow rate is achieved around the electrodes through proper solution mixing/reaction. pH elements should be easily accessible for cleaning and replacement (see figure 3-21). Sometimes sampling systems are used; however, they may change the pH of the measured sample as the temperature and/or pressure changes.

Some applications use retractable sensors (hot-tap) so sensors can be easily removed and inserted without shutting down the process. Such insertion probes are supplied with a ball valve and a safety chain to prevent probe ejection.

The probe should be located (see figure 3-22) to avoid oil deposits, static interference (e.g., on plastic vessels and pipework), and shock (e.g., from sudden changes in concentration, pressure, or temperature). The line containing the probe should be flushed clear after each use and the probe left immersed in water when not in use. In the case of fluids that contain solids, some form of screening is necessary to prevent mechanical damage to the electrodes (see figure 3-23). Slurries with soft particles will tend to coat the electrodes; whereas hard particles tend to pit the electrodes, especially in high-velocity streams. pH electrodes are sensitive to static electrical interference, particularly where plastic pipes and vessels are used. Static charge may easily develop around the pH membrane, causing a noisy signal.

Figure 3-21
Flow-through element installation.

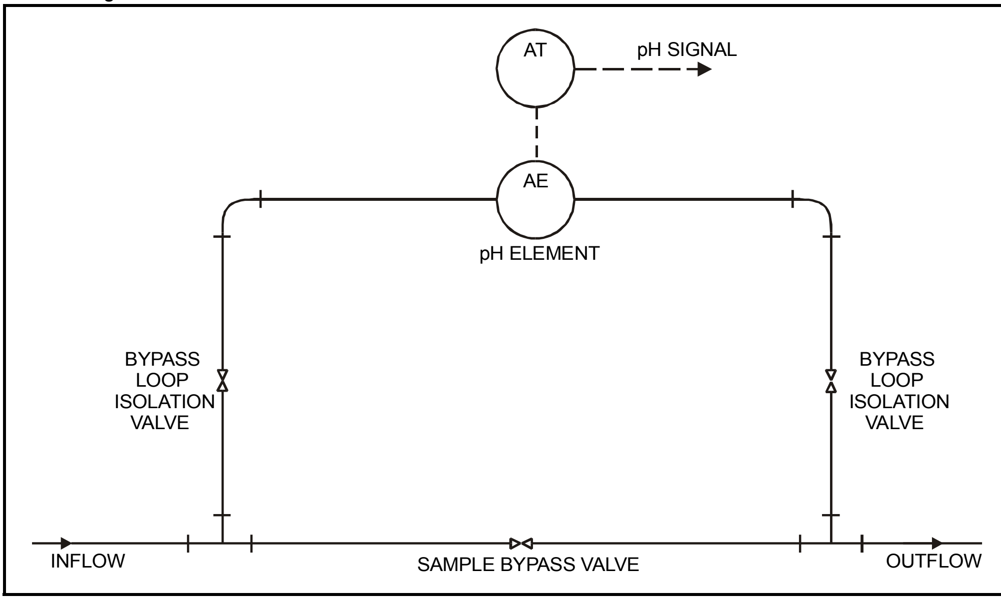


Figure 3-22
Probe protection using gravity effect.

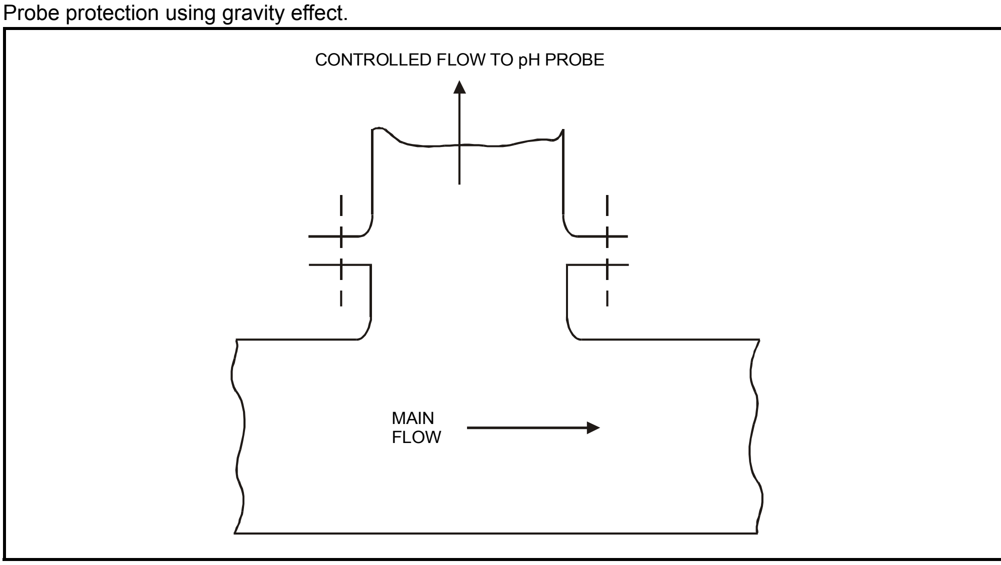
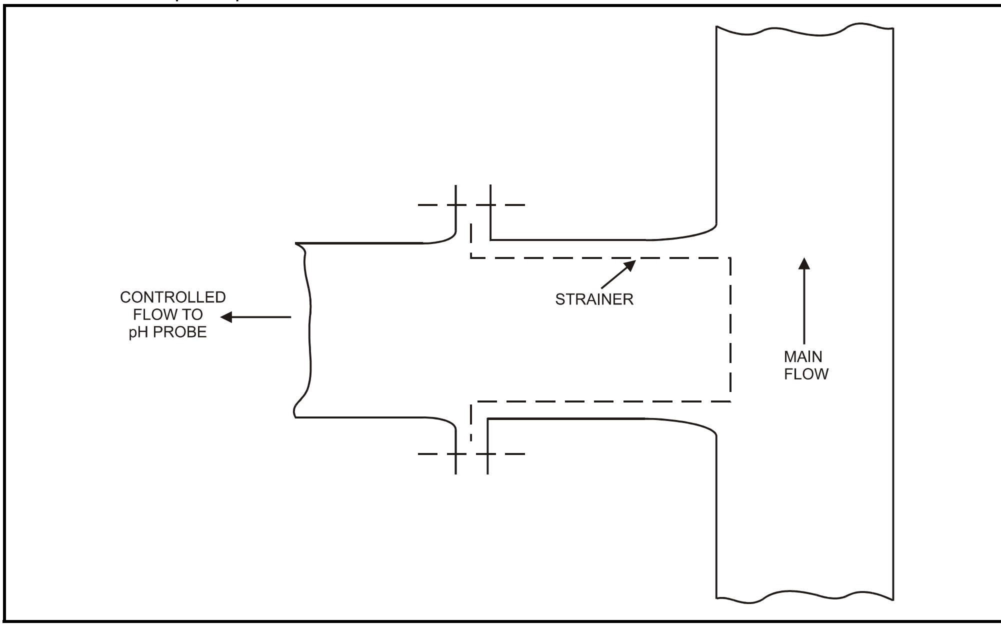


Figure 3-23
In-line strainer for probe protection.



Control

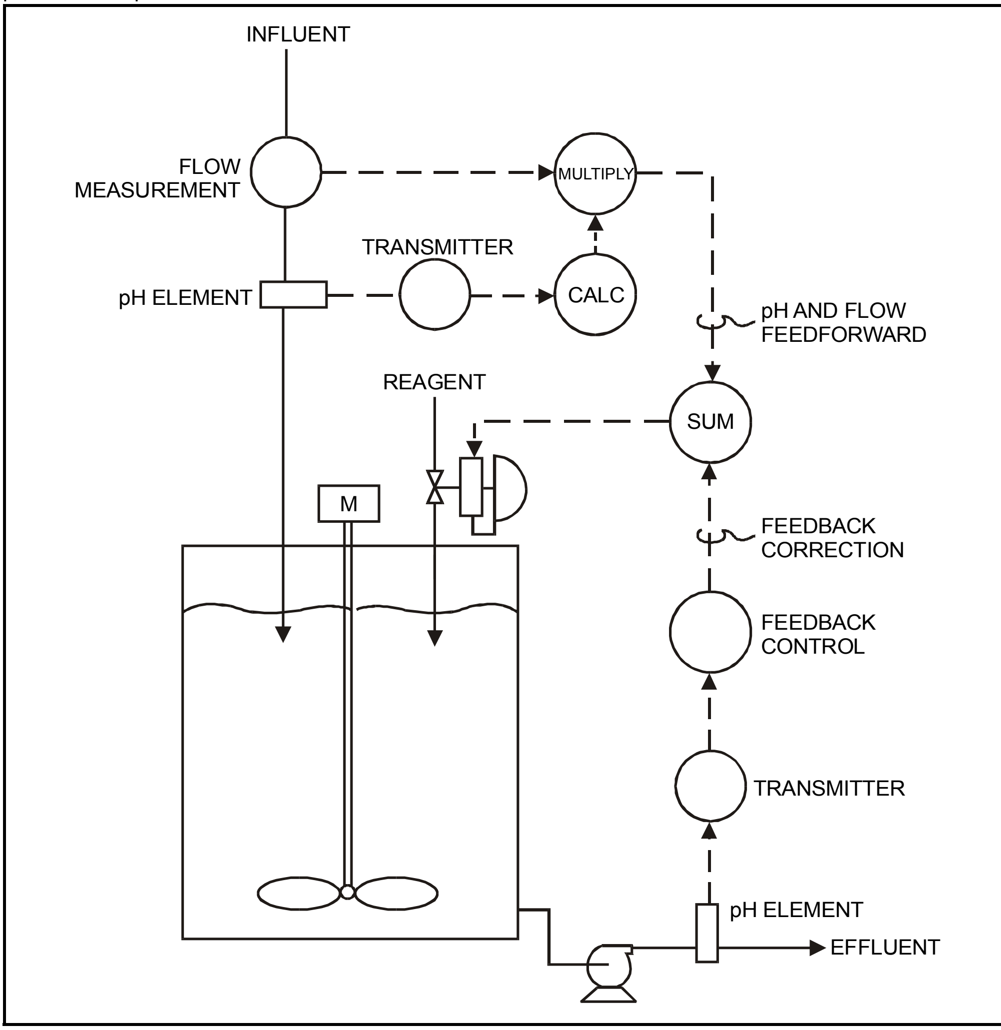
pH control has its own peculiar problems. The logarithmic term is non-linear, the titration curve is very sensitive near a pH of 7, and extensive dead time is normally present. In addition, the overall complexity of pH control is exacerbated by changes in effluent composition, flow errors in the reagent delivery system, performance degradation of pH probes, and imperfect mixing. In practice, after calibration a pH probe typically shows an error of 0.25 pH.

On its own, feedback control will generally not produce stable control because of the extensive dead time. For that reason, dead time must be minimized where possible. Typically, two or three stages of pH control may be necessary, and some plants add a few tanks in series to attain the desired pH, with each tank contributing ever closer to the pH setpoint. Feedforward offers a simple solution to this problem. It avoids, in many instances, the need to implement multiple tanks. As shown in figure 3-24, the feedforward action compensates for variations in flow and pH in the effluent stream before either one causes an error. Final corrections are performed by the feedback controller (refer to chapter 8 for more information on feedforward and feedback). In most cases, online pH loops will oscillate if the controller set point is on the steep part of the titration curve.

pH control that is performed in tanks will create a time delay. Following these rules may improve performance:

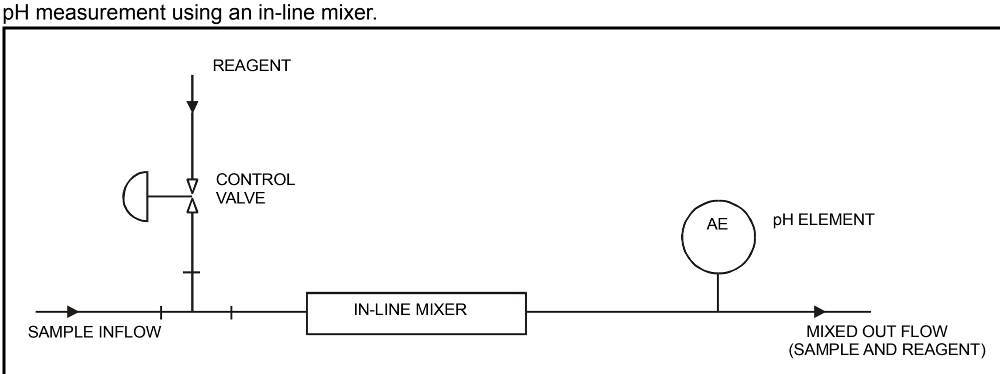
- the residence time T should be > 3 minutes ($T=V/F$)
- where V = volume of tank and F = effluent flow rate
- good mixing is achieved by using an agitator
- the vessel height should approximately equal the diameter
- the effluent should leave from the side opposite where the flow enters
- the reagent should be added before (and close to) the effluent flow inlet so as to pre-mix
- the pH probe should be located at (or close to) the flow outlet
- pH measurement in a recirculation line (sometimes incorporating an open weir box) makes retrieval or maintenance easy

Figure 3-24
pH control loop.



If pH control is done in a static in-line mixer (see figure 3-25), a pump may be required to provide sufficient driving head to overcome the friction of the mixer. This method is used where the pH inlet value varies by 1 unit maximum.

Figure 3-25
pH measurement using an in-line mixer.



The control valve required to add the reagent(s) should be linear with a 1:50 valve range (remember that pH is a log scale). The valve turndown must meet the process requirements, that is, split-range valving may be required (with two or even three valves), and the output should be linear throughout the range of all valves.

Because of how difficult it is to implement a correct pH installation that operates effectively, it is recommended that plants use conductivity measurements where possible. pH should be used only if hydrogen ions, rather than total ions, need to be measured.

Cleaning

Cleaning the pH electrodes is essential to their proper operation. For example, a 1 mm-thick slime will increase dead time from eight seconds to eight minutes. Grease and oil films coat the electrode and isolate the solution from the glass membrane, which results in a false reading. Therefore, plant personnel should not touch the sensitive glass area of the element with bare hands.

There are three basic methods for cleaning pH electrodes: manual, self-cleaning, and automatic. Note that during cleaning, the measurement signal should be isolated and held until the measurement returns to a steady value. In process environments where pH measurement is required continuously, the plant should make spare electrodes ready for use. In other cases, online backup electrodes, or even a two-out-of-three voting system, can be implemented to ensure continuous reliable measurement. In critical applications, the plant should install three electrodes (for a two-out-of-three vote) since with only two electrodes it is difficult to identify which one is drifting.

Manual cleaning. In the manual cleaning process a cleaning solution (for example, 5% muriatic acid) is used. Typically, it takes about 30 man-hours/year to manually clean an electrode that is set under average operating conditions.

Self-cleaning. Self-cleaning is accomplished by locating the electrodes in a high-velocity location that has a flow of 5 to 10 ft/sec (1.5 to 3 m/sec). However, while the impinging flow keeps the electrode clean, extremely high flow velocities will quickly deplete the reference electrode.

Automatic cleaning. Automatic cleaning can be accomplished by using ultrasonic, chemical, brush, or water-jet methods.

In the ultrasonic method, the liquid around the electrodes vibrates, and the cleaning effect is dependent on the vibration energy and the fluid velocity past the electrodes. This method is particularly effective with fine particles and supersaturated sediments, whereas soft or sticky deposits tend to absorb the ultrasonic energy. For ultrasonic cleaning, the electrodes must withstand the ultrasonic energy of approximately 70 kHz.

The chemical method consists of periodically spraying a chemical onto the electrodes, typically a dilute hydrochloric solution. It is particularly effective with light oils, fatty acids, and materials in suspension. It is important to ensure that the chemical used will not interfere with the sensor's operation or affect the process.

The brush method is used periodically (say, once a minute) and consists of moving a brush along the electrodes to prevent sediments from forming. There is no interruption of pH measurement during cleaning, however, sticky material can adhere to the brush and get smeared on the electrodes. The abrasiveness of the brush method may affect the sensor's performance, and it should therefore be used only on abrasion-resistant surfaces.

In the water-jet method, a spray of hot water is periodically aimed onto the electrodes. This method is particularly effective with slime, microorganisms, fatty acids, and clay in suspension. In some applications, the water-jet method is enhanced by introducing air into the water jet, improving the cleaning effect.

Calibration

Typically, calibration is performed weekly (and in some cases, more frequently) using one of three commonly available buffered solutions: 4 pH, 7 pH, and 10 pH.

The first step in calibration is to clean the electrodes. They are then immersed sequentially in two different buffered solutions set 3 pH units apart. These steps may be repeated a few times until correct values are reproduced. At the end of the process, the calibrated reading should be within 0.1 pH of the buffered solutions. The user should allow time for the electrodes to reach stability (i.e., develop a gel surface on the glass electrode) before considering whether the reading is accurate.

Another method is to use a calibrated portable pH sensor and to compare the reading with the online sensor by taking a sample from the process. This is sometimes called a "grab sample" calibration. In this method, the measuring sensor does not need to be removed from the process. However, a measuring error could result from the sample changing its temperature, pressure, or consistency when it is removed from the process.

Polarographic

Principle of Measurement

The polarographic element consists of placing a gold cathode (the measuring electrode) and a silver anode (the reference electrode) in contact with a buffered solid electrolyte that is protected from the process by a permeable membrane. A temperature electrode is added to compensate for varying potential caused by changes in temperature (see figure 3-26). In this method, gas from the process diffuses through the permeable membrane and is reduced at the cathode. This causes a current that is proportional to the gas concentration to flow between the cathode and anode.

Application Notes

The polarographic cell, which is used for gases, has a typical accuracy of 1 to 2 percent, a response speed of less than a minute, and a high degree of sensitivity. It provides continuous measurement, is relatively low in cost, and is easy to maintain. The polarographic unit is capable of handling process temperatures of 32 to 110°F (0 to 45°C) and pressures of 0 to 50 psig (0 to 350 Kpag). It can handle a sample of 0 to 95 percent relative humidity (non-condensing) and is commonly used for CO, percentage of O_2, and ozone analysis. However, the polarographic element experiences an interference from trace contaminants and is affected by H2S on the electrolyte.

Radiation Absorption

Principle of Measurement

Radiation absorption measurement (also known as "gamma-ray" or "nuclear" measurement) consists of two main components, a gamma-ray source and a detector, both of which are located outside the process. The measurement unit clamps onto the process line, with the source on one side and the detector on the other. The gamma rays pass from the source through the pipe (or vessel) wall, into the fluid, through the second wall, and onto the detector. Material flowing through the pipe (or contained in the vessel) will absorb some of the gamma rays. The remaining energy is measured at the detector and is inversely proportional to the density of the measured fluid (see figure 3-27).

Figure 3-26
Polarographic cell.

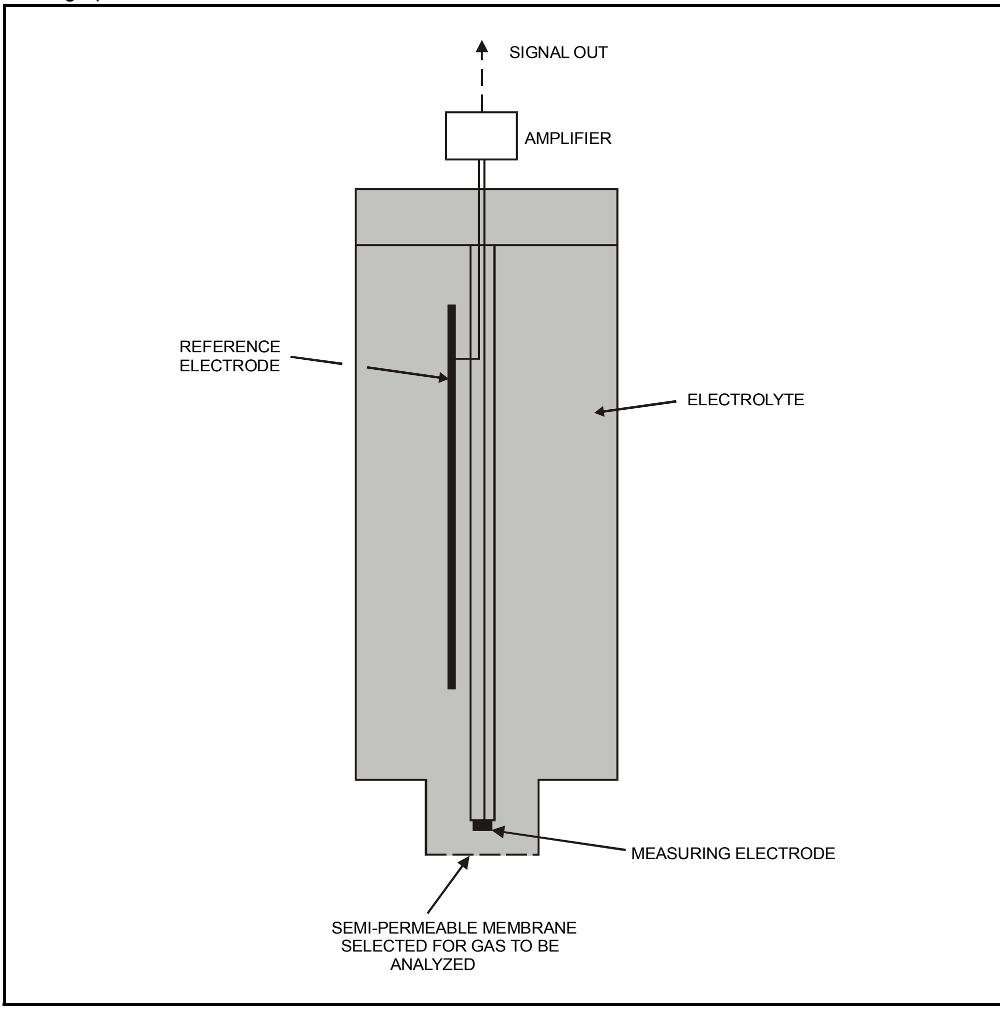
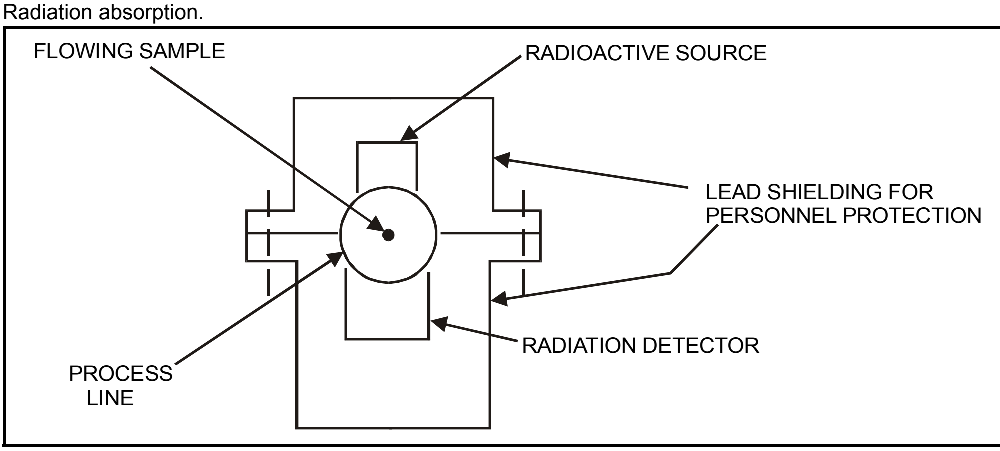


Figure 3-27
Radiation absorption.



Application Notes

The radiation absorption method will measure the density of solutions, liquids, slurries, or finely divided solids. It is applicable for clean as well as dirty fluids. The absorption unit is independent of the process conditions and therefore is not limited by process temperature and pressure. It is also non-contacting and therefore the process must not be shut down to install it or perform maintenance. The radiation absorption unit gives continuous measurements, has an accuracy of +/- 1 percent of span, is highly sensitive, requires little maintenance (about 1 man-week per year), and has a response time of about ten seconds. However, it is expensive, requires about 30 minutes of warm-up time, and presents a radiation hazard. Exposing personnel to radiation is an ever present hazard of this method. All codes must be strictly followed, including obtaining a license, disposing of old units, and properly training personnel.

Rotating Disk Viscometer

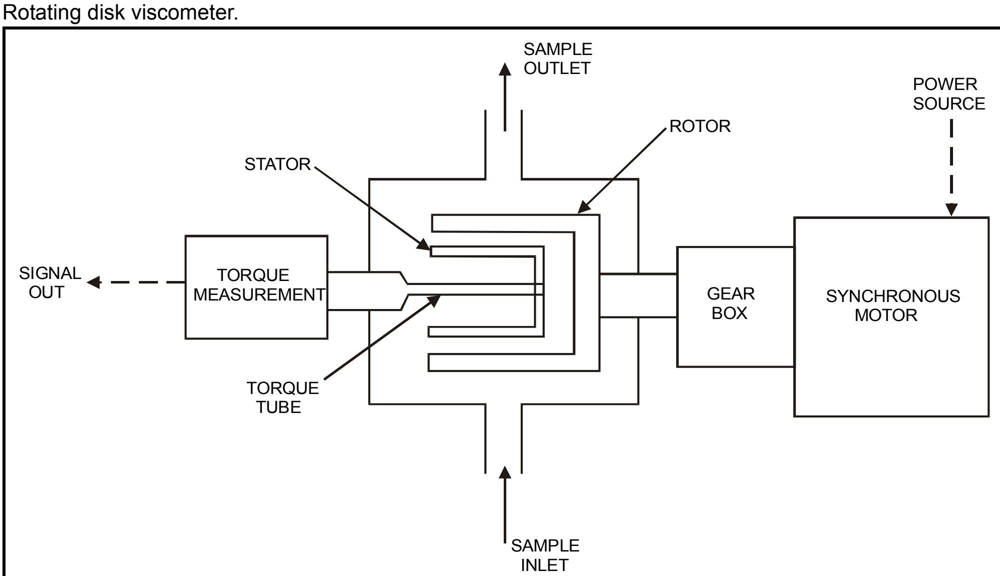
Principle of Measurement

The rotating disk viscometer consists of two concentric cylinders: a rotor and a stator. A single-speed synchronous motor rotates the rotor, while the stator senses viscosity by sensing the viscous drag as measured by a torsion element (see figure 3-28). The resistance to the rotation is a torque that is proportional to the shear stress of the fluid, which is then converted into a modulating signal. The multitude of shapes and sizes available for these rotors and stators, in addition to variations in rotating speed, make possible a wide range of measuring capabilities. A temperature compensation method is commonly added to maintain a constant reference temperature while the process temperature changes.

Application Notes

The rotating disk provides a measuring range of 50 to 25,000 centipoise (some units can even reach 720,000 centipoise). The disk has a typical accuracy of +/- 1 percent of span and a repeatability of +/-0.5 percent of span. It can operate from -40 to 300°F (-40 to 150°C) and up to 4000 psig (28,000 Kpag).

Figure 3-28
Rotating disk viscometer.



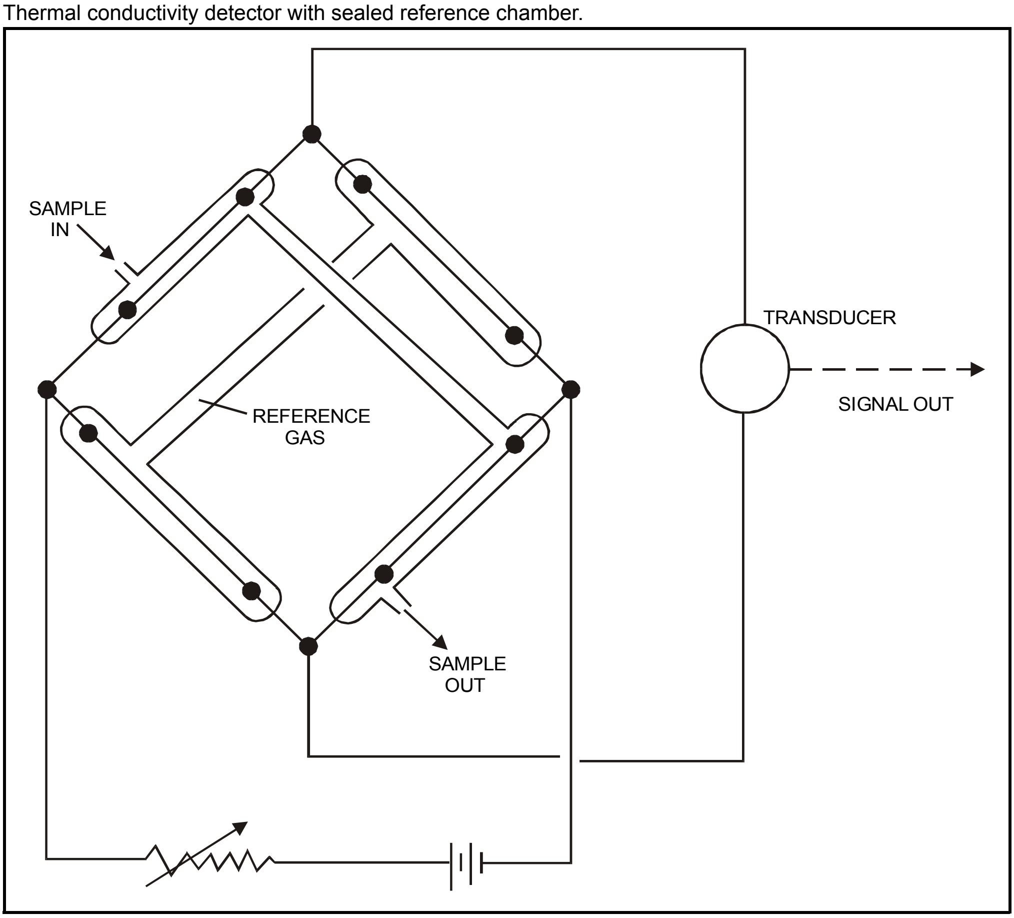
Thermal Conductivity Detector (TCD)

Principle of Measurement

The thermal conductivity detector (sometimes called a "katharometer") is based on the principle that different gases have different abilities to conduct heat. The detector measures the change in thermal conductivity of the sample gas versus a reference gas. The detector consists of heated temperature-sensitive (usually platinum) wires arranged in an elongated helix. Two wires are exposed to the sample and two to the reference gas. An equilibrium is reached when the electrical power input creates heat that is equal to the thermal loss from the wires. The temperature rise of the wire is inversely proportional to the thermal conductivity of the sample gas. When the sample composition changes, the temperature of the heated wire changes as well, changing the resistance of the wire. This resistance change is proportional to the gas concentration. The sensors are part of a Wheatstone bridge circuit (see figure 3-29).

The thermal conductivity detector typically requires that the detector be supplied with a sampling system and a clean sample. Some units have a sealed reference gas chamber, which does not require a flowing reference gas. Thermal conductivity is not an absolute method and depends on empirical calibration. It is also used as a detector in gas chromatography.

Figure 3-29
Thermal conductivity detector with sealed reference chamber.



Application Notes

The thermal conductivity detector is used for gases and vapors only. It has an accuracy of +/-1 to 5 percent of full scale, depending on the unit selected, and a response time of less than 30 seconds. It is reliable and simple to use, but it generally requires either that water vapor be removed from the sample stream or that the sample be saturated at a constant temperature so as to minimize the effect of water vapor on the measurement of thermal conductivity. The thermal conductivity detector also requires a clean sample that is free from suspended particles so the sensing wires are not contaminated.

Ultraviolet

Principle of Measurement

When ultraviolet (UV) light passes through a transparent material, some of the wavelength may be absorbed by the material. This selective absorption is the basis for UV analyzers. Light absorption is measured as a decrease in light intensity as a result of the interaction of the light energy with the absorbing material. The lost energy is converted into heat and/or chemical reactions. It is possible to identify several absorbing components of a mixture on the basis of their individual pattern of absorption versus wavelength. The absorbance of a component is directly proportional to the material concentration that causes the absorption; that is, the amount of radiation transmitted by the component decreases as the concentration increases. Many materials do not absorb UV, such as water, CO, CO_2, N_2, and O_2. Others, such as sulfur-containing compounds, strongly absorb UV radiation.

The ultraviolet (UV) analyzer applies the Lambert-Beer law. It consists of a light source, a wavelength isolator (i.e., a filter), a sample cell, and a detector. A basic single-beam UV analyzer is shown in figure 3-30.

When heat is applied to a material, radiant energy is emitted. The light source produces the radiant energy and consists of a long-life gas-discharge lamp that emits fixed wavelengths in the near-UV region of the spectrum (from 200 to 380 nanometers). The UV region has shorter wavelengths than those associated with visible light.

The wavelength isolator is basically an optical filter (or a holographic grating) that allows radiation to pass through the cell. The measuring filter is typically a narrow-band-pass filter that is chosen so only the wavelength of the component to be measured is allowed through. When a reference filter is used, it is selected to act as a narrow-band-pass filter that prevents the measured or background components from absorbing the radiation. The reference filter compensates for changes in radiation so as to maintain accuracy of the analyzer. Optical filtering can be located before or after the sample.

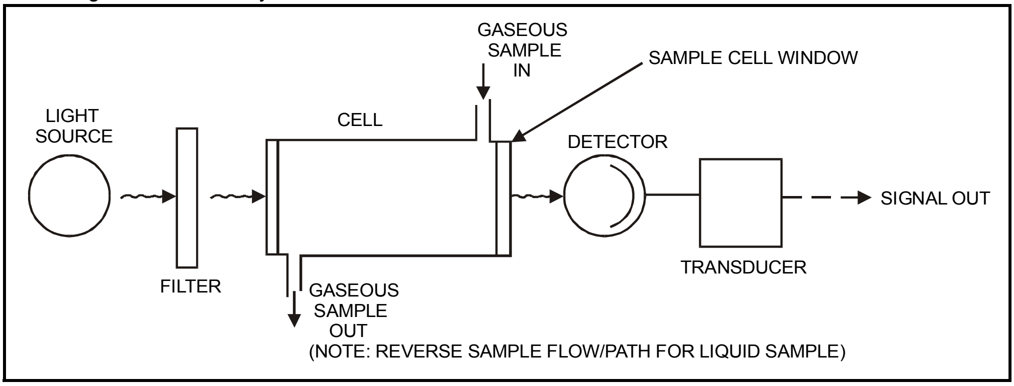
The sample cell is generally cylindrical with optical windows at both ends. Its purpose is to contain the sample and provide a flow path for the radiation from the light source to the detector. The windows are transparent at the chosen wavelength since different window materials will produce different wavelength regions. The cell must be mechanically and physically compatible with the sample being measured. The length of the cell varies from as small as 0.001" (0.025 mm) to as long as 6 ft (2 m).

The detector (with its transducer) measures the incoming radiation and converts it into an electrical output. The detector is selected based on the plant's sensitivity requirements and wavelengths.

There are different types of UV analyzers. The most common ones are the following:

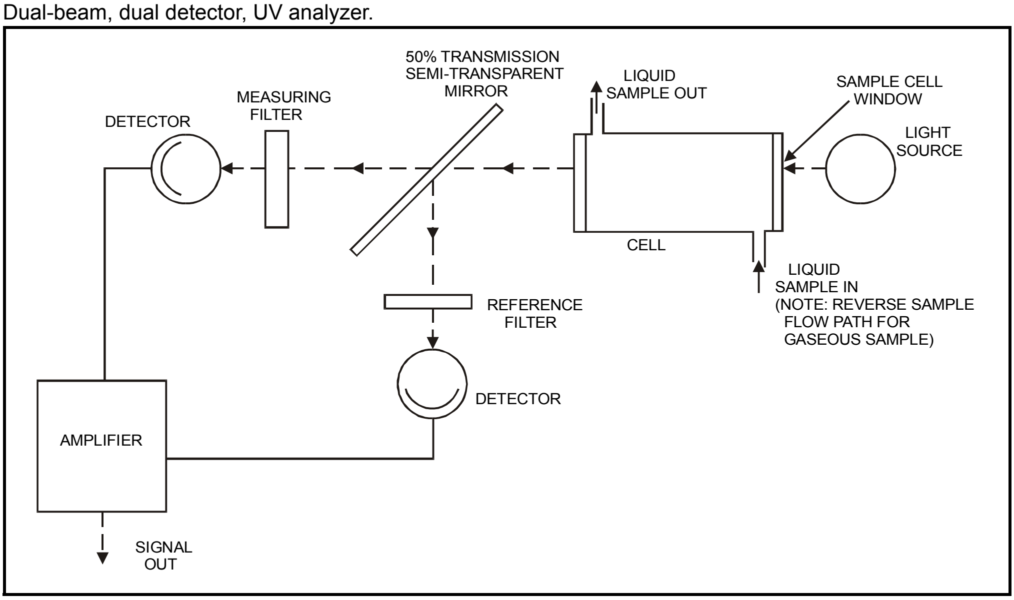
1. The basic single-beam (see figure 3-30). These analyzers are simple in design, but their outputs are affected by fluctuations and drifts of the light source and by dirt in the sample cell. They are used for low-sensitivity measurements such as go/no-go applications.

Figure 3-30
Basic single-beam UV analyzer.



2. The dual-beam, dual detector (see figure 3-31). In these analyzers, the beam is split by a semitransparent mirror. One beam goes through the sample while the other is used as a reference. These units are simple in design and easily manufactured; however, separate filters and optical trains create signal imbalances and zero drifts.

Figure 3-31
Dual-beam, dual detector, UV analyzer.



3. The single-beam, dual-wavelength, single detector (see figure 3-32). In these units, a chopper motor rotates the filter wheel, exposing filters alternately to the beam's path reference. The measure filter is selected to allow only one wavelength through, that of the component to be measured. These units are more stable then the dual-beam, dual detector type.

4. The dual-beam, dual-chamber, single detector (see figure 3-33). In these analyzers, the light source, reflecting from a conical front mirror, splits into two beams. A chopper wheel alternately blocks the beam to the sample and reference chambers. When the beam passes through the reference chamber, no absorption occurs. However, when the beam passes through the sample, absorption does occur and is sensed by the filter/detector assembly. The filter is selected so as to allow through only the wavelength for the component to be measured. These units are relatively stable.

Figure 3-32
Single-beam, dual-wavelength, single detector, UV analyzer.

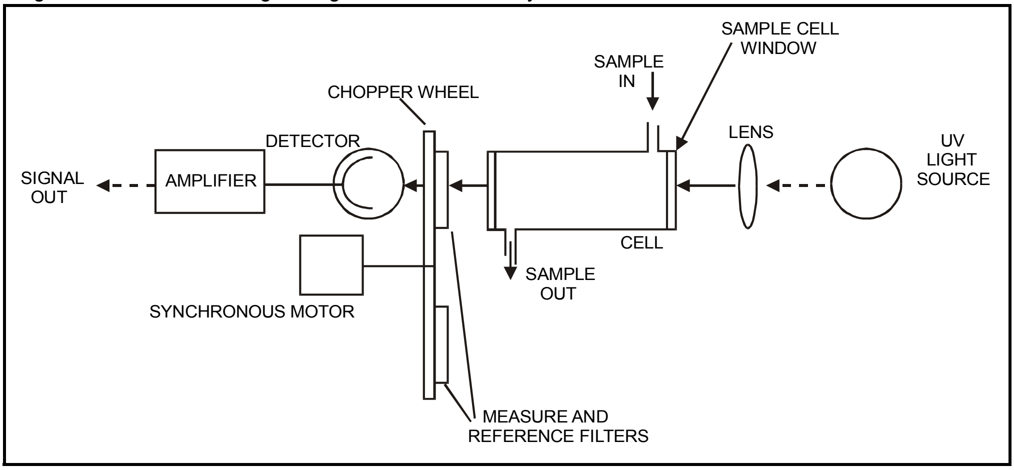
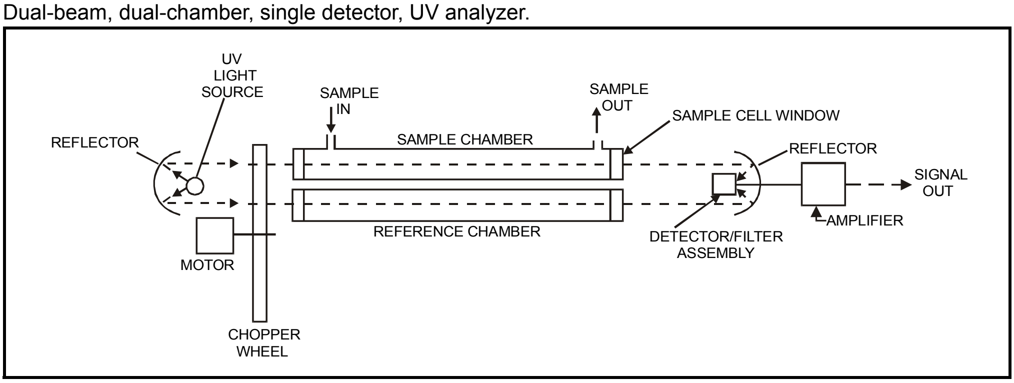


Figure 3-33
Dual-beam, dual-chamber, single detector, UV analyzer.



Application Notes

The ultraviolet (UV) analyzer will measure liquids, gases, vapors, and sometimes thin-film solids. It is rugged, provides a continuous measurement, and does not have many of the limitations applicable to infrared analyzers due to the relatively high energy level associated with UV. Most of the problems encountered in this method involve the sampling system rather than the UV analyzer itself.

UV analyzer units do not require that moisture be removed from the incoming sample, which results in a simpler system that does not require special condensers. These units have a typical error of +/- 1 to 2 percent of full scale and can measure concentrations down to 2 ppb for a 0-1000 ppb range. They can handle sample pressures up to 3000 psig (21000 Kpag) with special windows and temperatures up to 1000°F (538°C), but are generally limited to 100 psig (700 Kpag) and 140°F (60°C).

The UV analyzer is easy to maintain. It requires about one to two man-weeks per year for maintenance. It meets CFR 40 Part 60 and 75 when measuring SO_2, NO, NO_2, and NOx. It also meets CFR 40 Part 266 when measuring Hg. For liquid applications, the analyzer's sample cell should be arranged so that the flow enters at the bottom and exits at the top to prevent gas bubbles from being trapped. For gas applications, the analyzer's sample cell should operate such that the flow enters at the top and exits at the bottom to prevent liquids and solids from being trapped. The UV analyzer has a response time of 0.5 to 120 seconds, depending on the length of the analyzer cell path length and on the sample being analyzed. However, it does require a clean sample and is relatively expensive. Moreover, its light source can cause photochemical reactions, which can sometimes lead to dangerous conditions or maintenance problems.

Vibrating U-tube

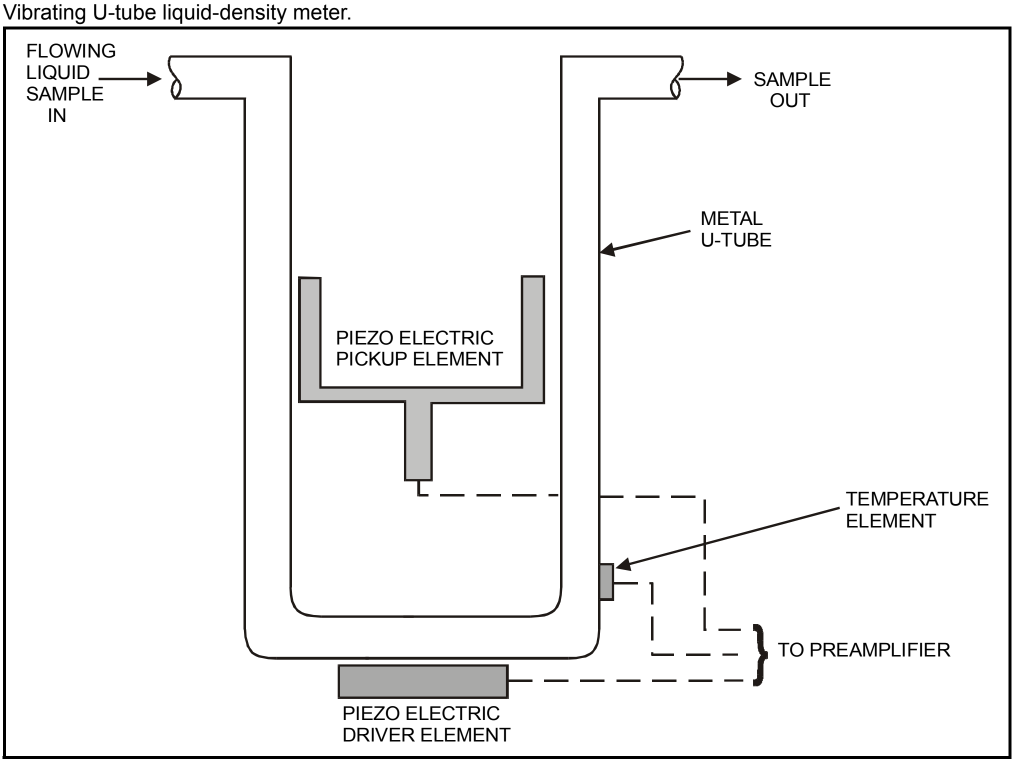
Principle of Measurement

The vibrating U-tube, which is used to measure density, consists of an electromagnetic circuit that supplies a transverse oscillation to a tube through a driver. As the liquid density changes, the measured frequency of oscillation, as detected by a pick-up element, will vary (see figure 3-34). This measurement is then converted into an output. Sometimes a straight rather than a U-tube is used, but the same principle of operation applies. Another way to describe this sensor is to compare it to a tuning fork whose frequency is determined by its material and shape. If the tuning fork is hollowed out and then filled with a liquid, that liquid will determine the tuning fork's vibrating frequency.

Some definitions:

- Density = mass per unit volume of a liquid
- Specific gravity = ratio of the liquid density being measured to the density of water (with the temperature of both liquids stated)

Figure 3-34
Vibrating U-tube liquid-density meter.



Application Notes

The vibrating U-tube is very reliable and accurate (up to 0.00015 g/cc), is unaffected by variations in viscosity and flow, and does not require frequent calibration (once every two years is average). It is used mainly to measure liquid density (or specific gravity), with process temperature and pressure ranges of up to 330°F (200°C) and 2000 psig (14000 Kpag). The vibrating

U-tube requires a sample flow rate of 0.5 to 7 gpm (2 to 25 L/min). Offsetting its advantages, it is expensive and neither initial setup or ongoing maintenance is simple. Temperature fluctuations are its greatest source of measurement error, and therefore, temperature compensation is required.

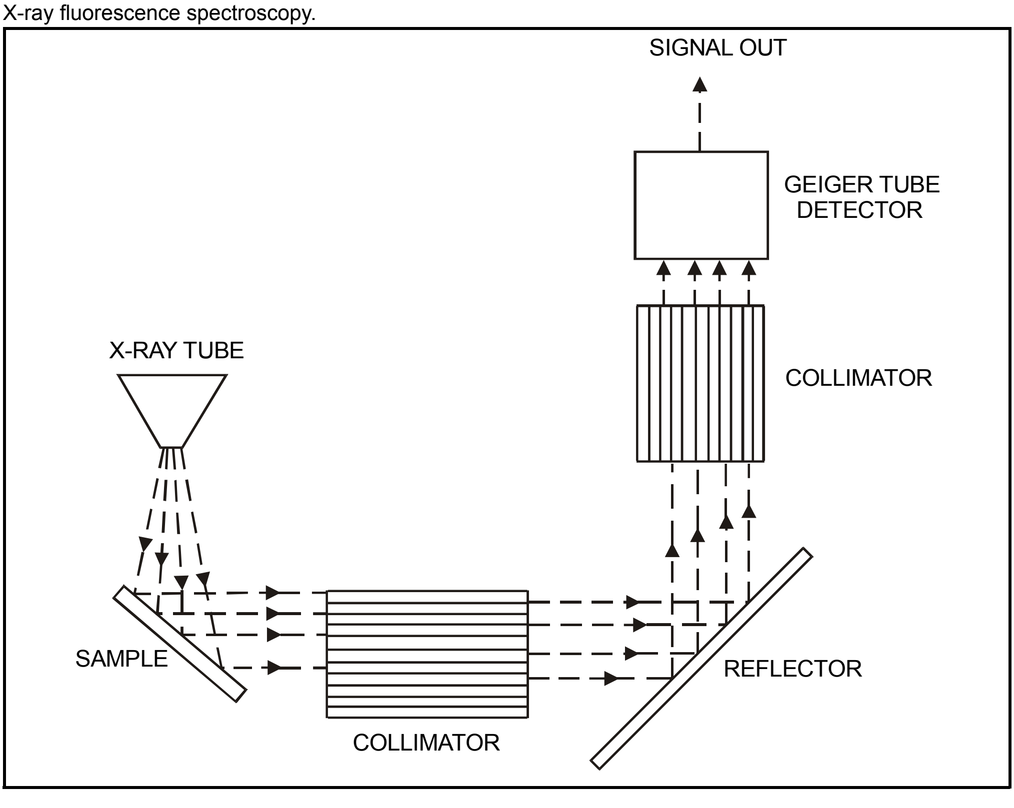
X-Ray Fluorescence Spectroscopy (XRF)

Principle of Measurement

In the x-ray fluorescence spectroscopy (XRF) method, a known volume of the sample is subjected to a low-level radiation source from one of a range of sources, depending on the application. This causes each element in the sample to emit characteristic fluorescent x-rays (see figure 3-35). The intensity of these characteristic x-rays is proportional to each element's concentration. For solids, XRF provides essentially surface analysis. However, with lighter elements, the analysis can reach a penetration of up to ¼″. A computer is commonly attached to the XRF as an analytical system.

The XRF technique can analyze up to 36 elements, though more commonly 6, simultaneously. XRF is typically used to measure metals in a variety of liquid and solid samples. Portable units are used particularly in remediating hazardous waste sites where contaminants such as lead, copper, zinc, nickel, mercury, and the like need to be detected. XRF is also used to analyze airborne particulates on filters.

Figure 3-35
X-ray fluorescence spectroscopy.



Application Notes

The XRF technique measures solids, liquids, slurries, and powders. It has a typical range of 5 ppm (and down to 1 ppm for heavier elements) to 100 percent and is available in a battery-powered field portable version. It provides continuous measurement, is easy to maintain, and is highly sensitive. The accuracy of its measurement depends on the particular element being analyzed and on the other elements that exist in the sample. Typically, an error of 1 percent is expected with this technique. On the other hand, it is expensive and is usually not applicable to elements whose atomic weight is less than that of sulfur.

Zirconia Oxide Cell

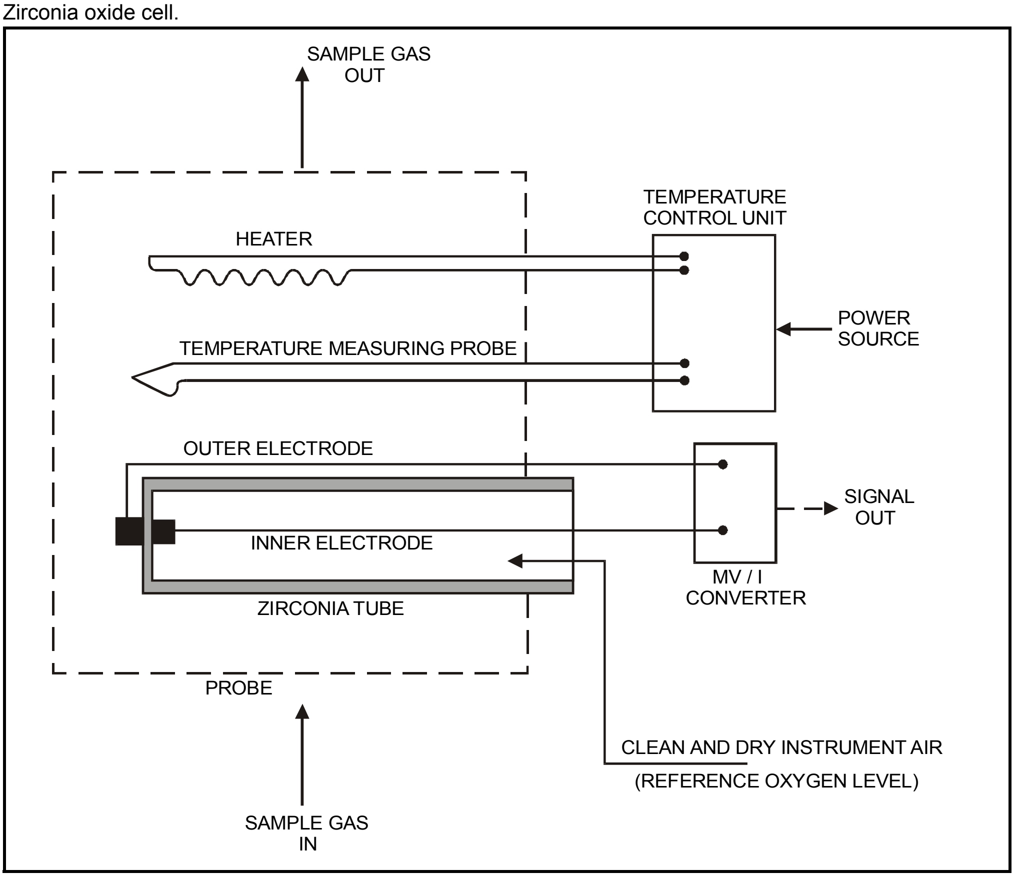
Principle of Measurement

The zirconia oxide cell consists of a solid electrolyte made of zirconium oxide ceramic. This material develops a potential difference (per the Nernst equation) between surfaces that are exposed to different concentrations of oxygen. On the inside and outside surfaces of the solid electrolyte, two porous platinum electrodes serve as conductors (see figure 3-36). Instrument-quality dry air is used as a reference gas on one side of the cell while the other is exposed to the sample gas.

The measured voltage has a logarithmic response to oxygen concentration, with the greatest sensitivity at low concentrations since the cell output increases with a decrease in oxygen concentration. Typical ranges are 0 to 10 vol.% and 0 to 30 vol.% oxygen.

The zirconia oxide cell must be maintained at a temperature of 1110 to 1470°F (600 to 800°C), depending on the selected unit. The cell's performance is sensitive to temperature fluctuations. To avoid significant errors, plants commonly use temperature sensors and heaters to maintain the set temperature.

Figure 3-36
Zirconia oxide cell.



Application Notes

The zirconia oxide cell may measure oxygen in gas on a wet basis, whereas paramagnetic oxygen measurement can only be done on a dry-gas basis. The cell has a response of 1 to 20 seconds (depending on the unit) and a typical accuracy of +/- 1 to 2 percent of full scale. It may be installed in line, thus avoiding the need for a sample line. The zirconia oxide cell is typically used in stack measurement; however, extractive types are used where extreme process conditions exist. These units are simple in design, meet CFR 40 Part 60 (Method 3A) when measuring oxygen, require relatively low maintenance (about two man days/year), and have a mean-time-between-failures of about one to two years. Some zirconia oxide cell units can handle process temperatures of up to 3200°F (1760°C), but the operating pressure is typically limited to 10 in. (250 mm) W.C.

Zirconia oxide cell units are susceptible to breakage from mechanical shock and unburned organic contaminants (e.g., CO) will introduce error into the measurement. They may require the use of purge connections with periodic blowback to minimize plugging by entrained particles.

CHAPTER 4

Flow Measurement

Overview

Flow measurement is a key parameter used by plants for reading values (including accounting needs) and for controlling processes. Of the typical process measurements—flow, level, temperature, and pressure—flow tends to be the most difficult and, therefore, the one for which incorrect devices are most likely to be selected.

The technology of flow measurement has evolved to the point where highly accurate and reliable devices are now on the market. Moreover, new measurement principles are being introduced, and existing principles are continuously improved upon. As a starting point, it should be mentioned that no single flowmeter can cover all flow measurement applications. For that reason, flowmeter selection has been referred to as both a science and an art. This chapter provides some of the basic knowledge plant personnel need in order to select the correct flowmeter. It is essential that the person selecting the instrument considers the actual users' experiences.

Classification

Flowmeters operate according to many different principles of measurement. They can be broadly classified into four categories:

1. Flowmeters that have wetted moving parts (such as positive displacement, turbine, and variable area). These meters utilize high-tolerance machined moving parts, which determine the meter's performance. These parts are subject to mechanical wear and thus are practical for clean fluids only.
2. Flowmeters that have wetted non-moving parts (such as vortex, differential pressure, target, and thermal). The lack of moving parts gives these meters an advantage. However, excessive wear, plugged impulse tubing, and excessively dirty fluids may cause problems for these meters.
3. Obstructionless flowmeters (such as coriolis and magnetic). These meters allow the fluid to pass undisturbed and thus maintain their performance when handling dirty and abrasive fluids.
4. Flowmeters with sensors mounted externally (such as clamp-on ultrasonic and weir flow measurements). These meters offer no obstruction to the fluid and have no wetted parts. However, their limitations prevent them from being used in all applications.

Flowmeters can also be classified into four types:

1. Volumetric, such as positive displacement meters. They measure volume directly.
2. Velocity, such as magnetic, turbine, and ultrasonic meters. These meters determine total flow by multiplying the velocity by the area through which the fluid flows.
3. Inferential, such as differential pressure (dp), target, and variable-area meters. These meters infer the flow by some other physical property such as differential pressure and then experimentally correlate it to flow.
4. Mass, such as coriolis mass flowmeters. These devices measure mass directly.

Measurement

Flow can be defined as a volume of fluid in a pipe passing a given point per unit of time. This can be expressed by

$$Q = A \times V$$

where A is the cross-sectional area of the pipe, and V is the average fluid velocity. Therefore, the mass flow may then be defined as

$$\text{volumetric flow} \times \text{density}.$$

Typically, measurements rely on empirical formulas and on test results. Therefore, the plant considering the specific application of any flowmeter should consider the limitations and test conditions under which certain meters are sold. For example, as temperature changes, the density of a fluid will change as well. That, in turn, may affect the accuracy of the reading unless compensation is implemented.

To standardize expressions of gas flow, process measurement professionals often refer to the gas flow at operating conditions to standard pressure and temperature conditions. Standard conditions are presumed to be 14.696 psia (101.325 KPa absolute) for pressure and 59°F (or 15°C) for temperature. However, such "standard" conditions may vary from industry to industry, so it is good practice to define these conditions to avoid errors. Gas flow expressed in standard units is the amount of gas at standard conditions that is required to effect the same mass flow. The reasoning behind this approach is to relate the volumetric flow to mass flow at given operating conditions, since the mass flow at 100 psig is quite different from the mass flow at 5000 psig due to density change.

For gases, pressure and temperature must be compensated for, if the measured values differ from the ones used for calculations. Unlike gases, liquids are incompressible but they may require temperature compensation since their density may vary significantly after a large change in temperature.

Accuracy

Accuracy is typically specified either as "% of flow rate" or as "% of full scale". The user should be careful when defining accuracy since "% of flow rate" and "% of full scale" are not the same. In "% of flow rate", the accuracy is the same for low flows as it is for high flows. For example, a device with 0-100 L/m range and ±1% flow rate accuracy, will have, at 100 L/m, an error of ±1 L/m and at a flow of 20 L/m, the error will be ±0.2 L/m (i.e., 1% of measurement in both cases).

On the other hand, a "% of full scale" device has different measuring accuracies at different flow rates. For example, a device with 0-100 L/m range and ±1% full scale accuracy will have, at 100 L/m, an error of ±1 L/m and at a flow of 20 L/m, the error will still be ±1 L/m (i.e., 5% of measurement). This is a much larger error than the flow of 20 L/m under "% of flow rate".

General Application Notes

Depending on which type of flowmeter is selected, many parameters need to be considered when applying flowmeters. Ignoring such parameters will result in a measurement with a high error or one with a short life span. In addition to the requirements common to most measurements—such as process conditions, measuring range, and accuracy—flow measurement also requires a closer look at the following:

- The type of fluid and whether it is dirty or clean
- The velocity profile
- The piping considerations
- The line size

Type of Fluid

The type of fluid may limit the type of flowmeter device available for the application. For example:

- On magnetic meters, severe service for conductive fluids can be measured, where orifice plates or vortex shedders are not suitable.
- On most turbine meters, steam cannot be measured.
- On vortex meters and differential-pressure devices, liquid, gas, and steam can be measured.

The condition of the fluid (i.e., clean or dirty) also presents limitations. Some measuring devices may become plugged or eroded if dirty fluids are used. For example, differential-pressure devices would normally not be applied where dirty or corrosive fluids are used (though flow nozzles may handle such applications under certain conditions). On the other hand, magnetic meters are capable of accurately measuring dirty, viscous, corrosive, abrasive, and fibrous liquids.

Velocity Profile

The velocity profile has a major effect on the accuracy and performance of most flowmeters. The shape of the velocity profile inside a pipe depends on the following:

- The momentum or inertial forces of the fluid, which tend to move the fluid through the pipe
- The viscous forces of the fluid, which tend to slow the fluid down as it passes near the pipe walls

Therefore, bends in the pipe, restriction in the lines, and roughness of the pipe walls affect the shape of the flow profile and the speed of recovery from flow disturbances. Flow profiles can be classified into three types: laminar, turbulent, and transitional (see figures 4-1 and 4-2).

In laminar flow, the viscous forces cause the fluid to slow down as it passes near the pipe walls. The flow profile is close to parabolic, with more flow traveling at the center of the pipe than at the pipe walls where the flow is slowed. In turbulent flow, the effect of inertial forces is much larger than the effect of the viscous forces, so the effect of pipe wall is reduced. The flow profile is therefore more uniform than laminar flow. However, the fluid layer next to the pipe wall remains laminar. The transitional flow profile is between the laminar and the turbulent flow profiles. Its behavior tends to be difficult to predict and may oscillate between the laminar and turbulent flow profiles.

The flow profile is affected by four factors whose relationship with each other is called the Reynolds number. The Reynolds number (Rd), a dimensionless quantity that indicates the conditions of flow in a given pipe, considers the combined effect of velocity, density, and viscosity. However, the Rd does not take into account the roughness of the pipe wall, which may affect the velocity distribution and applies only to Newtonian fluids. In such fluids, the viscosity is independent from the rate of shear. The Reynolds number is given as follows:

$$\text{Rd} = \frac{\text{diameter of pipe} \times \text{average flow velocity} \times \text{density of fluid}}{\text{absolute viscosity of fluid}}$$

The flow is considered laminar if Rd < 2000. If Rd reaches 4000, it starts becoming turbulent, and by 10,000 the flow profile should by well established as turbulent. The range between 2000 and 10,000 is an unstable and complex condition that is affected by many parameters (such as whether the velocity is increasing or decreasing).

Piping Considerations

Flowmeter performance is normally stated in terms of ideal reference conditions. Variances in the inside diameter of piping and in the upstream and downstream runs—including restrictions, valves, solid buildup, and misaligned gaskets—affect flowmeter performance. Therefore, on flow-measuring loops the control valve is typically located downstream of the measuring element. This is to avoid the disturbances to the flow stream caused by the throttling action of the valve, which affects the accuracy of the measuring element.

Figure 4-1
Flow profiles.

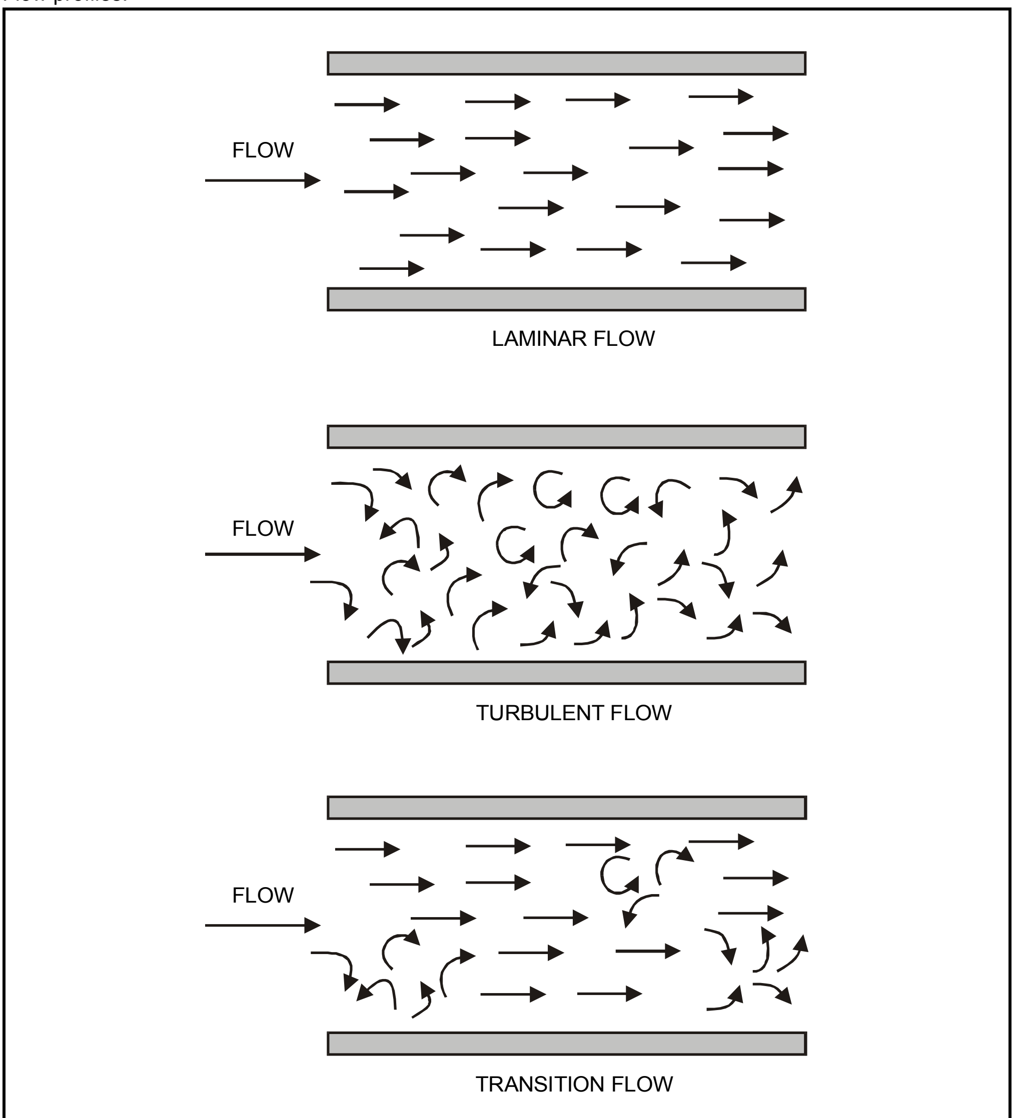
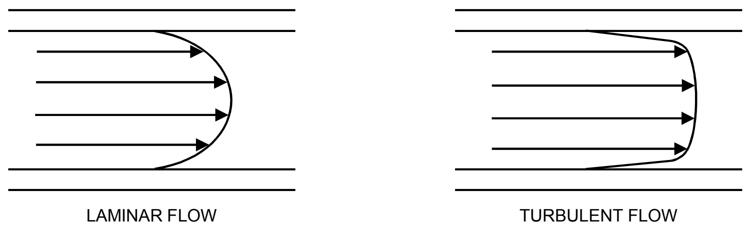


Figure 4-2
Velocity profiles.



In addition to the resistance of the line itself, many flow-measuring devices drop some of the line pressure as well. In some cases, this is not desirable, and the amount of pressure drop by the flowmeter is an important consideration when selecting meters. For example, the pressure drop for differential-pressure devices varies from low to moderate. In pitot tubes, pressure drop is low in comparison to other types. Elbow taps have no mentionable pressure loss, and on magnetic flowmeters there is no pressure loss.

The configuration of the piping must take into account the fact that most liquid-measuring flowmeters should remain filled with liquid in order to provide accurate measurement, since gas or vapors will adversely affect performance. Care should be taken if the pipe is drained when the pump is turned off, since restarting the pump may produce sufficient momentum to damage the flowmeter and sometimes the pipe itself.

Most applications require a method for pipe pressure testing called hydrotesting. When this is the case, the flowmeter components must be rated for very high pressures. If they are not, they should either be isolated or removed from the line to avoid damage.

Many types of flowmeters use a minimum number of upstream and downstream straight pipe runs because irregular velocity profiles affect the accuracy of the measurement. This requirement has a direct effect on the piping and may sometimes be a problem (especially on existing installations). For example, for orifice plates, typically a straight run of 10 to 20 upstream pipe diameters is required, with five pipe diameters for the downstream side. On the other hand, a pitot tube requires 40 upstream and 10 downstream pipe runs respectively, depending on the fluid dynamic disturbance. Major vendors offer tables to guide the user in determining the recommended upstream and downstream straight pipe runs. For coriolis and variable area flowmeters, no upstream and downstream pipe runs are required. There are many applications where appropriate upstream and downstream pipe lengths are not available to provide accurate measurement. In these applications, straightening vanes or flow conditioners (consisting, for example, of tube bundles) can be used. The length of these tubes should be more than ten times the diameter of the tubes, with the inside diameter of the tubes less than 1/4 the inside pipe diameter.

Line Size

Not all measuring devices cover all line sizes. For example, the maximum size of most vortex meters is eight inches. Therefore, the question is whether the selected flow device can handle the line size (and required flow).

Measuring Solids

The flow measurement of solids typically involves using a weighing device or a radioactive (radiation) device. For example, a batch in a hopper could be measured with load cells and then discharged. For a continuous process, isolated weighing conveyors provide the weight measurement. Such measurements are not provided in this handbook since in many cases they fall under the responsibility of mechanical engineering activities. Radioactive measuring devices are covered in chapter 5 (on level measurement).

Comparison Table

Table 4-1 summarizes the main types of flow measurement with respect to a set of common parameters. This comparison table can be used as a guide for selecting flowmeters. The information presented in table 4-1 indicates typical values; some vendors may have equipment that exceeds the limits shown. For environmental reasons, flowmeters that contain mercury are generally avoided.

Differential Pressure: General Information

The four most common types of differential pressure (dp) flowmeters are the following:

- Orifice plate, segmental orifice plate, and integral orifice plate
- Venturi tube and flow nozzle
- Elbow
- Pitot tube

Typically, a dp flowmeter consists of a primary element (e.g., an orifice plate) and a secondary element (e.g., a dp transmitter). The secondary element measures the differential head produced by the primary element.

$$\text{Flow rate} = \text{constant} \times \sqrt{(\text{differential pressure / density})}$$

Therefore, a square root extracting function is typically required.

Differential-pressure flowmeters have many advantages. They are simple to use, offer low cost (especially orifice plates), have no moving parts, are sturdy, and are available in a wide selection of ranges and models. However, they tend to have low accuracy (which is easily affected by wear on the primary element), some have a high permanent pressure loss, their flow range is generally limited to 4:1 at best, and the impulse lines may block or freeze. Where orifice plates erode, a more expensive solution is required, such as venturis or flow nozzles. Differential pressure flow measurement should occur under turbulent flow—that is, where Rd is > 10,000.

Where possible, the secondary element should be mounted above the primary element for gas measurement (to ensure that condensables do not influence the dp) and below the primary element for liquid, condensables, and steam (to ensure that vapors and gas bubbles flow back to the process). The impulse lines are typically sloped 1:10. Where condensation occurs in the measuring element on a steam line (or wet gas or vapor), condensate chambers are fitted to the impulse points, with both chambers at the same level. On condensables and steam, 1-1/2 in. tees generally provide sufficient capacity as condensate pots. Impulse lines in such cases may need to be insulated and/or heat traced.

For gases, tap connections are generally installed vertically (i.e., from the top of the pipe) or horizontally (i.e., from the side of the pipe). Tap locations are generally installed horizontally (i.e., from the side of the pipe) for steam and liquids to prevent the settling of dirt and sediments in the impulse lines. This approach minimizes the erroneous effects of liquid droplets in gas lines and of gas bubbles in liquid lines. Bottom connections are generally avoided.

Differential-pressure transmitters are typically equipped with three valve manifolds, which are sometimes integral to the transmitters. The integral manifolds are of unitized construction and when compared to part-assembled units, they provide fewer leak points, reduced material and labor costs (especially when supplied with the transmitter), and require less physical space. On toxic and hazardous fluids, a five-valve manifold with drain or vent legs to a safe location is frequently provided, and the impulse lines are flanged or welded, instead of threaded. Refer to chapter 5 for further information on valve manifolds.

Differential Pressure: Orifice Plate

Principle of Measurement

This primary element (see figure 4-3), often called a square-edged orifice plate, consists of a flat piece of metal in which a sized hole has been bored (concentric or eccentric). Fluid flow creates a differential pressure across the plate. The square root of the dp is proportional to flow. A common value used in orifice plate measurement is the beta ratio. This ratio is equal to the inner diameter of the orifice divided by the inner diameter of the pipe. Typically, the beta ratio should be within 0.3 to 0.7 and the dp between 25 and 200"WC (600 and 5000 mmWC). However, preferably the beta ratio will be between 0.4 to 0.6 with a dp between 70 and 170"WC (1800 and 4300 mmWC). Ideally, a designer will work around a beta ratio of 0.5 and a dp of 100"WC (2500 mmWC).

The most common pressure taps are flange taps and vena contracta taps. Flange taps are located 1" (25mm) upstream and 1" (25mm) downstream of the orifice plate. They are the most commonly used type of pressure taps in North America, particularly on lines 8" (200 mm) and smaller. They are compact and have been researched extensively, so application data is well documented. Flange taps introduce no disturbance to the piping, have symmetrical locations (and thus can accommodate reverse flow), and offer performance comparable to vena contracta taps.

Vena contracta taps are located 1 diameter upstream and at the vena contracta (point of minimum pressure) downstream of the orifice plate. They provide the best measurement for lines 10" (250mm) and larger, are commonly used for steam service, and provide the best dp. However, it should be kept in mind that the position of the vena contracta is not fixed but varies with flow rate.

Other less commonly used tap locations are radius taps (Up = D, Down = 1/2 D), corner taps (Up at plate, Down at plate), and pipe taps, also known as pressure taps (Up = 2 1/2 D, Down = 8 D).

Table 4-1
Flow measurement comparison

Parameters / Types	Fluid Type (for "S" see Note 7) (Y=Yes, N=No)													Meter Output				
				Liquids					Slurries									
	Gas	Vapor/Steam	Two-phase (1)	Clean	Dirty	With suspended solids	Corrosive	Viscous	Abrasive	Fibrous	Semi filled pipes	Open channels	Low fluid velocity	Electronic	Pneumatic	Type	Meter Size	Minimum Reynolds number for Newtonian fluids [2], [3]
dp: Square-edged orifice plate	Y	Y	S	Y	N	N	Y	N	N	N	N	N	Y	Y	Y	square root	1"–39" (25–990mm)[8]	5,000 [9]
dp: Segmental orifice plate	Y	Y	S	Y	N	Y	S	Y	N	N	N	N	Y	Y	Y	square root	1 in (25mm) and higher	2,000
dp: Integral orifice plate	Y	Y	S	Y	N	N	N	s	N	N	N	N	Y	Y	Y	square root	0.5"–1.5" (10–40 mm)	5,000
dp: Venturi tube	Y	Y	S	Y	Y	Y	S	N	S	S	N	N	S	Y	Y	square root	2"–70" (50–1800 mm)	20,000
dp: Flow nozzle	Y	Y	S	Y	S	N	S	N	S	S	N	N	S	Y	Y	square root	2"–60" (50–1500mm)	30,000
dp: Elbow	Y	Y	S	Y	S	S	S	S	S	S	N	N	N	Y	Y	square root	dependent on line size	50,000
dp: Pitot Tube	Y	Y	S	Y	N	N	N	N	N	N	N	N	S	Y	Y	square root	2"–48" (50–1200 mm)	1,000
Magnetic	N	N	S[12]	Y	Y	Y	Y	Y	Y	Y	N	N	Y[13]	Y	N	linear	0.1"–96" (2–2400 mm)	no effect
Mass: Coriolis	S	S[16]	Y	Y	Y	Y	S	S	S	S	N	N	Y	Y	N	linear	0.25"–6" (6–150 mm)	no effect
Mass: Thermal	Y	Y	N	S	S	S	S	S	S	S	N	N	Y	Y	N	exponential (linearized)	0.125"–10" (3–250 mm)	10
Turbine	S	S	N	Y	N	N	S	S	N	N	N	N	S	Y	N	linear [18]	0.1875"–24" (5–600 mm)	10,000
Positive Displacement	Y	S	N	Y	N	N	S	Y	N	N	N	N	Y	Y	N	linear	0.125"–16" (3–400 mm)	no effect
Vortex shedding	Y	Y	N	Y	S	S	S	N	N	N	N	N	N	Y	N	linear	0.5"–8" (12–200 mm)	10,000 to 20,000
Variable area (rotameter)	Y	Y	N	Y	N	N	S	N	N	N	N	N	S	Y	N	linear	0.25"–3" (6–75 mm) for glass 8" (200 mm) max for metal	10,000
Ultrasonic: Transit time	S	N	N	Y	N	N	S	S	N	N	N	N	S	Y	N	linear	0.25"–160" (6–4000 mm)	10,000
Ultrasonic: Doppler	N	N	N	N	Y	Y	S	S	S	S	N	N	S	Y	N	linear	0.5"–120" (12–3000 mm)	4,000
Weir and flume	N	N	N	Y	Y	Y	S	N	Y	Y	Y	Y	Y	Y	Y	non-linear [24]	1" (25mm) and up	NA
Target	Y	S	Y	Y	Y	Y	S	Y	N	N	N	N	S	Y	N	square root	0.5"–6" (12–1500 mm)	500

Notes
1. Liquid with vapor or gas.
2. Reynolds number (R_d) is a dimensionless quantity that indicates the conditions of flow in a given pipe (see Flow Profiles in the Introduction section). This number has been developed for Newtonian fluids. A Newtonian fluid has a constant ratio of: shear stress/shear rate. If this ratio is not constant it is considered a non-Newtonian fluid. In most cases, non-Newtonian fluids are fluids in the laminar flow region. Flow measurement data for non-Newtonian fluids is almost non-existent, therefore in such cases, flow measuring devices not dependent on R_d corrections should be used, such as magnetic meters (since the output of a mag meter is basically the average of the flow profile).
3. Where viscosity varies with the rate of shear.
4. Upstream and downstream pipe diameters.
5. Accuracy is measured in% of flow rate or in% of full scale;% of flow rate, measures low flow with the same accuracy as high flow.% of full scale has different measurement accuracies, e.g., a ± 1% FS error = a ± 5% error at 20% flow rate.
6. See chapter 1 for a definition of repeatability and accuracy.
7. S = sometimes, i.e., it is not a clear yes or no, and is suitable only under certain conditions. Refer to vendors.
8. For diameters less than or equal to 1" (25 mm), use integral orifice plate.
9. This R_d can sometimes reach up to 500,000. However, for orifices with conical entrance, the minimum Reynolds number may be less than 5000.
10. Depends on the capabilities of the secondary element - but generally not recommended.
11. Depending on pressure losses.
12. OK to use on low concentration of the gas/vapor phase
13. Velocity range should be about 0.3 to 10 m/sec (more typically around 2 to 4 m/sec), for abrasive fluids velocity, the velocity should be less than 3 m/sec to minimize damage to the liner.
14. For a higher accuracy a 10 up, 5 down may be required.
15. Some units can reach a 100:1 rangeability

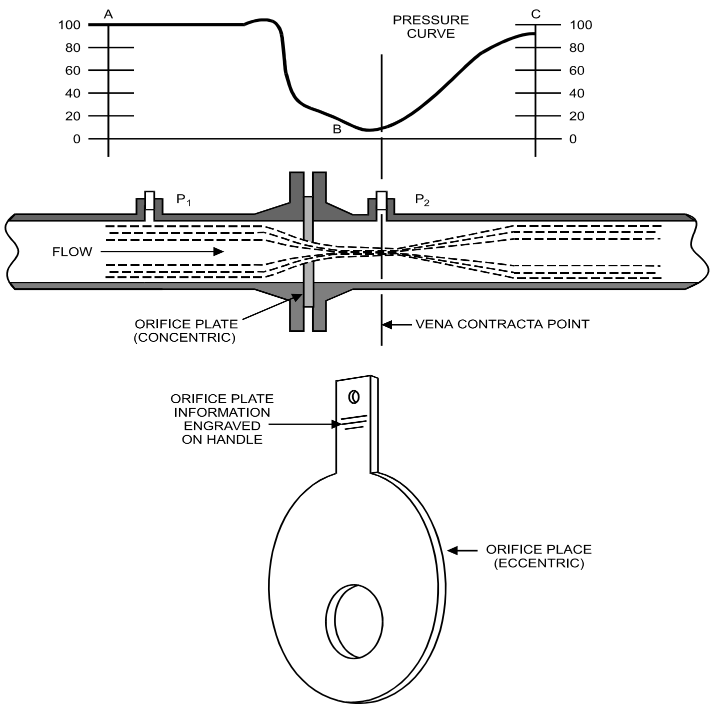
Table 4-1
Flow measurement comparison (continued)

Parameters / Types	Applicable to non-Newtonian fluids [2], [3]	Measurement of very small gas flow	Measurement of very small liquid flow	Measurement of pulsating flow	Temperature range °F (°C)	Pressure range psig (MPag)	Pressure loss by sensor	Straight pipe run requirements - up/down [4]	Rangeability (turndown)	Accuracy [5]	Repeatability % [6]
dp: Square-edged orifice plate	S	N	S	S[10]	400 (205) max	2000 (14) max	up to 90% of dP across plate	20 (±10) up, 5 down	3:1	±3% of full scale	±0.25
dp: Segmental orifice plate	S	N	S	S[10]	400 (205) max	2000 (14) max	up to 90% of dP across plate	20 (±10) up, 5 down	3:1	±4% of full scale	±0.25
dp: Integral orifice plate	S	N	S	S[10]	400 (205) max	2000 (14) max	90% of dP across plate	20 up, 5 dn	3:1	±3% of full scale	±0.25
dp: Venturi tube	S	S[11]	Y	S[10]	400 (205) max	2000 (14) max	10–25% of dP across tube	5–30 up, 5 dn	3:1	±3% of full scale	± 0.25
dp: Flow nozzle	S	N	N	S[10]	400 (205) max	2000 (14) max	about 60% of dP across nozzle	10–80 up, 5–10 dn	3:1	±3% of full scale	±0.25
dp: Elbow	S	N	S	S[10]	400 (205) max	2000 (14) max	very low; negligible	25–30 up, 10 Dn	3:1	± 8% of full scale	± 0.50
dp: Pitot Tube	N	S[10]	S[10]	N	400 (205) max	2000 (14) max	negligible	20–40 up, 10 dn	3:1	± 4% of full scale	±0.50
Magnetic	Y	N	Y	Y	390 (200) max	700 (5) max	none	5 up, 1 dn [14]	20:1 [15]	± 0.5% of rate	± 0.25
Mass: Coriolis	Y	N	Y	Y	480 (250) max	1500 (10) max	20 "WC (500 mmWC)	none	60:1	± 0.2% of rate	± 0.1
Mass: Thermal	S	Y	Y	Y	[17]	[17]	low	[17]	[17]	± 2% of full scale	± 0.25
Turbine	N	N	S	Y	-150–390 (100–200)	1400 (10) max	100 "WC (2500mmWC)	5-20 up, 5 dn	10:1 [19]	± 0.50% of rate	± 0.05
Positive Displacement	N	Y	Y	N	liquids: 480 (250) max gases: 140 (60) max	3000 (21) max	high	none	10:1 for liquids, 20:1 for gases	± 0.2%-2% of rate [20]	± 0.05
Vortex Shedding	N	N	N	Y	750 (400) max	1400 (10) max	liquids 30-150 (760-3800) gases 5-150 (130-3800)	15-25 up, 5-10 down [21]	35:1	± 1% of rate	± 0.5
Variable area (rotameter)	N	Y	Y	N	glass 250 (120) max metal 620 (325) max	glass 500 (3.5) max metal 1500 (10) max	20 (500)	none required	10:1	± 1 to 5% of rate	± 0.5
Ultrasonic: Transit Time	N	N	N	Y	175 (80) max [22]	[23]	none	5-30 up, 5 dn	30:1 to 100:1	± 2% of rate	± 0.25
Ultrasonic: Doppler	S	N	N	N	-12–480 (-25–250)	[23]	none	5-20 up, 5 dn	15:1	± 2% of full scale	± 0.5
Weir and Flume	N	N	N	N	ambient	atmospheric	flumes 10" WC (250 mmWC) weirs 30" WC (750 mmWC)	none	weir, flume 60:1 v-notch weir 300:1	± 4% of full scale [25]	[25]
Target	S	N	N	S	570 (300) max	5000 (35) max	90% of dp across sensor	30-50 up, 5 dn	7:1 to 15:1	± 1 to 4% of rate [26]	± 0.25

Notes (continued)

16. Limited gas and steam service (operating at very high pressures) – some vendors provide gas measuring capability.
17. * Temperature range; For insertion type 350°F (160°C) max; For in-line type 210°F (100°C) max; * Pressure range; For insertion type 1500 psig (10 MPag) max; For in-line type 140 psig (1MPag) max; * Straight pipe run requirements; For insertion type, 20 up, 2 down; For in-line type, 20 up, 2 down; *Rangeability; For insertion type, 30:1; For in-line type, 40:1.
18. When Reynold's number is greater than 10,000
19. Some units can reach a 100:1 rangeability
20. Accuracy is dependent on the type of meter; e.g., * rotary piston, +/- 0.55%; * rotary vane, +/- 0.2%; * reciprocating piston, +/- 0.55%; * nutating disc, +/- 2%; * oval gear, +/- 0.25%
21. 45 upstream run may be required for two elbows in different planes. Check with vendor for installation requirements.
22. Temperatures as low as -330°F (-200°C) can be reached with special unit. The temperature limits are basically dependent on the transducer crystals.
23. Obviously, the clamp-on type is dependent on the pipe rating.
24. The non-linearity is as follows: * proportional to the head to the 3/2 power for rectangular and trapezoidal weirs and Parshall flumes; * proportional to the head to the 5/2 power for V-notch weirs
25. It is dependent on the performance of the level measurement.
26. Better accuracies are obtained with turbulent flow.

Figure 4-3
Orifice plate.



Application Notes

Orifice plates have many advantages. They are easy to install, one dp transmitter will apply for any pipe size, and many materials are available to meet process requirements. Type 316 stainless steel is the most common material used in orifice plates unless the process conditions require material of higher quality. Orifice plates have no moving parts, have been researched extensively, and their application data has been well documented.

However, orifice plates also have disadvantages. The process fluid is in the impulse line, meaning there is the potential for freezing and plugging (unless chemical seals are used). Their accuracy is affected by changes in density, viscosity, and temperature, and they require frequent calibration.

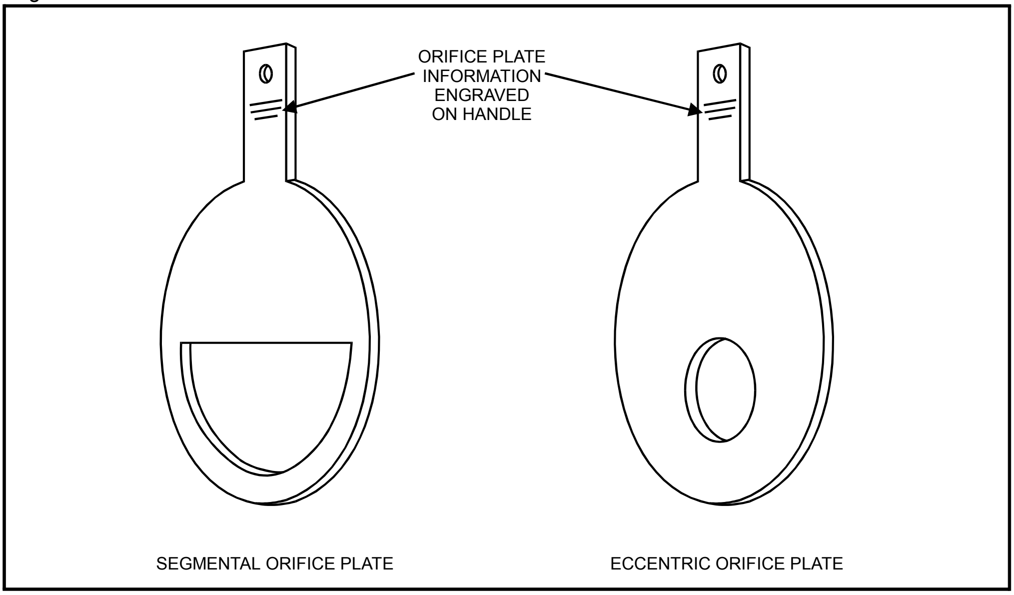
The orifice plate typically has a drain hole located at the bottom for steam and gas applications (to drain condensables) and a vent hole on the top for liquid applications (to let gas bubbles through).

Differential Pressure: Segmental Orifice Plate

Principle of Measurement

The segmental orifice plate (see figure 4-4) is the same as a square-edged orifice plate except that the hole is bored tangentially to a concentric circle whose diameter is equal to 98 percent that of the pipe's inside diameter.

Figure 4-4
Segmental Orifice Plate



Application Notes

The segmental orifice plate is less subject to wear than the square-edged orifice plate. However, it is good for low flows only. For slurry applications where dp devices are required, segmental orifice plates provide satisfactory measurement. During installation, care must be taken that no portion of the gasket or flange covers the hole.

Differential Pressure: Integral Orifice Plate

Principle of Measurement

The integral orifice plate is identical to a square-edged orifice plate installation except that the plate, flanges, and dp transmitter are supplied as one unit.

Application Notes

The integral orifice plate is used for small lines (typically under 2" [50mm]) and is relatively inexpensive to install since it is part of the transmitter.

Differential Pressure: Venturi Tube

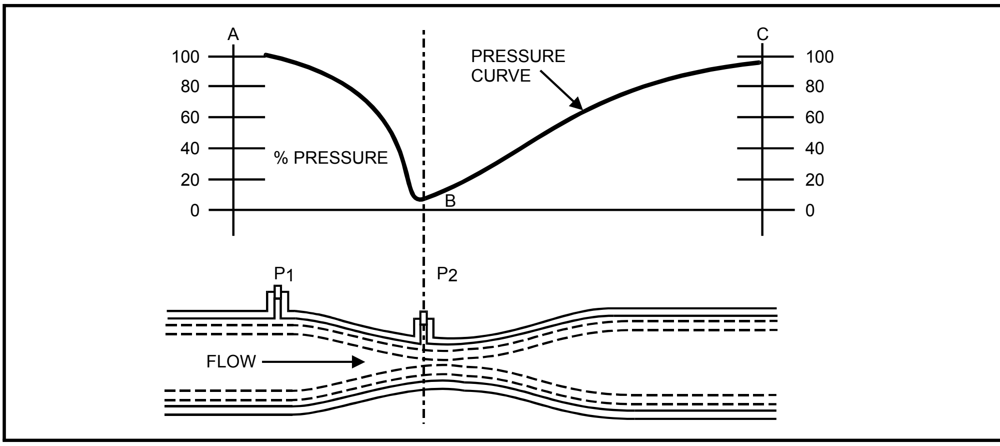
Principle of Measurement

The venturi tube (see figure 4-5) consists of a section of pipe with a conical entrance (typically 20 degrees), a short straight throat, and a conical outlet (typically, a 5- to 6-degree recovery cone). The velocity increases and the pressure drops at the throat. The dp is measured between the input (upstream of the conical entrance) and the throat.

Application Notes

The venturi tube will handle low-pressure applications and will measure 25 to 50 percent more flow than a comparable orifice plate. It is less affected by wear and corrosion than the orifice plate and is generally suited for measurement in very large water pipes and very large air/gas ducts. Venturi tubes provide better performance than the orifice plate when there are solids in suspension. However, it is the most expensive of dp meters, it is big and heavy in its larger sizes, and its length is considerable.

Figure 4-5
Venturi tube.



Differential Pressure: Flow Nozzle

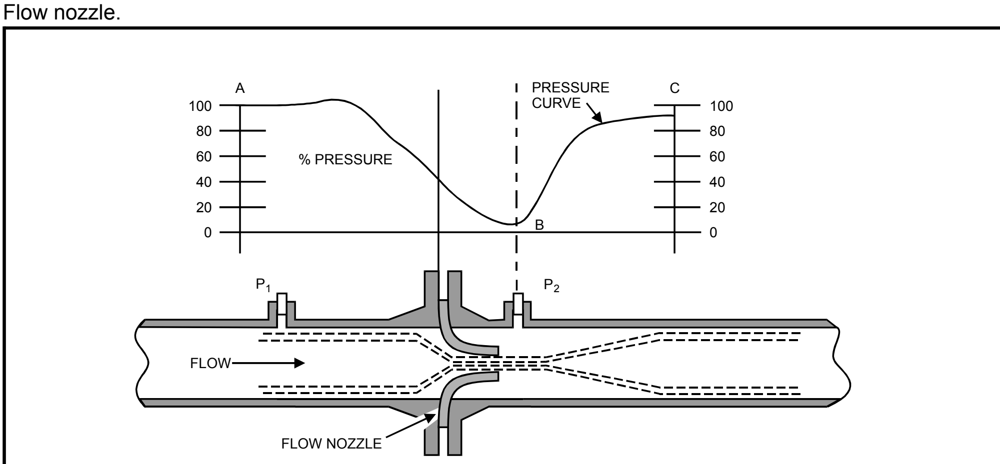
Principle of Measurement

The flow nozzle (see figure 4-6) is similar to the venturi tube except that there is no recovery cone.

Application Notes

Flow nozzles are commonly used for steam. They are economical, will handle high flow measurement with low dp loss, and permit approximately 60 percent greater capacity than comparable plates. Pressure taps for flow nozzles are located one pipe diameter upstream and one-half pipe diameter downstream from the inlet face of the nozzle.

Figure 4-6
Flow nozzle.



Differential Pressure: Elbow

Principle of Measurement

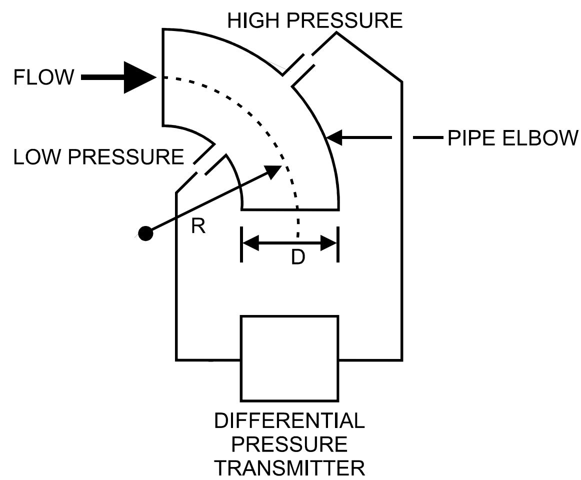
When liquid travels in an elbow (see figure 4-7), a centrifugal force is exerted on the outer edge (relative to fluid velocity). Pressure taps (to measure the dp) are located on the outside and inside of the elbow at 45 degrees. Flow can be expressed as follows:

$$\text{Flow} = \text{constant} \times \sqrt{R \times H \times D^3 \times \text{Density}}$$

where

R = elbow's center-line radius,
H = dp,
D = elbow/pipe diameter.

Figure 4-7
Elbow.



Application Notes

The advantages of the elbow dp meter (sometimes called a "centrifugal meter") are its low cost, its ease of installation (it can sometimes be mounted in an existing 90-degree elbow), its suitability for measurement in very large water pipes, and its ability to measure flow bidirectionally. Such meters can be used where a rough indication of flow is required. Otherwise, they should be individually calibrated with the fluid to be measured. The disadvantages of the elbow dp meter are that it must be calibrated with the working fluid for accuracy, and it is not recommended for low-velocity streams since it will not generate sufficient dp (e.g., water at 5 ft/sec will generate only 10"WC dp).

Differential Pressure: Pitot Tube

Principle of Measurement

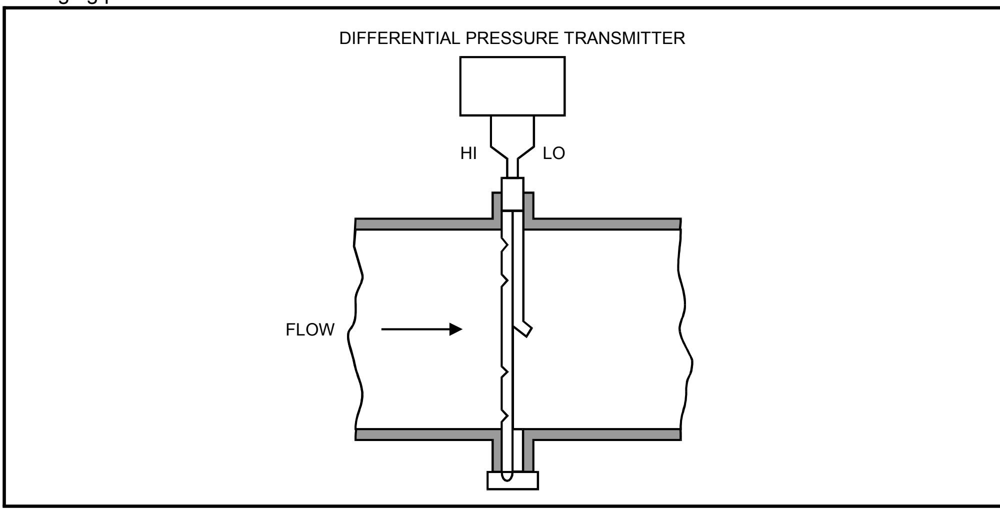
In a pitot tube (see figure 4-8), which is also called an insertion dp meter, a probe consisting of two parts senses two pressures: impact (dynamic) and static. The impact pressure is sensed by one impact tube bent toward the flow (dynamic head). The averaging-type pitot tube has four or more pressure taps located at mathematically defined locations to measure the dynamic pressure. The static pressure is sensed through a small hole on the side (static head).

The non-averaging type of pitot tube is extremely sensitive to abnormal velocity distribution profiles because it does not sample the full stream. The averaging type corrects this.

Application Notes

Pitot tubes are easy and quick to install, especially in existing facilities. They can be inserted and removed from the process without shutting down (by using hot taps). They are also simple in design and construction, and they produce energy savings when compared to equivalent orifice plates (due to low permanent pressure loss).

Figure 4-8
Averaging pitot tube.



Generally, pitot tubes are suited for making measurements in large water pipes and large air/gas ducts (6" [150mm] and larger). The disadvantages of pitot tubes are their low differential pressure for a given flow rate and their tendency to plug unless provision is made for purging or flushing.

Magnetic

Principle of Measurement

The magnetic flowmeter is a volumetric device used for electrically conductive liquids and slurries.

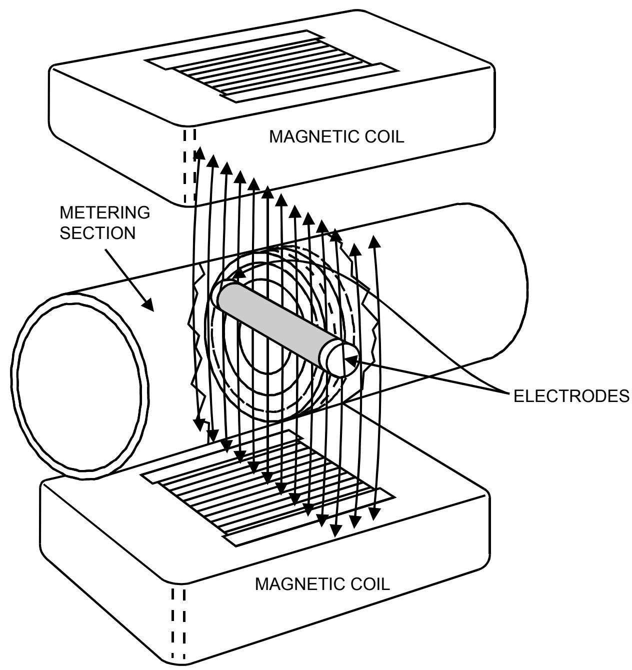
The magnetic flowmeter's design (see figure 4-9) is based on Faraday's law of magnetic induction. Faraday's law states that the voltage induced across a conductor as it moves at right angles through a magnetic field is proportional to the velocity of that conductor. That is, if a wire is moving perpendicular to its length through a magnetic field, it will generate an electrical potential between its two ends. Based on this principle, the magnetic flowmeter generates a magnetic field that is perpendicular to the flow stream and measures the voltage produced by the fluid passing through the meter as detected by the electrodes. The voltage produced by the magnetic flowmeter is proportional to the average velocity of the volumetric flow rate of the conductive fluid.

The magnetic flowmeter's tube is constructed of non-magnetic material (to allow magnetic field penetration) such as stainless steel and is lined with a suitable material to prevent short-circuiting the voltage generated between the electrodes. The tube is also used to support the coils and transmitter assembly. Generally, the electrodes are made of stainless steel, but other materials are also available (choose with care to avoid corrosion). Dirty liquids may foul the electrodes, and cleaning methods such as ultrasonic may be required.

Application Notes

The magnetic flowmeter has many advantages. Theoretically, it can measure flow down to zero, but in reality its operating velocity should not be less than 3 ft/s (1 m/s). A velocity of 6 to 9 ft/s (2 to 3 m/s) is preferred to minimize coating. It should be noted that accelerated liner wear can result at velocities greater than 15 ft/s (5 m/s).

Figure 4-9
Magnetic flowmeter.



The magnetic flowmeter has no moving parts. It can measure severe service for conductive fluids, and it is unaffected by changes in fluid density, viscosity, and pressure. It also is bidirectional, has no flow obstruction, is easy to respan, and is available with DC or AC power. The magnetic flowmeter will also measure pulsating and corrosive flow. It will measure multiphase fluid; however, all components should be moving at the same speed since the meter measures the speed of the most conductive component.

The magnetic meter is good for startup and shutdown operations. It can be installed vertically or horizontally (however, the line must be full). Changes in conductivity value do not affect the instrument's performance.

The disadvantages of a magnetic flowmeter are its above average cost, its large size and weight, and its need for a minimum electrical conductivity of 5 to 20 micromhos/cm (5 to 20 mS/cm). However, special low-conductivity units will operate at > 0.1 micromhos/cm. The magnetic flowmeter's accuracy is affected by slurries that contain magnetic solids (for these situations, some meters can be provided with compensated outputs), and the plant may have to provide appropriate mechanical protection for the electrodes.

Other disadvantages include the fact that electrical coating may cause calibration shifts. Also, the line must be full and have no air bubbles since air and gas bubbles entrained in the liquid will be metered as liquid, causing a measurement error. In some applications, vacuum breakers may be required to prevent the collapse of the liner under certain process conditions.

When installing a magnetic meter, the plant must ensure that proper grounding is in place. It must also consider the following points:

- Upstream and downstream pipe requirements are necessary since the meter is sensitive to nonsymmetrical flow profiles. Some meters compensate for such profiles.
- Possible failure of the seal between the electrode and the liner and the consequence of such a failure.
- Insertion meters may be sensitive to piping effects and also create an obstruction in the line.

Magnetic meters are available in DC and AC versions. DC types are commonly used. However, AC types are implemented for:

- Pulsating flow applications
- Flow with large amounts of entrained air
- Applications with spurious signals that may be generated from small electrochemical reactions.
- Slurries with non-uniform particle size (they may clamp together).
- Slurries with solids that are not well mixed into the liquid.
- Quick response. The time required to reach 63 percent of the final value of a step input is six times greater for a DC meter than for an AC. For example, a DC meter may require 6 seconds compared to 1 second for AC types.

Mass: Coriolis

Principle of Measurement

In the Coriolis effect design (see figure 4-10), one or two tubes are forced to oscillate at their natural frequencies perpendicular to the flow direction. The resulting Coriolis forces induce a twist movement of the tubes. This movement is sensed by pickups and is related to mass flow. There are two common Coriolis effect tube types: straight and curved.

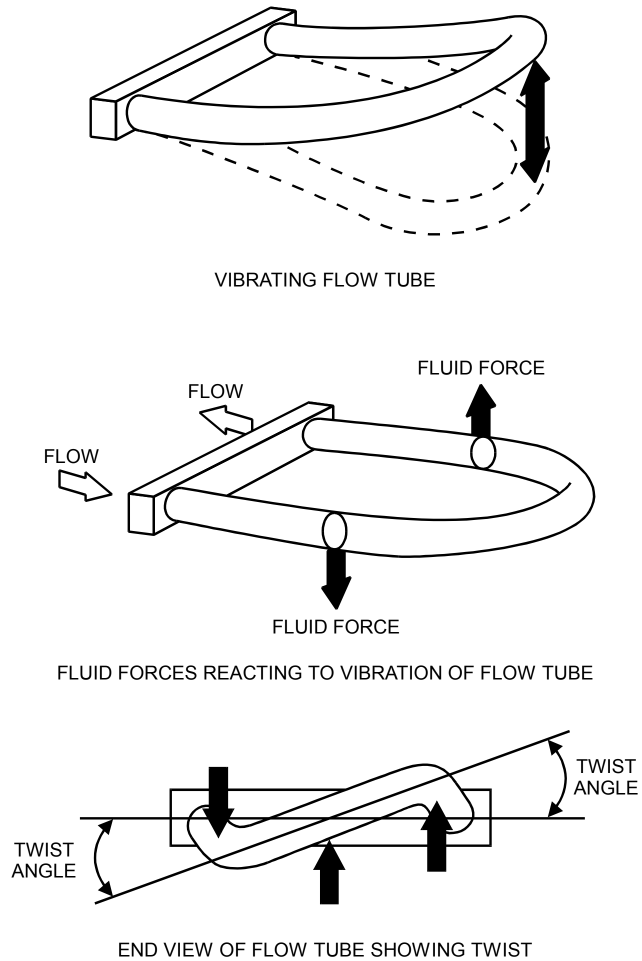
The straight tube is used mainly for multiphase fluids and for fluids that can coat or clog since the straight type can be easily cleaned. In addition, the straight tube requires less room, can be drained, has a low pressure loss, and reduces the probability of air and gas entrapment, which would affect meter performance. However, the straight tube must be perfectly aligned with the pipe (more so than the curved tube).

Compared to the straight tube, the curved tube has a wider operating range, measures low flow more accurately, is available in larger sizes, tends to be lower in cost (due to lower-cost materials), and has a higher operating temperature range. However, it is more sensitive to plant vibrations than is the straight type.

Application Notes

The Coriolis flowmeter has many advantages. It directly measures mass flow and density, and some also measure temperature. It handles difficult applications, is applicable to most fluids, has no Reynolds number limitation, and is not affected by minor changes in specific gravity and viscosity. In addition, the Coriolis flowmeter device requires low maintenance, is insensitive to velocity profiles, is bidirectional, will handle abrasive fluids, and is non-intrusive.

Figure 4-10
Mass flowmeter (Coriolis).



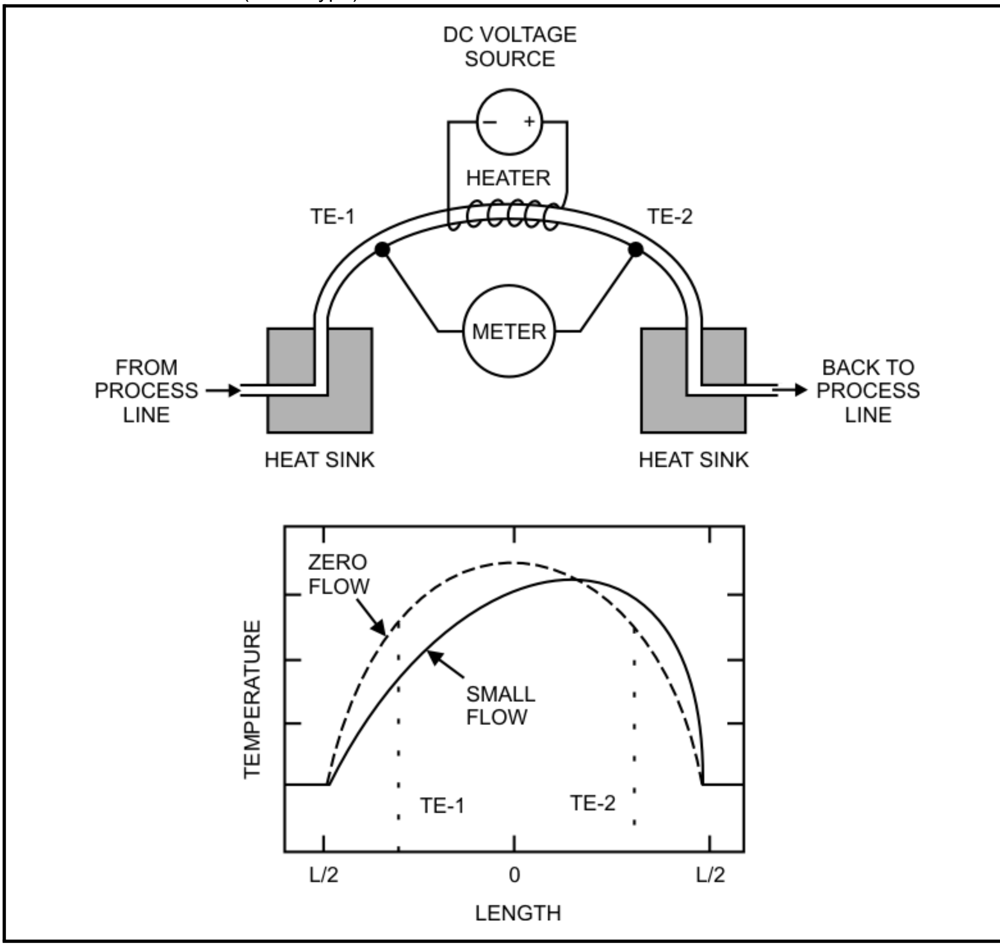
On the other hand, the purchase cost of Coriolis flowmeters is high, and inaccuracies are introduced from air and gas pockets in the liquid as well as by slug flow. The pipe must be full and must remain full to avoid trapping air or gases inside the tube. A high-pressure loss is generated due to the small tube diameters. Coating the tube affects the density measurement (since it will affect the measured frequency) but not the flow measurement (since the degree of tube twist is independent of tube coating).

Mass: Thermal

Principle of Measurement

The operation of a thermal flowmeter (see figure 4-11) is based on the cooling effect that a passing fluid has on a heated resistance temperature device. The flow is measured by either the change in heating power that is required to keep the device's resistance constant or by the change in temperature reading. The thermal flowmeter measurement is an indirect method for measuring mass flow (i.e., it is not a true mass flowmeter). Mass flow rate is inferred from the mass portion in the energy balance equation of the measured fluid.

Figure 4-11
Thermal mass flowmeter (in-line type).



There are two types of thermal flowmeters: the insertion type and the in-line type. The insertion type consists of a probe that is inserted in the stream, complete with heating and measuring elements. The in-line type consists of a sensor typically installed on a bypass around a restriction in the main line (see figure 4-11). The in-line element may be supplied with two temperature elements on both sides of a separate heating element. Alternatively, it may be supplied with only two externally wound self-heating RTDs that heat the tube and measure the temperature.

Application Notes

The thermal mass flowmeter has no moving parts and is unaffected by viscosity changes. However, this meter is affected by coating, and some designs are fragile. The thermal mass flowmeter depends on the thermal properties of the fluid (specific heat and heat transfer). For it to produce accurate measurement, properties must remain constant.

Turbine

Principle of Measurement

A turbine flowmeter (see figure 4-12) consists of a rotor (similar to a propeller) that has a diameter almost equal to the pipe's internal diameter, which is supported by two bearings to allow the rotor to rotate freely. A magnetic pickup, mounted on the pipe, detects the passing of the rotor blades, generating a frequency output. Each pulse represents the passage of a calibrated amount of fluid. The angular velocity (i.e., the rate of rotation) is proportional to the volumetric rate of flow.

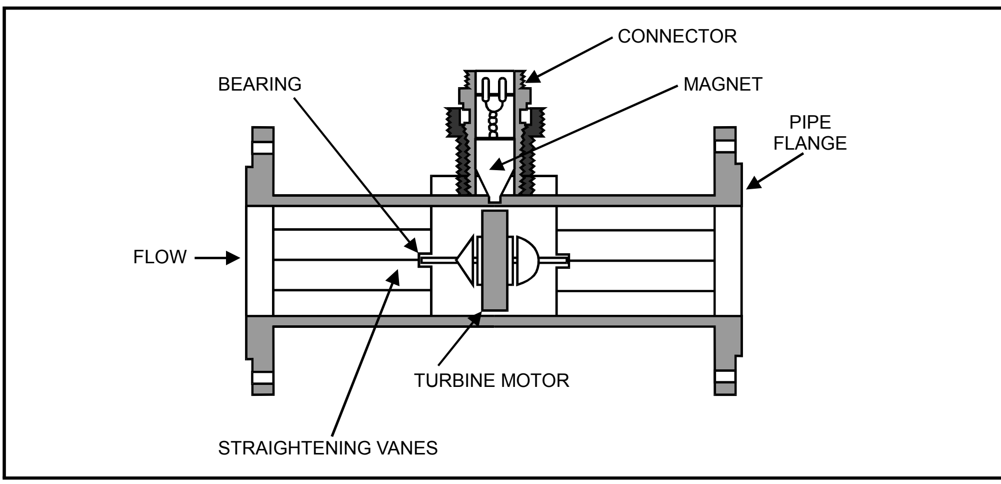
Application Notes

The turbine meter is easy to install and maintain. It is bidirectional, has a fast response, and is compact and lightweight. The device is not sensitive to changes in fluid density (though at very low specific gravities, rangeability may be affected), and it can generate a pulse output signal to directly operate digital meters.

However, turbine meters do have drawbacks. They are not recommended for measuring steam since condensate does lubricate the bearings well, though some designs will handle steam measurement. Also, they are sensitive to dirt and cannot be used for highly viscous fluids or for fluids with varying viscosity. Flashing, slugs of vapor, or gas in the liquid produce blade wear and excessive bearing friction, which results in poor performance and possible turbine damage.

Turbine meters are sensitive to the velocity profile and to the presence of swirls at the inlet. Therefore, they require a uniform velocity profile (i.e., they need a straight upstream run and/or the use of pipe straighteners).

Figure 4-12
Turbine flowmeter.



In addition, turbine meters are affected by air and gas entrained in the liquid (in amounts exceeding 2 percent by volume; therefore, the pipe must be full). Strainers may be required up stream to minimize particle contamination of the bearings (unless special bearings are used). However, finely divided solid particles generally pass through the meter without causing damage. Turbine meters also have moving parts that are sensitive to wear and can be damaged by over speeding. They may be destroyed by lines that fill rapidly during commissioning and startup. Thus, to prevent sudden hydraulic impact, the flow should increase gradually into the line.

When turbine meters are installed, the plant may need to use bypass piping for maintenance. The transmission cable between the magnetic pickup and the transducer must be well protected to avoid the effect of electrical noise. Finally, on flanged meters, gaskets must not protrude into the flow stream.

Additional information on turbine flowmeters is available from ISA-RP31.1-1977, Specification, Installation, and Calibration of Turbine Flowmeters.

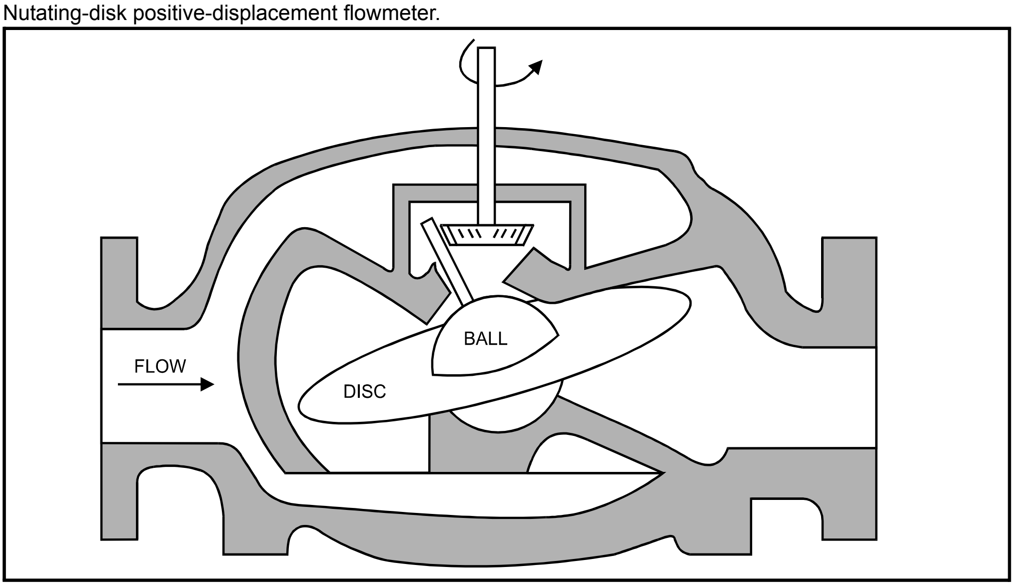
Positive Displacement

Principle of Measurement

The positive-displacement meter separates the incoming fluid into a series of known discrete volumes and then totalizes the number of volumes in a known length of time. It is analogous to pumps operating in reverse. The common types of positive-displacement flowmeters include the following:

- rotary piston
- rotary vane
- reciprocating piston
- nutating disc (see figure 4-13)
- oval gear

Figure 4-13
Nutating-disk positive-displacement flowmeter.



Application Notes

Positive-displacement meters have many advantages. Their simple design means electrical power is not required. They are unaffected by upstream pipe conditions, and direct local readout in volumetric units is available. The highly engineered versions are very accurate, and the low-cost mass-produced versions are commonly used as domestic water meters.

On the other hand, positive-displacement meters have many moving parts, clearances are small (and dirt in the fluid is destructive to the meter), and depending on the application, their seals may have to be replaced regularly since they are subject to mechanical wear, corrosion, and abrasion. In addition, they require periodic calibration and maintenance, and they are sensitive to dirt and thus may require upstream filters.

Moreover, positive-displacement meters cannot be used for reverse flow or for steam since condensate does not lubricate well, and viscosity variations have a detrimental effect on their performance. Finally, these meters can block the flow in the line when they fail mechanically.

Positive-displacement meters are selected mainly according to the type of fluid and the rate of flow that the plant wants to measure, and they are normally used for clean liquids where turbines cannot be used. After a plant installs a positive-displacement meter, it should avoid the following because they cause damage:

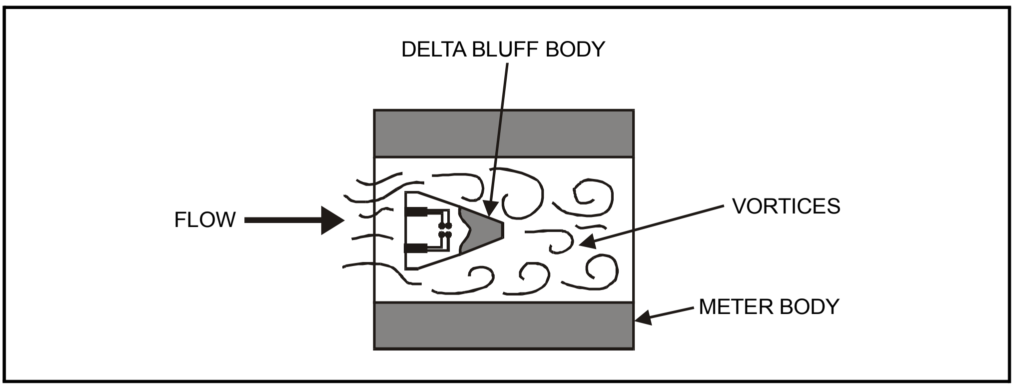
- over speeding
- backflow
- steam or high press cleaning

Vortex Shedding

Principle of Measurement

In a vortex flowmeter (see figure 4-14), an obstruction, or "bluff body," is placed across the pipe bore perpendicular to the fluid flow. Vortices are produced from the alternate edges of the bluff body at a frequency proportional to the fluid velocity. That is, the rate at which the vortices are created is proportional to the volumetric flow rate. Vibrations are sensed by strain gages, capacitance sensors, magnetic pickups, and so forth, and are converted into a flow value.

Figure 4-14
Vortex flowmeter.



Application Notes

The vortex meter has no moving parts. It can be installed vertically, horizontally, or in any position (for liquids, the line should be kept full and gas bubbles avoided). The vortex meter does not experience zero drift like a dp device and requires minimal maintenance. It is suitable for many types of fluids, has an excellent price-to-performance ratio, and its frequency output is linearly proportional to the volumetric flow.

However, the vortex meter's bluff body obstructs the pipe's center, and if the bluff body wears to critical shapes, calibration shift may occur. In addition, the meter should not be used where fluid viscosity may vary so much that unacceptable errors occur. It should also not be used where viscosity is greater than 30 cp, where the application produces an on-off flow, where the Rd is less than 20,000 (since as the Rd drops so does the accuracy), or where solids particles are more than 2 percent of the total flow.

Variable Area (Rotameter)

Principle of Measurement

The variable-area flowmeter, commonly known as rotameter (see figure 4-15), suspends a free-moving float in a tapered tube (sometimes the float is spring loaded). Its movement up and down inside the tube is related to flow and produces a linear signal with flow. Some rotameters are equipped with transmitters that have an output that is proportional to the measured flow.

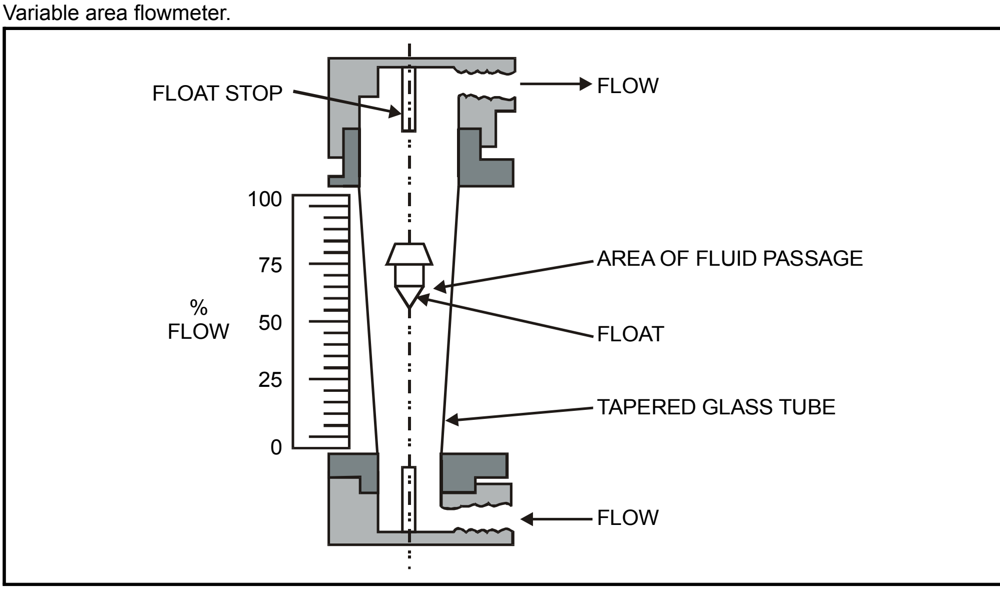
The term *rotameter* was derived from the fact that the float used to have grooves that generated a float rotation for the purpose of centering the meter. Today's floats are guided and do not rotate, but the name has stuck.

The rotameter uses the same basic principle of measurement as an orifice plate. The orifice plate has a fixed orifice with a varying pressure drop, whereas the rotameter has a variable orifice (the annular gap between the float and the tube walls) with a relatively constant differential pressure (due to the weight of the float and the density of the fluid). The annular passage increases as the flow increases (i.e., the tube enlarges as the flow rate increases), and the volume of flow is relative to the annular area.

Application Notes

The rotameter is the simplest form of flowmeter. It will handle low flow rates, is inexpensive and self-cleaning, provides direct indication, needs no power to operate, and is simple to install. However, it can only be mounted vertically (spring-loaded models can be horizontal), and it cannot be used on erosive, crystallizing, or opaque fluids because dirt and sediments make reading difficult. Optional accessories are needed to enable rotameters to transmit data transmission, and costs rise considerably as such options are added.

Figure 4-15
Variable area flowmeter.



The rotameter is affected by fluid density and will not handle high-viscosity fluids. However, it has good immunity to viscosity changes (except in small meters) and, where necessary, viscosity-compensating floats can be used. Float bounce is a limitation in gas applications (i.e., damping and/or a minimum back pressure may be required).

The preferred material for rotameter tubes is borosilicate glass (clearly legible scale gradations are engraved directly on the glass). However, the glass type cannot be used with opaque fluids or where the glass may break, causing a hazardous condition. For this reason, the tube may need a protective shield. For safety reasons, the metering tube should be statistically tested at 150 percent of its maximum working pressure. If the process is hazardous, the meter should be of the metal type. Glass and plastic meters should be confined to safe process fluids.

A rotameter should be

- installed with sufficient clearance to enable read-out and maintenance.

- mounted vertically with horizontal connections, where possible, to allow for a drain plug and/or clean-out openings.
- piped such that no strain is imposed on the meter.

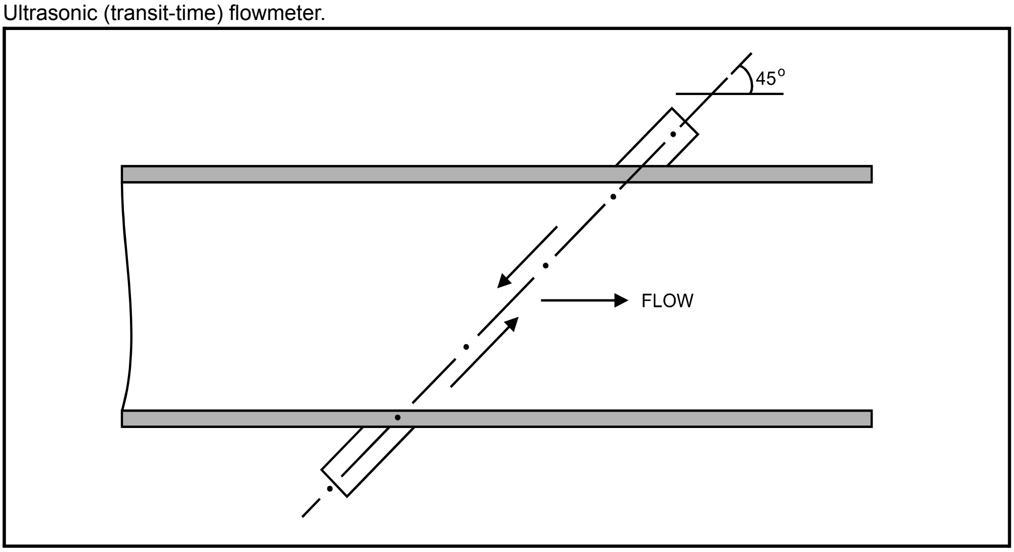
Ultrasonic: Transit Time, Time of Travel, Time of Flight

Principle of Measurement

In a transit-time ultrasonic flowmeter, also known as “time-of-travel” or “time-of-flight” ultrasonic flowmeter (see figure 4-16), two transducers are mounted diametrically opposite each other, one upstream of the other (at a 45 degree angle). Each transducer sends an ultrasonic beam at approximately 1 MHz (generated by a piezoelectric crystal). The difference in transit time between the two beams is used to determine the average liquid velocity in that the beam that travels in the direction of the flow travels faster than the opposite one.

Each transducer acts as both transmitter and receiver. The two transducers cancel the effect of temperature and density changes on the fluid’s sound transmission properties. The speed of sound is not a factor since the meter looks at differential values. The crystals that produce the ultrasonic beam can be in contact with the fluid or be mounted outside the piping (clamp-on transducers).

Figure 4-16
Ultrasonic (transit-time) flowmeter.



Application Notes

Transit-time ultrasonic flowmeters do not obstruct flow, are bidirectional, are unaffected by changes in temperature, and will handle corrosive fluids and pulsating flow. In addition, they can be installed by simply clamping them on the pipe. They are generally suited for measurements in very large water pipes.

However, transit-time ultrasonic flowmeters are highly dependent on the Reynolds number (i.e., the velocity profile), they must be used with pipe made of non-porous pipe material (i.e., not cast iron, cement, and fiberglass), and they require periodic recalibration.

Ultrasonic: Doppler

Principle of Measurement

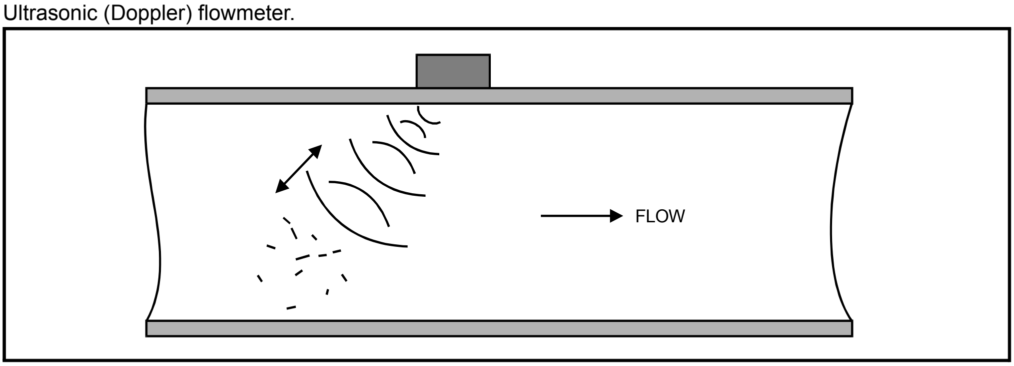
In a Doppler flowmeter (see figure 4-17), a piezoelectric crystal generates a sound wave. The receiver measures the velocity of small particles present in the fluid. The frequency of sound reflected from a moving object—solids and entrained gases—is proportional to the speed of the object. The system then averages the reflected velocity signals.

The fluid to be measured must be a liquid that has entrained gas (greater than 30 microns) or suspended solids (depending on particle size, but typically greater than 25 ppm). The crystal can be in contact with the fluid or mounted outside the piping (clamp-on transducers).

Application Notes

The Doppler flowmeter has many advantages. The common clamp-on versions are easily installed outside the pipe without shutting down the process. This flowmeter is also bidirectional and is unaffected by changes in viscosity. Moreover, the Doppler flowmeter is generally suited for measurements in very large water pipes, it does not obstruct flow, and its cost is independent of line size.

Figure 4-17
Ultrasonic (Doppler) flowmeter.



However, users should consider the following when selecting the Doppler flowmeter. More than 30 ft. (10 m) must be allowed between installations to prevent the meters from interacting. Some sound energy will travel from the environment through the pipe wall and into the sensor. This can cause interference, and poor sound penetration produces reading errors. Similarly, the Doppler flowmeter must be used with non-porous pipe material (i.e., avoid cast iron, cement, or fiberglass). Its accuracy depends on the difference in velocity between the particles and the fluid as well as on the particle size, concentration, and distribution. It must be recalibrated periodically.

Weir and Flume

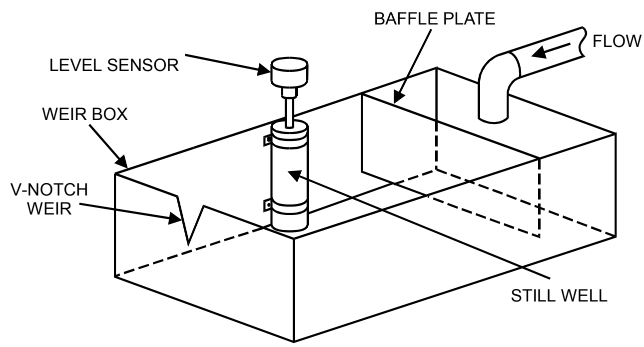
Principle of Measurement

A weir (see figure 4-18) is a plate with a trapezoidal, rectangular, or V-shaped notch in it. The trapezoidal weir is also known as the Cipolletti weir. The rectangular notch is easy to construct and can handle larger flows, whereas the V-notch has a relatively wide turndown capability.

A flume (see figure 4-19) is a free-flow open channel with a restriction (similar to an open venturi). The entrance section (on the up stream) converges to a straight section that has parallel sides, then the sides diverge. The Parshall flume is the most common type. Level is measured in the entrance section, and its value is converted into rate of flow.

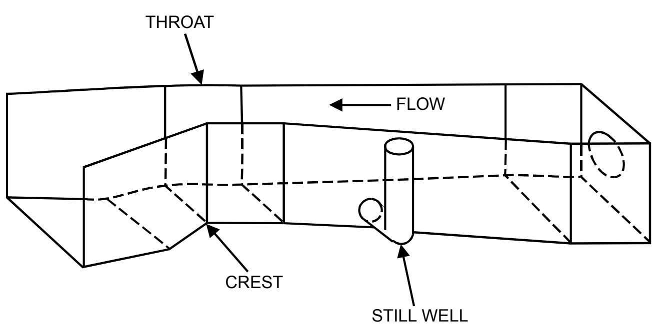
For both weirs and flumes, measuring the height of the water's surface from a datum is a direct indication of flow. Measurement of the liquid head is performed by float, ultrasonic, and other methods (see chapter 5 on level measurement). A stilling well is sometimes used to eliminate and reduce turbulence.

Figure 4-18
Weir with a V-notch.



(A) WEIR WITH A V-NOTCH

Figure 4-19
Parshall flume.



(B) TYPICAL PARSHALL FLUME

Application Notes

The main advantages of flumes over weirs include their ease of construction and their sturdiness. Their ability to handle flows at higher velocities makes it possible to measure liquids with entrained solids, and flumes' self-cleaning capabilities enable them to handle wastes that have suspended solids. Weirs, which can handle large volumes of liquid, are more accurate than flumes but require cleaning.

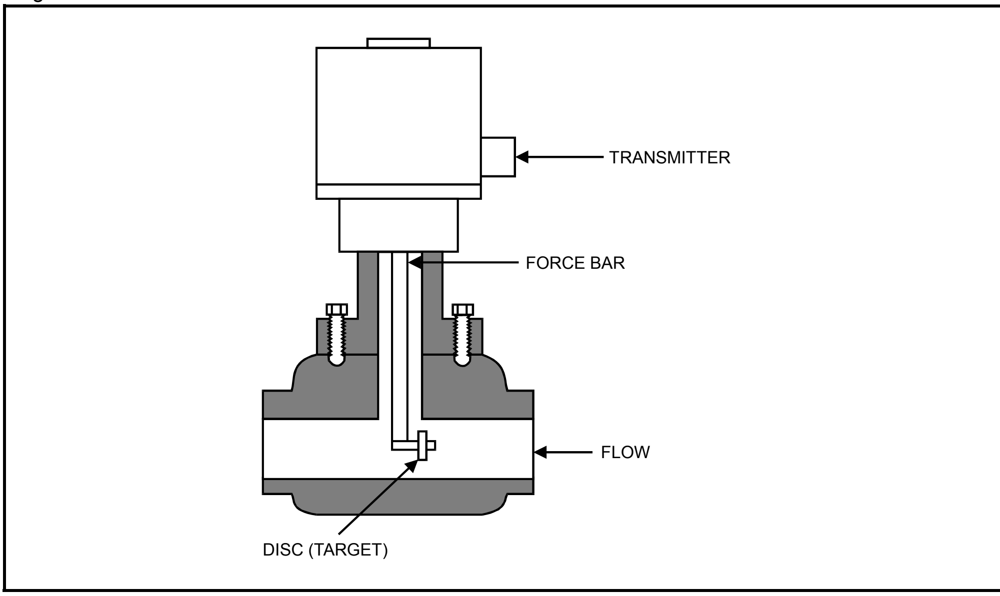
Weirs and flumes produce low head loss, are relatively low in cost, and are the only flowmeter that will handle semifilled pipes. Viscosity changes have little or no effect on weirs or flumes. Both are used in liquid (clean and dirty) applications in open channels—mainly, water and wastewater applications.

Target

Principle of Measurement

In a target flowmeter (see figure 4-20), the flow exerts a force on a solid disk that lies in the pipe at right angles to the flow. The force is related to the flow. The target flowmeter can be described as the opposite of an orifice plate.

Figure 4-20
Target flowmeter.



Application Notes

The target meter is inexpensive and has no moving parts. It is mainly used for viscous fluids, and is a good method for applications such as hot, tarry fluids and sediment-bearing fluids.

CHAPTER 5

LEVEL MEASUREMENT

Overview

Level measurement is defined as the measurement of the position of an interface between two media. These media are typically gas and liquid, but they also could be two liquids. The first method of level measurement, a few thousands of years ago, consisted of a graduated stick that was referenced to an arbitrary datum line. In more recent times, the glass gage was developed as an evolution of the U-tube principle (this is described further in chapter 6 on pressure measurement). Eventually, level measurement was used on pressurized tanks by connecting the upper end of the tube to the vessel. With equal pressure in the tube and the vessel, the liquid level in the tube was at the same point as the level in the tank.

Over the years, level measurement technology has evolved, and highly accurate and reliable devices are now on the market. New principles of measurement are being introduced, and existing principles are continuously improved upon. Many parameters need to be considered when applying level-measuring devices, depending on the type of level measurement selected. Ignoring such parameters may result in a measurement with a high error or one with a short life span. Like any item of instrumentation and control, level-measuring devices should be installed where they can be easily accessed for inspection and maintenance.

Level measurement is a key parameter that is used for reading process values, for accounting needs, and for control. Of the typical flow, level, temperature, and pressure measurements, flow tends to be the most difficult, but level follows closely behind. This chapter provides some of the basic knowledge plant personnel need to select the correct level-measuring device.

Classification

Level devices operate under different principles. They can be classified into three main categories that measure

- the position (height) of the surface.
- the pressure head.
- the weight of the material through load cells.

Load Cells

Mechanical lever scales, which provided 0.25 percent accuracy at best, were the typical load-measuring device before the advent of the strain-gage-based cell. These mechanical devices were also expensive and complex in design and maintenance. In contrast, today's strain-gage load cells can attain accuracies of 0.03 percent of full scale, have simple designs, are relatively inexpensive, and are easy to calibrate.

The strain gage itself is bonded to a beam or other structural member, which bends slightly under the applied weight. This deformation changes the electrical resistance in one of the legs of the Wheatstone bridge, and the electronics convert that change into a weight. For more information about the Wheatstone bridge, refer to figure 6-11.

Units of Measurement

The 0 to 100 linear scale represents a percentage of level. It is the most commonly used scale for measuring liquid level. In some cases, the level measurement is converted into volume (e.g., gallons or liters) to provide a more meaningful indication.

Measurement of Solids

The level of solids often must be measured because of the continuous increase in the processing of solids and industry's need to comply with regulations.

When plants are measuring the level of solids, sensors located near the bottom of a bin may need to be protected from falling material when the bin is being filled. Where rods and probes are implemented, users must assess the impact of forces and abrasive effects. In addition, solid material often arches or forms "rat holes," which sometimes makes measuring such material's level difficult. In these environments, vibrators may need to be strategically mounted on the bins to break down those bridges. Proper location of the sensor is essential if they are to operate well.

The top level of solids material in a bin is rarely horizontal since most solids have an angle of repose. Therefore, the location of the measurement point should provide a representative average of the overall level, and in some cases several probes may have to be used for this purpose. There are other specific requirements of solids measurements. For example, plants should keep in mind that, depending on the type of level sensor they use, the dielectric constant will vary for solids as the moisture content increases. Measuring devices that rely on such parameters may give the wrong reading.

The most common continuous types of measurements for solids are radiation, weighing, and ultrasonic. For on/off measurement, the most common types are diaphragm, rotating paddle, capacitance, and vibrating rod.

Weighing, which is performed by using load cells, is still one of the most common and reliable methods for measuring the contents of a tank. The advantages of weighing methods are that they are completely non-contacting and are relatively inexpensive to maintain. However, they have a higher initial cost than typical level sensors, and in existing installations, they may necessitate costly modification of the tank's construction.

Comparison Table

Table 5-1 summarizes the main types of level measurement with respect to a set of common parameters and can be used as a guide for selecting the appropriate method. The information presented in the table indicates typical values. Vendors may have equipment that exceeds the limits shown.

Table 5-1
Level measurement comparison

Parameters / Types	Fluid Types (Y=Yes, N=No, S=Sometimes)								Continuous sensing	Point sensing	Meter output		Measuring range	Temperature range	Pressure range	Accuracy
	Liquids			Solids				Slurries								
	Clean	Liquid-to-liquid interface	Foam	Powdery	Granular	Chunky	Sticky moist				Electronic	Pneumatic				
Differential pressure (static head, hydrostatic)	Y	Y	N	N	N	N	N	S[1]	Y	Y	Y	Y	0-100 psi (0-690 kPa) [2]	400°F (205°C) max [2]	2000 psig (14 mPag) max [2]	±0.1 to 0.5% of full scale
Displacement	Y[3]	Y[3]	N	N	N	N	N	S	Y	Y	Y	N	60 in (1500 mm) [4]	800°F (425°C) max	300 psig (2100 KPag) max	±1/4" (6 mm) or 0.25% of full scale
Float	Y[3]	Y[3]	N	N	N	N	N	N	N	Y	Y[5]	N	[6]	800°F (425°C) max	300 psig(2100 KPag) max	±1/4" (6 mm) or 0.25% of full scale
Sonic/Ultrasonic	Y	N	S[29]	S	Y	Y	Y	Y	Y	Y	Y	N	3–150 ft (1– 45 m)	-40–300 °F (-40–149°C)	50 psig (350 KPag) max	±1– 2% [7] of full scale
Tape (float and tape)	Y	N	N	N	N	N	N	N	Y	Y	Y	Y	60 ft (20 m) max	300°F (150°C) max	300 psig (2100KPag) max	±1" (25 mm)
Weight and Cable	Y	N	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	150 ft (50 m) max	0–140°F (-18– 60°C)[8]	5 psig (35 KPag) max	±1" (25 mm)
Gauge (sight glass)	Y	[9]	N	N	N	N	N	N	Y	Y	S[10]	N	glass gauges 2 ft (0.7 m) max armored gages 4 ft (1.5 m) max	glass gages 195°F (90°C) max armored 660°F (350°C) max	15 psig (100 KPag) max[11]	±1/4" (6 mm)
Radioactive (nuclear)	Y	N	N	Y	Y	Y	Y	Y	Y	Y	Y	N	15 ft (5 m) max[12]	-40–140°F (-40–60°C)[13]	unlimited (located outside tank)	±1/4" (6 mm) (point measurement) ±1– 2% (continuous measurement)
Bubbler	Y	N	N	N	N	N	N	S	Y	Y	Y	Y	[14]	[15]	atmospheric	±1 - 2% of full scale
Capacitance	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	- rod' ;20 ft (7 m) max - cable; 90 ft (30 m) max	840°F (450°C) max	7200 psig (50 MPag) max	±1/8" (3 mm) (point measurement) ±1–2% (continuous measurement) per 3' (1 m) length
Conductivity	Y[16]	S[17]	S[16]	S[18]	S[18]	S[18]	S[18]	Y	N	Y	Y	N	100 ft (30 m) max	[19]	3000 psig (21 MPag) max	±1/8" (3 mm)
Thermal	Y	N	S	N	N	N	S	S	N	Y	Y	N	unlimited	-76–221°F (-60–105°C)	3000 psig (21MPag) max	±1/4" (6 mm)
Radar	Y	N	S[29]	Y	Y	Y	Y	Y	Y	Y	Y	N	120 ft. (40 m) max	-76–750°F (-60–400°C)	[20]	±0.1" (±3 mm)
Beam breakers, photometric, light beams	Y[21]	S[22]	Y[23]	Y	Y	S	Y	Y	S	Y	Y	N	21ft (7 m) max	-27– 149°F (-35– 65°C)	80 psig (550 KPag) max	±2– 3% for broken beam ± 1/16" for reflected beam
Vibration	Y	N	N	Y[24]	Y	Y	Y	Y	N	Y	Y	N	45 ft(15 m) max	-150–300°F (-100–150°C)	140 psig (1MPag) max	±1/8" (3 mm)
Paddle wheel	Y	N	N	Y	Y	N	Y	N	N	Y	Y	N	depends on installation	343°F (175°C) max	30 psig (210KPag) max	±1" (25 mm)
Diaphragm	Y	N	N	Y	Y	N	N	N	Y	Y	Y	Y	[25]	850°F (450°C) max	atmospheric	±1–6 in (25–150 mm) [26]
Resistance Tape	Y	N	N	Y	Y	N	N	N	Y	Y	Y	Y	100 ft(30 m) max, [27]	-13–797°F (-25–425°C)	atmospheric	±4 in. (100 mm)
Laser	Y	N	S[29]	Y	Y	Y	Y	Y	Y	Y	Y	N	1 ft to 5000 ft (0.3m to 1500m)	15-120°F (-10–50°C) [28]	600 psig (4200 KPag) max	±0.4 in. (10 mm)

Notes [1] through [29] on following page.

Notes for Table 5-1:

1. With the proper design
2. Limited by dP cell range. Filled systems are limited to 400°F (205°C) and 2000 psig (14 MPag)
3. Good for non-freezing liquids only (unless heat tracing is used)
4. Between high and low points, some may extend to 15 ft. (5 m), beyond that it must be built in sections
5. Contact output only
6. Limited by float movement
7. 0.1% in some units with temperature compensation
8. Optional to -40°F (-40°C) with heater
9. S for glass and N for armored (magnetic)
10. Must be fitted with optional/additional electronic sensing equipment (e.g., beam breaker)
11. Armored/magnetic type to 3,000 psig (21MPa), bulls eye 10,000 psig (70MPag) max
12. Unlimited with multiple units (multiple sources may be used for wide ranges)
13. Water cooled detectors will handle temperatures to 3000°F (1600°C) – they are required for temperatures >140°F (60°C)
14. Limited only by pressure transmitter range
15. Temperature must be above dew point of purge gas
16. Must be conductive
17. Interface between conductive and non-conductive liquids/slurries
18. Conductive path is required (dielectric constant greater than 19.0)
19. Limited by probe materials (for electronics; 15–180°F (-26–82°C))
20. Limited to selected materials - typically full vacuum to 2300 psig (16 MPag)
21. Non-transparent liquids
22. Yes, if measuring light absorption level of different materials
23. Non-transparent foams
24. On wet powders the vibrating fork may have the tendency to generate a cavity around itself, affecting performance
25. Point; unlimited/continuous; from 6 in. (0.15 m) and up
26. Dependent on diaphragm construction
27. Theoretically limited by length of tape and sensitivity of sensor to pressure changes
28. Will withstand up to 2200°F (1200°C) with special protective equipment
29. Depends on foam density (foam may absorb signal) and signal strength

Differential Pressure (or Pressure/Static Head)

Principle of Measurement

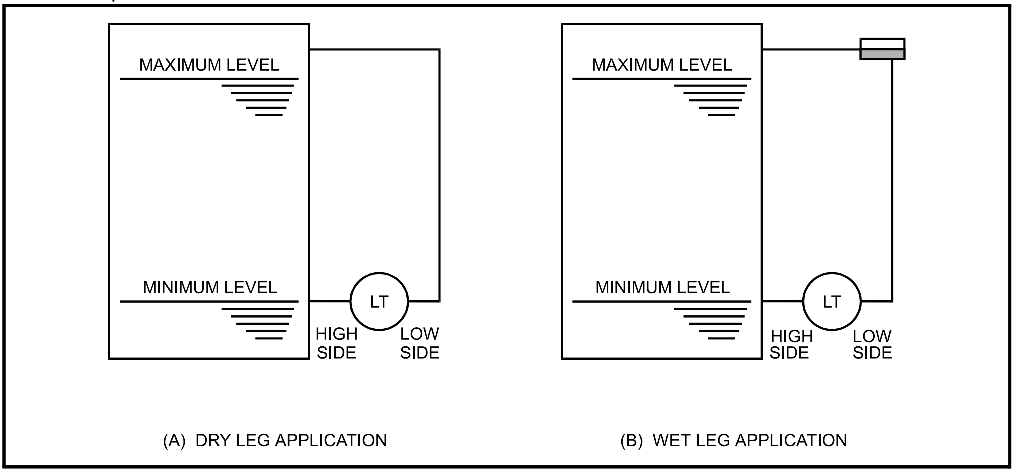
Differential-pressure level measurement (see figure 5-1), also known as “hydrostatic,” is based on the height of the liquid head (the U-tube principle).

Level measurement in open tanks is based on the formula that the pressure head is equal to the liquid height above the tap multiplied by the specific gravity of the fluid being measured. In closed tanks, the true level is equal to the pressure measured at the tank bottom minus the static pressure above the liquid surface. To compensate for that static pressure, a leg is connected from the tank top to the low side of the differential pressure transmitter (see figure 5-1). Two options are available: dry leg and wet leg.

In dry leg applications, it is expected that the low side will remain empty (i.e., no condensation). If condensation takes place, an error will occur because a pressure head will be created on the low side. This error is avoided by intentionally filling the low side with a liquid—hence the term wet leg.

Where filled systems (with diaphragm seals) are used between the transmitter and the tank, calibration of the transmitter should allow for the specific gravity of the fill fluid. The user should refer to the vendor’s instructions when setting the zero and span values.

Figure 5-1
Differential-pressure level measurement.



Application Notes

Differential-pressure measuring devices are easy to install and have a wide range of measurement. With proper modifications, such as extended diaphragm seals and flange connections, these instruments will handle hard-to-measure fluids (e.g., viscous, slurries, corrosive, hot). In addition, they are simple and accurate. Calibrating differential-pressure measuring devices is straightforward. Adjustments to zero, elevation/suppression, and span are easy, and no special tools are required.

On the other hand, differential-pressure measuring devices are affected by changes in density. They should be used only for liquids with fixed specific gravity or where errors due to varying specific gravities are acceptable or compensated for. Pressure gages can be used to measure tank level because the static head pressure equals the density of the fluid multiplied by the height of the liquid head. Note that changes in liquid density due to changes in temperature will introduce errors.

Differential-pressure devices are susceptible to dirt or scale entering the tubing (in small process connections), which can easily plug them. In addition, parts of the instrument may be exposed to the process fluid, while the outside leg may be susceptible to freezing. These problems can be overcome with the proper design.

Where feasible, differential-pressure measuring instruments should be isolated from the process by a shutoff valve so the instrument can be removed without affecting the operation. Where there is a possibility of condensation in the low-pressure impulse line, the plant should consider using filling tees. Differential-pressure devices often require the use of a constant head on the external (reference) leg. Keep in mind that the fill fluid should be compatible with the process fluid.

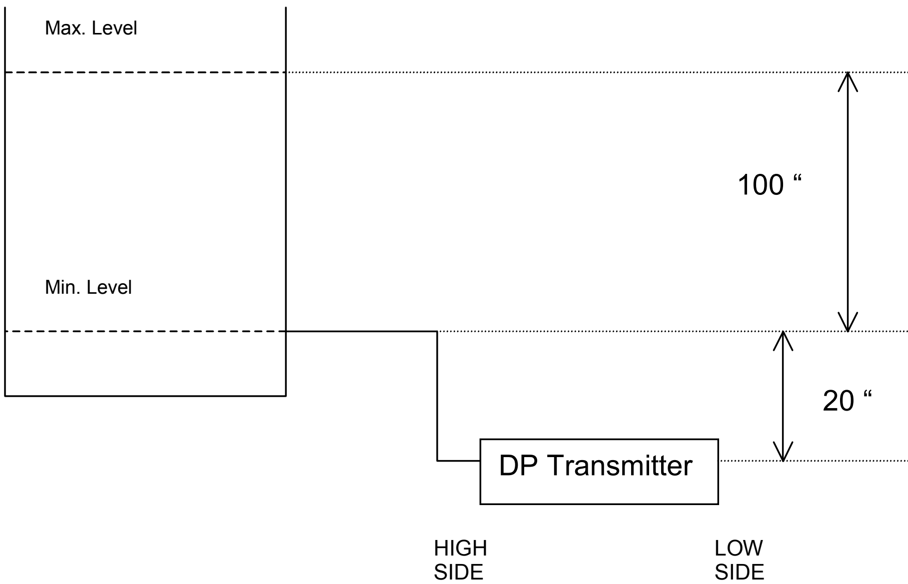
Zero Suppression and Elevation

When transmitters are mounted below the high side tap, a zero point adjustment is required. This is called "zero suppression." Zero suppression occurs when a liquid head causes the pressure reading in the impulse line to increase, causing a hydrostatic head. This head must be compensated for to avoid an error in measurement (see figure 5-2A).

Zero elevation is basically the opposite of zero suppression. It is used in differential-pressure level measurement when a hydrostatic head called a wet leg is applied to the low side. This decreases the transmitter output, making a "zero elevation" necessary (see figure 5-2B).

Major equipment vendors provide users with the necessary calculations for the correct zero adjustment based on the transmitter's position and on the specific gravities of the fill fluid and the process fluid. Smart transmitters simplify zero suppression/elevation calculations.

Figure 5-2A
Example of Zero Suppression calculations for an open vessel.

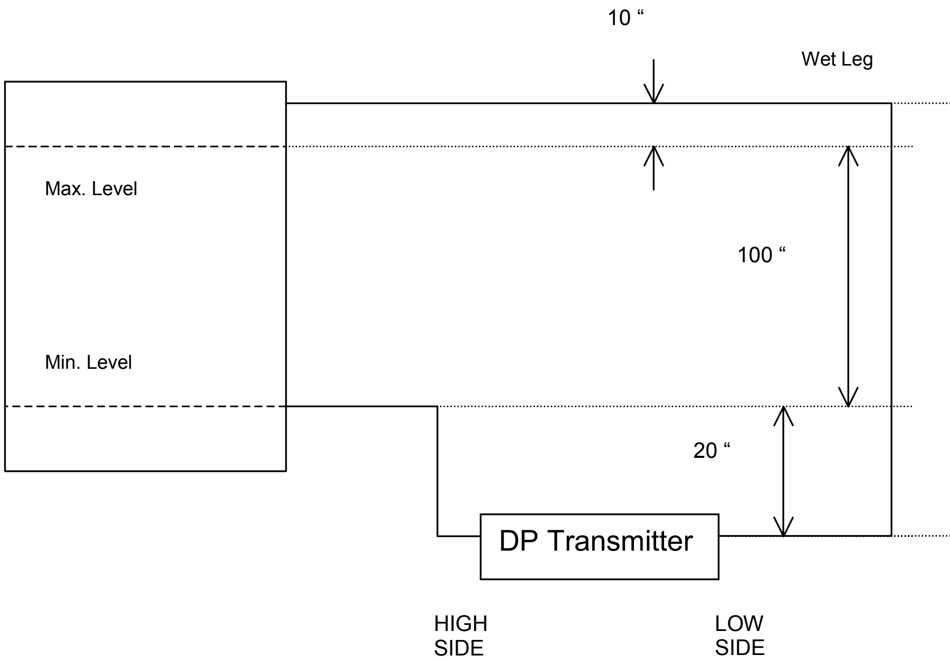


Fluid SG = 0.9
Span = 100″ x 0.9 = 90″ WC
Suppression = 20″ x 0.9 = 18″ WC
Range = 18 to 90″ WC

Calibration:
1- calibrate transmitter from 0 to 90″ WC (= span)
2- apply 18″ WC to the high side
3- adjust zero until transmitter output reads 4mA
Note: Do not adjust the span

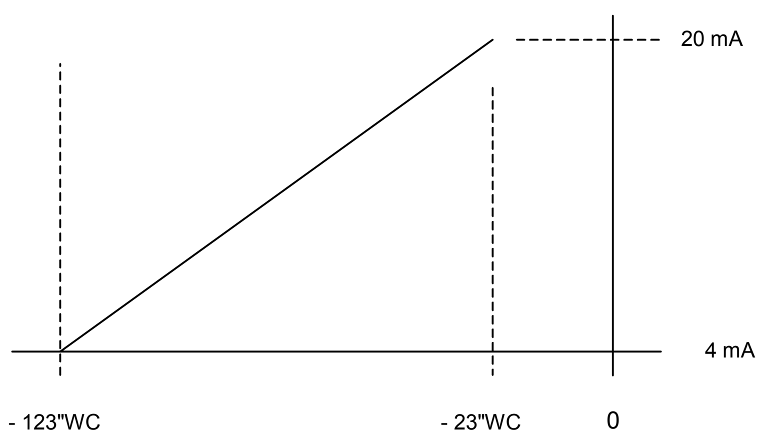
Zero is now set at 18″ WC
Span is set at 90″ WC

Figure 5-2B
Example of Zero Elevation calculations for a closed vessel with a wet leg.



Tank fluid SG = 1
Wet leg fluid SG = 1.1
Total wet leg height = 10 + 100 + 20 = 130″

Range = [(20 x 1) - (130 x 1.1)] to [(100 x 1) + (20 x 1) - (130 x 1.1)]
= -123″ WC to - 23″ WC



Valve Manifolds

Manifolding first emerged with the development of differential-pressure measurement. Three-valve and five-valve manifolds were assembled and piped using separate components. The three- and five-valve manifolds were unitized in the 1960s, and today are quite often sold as a component of the differential-pressure transmitter. The principal advantages of a unitized manifold are fewer leak points in the final installation, reduced material and labor cost, and reduced space requirements.

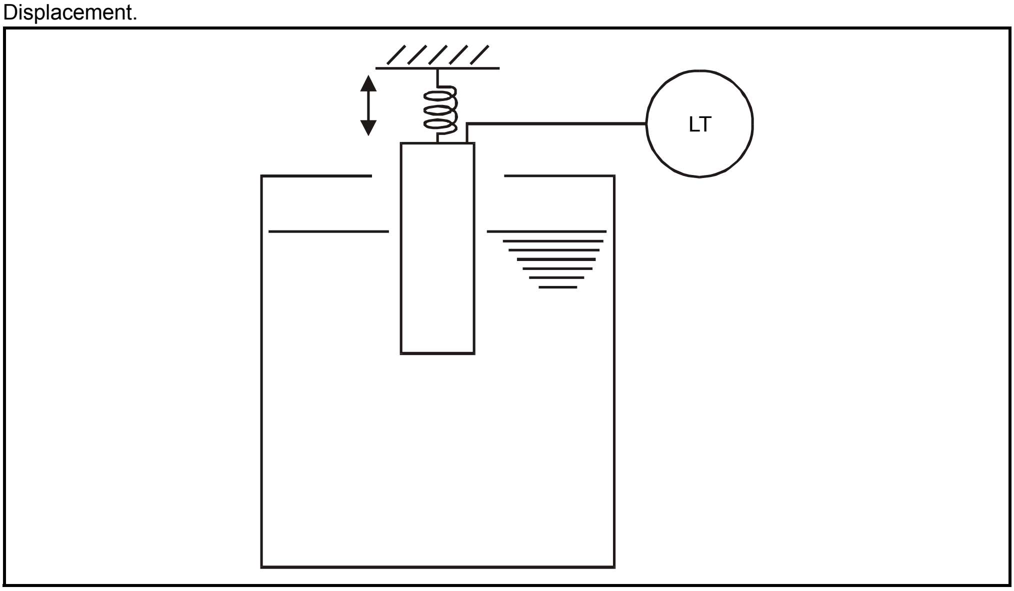
Most valve manifolds are threaded to the process tubing or piping. However, in plants where the process fluid is hazardous, the impulse line should be welded to the manifold. Welding makes repair and replacement expensive and difficult. Welding is generally available in two types: butt-weld and socket-weld. For additional information about line connections, refer to the section titled "Valve Bodies" in chapter 13.

Displacement

Principle of Measurement

A displacer (see figure 5-3), which can be either partially or totally immersed, is restricted from moving freely with the liquid level. It transmits its change in buoyancy (mechanical force) to a transducer through a torque-tube unit. Sometimes the term *float* is used instead of *displacer*. However, the element does not actually float; it is submerged in the liquid being measured.

Figure 5-3
Displacement.



Application Notes

Displacers are simple, dependable, and accurate, and they can be mounted internally or externally. This type of level measurement should be used only for liquids with fixed specific gravity, where errors due to process variations are acceptable, and where a change in process condition will not create crystallization or solids.

External cage-type instruments are generally preferred. They are typically isolated by block valves and are heat traced and/or insulated (depending on the process fluid and on ambient conditions). The piping arrangement should be designed to prevent the formation of sediment on the bottom of the displacer cage. All components, including piping material and isolation valves, must be compatible with the process fluid. Typically, a suitable drain is provided at the low point and a vent valve at the highest point.

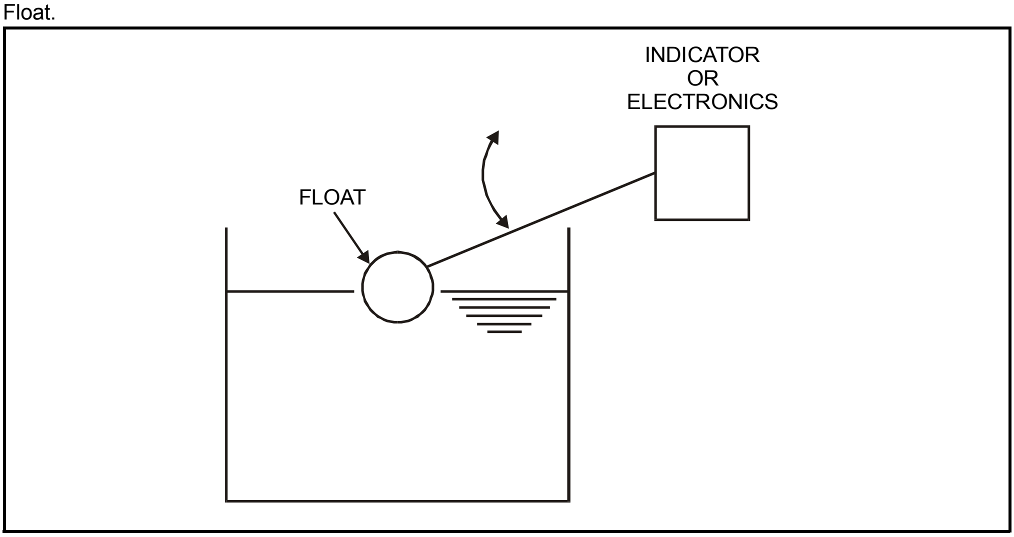
Displacers are difficult to calibrate and have numerous mechanical components. Therefore, it is important to ensure that the movement of the displacer, linkages, or levers is not restricted. In addition, boiling liquid may cause violent agitation at the liquid surface, so stilling wells may be required where turbulence exists. Also, the element may be affected by coating, buildup, or dirt that can cling to the displacer.

Float

Principle of Measurement

A float (see figure 5-4) consists of a hollow ball that rides freely on the surface of the liquid. Its position is a direct indication of level. The float is connected to an arm that operates a microswitch or a pointer and scale through a bearing. The spherical shape of the ball provides maximum volume—that is, maximum buoyancy—for its weight. For maximum sensitivity, the ball should be selected so it will sink to its largest (middle) section. This produces the largest force available to overcome friction and inertia of components.

Figure 5-4
Float.



Application Notes

Float devices are low in cost and simple in design. They are also accurate and reliable. However, for turbulent liquids they require the use of stilling wells, they are physically large, and they are generally used for clean services only. To maintain the float's accuracy, liquids must have a fixed specific gravity. In addition, the float instrument is in contact with the process material, and buildup on the float will affect performance. Corrosion and chemical reactions are also a concern. The float's effective travel is limited by its construction; typically, the angle of measurement is limited to ±30 degrees from the horizontal.

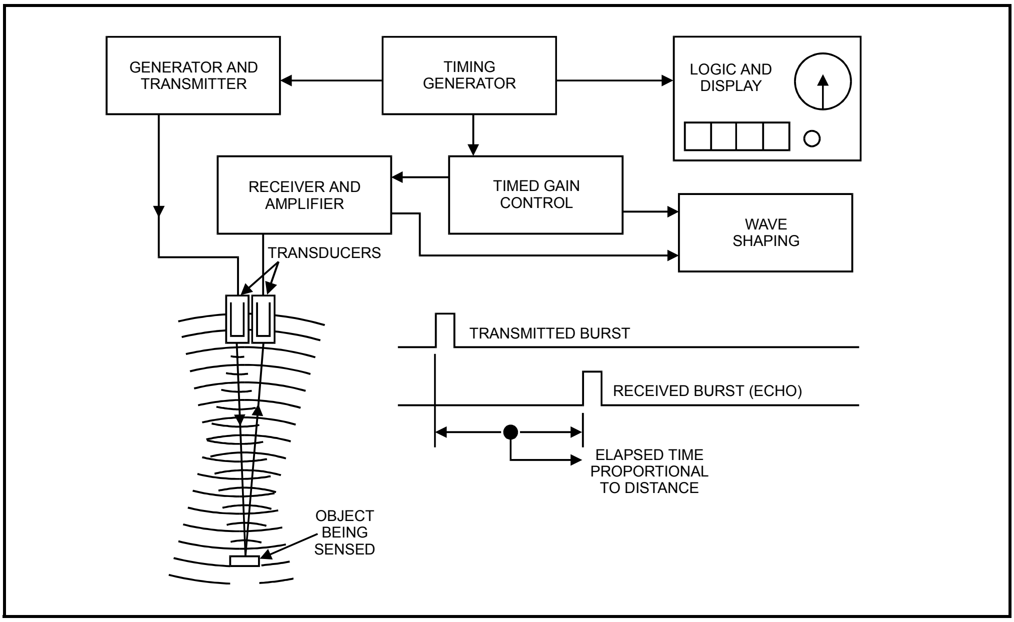
Generally, the float is not installed directly on top of pressurized vessels. If it is, the vessel may have to be taken out of service in order to do maintenance on the float. For this reason, external cage-type instruments are preferred. They are isolated from the process vessel by isolating valves. The movement of the float, linkages, or levers must not be restricted.

Sonic/Ultrasonic

Principle of Measurement

Sonic and ultrasonic sensors (see figure 5-5) consist of a transmitter that converts electrical energy into acoustical energy and a receiver that converts acoustical energy back into electrical energy. In sonic sensors, the unit uses the echo principle and emits pulses that have an approximate frequency of 10 kHz. After each pulse, the sensor detects the reflected echo. The transmitted and return time of the sonic pulse is relayed electronically and converted into a level indication. The principle for ultrasonic sensors is the same, except that the operating frequency is about 20 kHz or higher.

Figure 5-5
Sonic/ultrasonic.



Application Notes

Sonic and ultrasonic devices are noncontacting, reliable, and accurate. They penetrate high humidity, are cost effective, have no moving parts, and are unaffected by changes in density, conductivity, or composition.

However, strong industrial noise or vibration at the unit's operating frequency will affect performance, and in some designs, dusts tend to give false signals. In addition, coating may affect these devices' performance since deposit buildup on the probe (or the membrane) will attenuate the signal. For this reason, the unit should not come into contact with the process fluid. Users should compare the maximum process temperature and pressure with the limits of the sensor.

Sonic and ultrasonic devices cannot be used to measure the level of foam because the sound signal is absorbed by foam. Also, since the operation of these devices depends on the speed of sound, they will not work in a vacuum. Various factors can affect the speed of sound and so the instrument's accuracy, vapor concentration, pressure, temperature, relative humidity, and the presence of other gases/vapors. Frequently, temperature compensation may be required to avoid variations in accuracy.

The plant should follow the manufacturer's installation recommendations carefully. Users should consider the effect of the process material (since the sensor's thin membrane corrodes easily) as well as the effects of spurious echoes. Such echoes must be avoided to prevent errors in the signal. The beam divergence is typically between 8 to 15 degrees (compared to 0.3 degrees for a laser type), and it produces an increasing footprint as the distance increases. No braces, stiffeners, or other cross-members should lie in the path of the ultrasonic beam. Also, most operating span ranges will not measure levels of less than 1 ft (0.3 m). In closed flat-top tanks, it may be necessary to reduce the transmit repetition so that respective echoes have enough time to die out. In some cases, a sound-absorbing layer may have to be installed to the underside of the tank top.

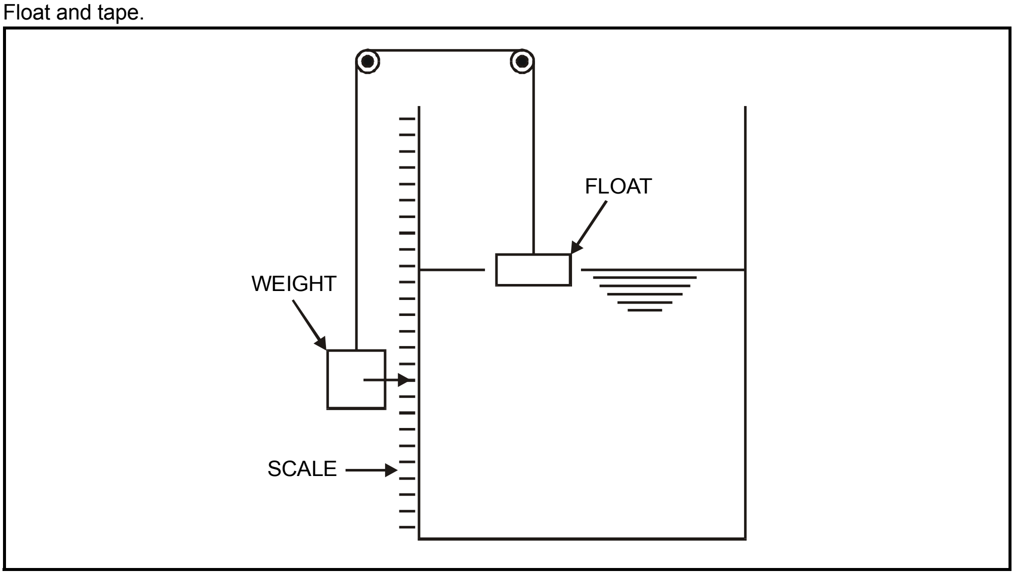
Tape (Float and Tape)

Principle of Measurement

Tape devices (see figure 5-6) are similar to floats. A tape connects a float on one end and a counterweight on the other. The counterweight moves up and down a graduated scale located outside the tank. The counterweight is used to keep tension on the tape as the float rises and falls with the level. Where the tape is replaced with a chain, the chain is engaged in a sprocket. For pressurized tanks, the connection is sealed through a magnetic link.

This level-measuring instrument is rarely used for signal transmission. It is generally used for local indication only. For maximum sensitivity, users should select a spherical float so it will sink to its largest (i.e., its middle) section. This produces the largest forces available to overcome friction and inertia of components.

Figure 5-6
Float and tape.



Application Notes

Tapes are accurate. However, they can have mechanical problems such as hang-up and friction. Also, material buildup on the float will affect performance. In applications where high accuracy is required, compensation for the varying specific gravity may be necessary. In addition, the tape's mechanical parts should be protected from possible weather interference.

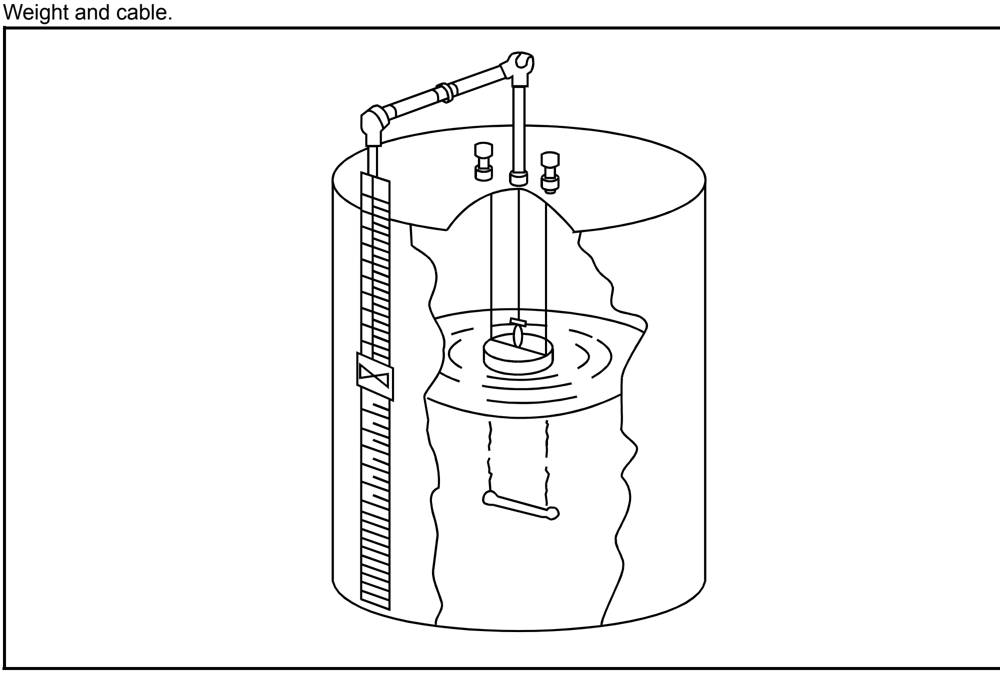
The sensor in the tank should be located close to a manway and sufficiently distant from agitation and from incoming or discharging lines to minimize the effect of turbulence. Stilling wells are often used if the vessel is agitated.

Weight and Cable

Principle of Measurement

With the weight and cable device (see figure 5-7), a cable or tape is attached to a weight that descends into the tank. This motion is activated by a timer. When the weight makes contact with the surface of the material, the motor automatically reverses direction and retrieves the weight at about 1 ft/s (0.3 m/s). During descent, pulses are generated and displayed on a counting unit, which indicates either material stored or available filling capacity.

Figure 5-7
Weight and cable.



Application Notes

Weight and cables are accurate devices, and the fact that they are only momentarily in contact with the process material prevents product from building up on the weight. However, they can have mechanical problems, such as hang-up and friction. Also, they must be activated in order to measure, and they have no signal transmission capability.

In outdoor installations, measures should be taken to protect the mechanical parts of the level-measuring instruments from possible weather interference. Stilling wells are often used if the vessel is agitated.

Gage

Principle of Measurement

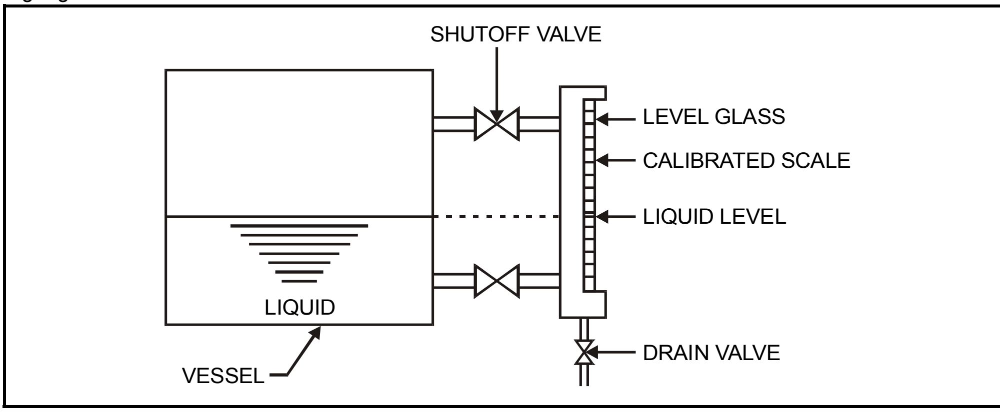
A gage, also known as a “sight glass” or “manometer” (see figure 5-8), operates on the U-tube principle. There are three basic types of gages: glass, reflex, and magnetic.

The glass type consists of two glass sections, in between which is the fluid to be measured.

The reflex type consists of a single glass with cut prisms. Light is refracted for the vapor portion of the column and is shown generally as a light color. Light is absorbed for the liquid portion of the column and is shown generally as a dark color.

Magnetic-type gages have a float that lies inside a nonmagnetic chamber. The float contains a magnet, which rotates wafers 180 degrees as the level increases or decreases. The rotated wafers present the opposite face with a different color.

Figure 5-8
Sight glass.



Application Notes

Gages are used as a local indicator for open or pressurized vessels. They must be accessible and located within visual range. In certain services, such as steam drum service, glass gages must conform to local code requirements (e.g., ASME Power Boiler Code). Gages are low in cost and provide direct-reading measurement. However, they are not suitable for dark liquids (except if the magnetic type is used), and dirty fluids will prevent the liquid level from being viewed.

On safe applications, glass gages can be used. However, they can be easily damaged or broken. Glass gages should not be used to measure hazardous liquids. Reflex gages are permissible for low- and medium-pressure applications. For high-pressure applications, or where the fluid is toxic, magnetic-type armored gages should be used. However, this type should be kept away from magnetic fields.

For safety reasons, the length of glass gages between process connections should not exceed 4 ft (1.25 m). In addition, to perform maintenance on glass gages, isolating valves are required to facilitate the removal of the gage glass. Drain and vent valves also are frequently installed. These isolating valves must be implemented in accordance with the piping specifications. In addition, glass tubes are sometimes provided with ball check valves so the process connection shuts off in the event the glass tube breaks.

When installing such devices, good lighting is required. Sometimes an illuminator may be required in dark areas. In installations where the gage is at a lower temperature than the process, condensation may occur on the walls, making the reading difficult.

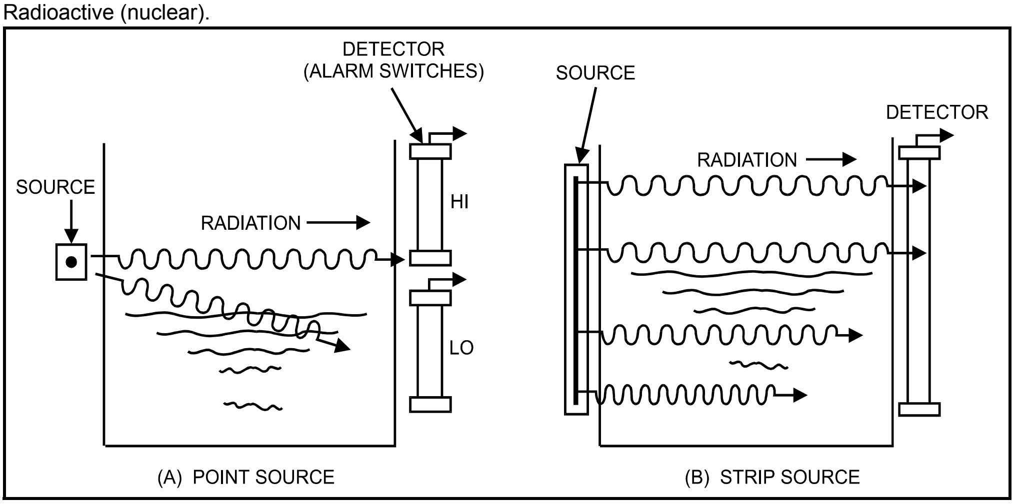
Radioactive (Nuclear)

Principle of Measurement

With the radioactive (nuclear) device (see figure 5-9), a radioactive source radiates through the vessel. The gamma quantum is seen by the radiation detector (such as a Geiger counter) and is transformed into a signal. When the vessel is empty, the count rate is high. The radioactive source holder is designed to direct a collimated beam of radiation toward the tank and to be shielded in all other directions so as to reduce the radiation levels to below the legal limit.

The strength of the sensed radiation depends on the thickness of the vessel wall, the distance between the source and detector, and the density and thickness of the measured material. The radiation source generally has a half-life of 30 years; therefore, corrections for source decay are rarely required.

Figure 5-9
Radioactive (nuclear).



Application Notes

Radioactive level measurement is external to the vessel. It can be added or removed without disturbing the process. Radioactive (nuclear) devices are highly reliable, non-contacting devices with no moving parts. They are unaffected by temperature, pressure, and corrosion, and their mode of failure is limited and predictable.

However, radioactive (nuclear) devices require special engineering and licensing for the application they are used with, and extreme care is required when locating and installing the radioactive source. The manufacturer's recommendations must be closely followed, and the manufacturer should be consulted to obtain optimum results and maximum safety. Operator exposure to radiation must be minimized, and therefore, plants may need shielding lead plates at the source or detector.

Radioactive (nuclear) units are expensive to install and operate in order to maintain their compliance with regulations. Special care must be exercised when installing them, which drives their cost up, and they are difficult to calibrate. Before installing such a device, the user should keep in mind that the plant will need a special license and training.

The radioactive (nuclear) measuring device is applied where other types of measurement cannot be used. On vessels larger than 30 ft (10 m) in diameter or on vessels with extremely thick walls, the source may have to be suspended vertically inside the vessel. Special shield containers are then required.

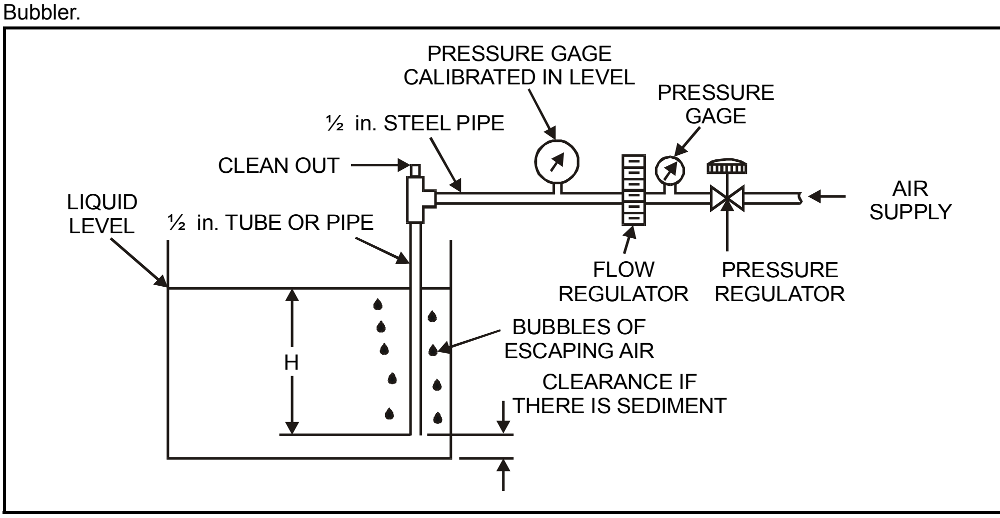
Bubbler (Dip Tube)

Principle of Measurement

In a bubbler (see figure 5-10), a small amount of air (or inert gas) purge flows through a dip tube in the vessel. Sometimes, to provide rigidity, a stand pipe is used instead of a dip tube. The dip tube (or pipe) generally extends to about 3 inches (75 mm) from the bottom of the tank and is notched to keep the size of the air bubble small. The pressure that is required to force air bubbles from the bottom of the tube is the liquid head above the end of the tube. A purge meter, which consists of a rotameter with a needle valve, is required to provide a constant airflow of about 0.2 to 2.0 scfh (0.005 to 0.05 m^3/hr). A pressure regulator located upstream of the purge meter provides a smooth operation. In plants where remote level indication is required, the high-pressure side of the differential-pressure transmitter measures the tube pressure, and the low side measures the vessel's top pressure, if it is not vented to the atmosphere.

In some cases, liquid purge is used instead of air purge, usually in cases where air or other gases cannot be used. Generally, about 1 U.S. gal/h at 15 psi (4 L/h at 100 kpa) differential pressure is the maximum required liquid purge rate. In other cases, where level measurement is required only occasionally or where utilities are not available, a hand pump (instead of a constant air supply) can be connected to the dip tube in order to measure level.

Figure 5-10
Bubbler.



Application Notes

The bubbler offers low cost and easy maintenance, it can operate without electrical power, and it can be used on pressurized or unpressurized vessels. However, variations in density will affect the bubbler's readout, and bubblers can become coated or plugged by process fluid residue or dirt. In addition, the cost of purging fluid is ongoing, and the purge gas can introduce unwanted components into the process. The introduction of a foreign material, usually instrument air, into the process should be acceptable. Otherwise, a special gas (or liquid) should be used instead. Also, if a vessel is emptied by pressurization, the liquid being measured may be forced up the dip tube/pipe, which causes an incorrect readout.

This measuring device is not an off-the-shelf item; some engineering is required. The materials of construction for the bubbler must be compatible with the process it is used in, and the bubbler's dip tube installation must be capable of withstanding the maximum air pressure that blockage causes. A tee piece at the top of the dip tube (or pipe) may be required to enable rodding.

Capacitance

Principle of Measurement

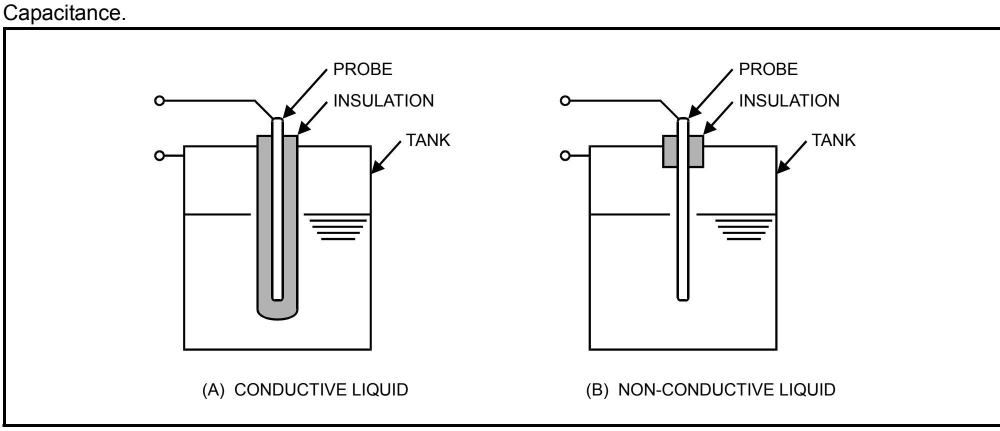
Capacitance level measurement (see figure 5-11) measures the changing electrical capacitance that occurs within the device as the level in the vessel varies. This device can be used for conductive or nonconductive fluids, but the dielectric constant of the fluid being measured must remain constant, unless a unit is used that compensates for dielectric variations. When plants apply the capacitance type of measurement, they must keep in mind that dry, nonconductive materials with a moisture content may become conductive.

If the material to be measured is nonconductive, the capacitor consists of two conductive plates (the probe and the vessel wall) that are separated by an insulator (the material being measured). If the material being measured is conductive, an insulated probe is used. This insulation serves as the dielectric, and the material serves as one of the plates. Capacitors can also be used for quantitative analysis of water in oil down to 0.1 percent water.

Capacitor operation is affected by three factors; plate area, dielectric material, and plate spacing. Greater capacitance is obtained from a larger plate area, a higher dielectric constant, and less plate spacing. The relationship between these three factors is:

$$\text{Capacitance} = \frac{\text{Plate Area} \times \text{Dielectric Constant}}{\text{Distance Between Plates}}$$

Figure 5-11
Capacitance.



Application Notes

Capacitance level measurement is an easy technique to install. It is simply designed with no moving parts, is unaffected by nonconductive buildup, and can be used for pressurized or unpressurized vessels. However, calibration may be time consuming. The unit is affected by changes to the material's dielectric constant and thus requires temperature compensation. In addition, conductive residue coating will affect the unit's performance.

The installation must ensure that the probe is not in contact with the tank walls. If the application requires an insulated probe, users must take care during installation to prevent damage to the probe's insulating material.

Conductivity

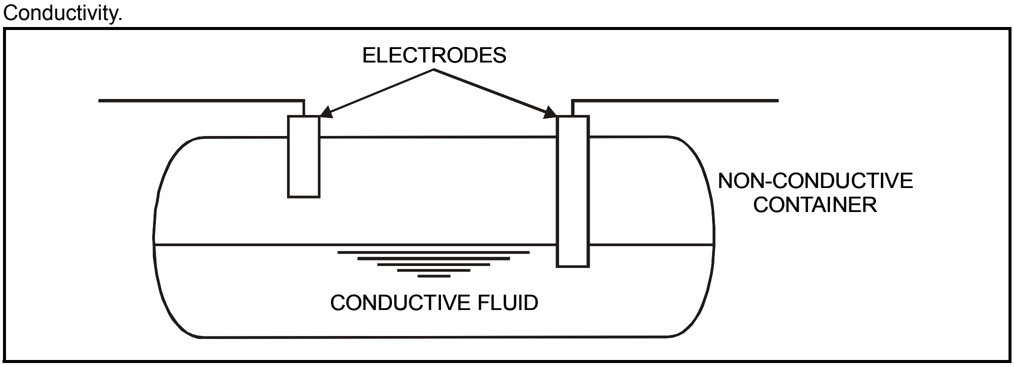
Principle of Measurement

Conductivity level measurement (see figure 5-12) works as follows: when material contacts the probe, a low-voltage electrical path is completed between the container wall and the probe, which actuates a relay. For nonconductive containers, the path is between the level probe and a reference probe.

Application Notes

Conductivity measuring devices are easy to install, have no moving parts, are relatively simple and low in cost, and can be used on pressurized or unpressurized vessels. However, they provide only a point measurement, and they are susceptible to coating by nonconductive materials. In DC circuits, the conductivity unit may cause electrolytic corrosion at the probe (whereas AC circuits prevent electrolytic plating).

Figure 5-12
Conductivity.



When implementing a conductivity device, users should consider that the unit may cause sparking as the liquid level rises to reach the probe. Intrinsically safe designs are available if they are required.

Thermal

Principle of Measurement

Typically, thermal devices (see figure 5-13) consist of a heater element next to a temperature switch. When the liquid rises above the switch, it dissipates the heat, and the temperature switch activates (or deactivates).

Application Notes

A thermal level switch offers low cost, uses semiconductor electronics with no moving parts, is sensitive, and has a simple and reliable design. However, such devices are sensitive to coating or caking materials, and they provide point measurement only. Also, they cannot be used where heating will affect product quality.

Radar

Principle of Measurement

The radar (see figure 5-14) is similar to the sonic and ultrasonic unit, but operates at a frequency of about 24 GHz.

Figure 5-13
Thermal.

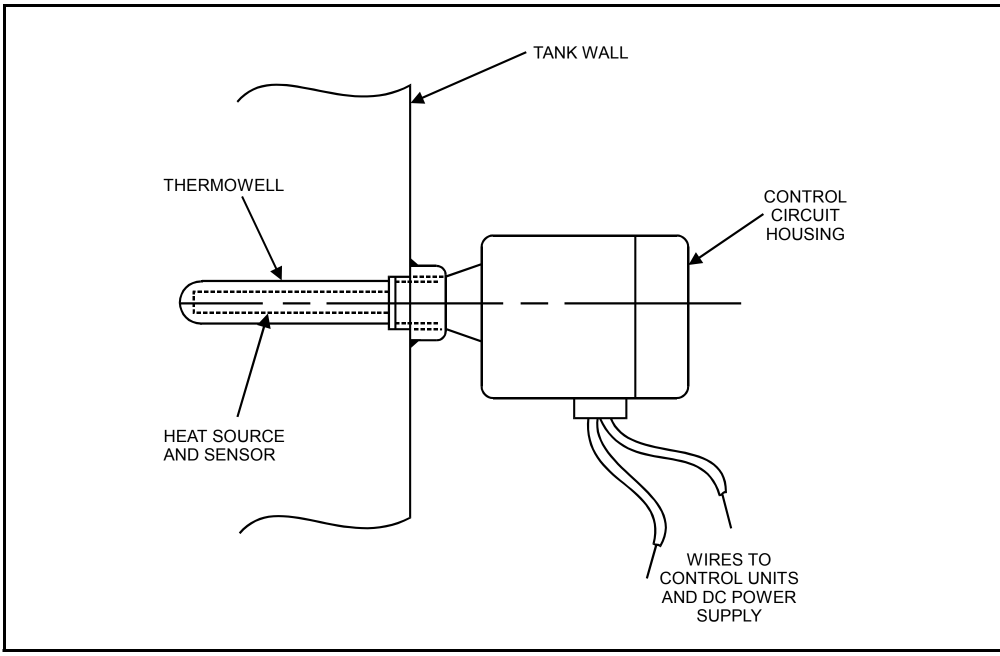
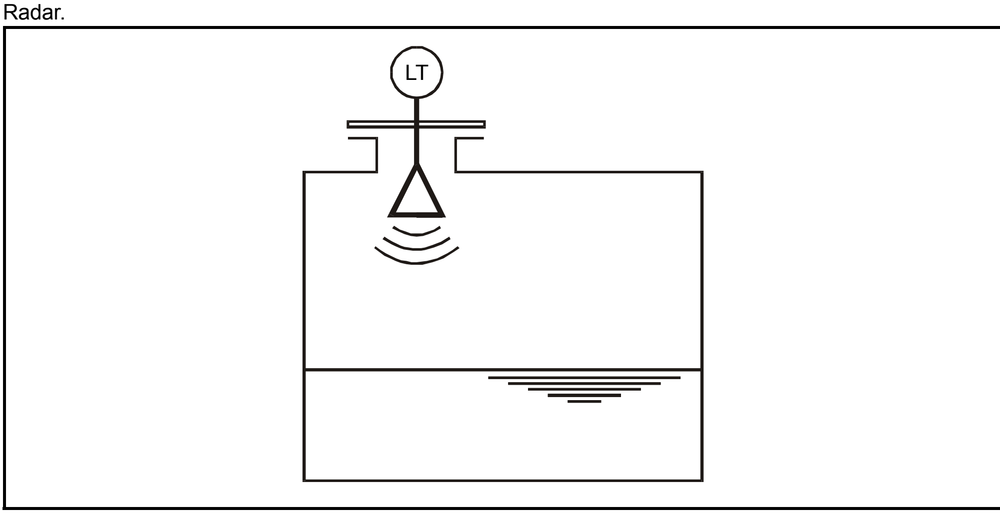


Figure 5-14
Radar.



Application Notes

The radar is easy to install and provides reliable noncontact measurement. It provides touch-free indication without special licensing (as is required for nuclear units) and will "see through" vessels made of plastic. Transducers that are mounted outside a metal vessel must be provided with a nonmetallic window since radar transducers will not penetrate metal. However, they will penetrate material with a low dielectric constant such as plastic, wood, glass, and the like.

Radar units are expensive. In addition, spurious reflections from metal objects will cause interference and affect the radar's performance. However, the 24 GHz signal provides a relatively narrow bandwidth (when compared to ultrasonic devices), and when well aimed, it should avoid tank obstacles such as tank walls, baffle plates, and agitators.

Beam Breakers

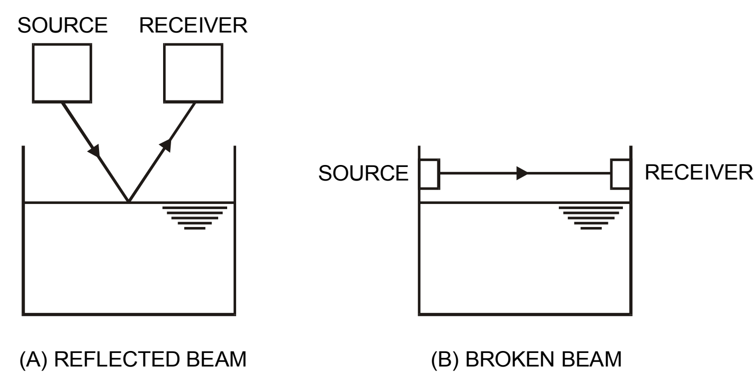
Principle of Measurement

The beam breaker (see figure 5-15) is also known as a "photometric" or "light beam." Its basic components are a light source and a receiver (photocell) that accepts the light beam and measures it. The light travels in a straight line until it is intercepted by an object (such as the liquid level in a tank). The light beam is broken or reflected by the level in the vessel, as detected by the receiver.

Application Notes

The beam breaker offers a low cost solution and can be used for pressurized or unpressurized vessels. It is also easy to apply, is of simple construction, and is unaffected by gravity. However, sensitivity adjustment is available only in some units, and residue coating will affect the beam breaker's performance. In addition, beam breakers have a limited range and are affected by changes in reflectivity.

Figure 5-15
Two types of beam breakers.



When applying such devices, the designer should consider the effect of liquid drops or condensation since they will deflect the beam and affect performance. In addition, on clear liquids it may be difficult to interrupt the light beam (and get an indication). In some cases, it may be necessary to shield the light receiver from outside light sources to avoid the introduction of measurement errors.

Vibration

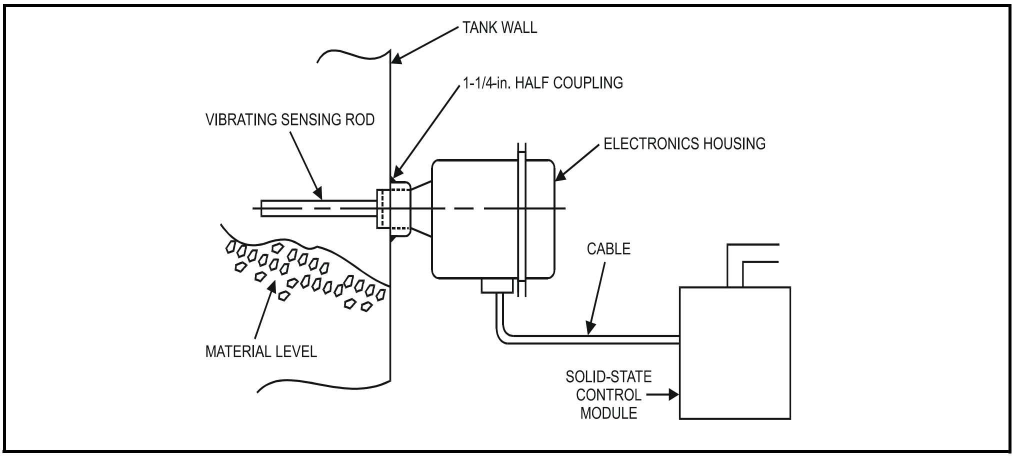
Principle of Measurement

Vibration devices (see figure 5-16) consist of a tuning fork that vibrates at its natural resonant frequency by a piezoelectric crystal, which is located at the base of the probe. When the vibrating fork contacts a material, either dry or in suspension (20% minimum), the vibration frequency is altered, which switches a relay. The material needs to have a bulk density of 0.9 lb/ft^3 (12.8 kg/m^3) or greater. When the level drops below the fork, the vibrating frequency is again in effect, and the relay is reversed.

Application Notes

Vibration units have no moving parts, are rugged and reliable, are good for low-density materials, and require little maintenance. However, they should not be used in vibrating bins, especially if the two frequencies are close. In addition, product buildup will affect the performance of vibration units, the switch setting cannot be readily changed, and vibration units typically require protection from materials that are charged from the top.

Figure 5-16
Vibration.

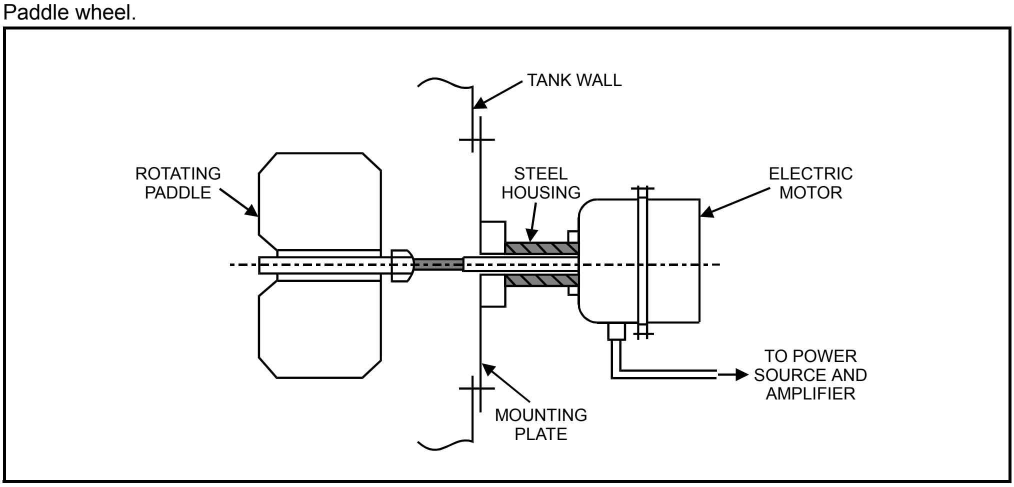


Paddle Wheel

Principle of Measurement

In a paddle wheel (see figure 5-17) a motor keeps the paddle rotating. When the material rises and prevents the paddle's rotation, a switch is actuated.

Figure 5-17
Paddle wheel.



Application Notes

A paddle wheel is inexpensive, simple, and reliable. However, it is susceptible to shock, vibration, and damage by falling material. Therefore, paddle wheels generally require some protection (e.g., a protective baffle) from material charging from the top. In addition, hang-ups or material buildup on the paddle will affect the device's performance, and material bridging around the switch will give an erroneous state.

Diaphragm

Principle of Measurement

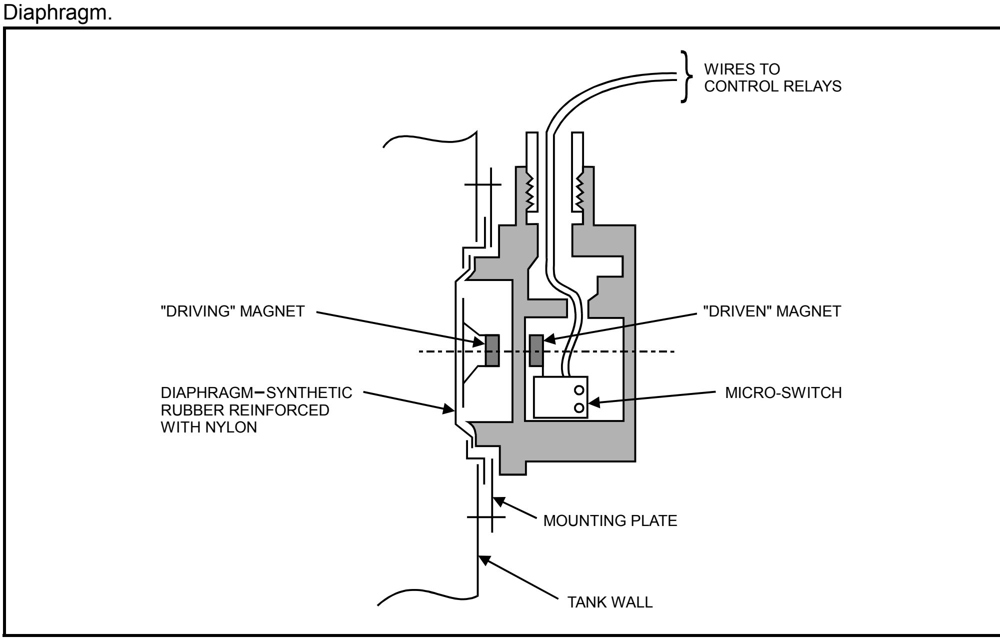
The diaphragm (see figure 5-18) is a point measurement device. The process materials (or hydrostatic pressure) apply pressure on a diaphragm, which in turn actuates a switch.

Application Notes

The diaphragm is reliable, easy to maintain, and available for different applications. However, coating may affect the flexing of the diaphragm, and abrasive material may affect its performance. In addition, the accuracy of the unit is affected by changes in specific gravity.

The diaphragm must be in contact with the material. It should be at least 2 to 3 in. (50 to 75 mm.) above any sediment in the vessel bottom to prevent dirt from building up at the diaphragm.

Figure 5-18
Diaphragm.



Resistance Tape

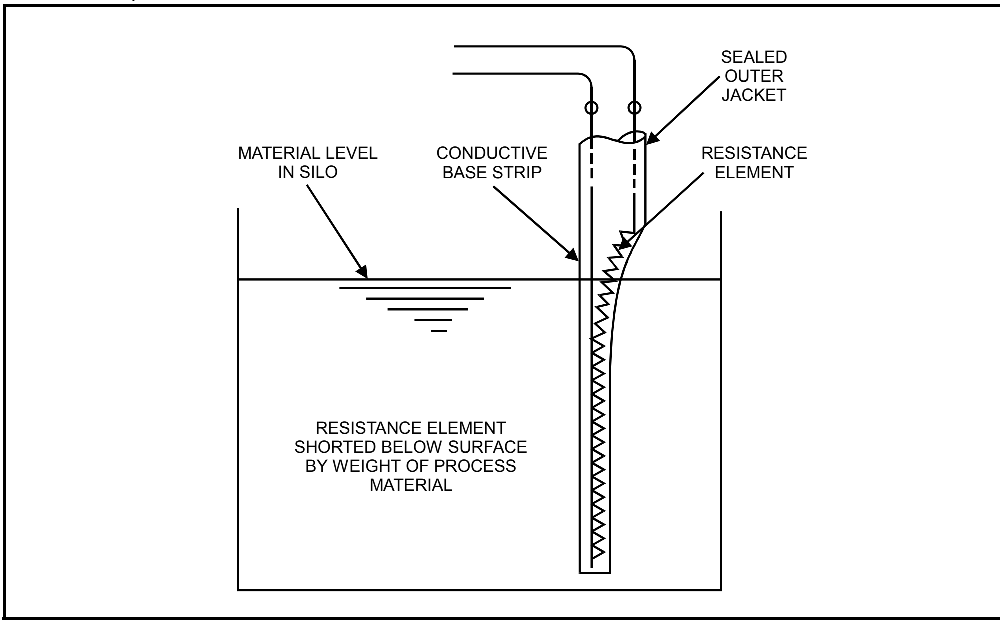
Principle of Measurement

Resistance tapes (see figure 5-19) function as follows: as the level rises in the tank, the resistance element is shorted to the conductive probe (due to liquid pressure), affecting loop resistance. The unit measures the loop resistance and provides an indication of level.

Application Notes

A resistance tape will handle corrosive liquids and slurries. However, it must contact the material and is susceptible to moisture getting inside the tape. Users may therefore need to use a desiccant, which entails additional maintenance. In addition, resistance tape devices are affected by changes in specific gravity, are not suitable for flammable atmospheres, and are neither accurate nor rugged. They require careful engineering and careful installation. Plants may need to use stilling if turbulence exists.

Figure 5-19
Resistance tape.



Laser

Principle of Measurement

There are two types of laser measurement (see figure 5-20): pulsed and continuous wave (frequency modulated). In industrial applications, the pulsed-type is the most common because of its range and ability to penetrate through vapors and dust.

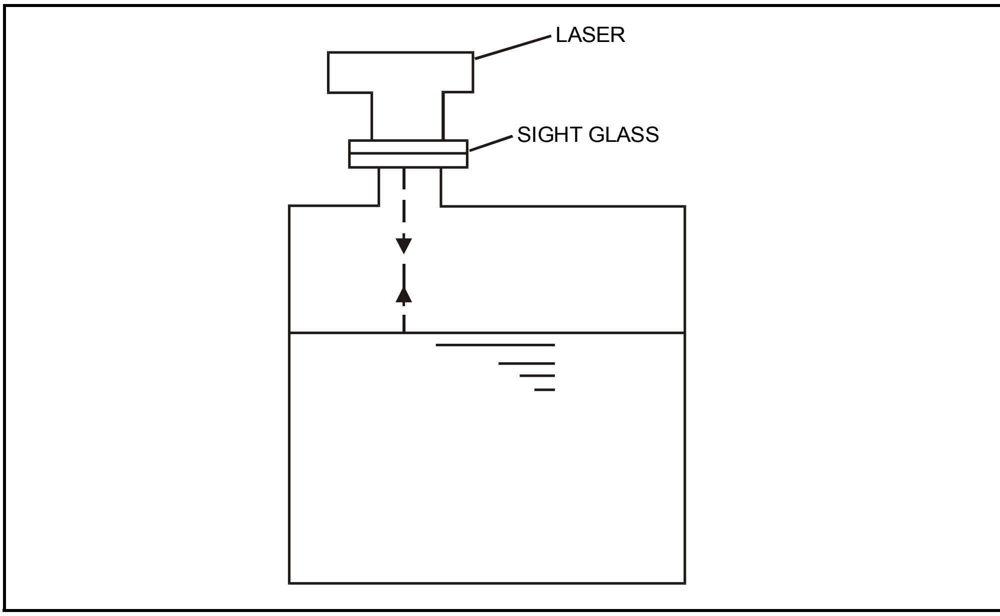
The pulsed-type laser operates as follows: its transmitter emits a continuous series of pulses at a target. The time taken by each pulse to travel from the transmitter to the target (e.g., the liquid surface) and back is measured and converted into distance.

The continuous wave laser consists of a transmitter that emits a continuous laser beam at the target. When the beam hits the target, phase-shifting occurs. Based on the degree of phase shift and on other constant parameters such as wave frequency, the device determines the distance of the target and therefore level.

Application Notes

Laser transducers mounted outside a metal vessel can measure level through a process-rated sight glass. This means the laser unit can be accessed without having to interrupt the process. Laser-type level measurement uses an extremely short wavelength and produces a very narrow beam. These features provide very good accuracy and non-contact measurement for difficult applications. However, lasers are relatively expensive, though still better then radioactive (nuclear) types.

Figure 5-20
Laser.



C H A P T E R 6

Pressure Measurement

Overview

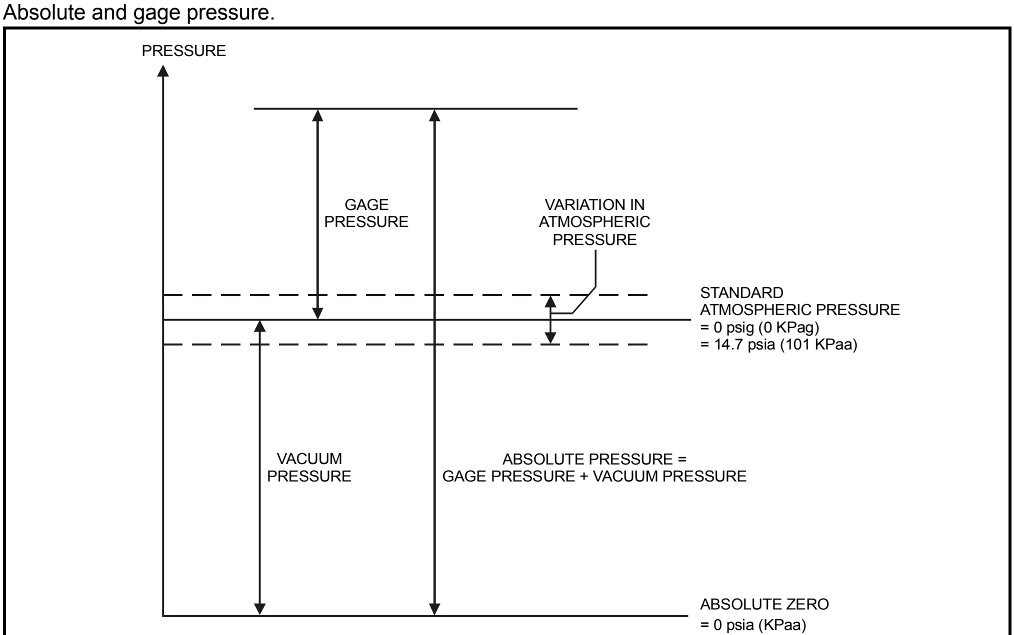
Pressure is measured as a force per unit area. Pressure measurements are important not only for the monitoring and control of pressure itself but also for measuring other parameters, such as level and flow (through differential pressure). Pressure measurement is one of the most common measurements made in process control. It is also one of the simplest in terms of which measuring device to select. One of the key items to consider is the primary element (i.e., strain gage, Bourdon tube, spiral, etc.). Primary-element materials should be selected to provide sufficient immunity from the process fluids and at the same time the required measured accuracy under the process conditions they will encounter.

This chapter provides some of the basic knowledge plant personnel will require to select the correct pressure-measuring device. However, it is essential that the instrument selector take into consideration the users' experiences.

Pressure-measuring instruments are really pressure transducers that convert the pressure energy into a measurable mechanical or electrical energy. Pressure measurement is always made with respect to a reference point. There are basically three types of pressure-sensing configurations (see figure 6-1).

1. Gage pressure, where the reference is atmospheric pressure
2. Absolute pressure, where the reference is complete vacuum
3. Differential pressure, which represents the difference between two pressure levels (note that gage pressure is a differential pressure between a value and atmospheric pressure)

Figure 6-1
Absolute and gage pressure.



In certain cases, pressure devices must conform to specific requirements. For example, on pressures greater than 15 psig (103 kPag) or in applications that contain lethal, toxic, or flammable substances, pressure devices may need to be registered, regardless of the design temperature. In oxygen service, the equipment should be degreased and ordered as such for this application, then labelled "FOR OXYGEN SERVICE." Individual countries may have specific requirements.

Units of Measurement

Most industrial pressure measurements function within a range between the atmospheric pressure and the operating pressure. This pressure measurement is known as "gage pressure", it is a measurement that plant personnel commonly use. Units such as psig or kPag are used in these cases. When referring to units of pressure, it is important to ensure that the measuring units are correct (i.e., gage or absolute). In uses where the pressure is measured in absolute terms, as is the case in making engineering calculations (i.e., in reference to full vacuum), the units used are psia or kPa absolute (sometimes referred to as kPaa). Note that if the absolute pressure of the process remains constant and the atmospheric pressure increases, the gage pressure decreases.

Differential pressure is the difference between two process pressures. The common units of measurements are psi and kPa, although some plants use the psid and kPad terminology. Standard atmospheric pressure is equal to 14.7 psia (101.3 kPa absolute).

Gages

Normally, pressure gages intended for field mounting are 4½ in. (about 120 mm) in diameter and contain a blowout disk and a standard bottom connection of ½ in. (or ¾ in.) male NPT (National Pipe Taper thread), unless different requirements are dictated by pipeline or vessel specifications. Instrument air applications typically use ¼ in. connections. Generally, the maximum working pressure to which a gage is subjected should be around 75 percent of full-scale pressure range.

Transmitters

A typical pressure transmitter consists of two parts: the primary element and the secondary element. The primary element (which includes the pressure sensor or pressure element) converts the pressure into a mechanical or electrical value to be read by the secondary element. It is the part that is most subject to failure since it faces the process conditions.

The secondary element is the transmitter's electronics: basically, a transducer to convert the output from the primary element into a readable signal such as 4-20 mA. Typically, electronic-based sensors such as strain gages have a better response and a higher accuracy than mechanical-based types such as Bourdons (which are still acceptable in many applications).

Filled Systems and Diaphragm Seals

Filled systems are used to protect the sensing element from corrosive, toxic, or highly viscous fluids or sediments. They are also used to overcome the effects of deposits or solidification in the impulse line or in the sensing element, which may block the line or sensor. Filled systems consist of a diaphragm seal that is attached to a transmitter (or other pressure-sensing device), through either a capillary or a direct-mount-style connection, and a fill fluid (such as silicone oil). The thin diaphragm and fill fluid isolate the pressure-sensing elements from the process fluid. When pressure is applied, the diaphragm flexes and transfers the measured pressure through the fill fluid to the pressure-sensing element.

Where diaphragm seals are used, users should consider the following:

1. The potential need for a flushing connection since a plugged diaphragm will not perform as intended.
2. The diaphragm diameter is dependent on the measuring span and the temperature effects.
3. The rating and material of flanges must comply with the pipeline or vessel specifications.
4. The seal fill fluid must be compatible with the process fluid. This will prevent the introduction of unwanted seal fluid into the process following a diaphragm leakage. This is critical in applications that involve pharmaceuticals, foodstuffs, and hazardous chemicals.

Installation

Where process conditions permit, the common practice is to isolate all pressure instruments from the process with a valve. Such an isolating valve (and its associated piping/tubing) must comply with the piping requirements for the process fluid in question. This permits maintenance activities to be performed without having to shut down the operation. In most cases, the impulse piping must be kept as short as possible unless the need to protect the instrument from high temperature dictates the use of sufficient impulse piping to avoid damaging the instrument. High process temperatures require that heat be dissipated, and if condensation will occur, a pigtail siphon may also be required. Typically, siphons made of the proper material are required for all vapors above 140°F (60°C).

Protection may also be required from detrimental conditions such as pulsating pressure. Such protection is provided by using a dampening fluid or pulsation dampeners. These methods basically retard the instrument's rate of response. If pulsation dampeners are required, the materials they are made of must conform with the fluid being measured.

Test and drain valves may also be necessary. Isolating valves must be accessible to personnel from the ground or from a platform, and the entire system must provide accessibility for maintenance. If the fluid measured is toxic or corrosive, the plant must provide a blowdown valve and blowdown line.

If solids will accumulate in the impulse line, the plant must install tees and plug fittings (or ball valves) instead of elbows to allow plugged lines to be rodded. To maintain a constant hydrostatic head on the instrument, the impulse line should be free of liquids, for gas service, and should be filled with liquid, for liquid or vapor service.

Plant personnel must assess, based on the fluid being measured, whether the connection should be on the top or side of the process line. Typically, on liquid lines the connection is on the side to avoid traveling air or gas bubbles. For gas lines it is on the side or top to avoid condensing droplets. The instruments in gas applications should be self-draining, that is, lines are sloped toward the process to avoid trapping condensables and liquids. Instruments in liquid and condensable applications should be self-venting, that is, lines are sloped toward the instrument to avoid trapping of gas. Therefore, where possible, transmitters are mounted above the process lines for gas applications and below the process line for liquid applications.

Differential-pressure transmitters should have a valve manifold and sometimes a blowdown valve or vent valve. This manifold must be made of a material that meets the piping specification for the fluid in question. For additional information on manifolds, refer to the section "Differential Pressure" in chapter 5 on level measurement.

Comparison Table

Table 6-1 summarizes the main types of pressure sensors with respect to a set of common parameters. The table can provide plant personnel with guidance on evaluation criteria for selecting pressure sensor devices. The information presented in table 6-1 indicates typical values; vendors may have equipment that exceeds the limits shown.

Table 6-1
Pressure measurement comparison.

Types \ Parameters	Pressure range	Temperature range	Accuracy	Sensitivity to shock and vibration
Manometers	0.1–140 psig (0.7–980 KPag)	ambient	±0.02 in (0.5 mm)	poor
Bourdon tubes (diaphragm, bellows)	0.01–14,500 psig (0.07–101,500 Kpag)	200°F (90°C) max	±0.05% of full scale	fair
Capacitive	0.01–600 psig (0.07–4,200 KPag)	0–165°F (-18–74°C)	±0.05%–0.2% of span	fair
Differential Transformer	30–10,000 psig (210–70,000 KPag)	0–165°F (-18–74°C)	±0.5% of span	poor
Force Balance	1–5,000 psig (7–35,000 KPag)	40–165°F (4–74°C)	±0.05% of span	poor
Piezoelectric	0.1–6,000 psig (0.7–42,000 KPag)	-450–400°F (-270–200°C)	±0.1–1% of span	very good
Potentiometer	5–10,000 psig (35–70,000 KPag)	-65–300°F (-54–150°C)	±1% of span	poor
Strain Gage—Unbonded	0.5–10,000 psig (3.5–70,000 KPag)	-320–600°F (-195–315°C)	±0.1–0.25% of span	good
Strain Gage—Bonded foil	5– 10,000 psig (35–70,000 KPag)	-65–250°F (-54–121°C)	±0.1%–0.5% of span	very good
Strain Gage—Thin film	15– 5000 psig (105–35,000 Kpag)	-320–525°F (-195–274°C)	±0.1%–0.25% of span	very good
Strain Gage—Diffused semi-conductor	15–5000 psig (105–35,000 Kpag)	-65–250°F (-54–121°C)	±0.1%–0.25% of span	very good

Manometer

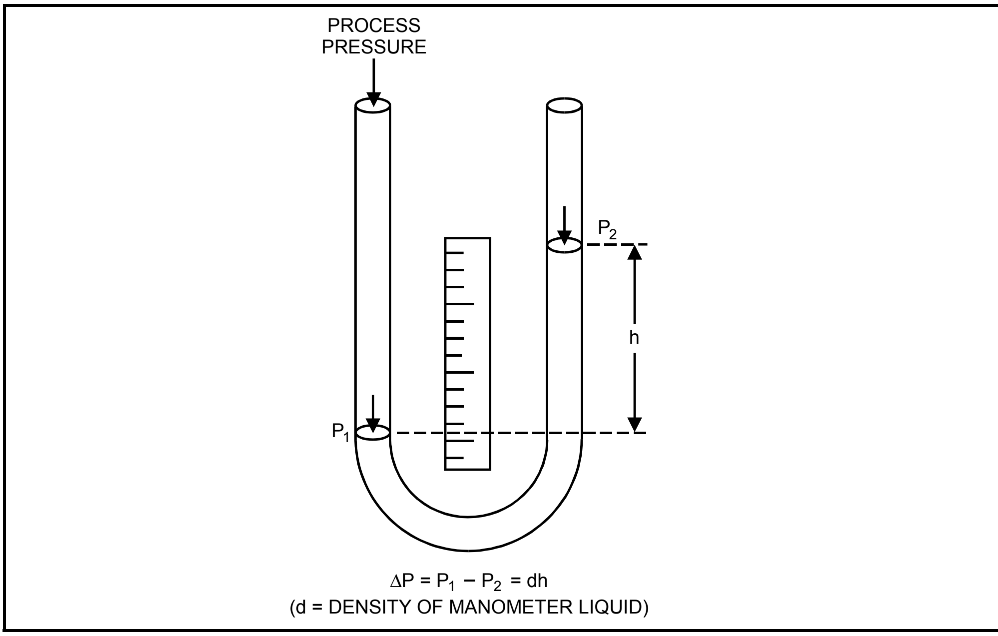
Principle of Measurement

The manometer (see figure 6-2) is based on the principle of hydrostatic pressure and on the relationship between pressure and the corresponding displacement of a column of liquid. The same principles apply to the U-tube, where the process pressure supports a column of liquid of known density. The height of the liquid column is then read on a graduated scale. Pressure applied to the surface of one leg causes a liquid elevation in the other leg. Generally, the unknown pressure is applied to one leg and a reference pressure (typically atmospheric pressure) to the other. The amount of elevation is read on a scale that is calibrated to read directly in pressure units.

Application Notes

Manometers are simple and provide direct operation. However, they are limited in application to low pressures and will not handle overpressures. They are typically used only in laboratories or maintenance shops.

Figure 6-2
U-tube manometer.



Bourdon Tube, Diaphragm, and Bellows

Principle of Measurement

In this method, process pressure is applied to a resilient, sealed container, usually a Bourdon tube, diaphragm, or bellows. The container, under pressure, will distort in a predefined way. This mechanical movement is converted, through gears and pivots, into a pointer on a graduated dial. All three container types come in a variety of materials and thicknesses to cover different applications, process materials, and pressure ranges.

The Bourdon tube (see figure 6-3) consists of a bent oval tube. One end of the tube is linked to the process pressure, and the other end is sealed and linked to the mechanism operating the pointer. As the pressure increases, the tube tends to straighten itself out. This movement is indicated by the pointer. Bourdon tubes are generally available in spiral shapes for low-pressure applications and in helical shapes for high-pressure applications.

The diaphragm (see figure 6-4) converts the increasing process pressure on one side of the disk (flat or corrugated) into a mechanical movement by monitoring the bulging of the disk. The diaphragm gage has a port diameter that is much larger than the Bourdon tube. It is therefore more capable of measuring low pressures and less prone to blockage. On the other hand, if the diaphragm ruptures there is a much higher leakage rate than with the Bourdon.

The bellows (see figure 6-5) is a one-piece axially expandable and collapsible element. A bellows consists of many folds. Its mechanical motion is similar to the diaphragm, but it has a wider span of movement.

Application Notes

Because of these instruments' principle of operation, their sensitivity tends to increase as their size increases. The response of the element may be affected by temperature changes, and mechanical components may wear over time. These instruments are most commonly used in pressure gages and pressure switches.

Figure 6-3
Bourdon gage.

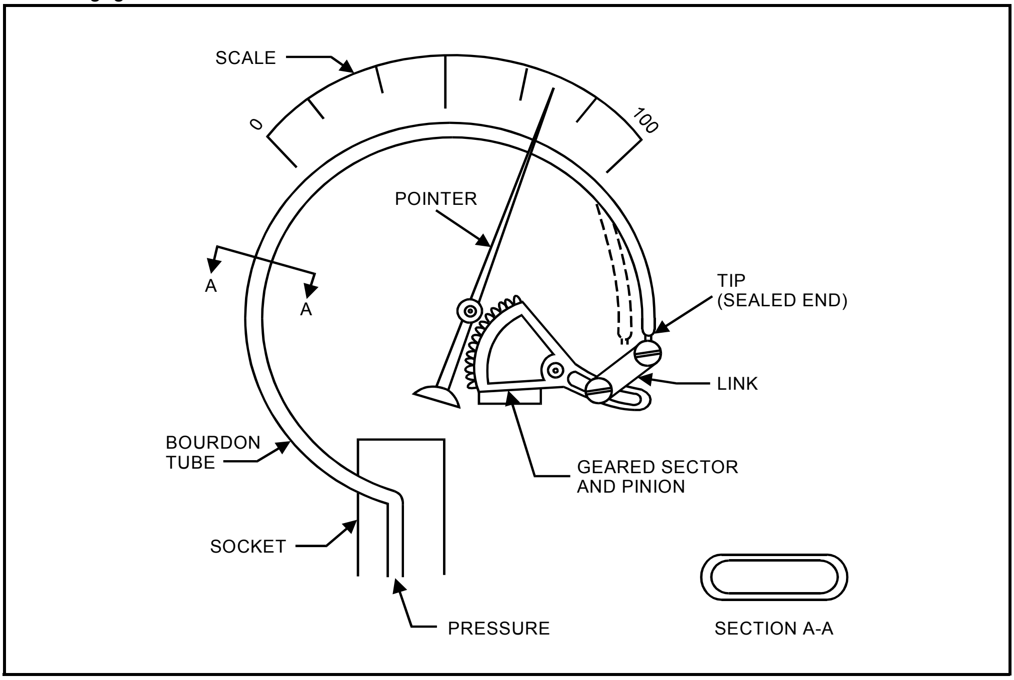


Figure 6-4
Diaphragm gage (differential pressure).

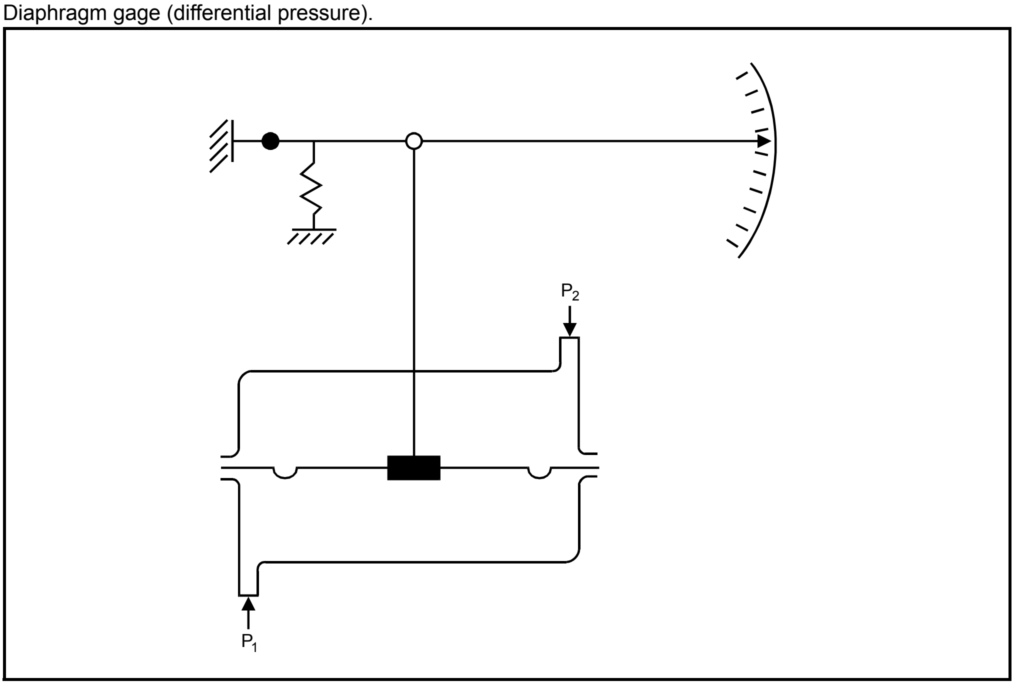
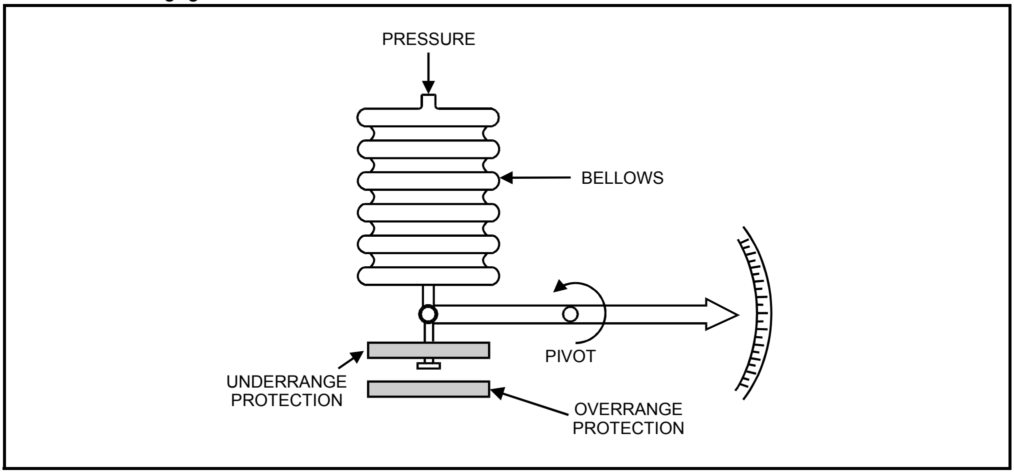


Figure 6-5
Bellows element gage.



Capacitive Transducer

Principle of Measurement

In a capacitive transducer (see figure 6-6), the inlet pressure activates a diaphragm that is mounted between two fixed plates. This causes a capacitance change, which is measured in the electronic circuitry as a direct relation to pressure. Dual- or single-element units are available. The dual elements tend to be extremely linear when compared to the single-element type.

Application Notes

Capacitive transducers have a proven track record and are commonly used. They provide excellent response, resolution, linearity, repeatability, and stability. In addition, since they are small and have low mass, inertia forces are low where vibration is present. However, they are relatively expensive and are sensitive to stray magnetic fields if they are not well designed. Capacitive transducers are also affected by temperature changes and by variations in the dielectric constant of the process fluid.

Differential Transformer

Principle of Measurement

In differential transformers, the inlet pressure activates a diaphragm (sometimes a bellows may be used) that moves a magnetic core inside the transformer (see figure 6-7). This movement creates an imbalance in the secondary windings that is measured in the electronics and converted into pressure measurement.

Application Notes

These instruments provide excellent resolution, with low hysteresis. They are very rugged, and they have high overpressure capability and wide pressure ranges. However, differential transformers are massive, expensive, sensitive to stray magnetic fields, and have poor linearity. They also are sensitive to acceleration and vibration.

Figure 6-6
Capacitive pressure transducer (differential pressure).

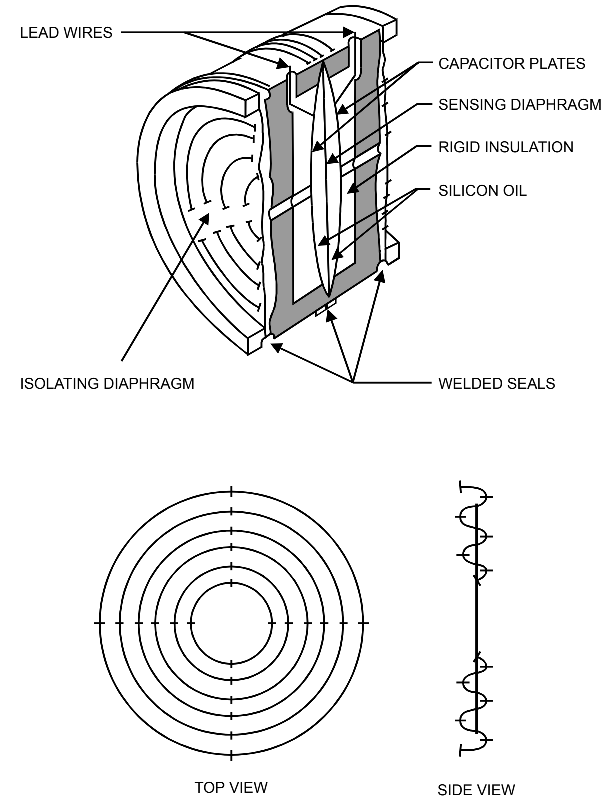
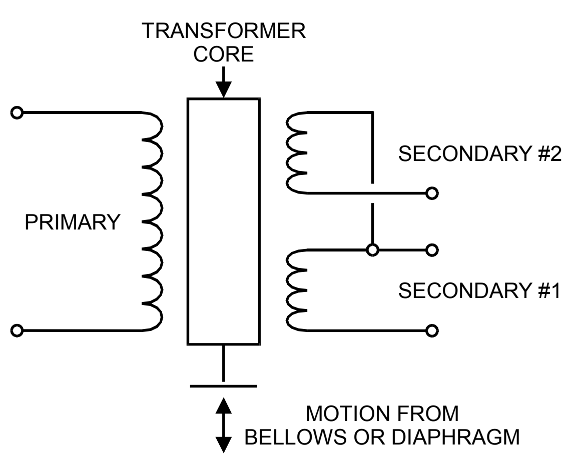


Figure 6-7
Differential transformer.

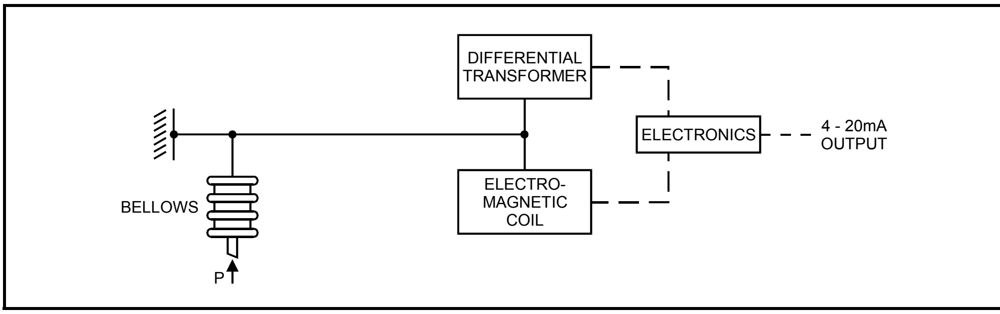


Force Balance

Principle of Measurement

In force balances, the inlet pressure activates a bellows (see figure 6-8). This signal is amplified through the linkage and acts against a restoring force through a balance beam from an electromagnetic coil (or a servomotor). The movement created by the varying pressure is measured by a capacitive (or differential transformer) sensor. The term *force balance* comes from the forces exerted on the balance beam.

Figure 6-8
Force balance electronic transmitter.



Application Notes

Force balance transmitters provide a high-level output, high resolution, and very good accuracy and stability, and they measure a wide range of pressures. However, they are relatively large in size and are sensitive to shock and vibration.

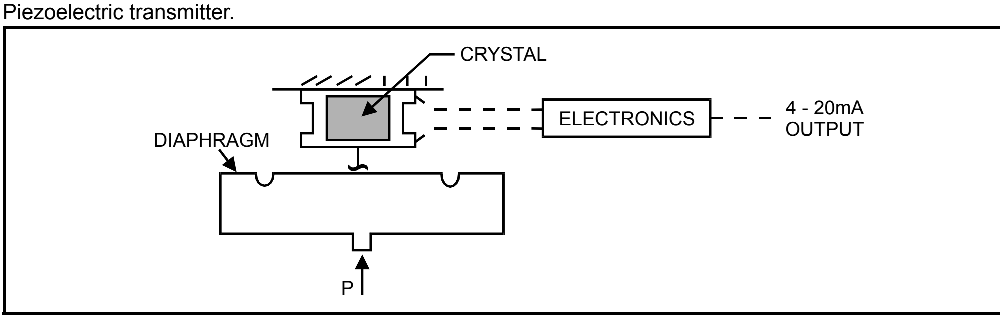
Piezoelectric

Principle of Measurement

In piezoelectric devices, the inlet pressure activates a diaphragm (sometimes a bellows may be used) that applies strain on a crystal (e.g., quartz) (see figure 6-9). The strained quartz produces an electrical charge that is measured by the electronics and converted into an output that indicates pressure.

There are two common types of piezoelectric crystals, those that occur in nature, such as quartz, and synthetic ones, such as Rochelle salts. Natural crystals are rugged and will withstand shock and high temperatures. Synthetic crystals produce a higher electrical output.

Figure 6-9
Piezoelectric transmitter.



Application Notes

Piezoelectric sensors are rugged and small in size. They provide a very high frequency response and a linear output and do not require frequent calibration. However, they are sensitive to temperature changes (and thus must be temperature compensated) and recover poorly from overpressure.

Potentiometer, Wheatstone Bridge

Principle of Measurement

In potentiometers, the inlet pressure activates a diaphragm (or bellows) that moves a potentiometer wiper across a multiturn resistor (see figure 6-10). This movement causes a change in the potentiometer's resistance, sending a signal change to the Wheatstone bridge (see figure 6-11). The electrical signal generated is directly proportional to the displacement of the diaphragm.

Figure 6-10
Potentiometer transmitter.

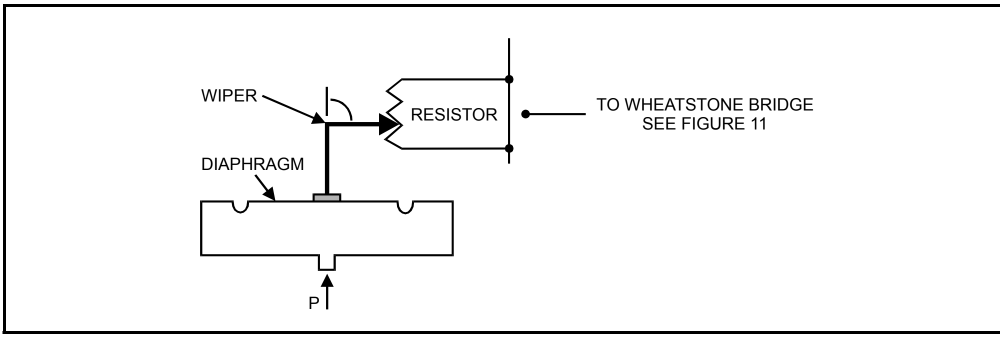
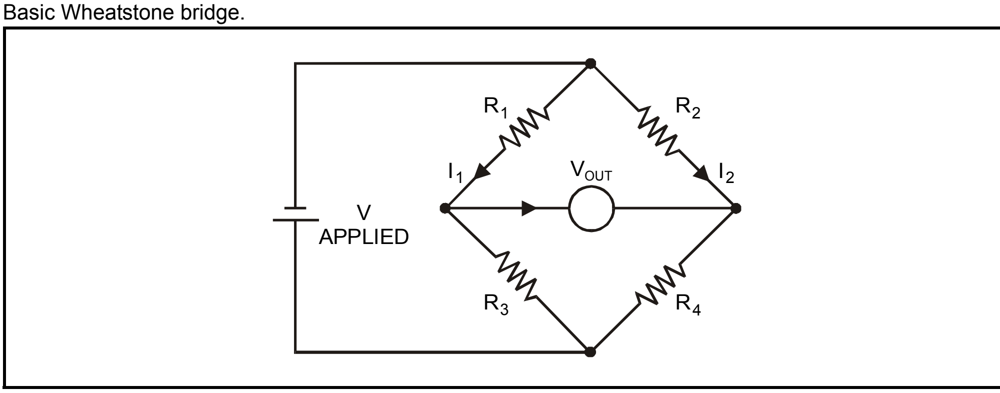


Figure 6-11
Basic Wheatstone bridge.



The Wheatstone bridge was one of the earliest electrical devices to accurately measure resistance. The Wheatstone bridge's circuit has four resistors. If R_1 and R_3 are fixed resistors, then a change in R_2 will have to be balanced against R_4, with the value of R_4 varied until:

$$V_{out} = 0$$

$$(I_2 \text{ x } R_2) / (I_2 \text{ x } R_4) = (I_1 \text{ x } R_1) / (I_1 \text{ x } R_3)$$

Therefore:

$$R_2 / R_4 = R_1 / R_3$$

And the unknown resistance,

$$R_2 = R_4 (R_1 / R_3)$$

The Wheatstone bridge is used to measure temperature, pressure, weight, and the like. In all these cases, R_2 is used as an RTD or a strain gage, depending on the application.

Application Notes

Potentiometers are simple and inexpensive and provide a high-level output. However, the friction between the wiper and the resistor, along with bearing friction at the linkage, causes hysteresis. In addition, pressure fluctuations and vibrations accelerate the wear on the wiper/resistor combination. Potentiometers have a limited life and below-average resolution.

Strain Gage: General Information

Principle of Measurement

Several types of strain gages are available, all of them based on the principle that any material changes its resistance when it is stretched. Strain gages are the most commonly used type of pressure-sensing element for pressure transmitters. Strain gages also are used in weight measurement and strain measurement in concrete and metal structures.

In strain gages, a displacement is caused by the increasing or decreasing pressure. This displacement causes a change in the length of the element, which is part of a Wheatstone bridge circuit. The change in resistance within the bridge is converted, through electronics, into a pressure value. In addition, the circuitry can easily adjust the zero output level, the span of measurement, and the ambient temperature effects (through automatic temperature compensation).

Application Notes

Since the change in resistance is very small, the electronics of the strain gage must be sensitive enough to detect such minute changes. Strain gage sensors have proven performance and provide reliable data. They are available from most vendors and offer better performance for the cost than thin-film or semiconductor sensors. However, strain gages are sensitive to temperature variations, and thus temperature compensation is necessary.

Strain Gage: Unbonded

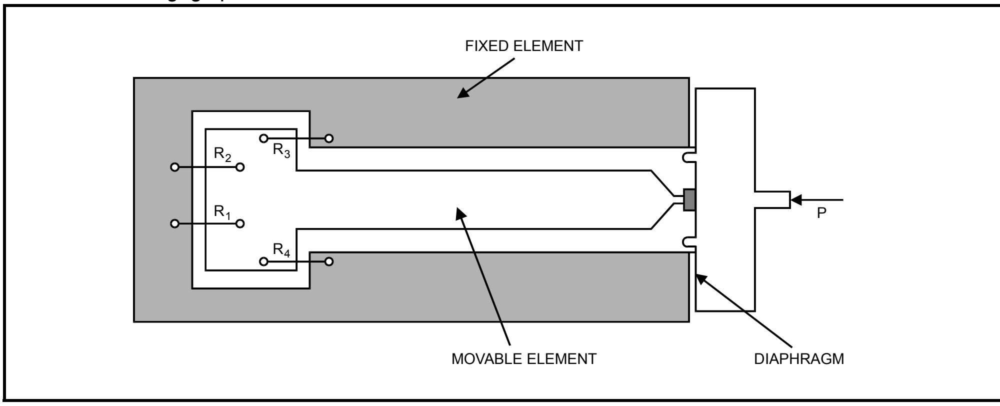
Principle of Measurement

An unbonded strain gage (see figure 6-12) has a frame that consists of stationary and movable parts. A wire (about 0.4 mil in diameter) is located on both parts and is wrapped around non-conductive posts. Wire tension increases and decreases with changes in pressure. When the movable part is displaced, this strains the wire(s) and increases or decreases the resistance accordingly. The electronics convert this resistance measurement (through the Wheatstone bridge) into a pressure output. Sometimes four wires are used, two in tension and two in compression.

Application Notes

Unbonded strain gages can accommodate overtravel stop limits. This provides mechanical overpressure protection. They have a low mass and long-term stability. However, they are sensitive to shock.

Figure 6-12
Unbonded strain-gage pressure transmitter with four wires.

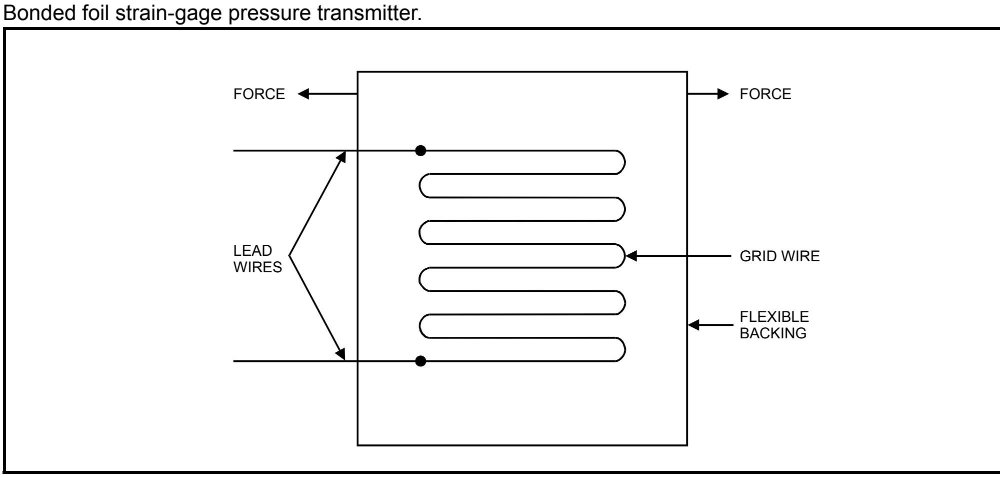


Strain Gage: Bonded

Principle of Measurement

In a bonded strain gage (see figure 6-13), a foil (or wire) is bonded to a diaphragm. Changes in pressure cause the diaphragm to flex, which in turn is sensed by the foil (or wire). Sometimes four strain gages are used as a set: two near the center of the diaphragm, where they encounter maximum tangential strain, and two near the circumference, where they encounter maximum radial strain. This is an improvement over the unbonded type since it eliminates the posts and frame.

Figure 6-13
Bonded foil strain-gage pressure transmitter.



Application Notes

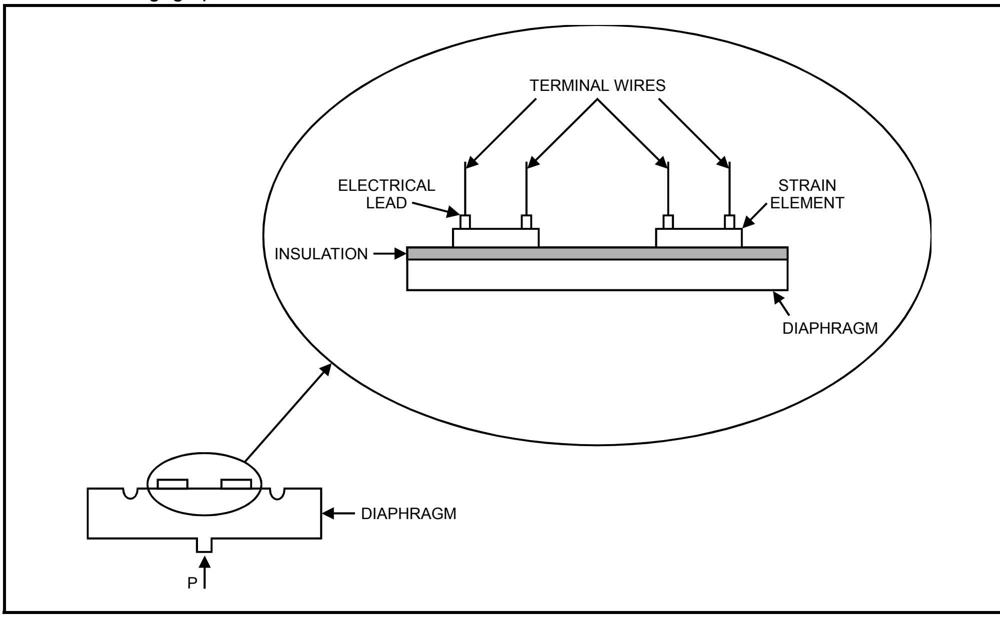
Bonded strain gages offer a rugged assembly and good accuracy that is not degraded by shock and vibration. However, bonded strain gages are limited in their pressure and temperature ranges.

Strain Gage: Thin Film

Principle of Measurement

Thin-film strain gages (see figure 6-14) are very similar to bonded-foil strain gages except that integrated-circuit technology and processes are used to fabricate them. Laser trimming is used to obtain the exact resistance for each strain element, and the strain element is produced by vacuum deposition directly into the diaphragm.

Figure 6-14
Thin-film strain gage pressure transmitter.



Application Notes

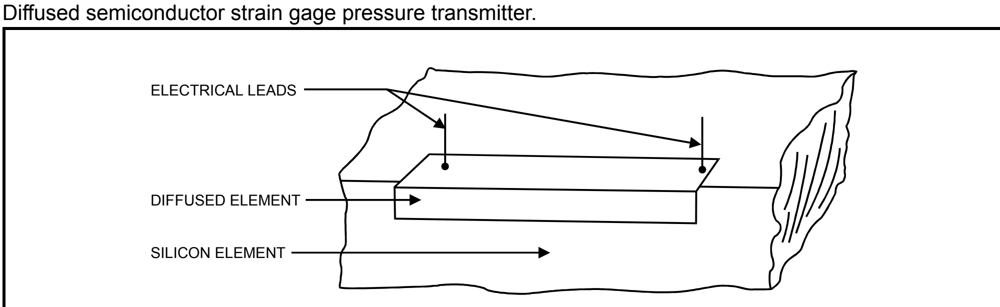
Thin-film strain gages provide the best response and sensitivity of any strain gages, but they tend to be the most expensive. They are stable, with no or very little creep, and they provide good immunity to vibrations. They also have good long-term stability (including resistance to sensitivity and thermal shifts). However, distortion of the sensor case may cause major measurement errors. In addition, thin-film strain gages are of limited advantage in high temperature applications due to the nature of semiconductors, and they are not as rugged as unbonded strain gages. Also, they are more sensitive to transient voltages and radio frequency interference (RFI).

Strain Gage: Diffused Semiconductor

Principle of Measurement

The diffused semiconductor type of strain gage (see figure 6-15) uses integrated-circuit manufacturing techniques. The strain gage is diffused in a silicon element, which is the mechanical structure.

Figure 6-15
Diffused semiconductor strain gage pressure transmitter.



Application Notes

Diffused semiconductor strain gages provide good long-term stability and good immunity to vibrations. However, they are limited in high-temperature applications due to the nature of semiconductors.

CHAPTER 7

TEMPERATURE MEASUREMENT

Overview

Temperature is a widely used measurement. Galileo is credited with inventing the first thermometer in 1595. Over the years thermometer technology has evolved, and measuring principles are continuously improved upon. Today, highly accurate and reliable devices are available. This chapter provides some of the basic knowledge users need to select the proper temperature-measuring device. However, it is essential that the instrument selector take into consideration the users' experiences.

For process applications, a typical temperature measurement assembly consists of a thermowell, a temperature element, sometimes extension/connecting wires, and a temperature transmitter (local or remote). Temperature elements frequently include a spring-loaded mechanism to ensure that the element tip makes positive contact with the internal bottom of the well.

Temperature elements should be installed where good mixing is ensured, such as in pipe bends and in the liquid phase (if a vapor/liquid interface exists). The optimum immersion length for temperature elements varies with the application. If they are installed perpendicular to the line, then the tip of the element should be between one-half and one-third the pipe diameter. If they are installed in an elbow (the recommended option), with the tip pointing towards the flow, about one-quarter pipe diameter is sufficient since the flow is impinging on the tip of the temperature element.

Units of Measurement

The most commonly used units of temperature measurement are the Fahrenheit scale and the Celsius scale. The Fahrenheit scale was invented by Daniel G. Fahrenheit and published in 1724. It is still extensively used in the United States, although some industries are gradually converting to Celsius. The Celsius scale was developed by Anders Celsius, a Swedish scientist, in 1742.

Degrees fahrenheit (°F), degrees Celsius (°C), and Kelvin (K, used mainly for scientific work) are recognized internationally as scales for measuring temperature. The Fahrenheit and Celsius scales have been developed from two fixed points: ice and steam, at atmospheric pressure.

Conversion from one scale into the other follows these equations.

Point	°F	°C	K
Steam point	212	100	373.15
Ice point	32	0	273.15
Absolute zero	-459.67	-273.15	0

$$°F = \left(°C \times \frac{9}{5}\right) + 32$$

$$°C = K - 273.15$$

Classification

Physical properties that change with temperature are used to measure temperature. For example, the property of material expansion when heated is used in liquid-in-glass, bimetallics, and filled-system measurement. The electromotive force (emf) principle is used in thermocouples, and electrical resistance changes are used in resistance temperature detectors (RTDs). Other means of temperature measurement include temperature-sensitive paint and crayons, and optical devices.

In the traditional medical thermometer, liquid-in-glass measurement takes the form of mercury enclosed in glass. Obviously, the delicate nature of the glass and the toxicity of mercury limit the usefulness of this type of thermometer in industrial applications. An improvement on the liquid-in-glass thermometer is the filled system.

Temperature-sensitive paint and crayons can be applied to a surface to determine its temperature. Some of them are reversible, such as desktop thermometers, while others are irreversible. They are available in a wide range of temperatures. Crayons have a calibrated melting point, and the crayon mark melts when the rated temperature is reached. Paints, which are suspended in a medium, function similarly. Both crayons and paints have ranges varying from 120 to 2000°F (50 to 1090°C).

Thermowells

Thermowells (T/Ws) are used to protect the element (which is typically fragile) and to make it easier to replace the element without interrupting the process (see figure 7-1). If a plant does not need a well, for safety reasons, a label should be attached to the element to indicate that no well is present. The downside of T/Ws is that they create a time delay. If, for example, a temperature measurement without a well has a 1 to 10 seconds time delay, with a well the measurement may degrade to a 20 to 50 seconds delay.

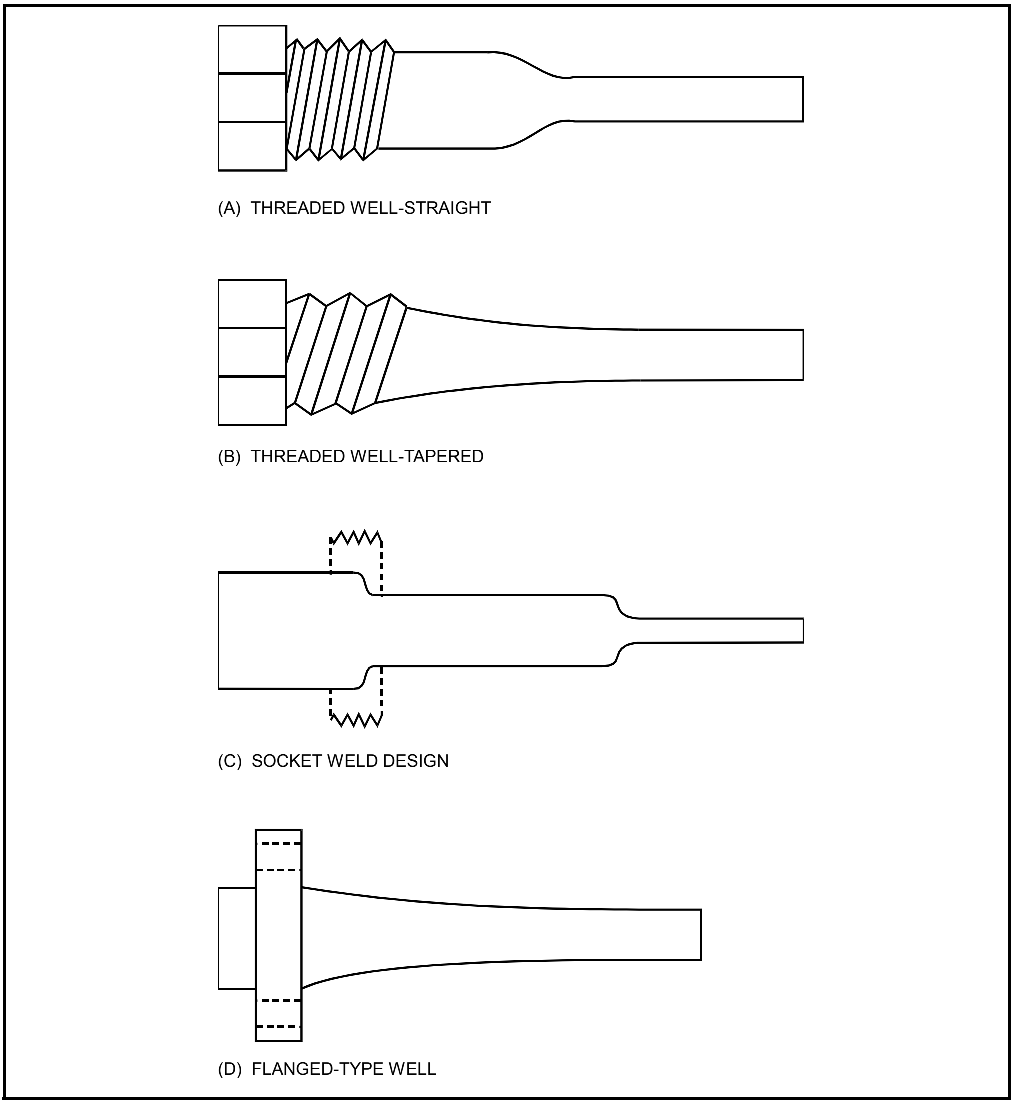
Thermowells are used in most cases where temperature elements are installed, with some exceptions.

- The internals of some equipment (e.g., compressors, turbines, etc.)
- Bearings where space is very limited
- In measuring surface temperature
- In fast-response applications (i.e., if thermowells create too much of a delay)
- In measuring air-space temperature

Thermowells must comply with the pipeline's or vessel's specifications. The thermowell's construction and material must be carefully matched with the process requirements (including abnormal and emergency conditions). Many plants have standardized the connection size and material of wells, for example:

- The well connection to the process has been standardized to 1½ in. flanged or 1 in. NPT (National Pipe Taper thread). This connection should always comply with the piping specification. Note that the exposed part of the well will conduct heat to the pipe surface, and thus insulation may be required.
- The well material has been standardized to 316 SS material, with special applications requiring special materials. Thermowell material will vary with the application and the required speed of response. The maximum recommended temperature for metal T/Ws varies from 800°F (425°C) for iron to 2300°F (1260°C) for Inconel. For ceramic tubes, the maximum temperature varies from 1900°F (1050°C) for fused silica to 3000°F (1650°C) for silicon carbide.

Figure 7-1
Thermowells.



Comparison Table

Table 7-1 summarizes the main types of temperature measurement with respect to a set of common parameters.

This comparison table can be used as a selection guide. Note that the information presented in Table 7-1 indicates typical values; vendors may have equipment that exceeds the limits shown.

Filled System

Principle of Measurement

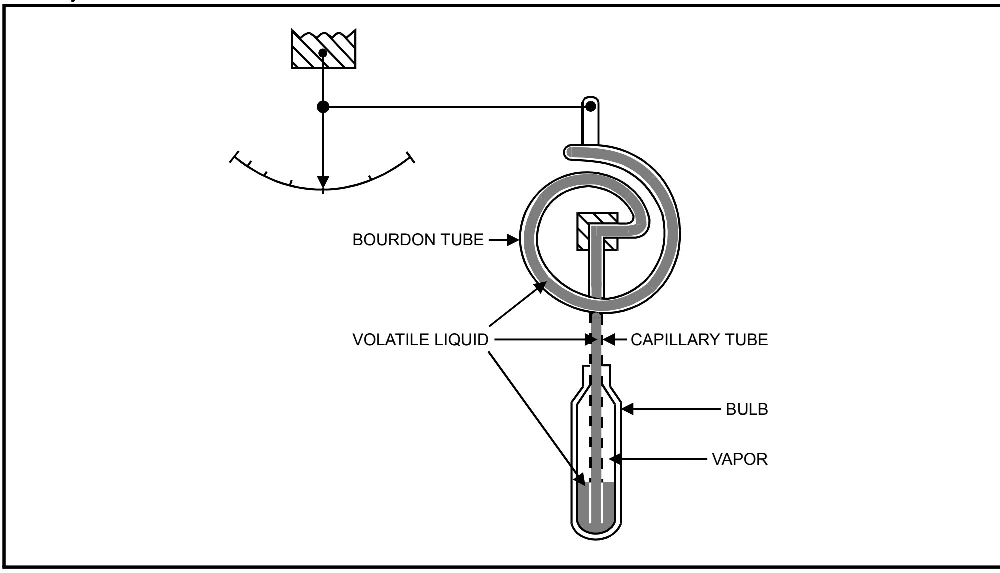
A filled system (see figure 7-2) is a metallic assembly that consists of a bulb, small-diameter tubing (known as capillary), and a Bourdon spring. An indicator linked to the Bourdon tube indicates temperature. Sometimes bellows and diaphragms are used instead of a Bourdon.

Table 7-1
Temperature measurement comparison.

Parameters / Types	Measuring range				Accuracy		Response time	Sensor output (Y=Yes, N=No)	
								Electronic	Mechanical
Filled systems	-148–985°F (-100–530°C)				± 1–2% of full scale		fair[1]	N	Y
Bimetallics	-75–790°F (-60–420°C)				± 1–2% of full scale[2]		fair	N	Y
Thermocouples [3]	Theoretical range		Recommended range		T/C calibration tolerances above 530°F (275°C)[4]		few milliseconds	Y	N
	°F	°C	°F	°C	Standard	Special			
B	32–3270	0–1820	1600–3090	870–1700	± 0.5%	± 0.25%			
E	-455–1800	-270–1000	-330–1650	-200–900	± 0.5% to ± 1%	± 0.4% to ± 0.8%			
J	-345–1400	-210–760	32–1380	0–750	± 0.75%	± 0.4%			
K	-455–2500	-270–1370	-330–2280	-200–1250	± 0.75%	± 0.4%			
R	-60–3220	-50–1770	32–2640	0–1450	± 0.25%	±0.1%			
S	-60–3220	-50–1770	32–2640	0–1450	± 0.25%	±0.1%			
T	-455–750	-270–400	-330–660	-200–350	± 0.75% to 1.5%	± 0.4% to ± 0.8%			
Resistance elements (known as RTDs)	-420–1185	-250–640	-300-500	-180-260	0.1% full scale[5]		slow[6]	Y	N
Noncontact optical-type (pyrometers)	32–5400	0–3000[7]	2000-5000	1100-2800	± 1–2% of full scale		very good	Y	N

1. 2 to 60 seconds and up to 90 seconds when fitted with a well
2. Switches have a set repetition accuracy under normal operation conditions of +1% of the span (or better)
3. Most common are types J and K
4. Below 530°F (277°C) the temperature error is 2 to 4°F (1 to 2°C). Also, add 2 to 4°F (1 to 2°C) for the extension wire errors
5. This accuracy applies to the commonly used platinum
6. RTDs heat when current passes through them (therefore adding a small error). A small diameter RTD will provide a fast response time and a high self heating error, whereas a large diameter RTD provides a slow response time and a low self heating error.
7. Narrow spans of 100°C are available

Figure 7-2
Filled system.



The system is filled with a liquid or gas that expands and contracts as the temperature sensed at the bulb increases and decreases. This expansion/contraction is translated into a mechanical motion. Liquid causes volume changes, and gas causes pressure changes.

Application Notes

The filled-system type of measurement is generally used for local indication or for temperature sensing in self-actuated temperature control valves. Its use has decreased over the years, but there are still some applications for it. This device is an improvement over the liquid-in-glass thermometer. It needs no power to function and is simple, rugged, self-contained, and accurate over narrow temperature spans.

However, the unit's bulb may be too large to fit existing applications, and if the filled system fails, the whole system must be replaced, which is expensive. In addition, the capillary tubing is generally limited to a distance of 250 ft (80 m), and the filled system as a whole is slow to respond and relatively expensive. Moreover, it is susceptible to ambient temperature changes around the capillary, and ambient temperature compensation is often necessary.

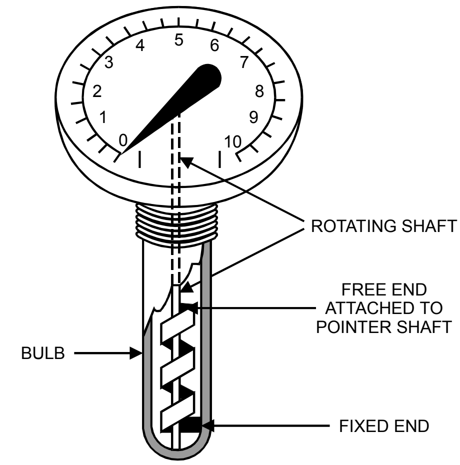
Filled-system measuring devices must be free of leaks in order to maintain their accuracy. Therefore, plants must occasionally check and test them, and continuously support and protect the capillary tubing against damage. In addition, the capillary's material of construction should be compatible with the surrounding environment. Finally, the bulb must be sufficiently immersed to ensure that the actual temperature is being measured.

Bimetallic

Principle of Measurement

In a bimetallic device (see figure 7-3), a spiral made of two metals with different coefficients of expansion expands as the temperature increases. The movement generated by the expansion drives an indicator on a scale. Industrial bimetallics use a helical coil to fit inside a stem. Most temperature switches operate on this principle, except that the pointer is replaced with a microswitch. Precision-made bearings and guides provide minimum acceptable friction for the moving components.

Figure 7-3
Bimetallic.



Application Notes

The bimetallic method of measurement is generally used in local temperature gages and switches. To facilitate the reading of process temperatures, plants usually select "all-angle" gages with a 5 in. (120 mm) diameter dial. A capillary type is sometimes used for operating visibility. If vibration exists, the plant may have to fill the thermometer with a dampening fluid that is compatible with the process fluid, in case of leakage.

The bimetallic has a simple construction and few moving parts and requires little maintenance. Its cost is the lowest of all temperature-measuring devices. However, its accuracy is low, and it provides no remote indication. Calibrating bimetallics requires immersing them in a bath of known temperature.

Thermocouple

Principle of Measurement

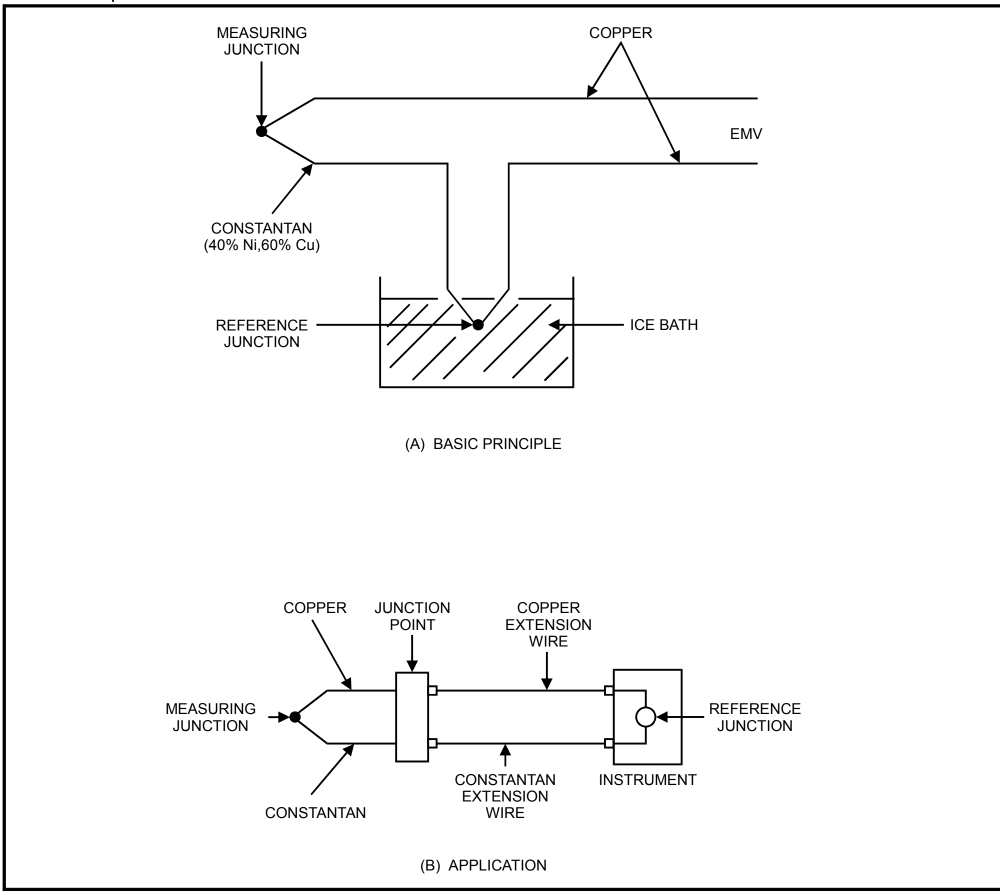
In 1821, T. J. Seebeck discovered that when two dissimilar metals are joined together, an electromotive force (emf) is generated between the hot and cold (reference) junctions (e.g., 4 mV for 100°C between the two junctions). An increase in temperature produces an increase in voltage output. Originally, the "cold" junction was actually immersed in an ice bath to maintain a constant reference temperature. Modern electronics have replaced this ice bath.

Theoretically, any two dissimilar metals will form a thermocouple (T/C) (see figure 7-4). However, only a few are used because of their superior response to temperature changes (i.e., sensitivity) and performance in general. There are many types of thermocouples, each with its advantages and disadvantages—refer to table 7-1.

Thermocouple wires are manufactured to close tolerances and tend to be expensive. Their use is thus limited to the probe itself. Thermocouple extension wires, which are compatible with the T/C wires, are used as the link between the T/C and the measuring device or transducer.

The evolution of modern electronics has created transducers that are small enough to fit inside the T/C box (or head). The major advantage of this arrangement is that it avoids long-distance transmission of a very low T/C voltage signal, which is prone to electrical noise (as opposed to the 4-20 mA signal).

Figure 7-4
Thermocouples.



EMF Calculations

For each type of thermocouple there is a corresponding reference table that converts mV reading (i.e., thermocouple output) into a temperature. These tables are available from many sources and vendors, including National Bureau of Standards Monograph 125, ISA Recommended Practices, or ISA Standards (ISA-MC96.1-1982). As an example, a portion of a K type reference table is shown in table 7-2. From that table, it can be seen that if a K-type thermocouple has an output of 4.012 mV and the temperature of the reference junction is at 0°C, then the measured temperature is of 98°C.

Note that sometimes the mV values must be interpolated from the table to obtain the corresponding temperature. Linear interpolation is acceptable.

Application Notes

The three basic types of T/C construction are the following:

1. Ceramic beaded.

2. Insulated (plastic, glass, or ceramic fiber). These types are generally extruded (see figure 7-5).

3. Metal-sheathed mineral-insulated (MSMI). The sheath is generally stainless steel or Inconel, and mineral insulation is generally magnesium oxide or aluminum oxide. Sheathed material gives the T/ C excellent protection from outside chemical and mechani-

cal effects. However, sheathed T/Cs, since they are a one-piece construction, are more difficult to strip and terminate than other types. The junction should be welded and insulated. Different types of sheathed thermocouples are shown in figure 7-6.

Table 7-2
Partial type K thermocouple temperature – emf table.

Temperatures in degrees Celsius (IPTS-68) Reference junctions at 0°C

DEG C	0	1	2	3	4	5	6	7	8	9	10	DEG C
						THERMOELECTRIC VOLTAGE IN MILLIVOLTS						
–270	–6.458											–270
–260	–6.441	–6.444	–6.446	–6.448	–6.450	–6.452	–6.453	–6.455	–6.456	–6.457	–6.458	–260
–250	–6.404	–6.408	–6.413	–6.417	–6.421	–6.425	–6.429	–6.432	–6.435	–6.438	–6.441	–250
–240	–6.344	–6.351	–6.358	–6.364	–6.371	–6.377	–6.382	–6.388	–6.394	–6.399	–6.404	–240
–230	–6.262	–6.271	–6.280	–6.289	–6.297	–6.306	–6.314	–6.322	–6.329	–6.337	–6.344	–230
–220	–6.158	–6.170	–6.181	–6.192	–6.202	–6.213	–6.223	–6.233	–6.243	–6.253	–6.262	–220
–210	–6.035	–6.048	–6.061	–6.074	–6.087	–6.099	–6.111	–6.123	–6.135	–6.147	–6.158	–210
–200	–5.891	–5.907	–5.922	–5.936	–5.951	–5.965	–5.980	–5.994	–6.007	–6.021	–6.035	–200
–190	–5.730	–5.747	–5.763	–5.780	–5.796	–5.813	–5.829	–5.845	–5.860	–5.876	–5.891	–190
–180	–5.550	–5.569	–5.587	–5.606	–5.624	–5.642	–5.660	–5.678	–5.695	–5.712	–5.730	–180
–170	–5.354	–5.374	–5.394	–5.414	–5.434	–5.454	–5.474	–5.493	–5.512	–5.531	–5.550	–170
–160	–5.141	–5.163	–5.185	–5.207	–5.228	–5.249	–5.271	–5.292	–5.313	–5.333	–5.354	–160
–150	–4.912	–4.936	–4.959	–4.983	–5.006	–5.029	–5.051	–5.074	–5.097	–5.119	–5.141	–150
–140	–4.669	–4.694	–4.719	–4.743	–4.768	–4.792	–4.817	–4.841	–4.865	–4.889	–4.912	–140
–130	–4.410	–4.437	–4.463	–4.489	–4.515	–4.541	–4.567	–4.593	–4.618	–4.644	–4.669	–130
–120	–4.138	–4.166	–4.193	–4.221	–4.248	–4.276	–4.303	–4.330	–4.357	–4.384	–4.410	–120
–110	–3.852	–3.881	–3.910	–3.939	–3.968	–3.997	–4.025	–4.053	–4.082	–4.110	–4.138	–110
–100	–3.553	–3.584	–3.614	–3.644	–3.674	–3.704	–3.734	–3.764	–3.793	–3.823	–3.852	–100
–90	–3.242	–3.274	–3.305	–3.337	–3.368	–3.399	–3.430	–3.461	–3.492	–3.523	–3.553	–90
–80	–2.920	–2.953	–2.985	–3.018	–3.050	–3.082	–3.115	–3.147	–3.179	–3.211	–3.242	–80
–70	–2.586	–2.620	–2.654	–2.687	–2.721	–2.754	–2.788	–2.821	–2.854	–2.887	–2.920	–70
–60	–2.243	–2.277	–2.312	–2.347	–2.381	–2.416	–2.450	–2.484	–2.518	–2.552	–2.586	–60
–50	–1.889	–1.925	–1.961	–1.996	–2.032	–2.067	–2.102	–2.137	–2.173	–2.208	–2.243	–50
–40	–1.527	–1.563	–1.600	–1.636	–1.673	–1.709	–1.745	–1.781	–1.817	–1.853	–1.889	–40
–30	–1.156	–1.193	–1.231	–1.268	–1.305	–1.342	–1.379	–1.416	–1.453	–1.490	–1.527	–30
–20	–0.777	–0.816	–0.854	–0.892	–0.930	–0.968	–1.005	–1.043	–1.081	–1.118	–1.156	–20
–10	–0.392	–0.431	–0.469	–0.508	–0.547	–0.585	–0.624	–0.662	–0.701	–0.739	–0.777	–10
–0	0.000	–0.039	–0.079	–0.118	–0.157	–0.197	–0.236	–0.275	–0.314	–0.353	–0.392	–0
0	0.000	0.039	0.079	0.119	0.158	0.198	0.238	0.277	0.317	0.357	0.397	0
10	0.397	0.437	0.477	0.517	0.557	0.597	0.637	0.677	0.718	0.758	0.798	10
20	0.798	0.838	0.879	0.919	0.960	1.000	1.041	1.081	1.122	1.162	1.203	20
30	1.203	1.244	1.285	1.325	1.366	1.407	1.448	1.489	1.529	1.570	1.611	30
40	1.611	1.652	1.693	1.734	1.776	1.817	1.858	1.899	1.940	1.981	2.022	40
50	2.022	2.064	2.105	2.146	2.188	2.229	2.270	2.312	2.353	2.394	2.436	50
60	2.436	2.477	2.519	2.560	2.601	2.643	2.684	2.726	2.767	2.809	2.850	60
70	2.850	2.892	2.933	2.975	3.016	3.058	3.100	3.141	3.183	3.224	3.266	70
80	3.266	3.307	3.349	3.390	3.432	3.473	3.515	3.556	3.598	3.639	3.681	80
90	3.681	3.722	3.764	3.805	3.847	3.888	3.930	3.971	4.012	4.054	4.095	90
DEG C	0	1	2	3	4	5	6	7	8	9	10	DEG C

Figure 7-5
Typical thermocouple assembly.

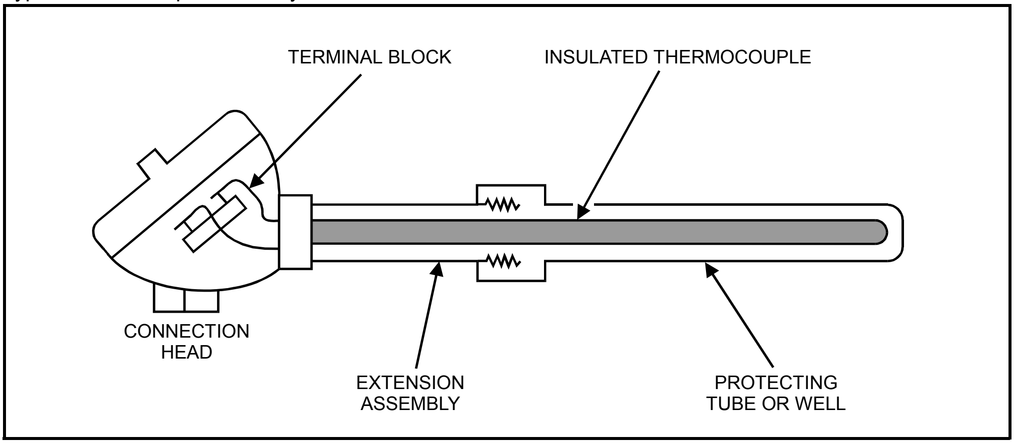
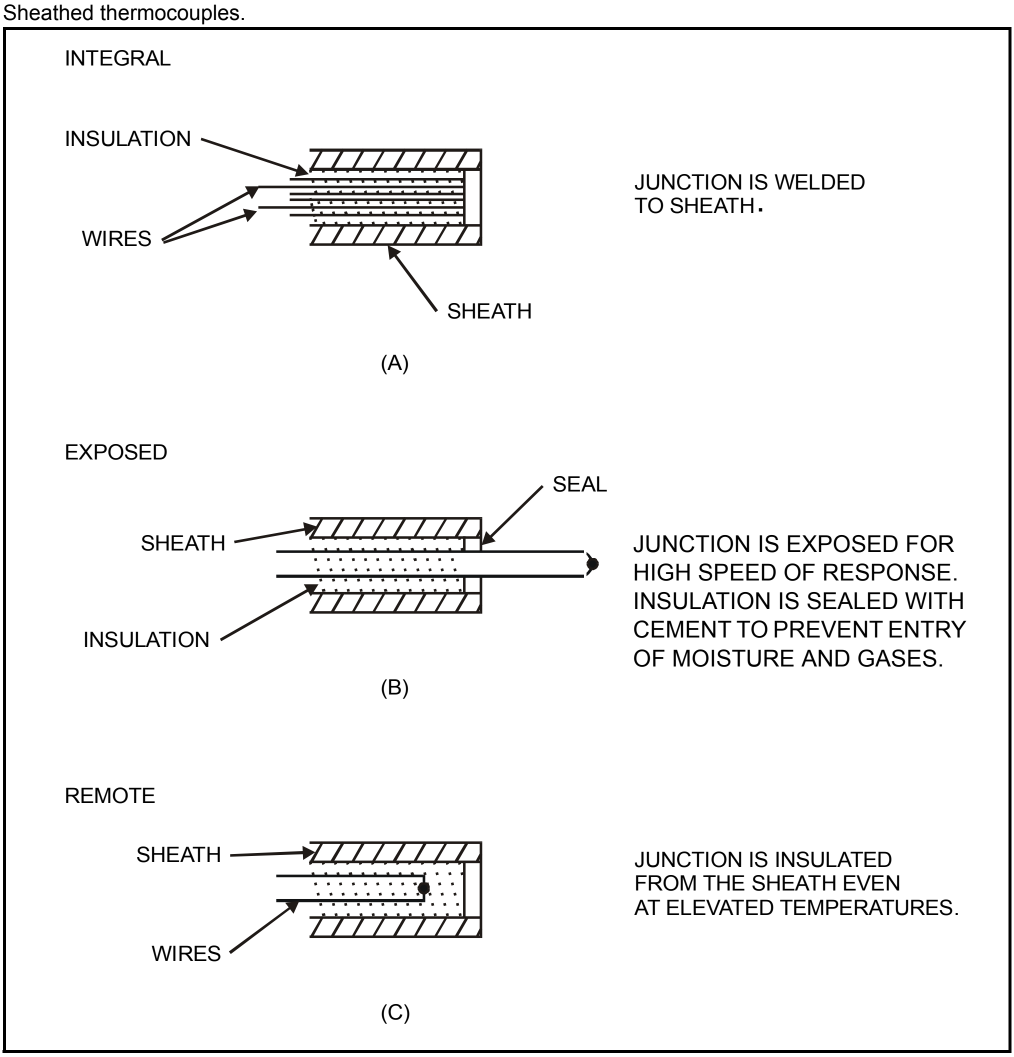


Figure 7-6
Sheathed thermocouples.



T/Cs can be constructed so as to be exposed or protected. Exposed T/Cs provide the fastest response, but the wires are totally unprotected. Protected T/Cs can be grounded or ungrounded. When grounded they give a faster response since good temperature transfer is obtained. However, grounded-protected T/Cs are susceptible to electrical noise due to stray electrical signal pickup. When T/Cs are ungrounded, they are slower to respond but are electrically isolated. In addition, a T/C may be spring-loaded in the thermowell so that its tip and the well's surface remain in contact to ensure good heat transfer.

T/C wire is available in different gauges. As the T/C wire gets thinner,

- the recommended upper temperature limit is reduced. For example, the upper limit for a type J T/C is 1400°F (760°C). With a No. 8 gage T/C wire, it is 1095°F (590°C), with a No. 14 gage T/C wire it is 895°F (480°C), and 700°F (370°C) with a No. 24 gage T/C wire.
- the error decreases and the response is faster to temperature changes.
- the element becomes more fragile (i.e., more frequent maintenance is required).
- at high temperatures, the accuracy is more sensitive to material quality (wire impurities, etc.).

T/Cs are identified through color coding. All color coding, accuracy, and symbol designation for T/Cs and extension wire should conform with the local authority that has jurisdiction at the site. For example, a typical authority is the ISA-MC96.1-1982 where the negative wire is always red in color.

Thermocouples are self-powered and of simple and rugged (shock-resistant) construction. They are also inexpensive (half the price of an RTD), come in a wide choice of physical forms, and provide a wide temperature range. In addition, they can be calibrated to generate a specific curve (for an extra cost) and are easy to interchange. They provide a fast response and measurement at one specific point. The typical response time of a bare T/C is from 0.2 to 12 seconds.

Whereas RTDs average the temperature over their element, T/Cs measure the temperature at their tip only and are thus faster. However, T/Cs generate a nonlinear output and a low voltage. The accuracy of T/Cs varies with temperature. Therefore, plants must assess the T/C's accuracy at the operating temperature to determine whether it is acceptable.

T/Cs require a reference junction, have low sensitivity, are limited in accuracy, and need type-matching extension wires. In addition, they are subject to deterioration from adverse conditions, usage, and time; are susceptible to stray electrical signals; and require amplifying electronics. However, the unit’s electronics can identify T/C failure as being either an upscale or downscale indication.

Resistance Temperature Detector (RTD)

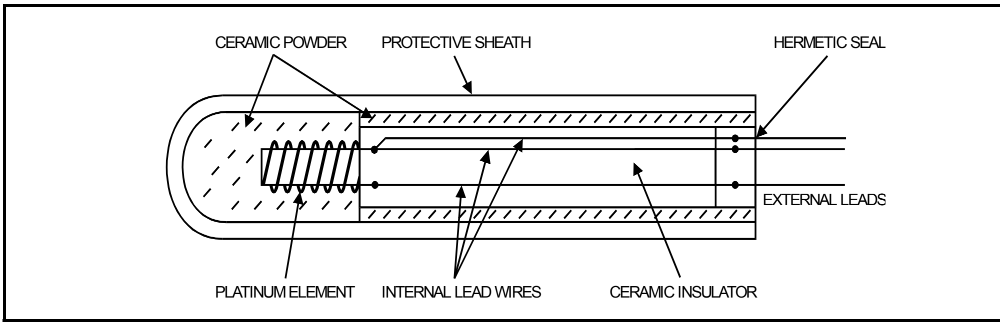
Principle of Measurement

Pure metals will produce an increase in resistance with an increase in temperature. In resistance temperature detectors (RTD), the electronics sense the change of resistance of a resistor (on a Wheatstone bridge) as temperature changes and generate a proportional output. For more information about the Wheatstone bridge, refer to figure 6-11. The most common RTD element is 100Ω at 0°C platinum; nickel is generally the second choice. The RTD is an accurate sensor that theoretically could measure a temperature change of 0.00002°F (0.00001°C).

Resistance temperature detectors are usually protected from the environment by a sheath made of stainless steel or any other temperature- and corrosion-resistant material (see figure 7-7).

The element fits snugly inside the sheath to produce a high rate of heat transfer. A fine powder is used to eliminate air pockets. Ceramic insulators are typically used to isolate the internal lead wires. At the end of the tube a hermetic seal protects the element. The assembly may be terminated with the lead wires or may be supplied with an appropriate terminal block similar to a T/C assembly.

Figure 7-7
Three-wire RTD.



Application Notes

As a rough rule of thumb, RTDs are used where the temperature is less than 250°F (120°C), whereas T/Cs are used where the temperature is greater than 930°F (500°C). Since the accuracy of RTDs varies with temperature, the user must assess the process's operating temperature and deemed whether an RTD is acceptable.

Resistance temperature detectors are available as two-wire, three-wire, and four-wire elements. With a two-wire element (see figure 7-8A), the effect of the lead wire resistance (and the effects of the change in resistance that occurs as the ambient temperature changes) introduces significant errors.

With a three-wire element (see figure 7-8B), the impedance in the wires will cancel because the wires are in opposite legs of the bridge. In other words, the three-wire method compensates for the effect of lead resistance. This is the most practical and commonly used RTD method. A four-wire element (see figure 7-8C) requires an extra wire but provides additional accuracy. It is generally used only rarely where very high degrees of accuracy are required. The four-wire element is immune to lead resistance. Its current is sourced on one set of leads and the voltage is sensed on another set of leads. The lead resistance is not part of the measurement and the output voltage is directly proportional to the RTD resistance.

Of all temperature-measuring devices, RTDs are, at moderate temperatures, the most stable and the most accurate. Their output is stronger than that of a T/C, they are less susceptible to electrical noise, and they operate on a higher level of electrical signals. Moreover, they are more sensitive and more linear than a T/C (output versus temperature), use copper extension wire (not special extension wire), require no reference junction, and are easy to interchange.

However, RTDs are relatively expensive compared to thermocouples, have a slow response, and require a current source. They are susceptible to small resistance changes, and self-heating appears as a measurement error (the main source of RTD error). In addition, RTDs have a limited temperature range, are susceptible to strain and vibration, generate some nonlinearity, and require three (or four) extension wires. Their resistance curves vary from manufacturer to manufacturer, and their accuracy and service life are limited at high temperatures.

Thermistor

A thermistor is basically a semiconductor that is performing the function of an RTD, but with a higher resistance. The resistance change (due to a temperature change) is about ten times that of a metallic RTD. However, the self-heating error is high, and the resistance values are nonlinear, which limits the thermistor's measuring range.

Figure 7-8A
2-Wire RTD.

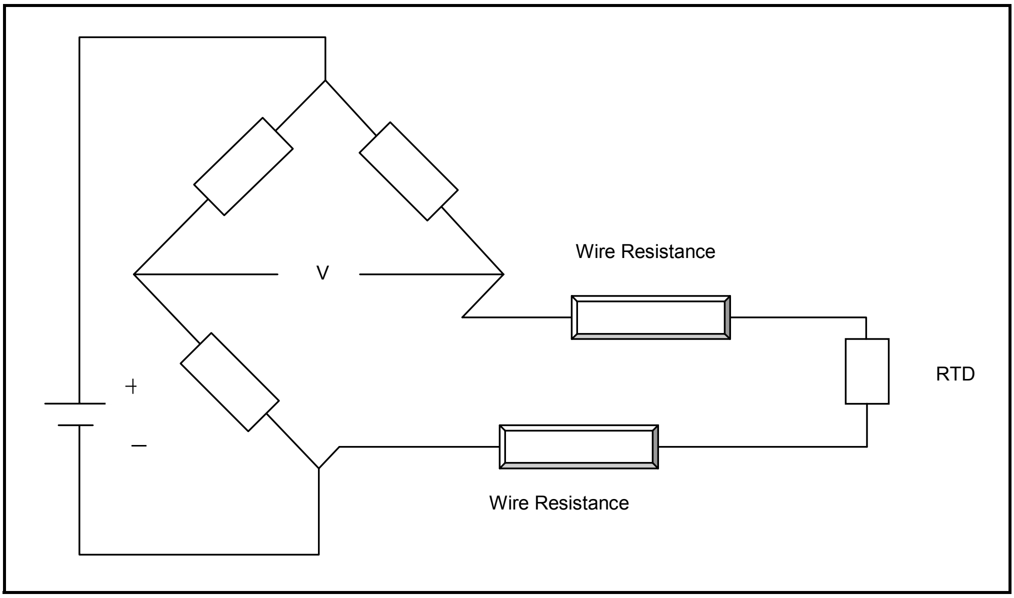


Figure 7-8B
3-Wire RTD.

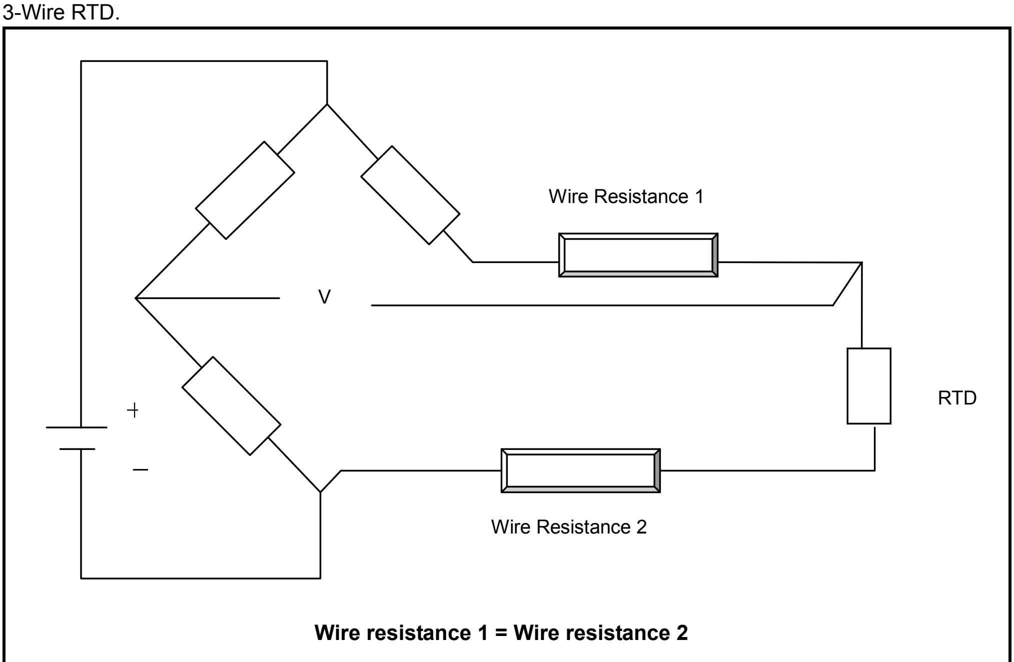
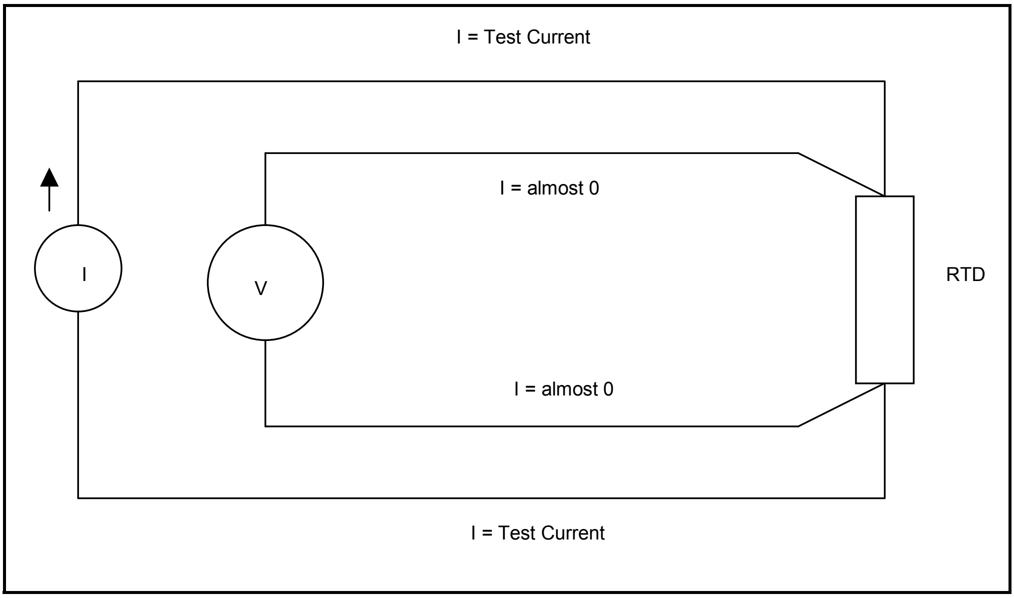


Figure 7-8C
4-Wire RTD.



Noncontact Pyrometry

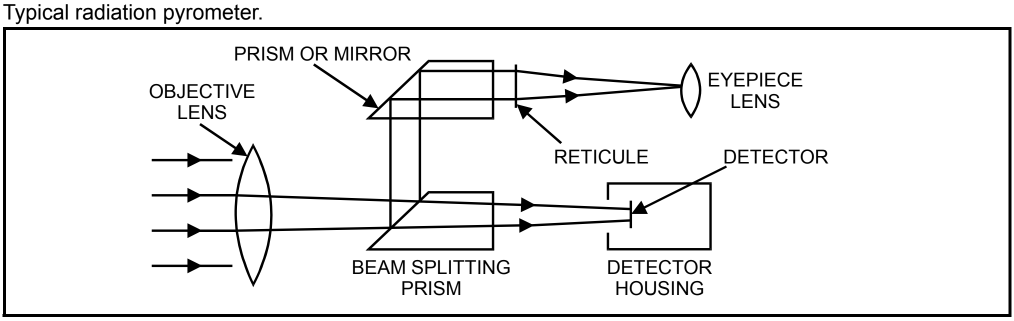
Principle of Measurement

Pyrometry is based on the principle that all objects emit radiant energy in the form of electromagnetic waves. “Red hot” means that the radiant energy is in the visible light portion of the spectrum. Pyrometers measure the temperature of an object by measuring the intensity of the emitted radiation (visible or non-visible). Emitted radiation is a measure of an object's ability to send out radiant energy. A black body is considered as the perfect emitter and is commonly used as a standard when calibrating pyrometers. The two most common pyrometric techniques are radiation and optical.

Radiation

In radiation pyrometry, the radiation from a hot surface is measured when it is focused on a T/C. The measured temperature is directly proportional to the heat radiated and therefore its temperature (if the emissivity is known). The instrument calibration is based on a blackbody radiation; if targeting non-blackbodies, correction must be applied (see figure 7-9).

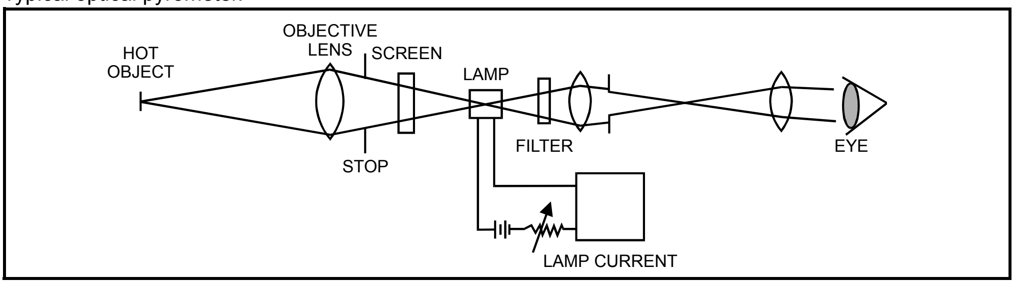
Figure 7-9
Typical radiation pyrometer.



Optical

In optical pyrometry, the radiant energy from the filament inside the instrument is compared to the incoming radiant energy by manually (or automatically) adjusting the rheostat. The radiant energy of the filament blends into the measured radiant energy. This type of device is sometimes known as the "disappearing filament." The value of this radiant energy (i.e., the current measured) is converted into degrees if the emissivity is known (see figure 7-10).

Figure 7-10
Typical optical pyrometer.



Application Notes

Pyrometry is used for noncontact measurement where the point to be measured is out of reach (such as a moving target or an inaccessible target). It is also used to measure the average temperature of a very large target, or if the temperature is too high (such as with molten metal).

Pyrometers may be portable, and they have a high response speed of a few milliseconds. For industrial-type meters, a one- to two-second response time is common. Pyrometers are relatively expensive. In addition, errors can be introduced in pyrometers through condensation on the window or lens, smoke or fumes in the atmosphere, gases such as products of combustion, or dirt on the optical system. For fixed units, a special housing may be required to protect units that are subject to extremely high surrounding temperatures (e.g., cast aluminum jackets to accommodate coolants). Special housings may also be needed to meet production needs (e.g., water cleaning, sprays, etc.) or to protect units from cold winters (where heat tracing may be required).

Pyrometers may require the use of focusing devices, such as sighting telescopes, alignment tubes, and aiming flanges. They may also require the use of safety shutters to safeguard the lenses and motorized bases to redirect the instrument's position.

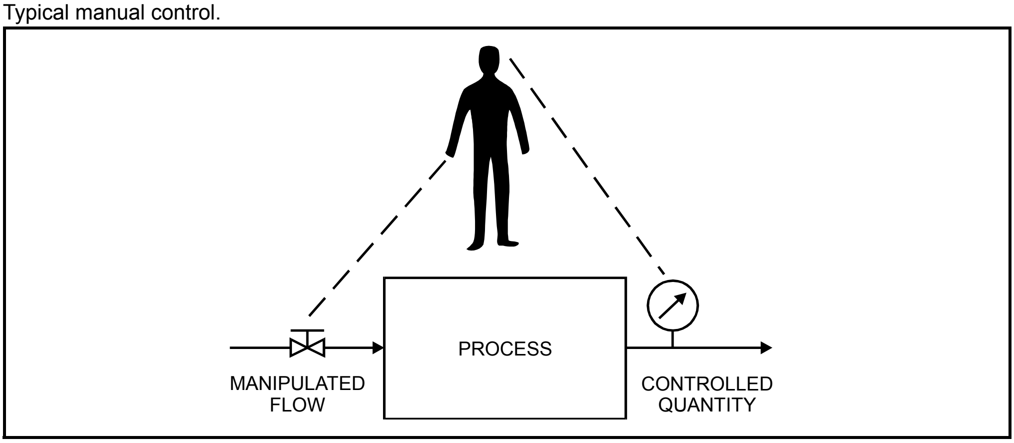
CHAPTER 8

CONTROL LOOPS

Overview

Historically, control functions were originally performed manually by operators (see figure 8-1). The operator typically used the senses of sight, feel, smell, and sound to "measure the process." To maintain the process within set limits, the operator would adjust a device, such as a manual valve, or change a feed, such as adding a shovelful of coal. The quality of control was poor by today's standards and relied heavily on the capabilities, response, and experience of the human operator.

Figure 8-1
Typical manual control.



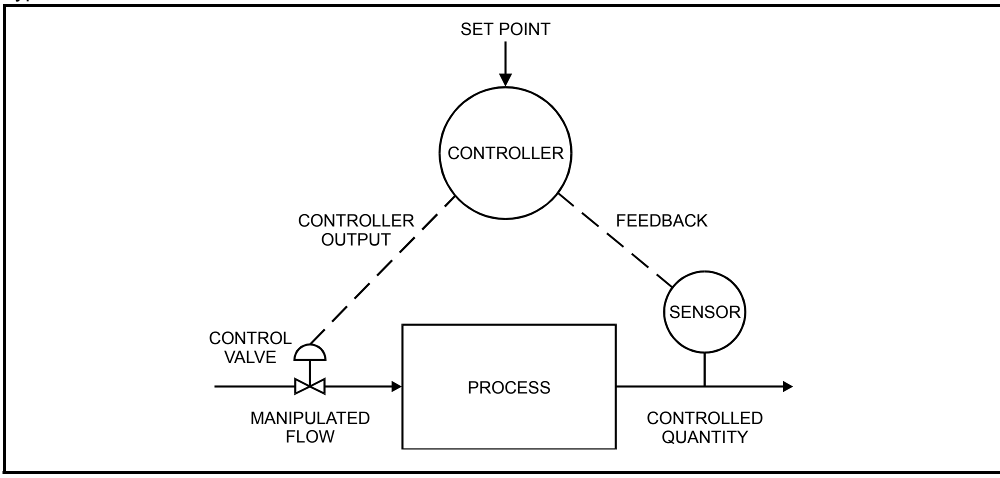
In modern systems, by contrast, the operator's control function has been replaced by a control unit that continuously compares a measured variable (the feedback) with a set point and automatically produces an output to maintain the process within limits (see figure 8-2). This control unit is the "controller." The operator acts as a supervisor to this controller by setting its set point, which the controller then works to maintain. Automatic controls provide consistent quality products, reduced pollution, labor savings, optimized inventory and production, increased safety, and control of processes that could not be operated manually with any efficiency. In addition, automatic controls release the operator from the need to perform tedious activities, making possible more intelligent and efficient use of labor.

Controllers have evolved from simple three-mode pneumatic devices to sophisticated control functions that are part of a larger computer-based system such as a distributed control system (DCS) or a programmable logic controller (PLC). Such microprocessor-based units commonly provide self-tuning, logic control capabilities, digital communication, and so forth.

When selecting a controller for an application, users should keep in mind certain considerations to ensure correct operation. In addition to basic requirements such as the controller's range of input and output signals, accuracy, and speed of response, personnel selecting controllers should also consider

- the effect the controller mode will have on the process if it is left on manual (typically, the transfer from auto mode to manual mode should be a closely controlled activity).

Figure 8-2
Typical automatic control.



- the ability of the control function to switch bumplessly from automatic to manual and manual to automatic.
- the implementation of direct-reading scales in engineering units.
- the inclusion of built-in external feedback connection (or anti-reset windup) to prevent the development of reset windup caused by the application (refer to the section "Modulating control" later in this chapter).
- the effect on the process if the controller fails and the potential need for manual takeover or automatic shutdown.

Control Modes

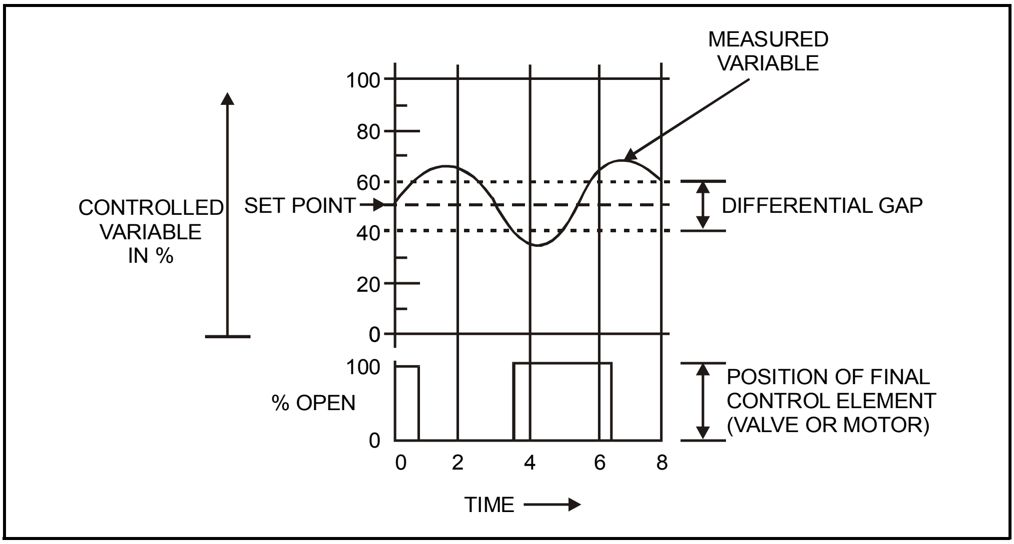
The two basic modes of control are "on-off" and "modulating." In either case, the values that are the object of measurement are generally referred to as "measured variables" or "process variables" (PV). These variables include chemical composition, flow, level, pressure, and temperature. These measured variables represent the input into the control loop. Before loops can be controlled, the variables must be capable of being measured precisely. The more precisely the variable can be measured, the more precisely the controller controls.

On-Off Control

On-off control (see figure 8-3) is also known as "discrete control" or "two-position" control. In it, the output of the controller changes from one fixed condition to another fixed condition. Control adjustments are made to the set point and to the differential gap. The differential gap has basically two set points, or one set point with a differential gap or deadband.

On-off control is the simplest and least expensive. It provides some flexibility since the valve size is adjustable. However, it should only be used where cyclic control is permissible (e.g., in large-capacity systems). On-off control cannot provide steady measured values, but it is good enough for many applications.

Figure 8-3
On-off control.



Modulating Control

In modulating control, the feedback controller operates in two steps. First, it computes the error between the measured variable (the process feedback) and the set point. Then it produces an output signal to the control valve to reduce the measured error to zero.

This type of control—operating with continuously changing analog values—includes three basic functions: proportional, integral, and derivative (PID). Most modern controllers include the three PID functions. Loop operation and tuning parameters may activate a single function, a combination of two functions, or a combination of all three functions.

Proportional (P)

This function, also known as "gain," provides an output that is proportional (in linear relation) to the direction and magnitude of the error signal. The larger the gain, the larger the change in the controller output caused by a given error. Some controller vendors use the term *gain* while others use *proportional band* to describe a similar function. The relationship between a controller's gain and its proportional band (PB) is as follows:

$$PB = \frac{100}{\text{Gain}}$$

Integral (I)

This function, also known as "reset," provides an output that is proportional to the time integral of the input. That is, the output continues to change as long as an error exists. In other words, the integral function acts only when the error exists for a period of time.

The integral function is used to gradually eliminate the offset. Loops with low gain only (i.e., no integral function) will provide stable performance but will generate large offsets, and vice versa. The integral function is slower than the proportional function because it must act over a period of time.

One drawback of the integral function is the "integral windup" (or "reset windup"). This occurs when the deviation cannot be eliminated, such as on open loops, and the controller is therefore driven into its extreme output. This condition creates loss of control for a period of time, followed by extreme cycling. Implementing protection from such an occurrence is generally necessary and can be built into the controller as an "anti-integral windup."

Derivative (D)

The derivative function, also known as "rate," provides an output that is proportional to the rate of change (derivative) of error. In other words, the derivative function acts only when the error is changing with time. The derivative speeds up the controller action, compensating for some of the delays in the feedback loop. It is used to provide quick stability to sudden upsets.

PID Control

When combining the effects of P, I, and D, the typical PID equation is as follows:

$$\text{Output} \propto \text{gain}\left(e + \frac{1}{T_i}\int_0^t e\,dt + T_d\frac{de}{dt}\right)$$

where:

Output = controller output
T_i = integral time in minutes
t = time
T_d = derivative time in minutes
e = error = measured variable - set point (for direct acting controllers)
= set point - measured variable (for reverse acting controllers)

Controller action is available either as direct or reverse. Direct action means that when the measured variable (also known as process variable PV) increases, the output increases. Reverse action means that when the measured variable increases, the output decreases.

Tuning controllers means setting the values of the PID for optimum performance. Additional information on PID tuning is provided in the section "Controller Tuning" later in this chapter.

The following general rules provide an idea of the PID requirements for different loops. However, keep in mind that each application has its own needs.

- *Flow control:* P and I are required; D is set at 0 or at minimum.
- *Level control:* P is required, I is sometimes required, and D is set at 0 or at minimum.
- *Pressure control:* P and I are required; D is generally set at 0 or at minimum.
- *Temperature control:* P, I, and D are required, and the integral action is sometimes fairly long.

Control Types

Four main types of control are commonly used: feedback, cascade, ratio, and feedforward.

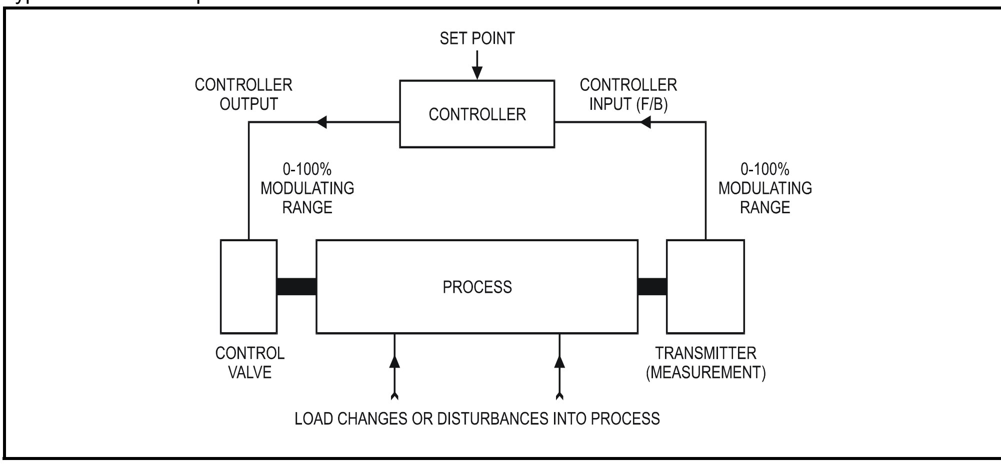
Feedback

This is the basic closed loop (see figure 8-4), the oldest type of control. It was developed in 1774 when, in the first industrial application, James Watt used a flyball governor to control the speed of a steam engine.

In a closed loop, a process variable (also know as the "measured variable" or "feedback") is fed as an input into a controller. That input is compared to a set point, and if there is a difference between the two (i.e., an error), the controller output will change in an attempt to bring this error to zero. This output change typically modulates by opening or closing a controlling device, such as a modulating control valve.

An open loop has no feedback and cannot be considered a closed loop. Remember that the operator, who monitors the controlled variable and manually adjusts the output to the valve, acts as a "controller," thereby closing the loop (see figure 8-1). However, the "closing of the loop", by the operator's actions, is not an automatic function, and it totally depends on the operator's sensory capabilities, knowledge, and manual output.

Figure 8-4
Typical feedback loop.



Cascade

In cascade control (see figure 8-5), the "primary" variable is controlled by the primary controller (sometimes known as the master), however, it is not a direct control. Instead, it manipulates the set point of the secondary controller, which controls the secondary variable.

Cascade control corrects the disturbances in the secondary loop before they affect the primary process variable. It should be noted that cascade control systems control both primary and secondary variables. To maintain stability, the secondary loop must be much faster than the primary loop, and the secondary loop must receive the maximum disturbances (instead of—and before they affect—the primary loop).

Ratio

In ratio control (see figure 8-6), the controlled variable follows in proportion to a second variable known as the "wild" variable. The proportionality constant is the ratio. Ratio systems are not limited to two components; one wild flow can adjust several controlled flows.

Feedforward

A feedforward control system (see figure 8-7) measures a disturbance, predicts its effect on the process, and immediately applies corrective action. Feedforward control is by itself insufficient. It is generally used in conjunction with feedback control to trim the feedforward model. It should be noted that

- feedforward on its own is an open loop.
- feedforward and feedback systems independently adjust the control valve.
- there is no control applied to the feedforward variable.

Figure 8-5
Typical cascade loop.

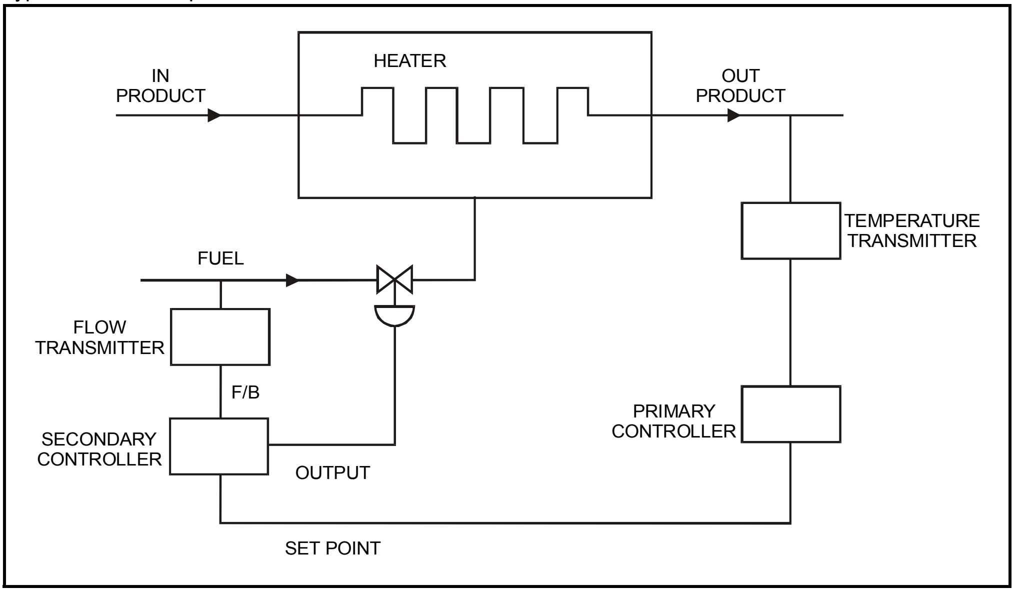
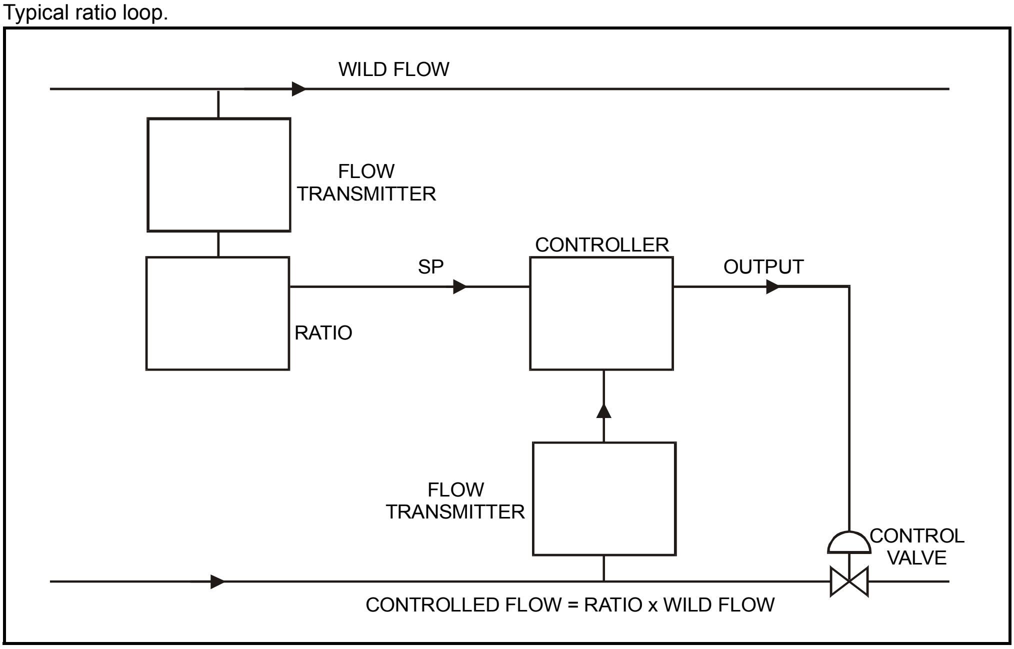


Figure 8-6
Typical ratio loop.



Controller Tuning

The performance of a PID control loop depends on the following:

- The quality of the measuring and control devices.
- The effect of process upsets.
- The control stability as manifested in the ability of the measured variable to return to its set point after a disturbance (see figure 8-8). This ability is dependent on the correct controller PID settings, which is accomplished through good tuning.

Tuning means finding the ideal combination of P, I, and D to provide the optimum performance for the loop under operating conditions. Keep in mind that “ideal control” must be determined for a specific application.

Figure 8-7
Feedforward control systems.

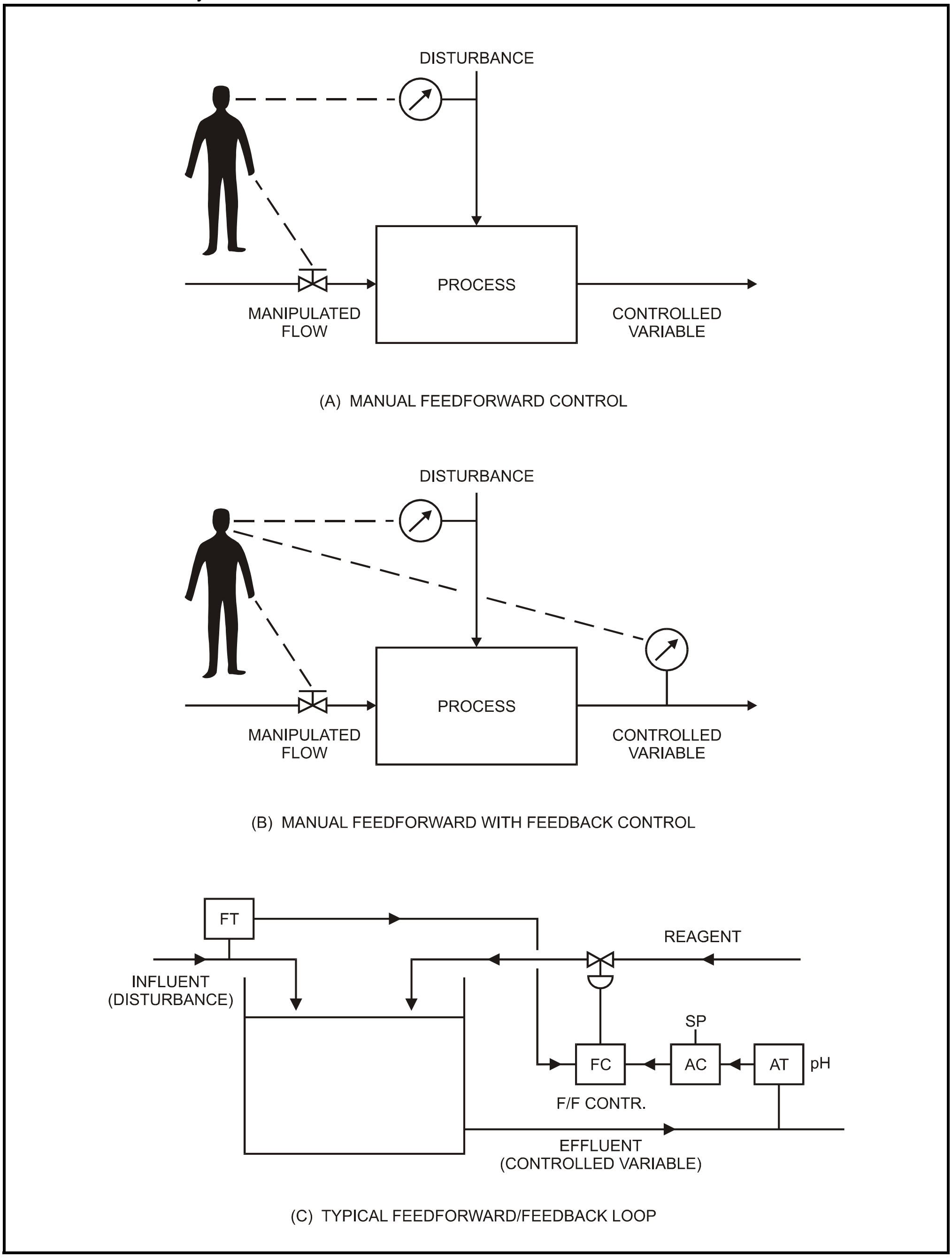
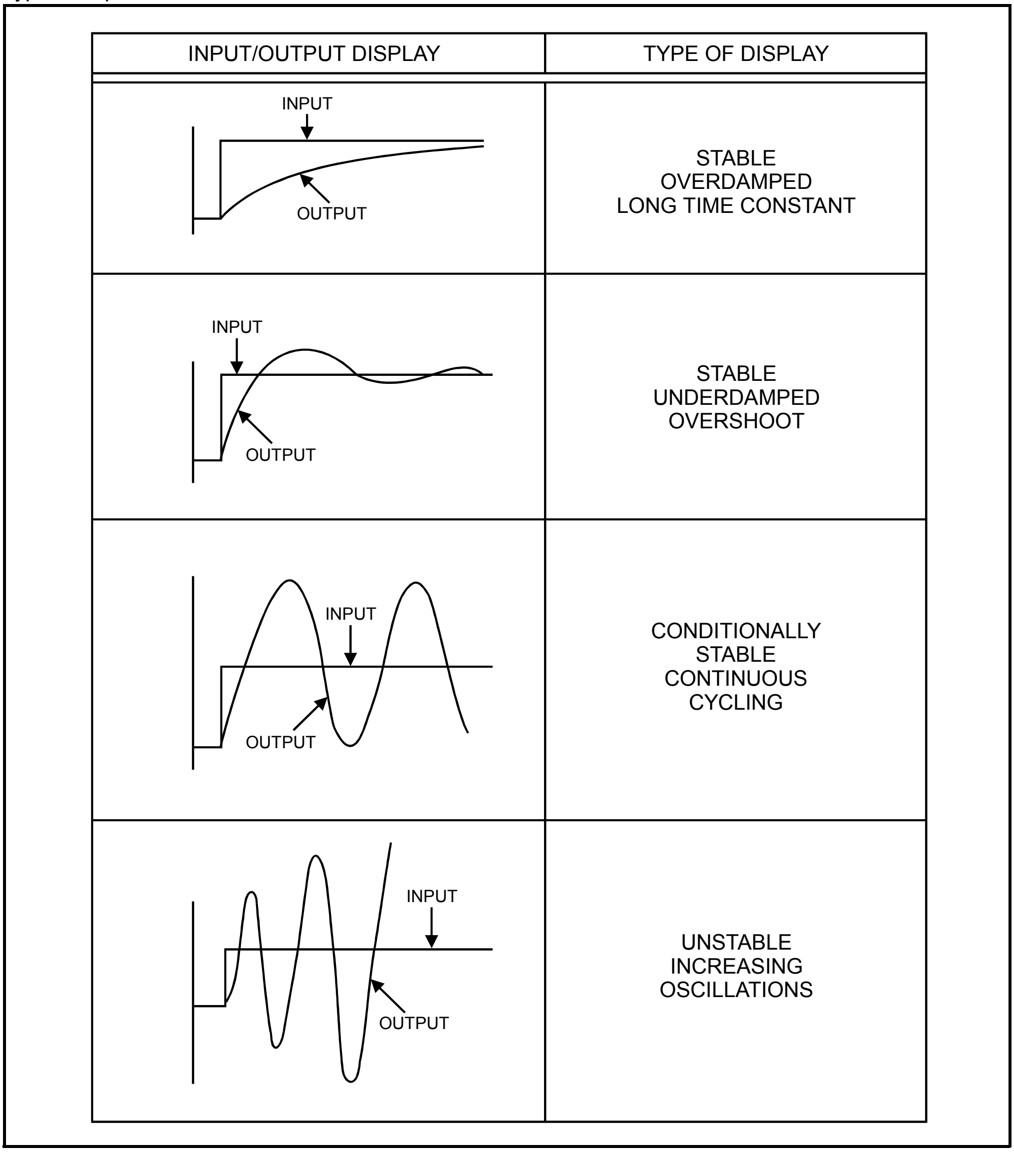


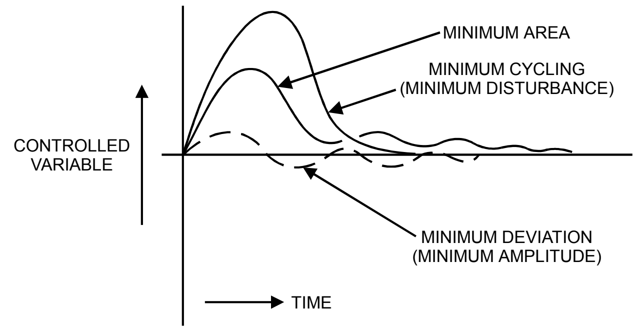
Figure 8-8
Typical response curves.



Loops can be tuned either for minimum area, minimum cycling, or minimum deviation (see figure 8-9).

- "Minimum area" produces a longer-lasting deviation from the set point. It is used for applications in which overshoot is detrimental (e.g., a defective product would result).
- "Minimum cycling" produces minimum disturbances with a minimum time duration. Applications with a number of loops in series benefit from this setup because it provides overall process stability.
- "Minimum deviation" maintains close control with small deviations and is the most commonly used. However, there is cycling around the set point. The amplitude should be kept at minimum.

Figure 8-9
Different control stabilities.



Controller tuning is generally done automatically, manually, or through adjustments based on experience. In all cases, a few simple rules will minimize problems.

- Check with the operator before starting.
- Before retuning an existing controller, note the old settings (just in case you need to go back to them in a hurry).
- If you are on manual, and the process is steady, take note of the output signal to the valve (in case you need to go back to manual in a hurry).
- On cascade loops, tune the secondary controller first, with its set point in local mode.

Automatic Tuning

In automatic controller tuning, the software/hardware vendor has included a feature in the equipment to perform the tuning function.

Manual Tuning

Manual tuning is a combination of art, science, and experience. In addition, two elements are required for good tuning. First, a good understanding of the loop being tuned is required; second, lots of patience is essential, since some loops may take a long time to properly tune.

There are two basic methods for manual tuning: open loop and closed loop. Open loop tuning may be used to tune loops that have long delays such as analysis and temperature loops, and closed loop tuning may be used to tune fast loops such as flow, pressure, and level loops.

Open Loop

The open loop method (see figure 8-10) consists of the following steps:

- Putting the controller on manual (open loop)
- Making a step change to the output (X) (5 to 10%)
- Recording the resulting action (PV) from the feedback element
- Finding the reaction rate R (= B/A)
- Finding the unit reaction rate R_u (= R/X)
- Finding the effective lag L (time intercept)
- Setting the controller PID values

gain = 1.2 / (Ru x L)
integral = 0.5 / L in repeats/minute
derivative = (0.5) L in minutes

- Where only P and I values are required, the settings are

  gain = 0.9 / (Ru x L)
  integral = 0.3 / L in repeats/minute

- Testing and fine tuning, if required

Closed Loop

The Ziegler-Nichols closed loop method (see figure 8-11) consists of the following steps:

- Putting the process on auto control using "P only" mode (set I and D to minimum)
- Moving the controller set point 10 percent and holding until *PV* begins to move
- Returning the set point to its original value
- Adjusting gain until a stable continuous cycle is obtained (i.e., critical gain, G_c)
- Measuring period of cycle (P_c)
- Setting the controller PID values

  gain = (0.6) G_c
  integral = 2 / P_c in repeats/minute
  derivative = (0.125) P_c in minutes

- Where only P and I values are required, the settings are

  gain = (0.45) G_c
  integral = 1.2 / P_c in repeats/minute

- Testing and fine tuning, if required

Figure 8-10
Open-loop method.

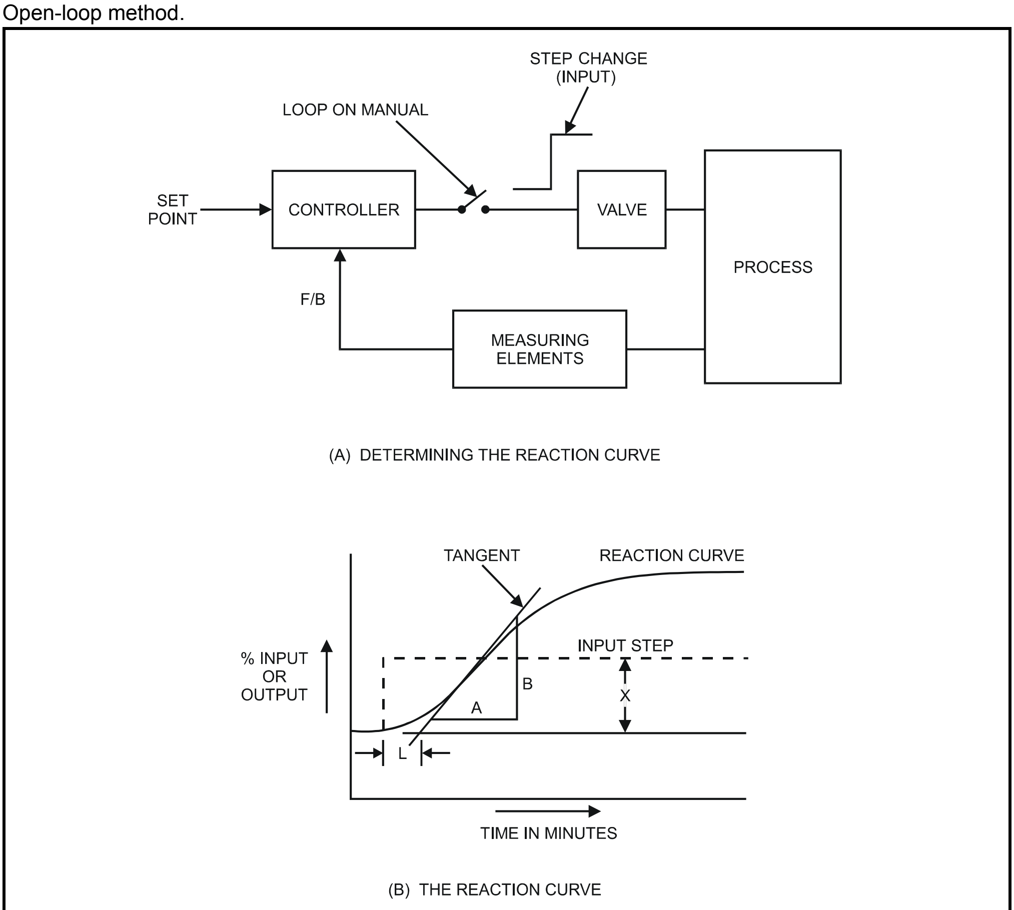
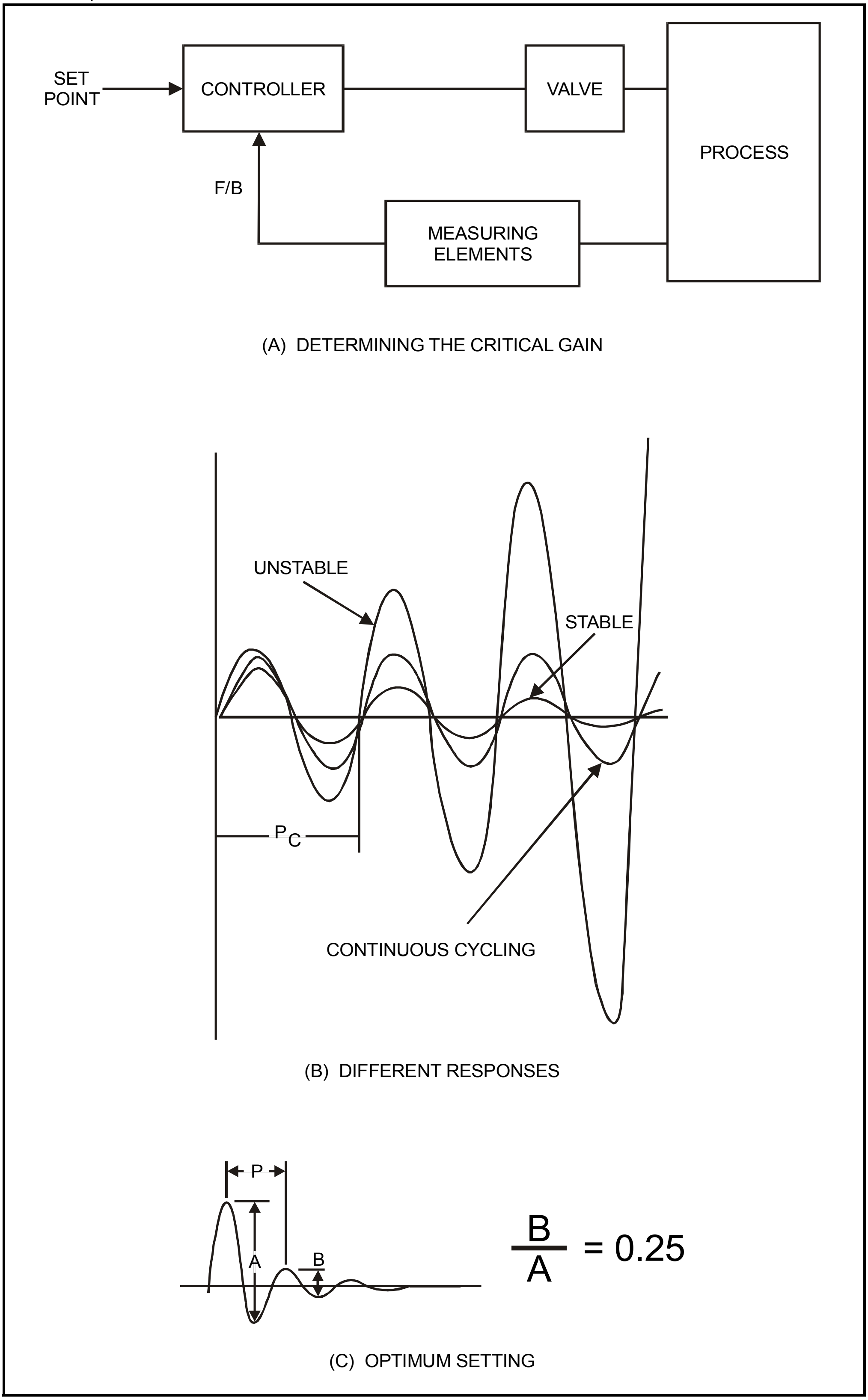


Figure 8-11
Closed-loop method.



Based-on-Experience Tuning

In the tuning method "based-on-experience", known values of P, I, and D are entered. This is a rough way of doing controller tuning, and it does not generally work from the first trial. To make it work, repeated "fine tuning" is required: tweaking the PID settings until acceptable settings are obtained through trial-and-error adjustments. Approximate typical settings for based-on-experience tuning are as follows:

Loop type	Gain (PB)	I (repeats/min)	D (time)
Flow	0.7 (150)	20	0
Level	1.7 (60)	0.2	0
Temperature	2(50)	0.5	2
Header/pressure	0.5 (200)	5	0
Tank pressure	2 (50)	0.5	0.5

CHAPTER 9

PROGRAMMABLE ELECTRONIC SYSTEMS

Overview

The majority of modern control systems today are programmable electronic systems (PESs). They are typically supplied with display systems, printers, and communication links. PESs include the following systems:

- direct digital control (DDC)
- distributed control systems (DCSs)
- programmable controllers (PLCs) and personal computers (PCs)
- microprocessor-based standalone PID controllers

Before the introduction of PESs, standalone indicators, controllers, recorders, annunciators, and the like were used for monitoring and control. Such standalone devices are still used for small applications, but for large applications they would be expensive and relatively difficult to modify. In addition, these standalone devices have limited features that are not acceptable in today's control requirements, take up a large amount of space in the control room, and have limit capacity for field-to-control room data exchange.

When implementing PESs, plant personnel should always keep the following key items in mind:

1. The simplest solution that meets the project requirements is generally the best approach.
2. The operator, who is really the end user, should be involved from the time the equipment is selected, through the design and implementation phases, and including graphics design and color selection. In addition, the operator must be well trained in how to use the system.
3. A successful implementation depends crucially on the quality of engineering and equipment.

Components

A PES is made of hardware and software. The hardware consists of input modules (accepting analog, discrete, or digital signals), control modules (which perform the logic), output modules (which send out analog, discrete, or digital signals), communication components, and operator interfaces (see figure 9-1).

- Input modules sense the process conditions and feed their own outputs to the control modules (see figure 9-2).
- Control modules form the computer portion of the PES and provide the data processing, logic, PID, and mathematical capabilities to meet the functional intent of the PES. The main components of the control modules are the processor and memory. The memory is classified as either volatile or non-volatile. Volatile memory will lose its content (the program) when power is lost unless it is supported by a battery backup.
- Output modules are the inverse of input modules. They translate the signals from the control modules into the process by generating signals that are fed to control valves, stepper motors, and so on (see figure 9-3). An electric fuse is typically provided on all output cir-

cuits for protection. Discrete outputs are available as a dry contact or as a solid state. In the off mode, solid-state devices will generate an off-state current that is also known as "leakage current." Plant personnel should assess whether this leakage current is acceptable for the circuits.

Figure 9-1
Simplified diagram of a PLC.

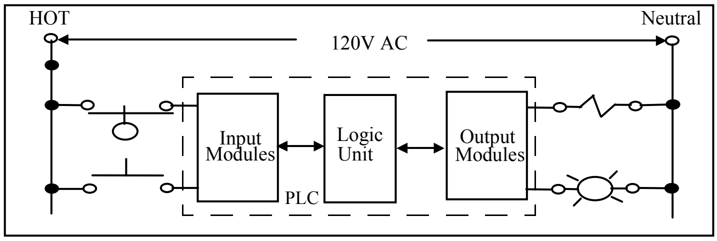
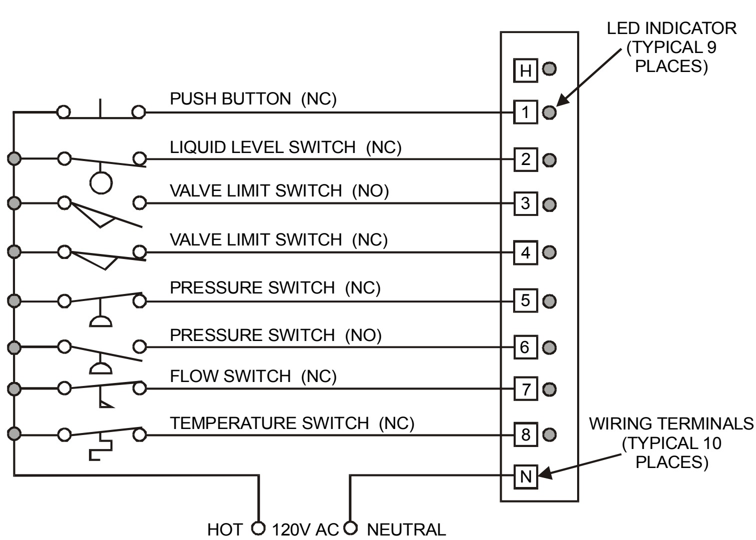


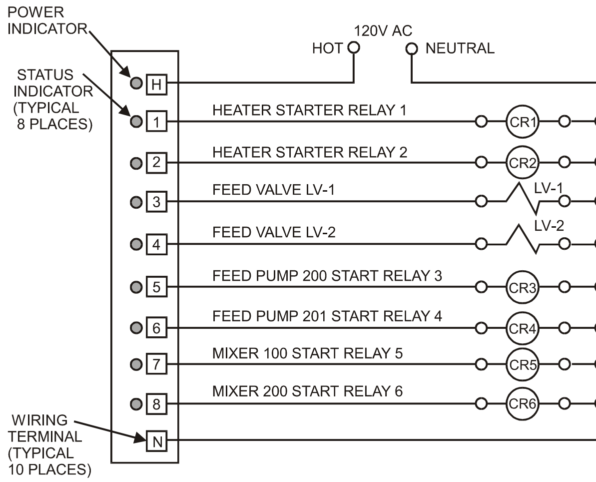
Figure 9-2
Typical discrete input module.



- Communication links the components of a PES. A communication port is required at each component, and data is transmitted from port to port according to a protocol. The link between ports is established through networks, of which there are many available types. For extra reliability, plants should consider communication redundancy (the two communication links should, where possible, be routed separately).
- The operator interfaces provide a window into the process so the operator can view the information inside the PES through various formats such as graphics, alarms, and historical trends. It is good practice to ensure that this interface is available at all times. Therefore, the plant should consider installing a minimum of two operator interfaces functioning in full redundancy, even for a simple control system.

The software of a PES consists of two main parts: operating software and application software. The operating software is fixed by the system vendor and cannot generally be accessed or changed by the user. The application software is implemented by the user to meet the project's requirements. Built-in capabilities, set by the system vendor and known as "firmware," may include input/output signal linearization, digitizing of analog signals, out-of-range signal detection, open input circuit, etc. These capabilities are available on most systems.

Figure 9-3
Typical discrete output module.



A PES is a relatively small and economical device that can handle very complex applications at high speed. When selecting a PES, the choice should be based on functional capabilities, such as the following:

- General capabilities of the processor unit and memory (including data processing speed).
- The variety of inputs/outputs and number of points per module.
- Networking and communication capabilities.
- Modularity and ease of expansion.
- Operator devices and peripherals.
- Reliability, failure options, and redundancy capabilities.
- Programming and configuration requirements.
- Ease of repair and diagnostic capabilities.
- Environmental conditions sustainable by the PES.
- Manufacturer's service network, control experience, and financial health.

The user should understand well the options available, since they determine whether the PES will meet the plant's future needs.

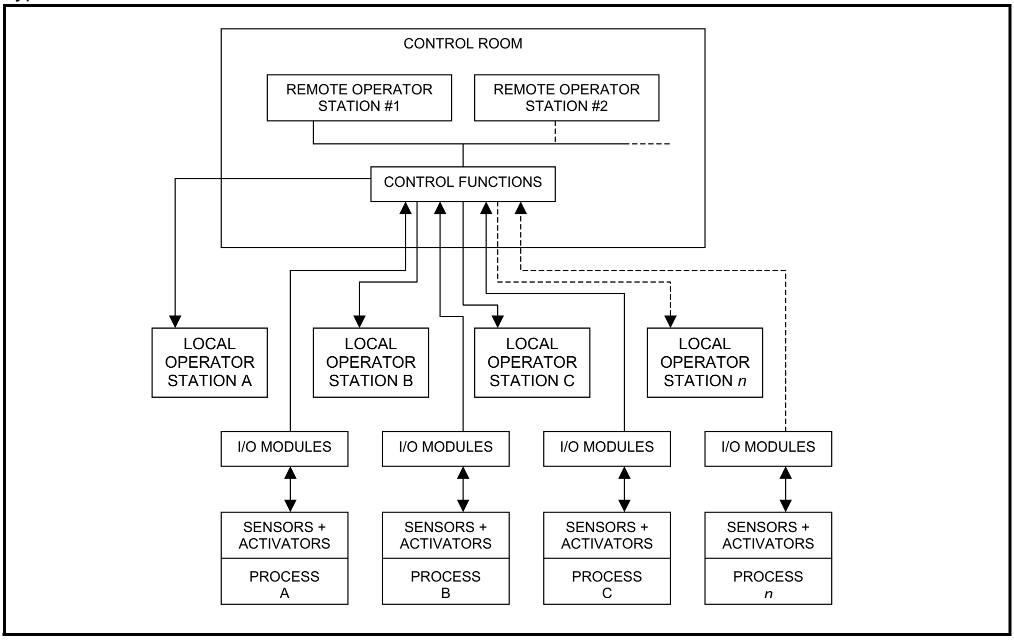
Centralized Control versus Distributed Control

Modern industrial controls can broadly be categorized into two types: centralized and distributed controls. The location of the system's processing power defines which of the two categories a control system belongs to. Quite often, a plant will implement a combination of the two types to meet its requirements.

Centralized Control

Centralized control, also known as direct digital control (DDC), was introduced in the early 1960s. These systems were relatively slow, had limited memory, required complex programming techniques, and were not very reliable. Centralized control consists of a mainframe, a minicomputer, or a microcomputer to which are connected remote or local I/Os. In this architecture, all control functions as well as the operator interface are centrally located (see figure 9-4). Modern centralized control provides the most powerful and most flexible control systems by providing plants with custom control strategies to closely meet their requirements. However, the centralized control architecture may require specialized computer personnel, resulting in high implementation and maintenance costs. It also requires a clean control room environment.

Figure 9-4
Typical centralized controls.



Improvements in PC reliability (both in terms of hardware and software) and the availability of off-the-shelf software have started a trend toward using PCs as the controlling platform, marking a return to centralized controls. Many industries are now switching to this new approach, while others are waiting to see if PC-based control systems are as reliable as the well-proven distributed controls.

Distributed Control

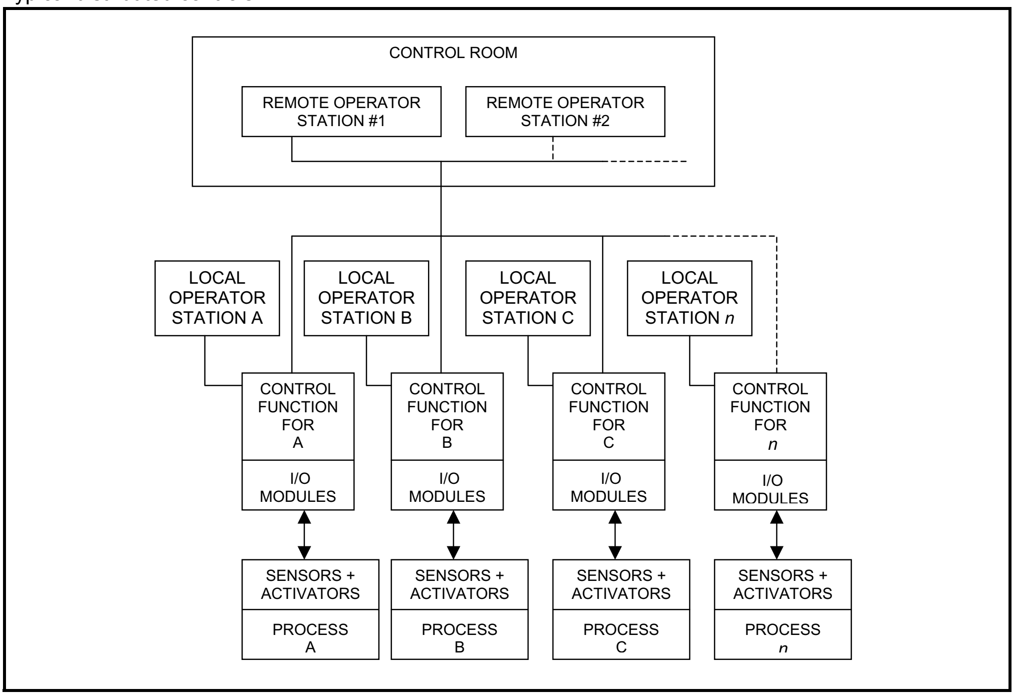
Distributed control remains a strong trend at the moment. This type of control was introduced in the mid-1970s to solve the problems of centralized controls. In this architecture, the control and input/output functions can be close to the process while the operator interface is located in a remote control room (see figure 9-5). The hardware can be concentrated in one area or have its components spread throughout the process areas. Typically, distributed controls are one of two types: Distributed Control Systems (DCSs) or Programmable Logic Controllers with Personal Computers (PLCs/PCs). Sometimes, both PLCs and DCSs are used together in the same plant control system. Computers and standalone PID controllers operating in tandem are also considered distributed controls when the PCs act as supervisors and standalone PID controllers control the process.

DCSs are relatively easy to implement. They can be configured simply without complex programming, and their configuration is well documented. (Configuration means completing vendor-developed pre-set tables, while programming involves writing lines of code.) However, the costs of DCSs are relatively high (compared to PLCs/PCs), DCSs require specialized support, and the simple configuration sometimes results in limited functionality. Moreover, DCSs typically require a reasonably clean control room environment, and the user is commonly tied up to a specific vendor.

PLCs/PCs are relatively low in cost, easy to maintain, and comparatively fast. They have a versatile line of I/Os and can be mastered by maintenance personnel in a relatively short time.

However, PLCs/PCs typically require separate suppliers for the hardware and software and may present difficulties when implementing advanced control strategies. Moreover, creating two databases (one in the PLC and one in the PC) leads to errors. When implementing PLC/PC systems, the plant must establish the line of functional demarcation between the PLCs and PCs from the beginning. Typically, PLCs are used for process control and data collection, whereas PCs are used for PLC programming, documentation, and operator interface. With this functional-split philosophy, if the PC or its link fails the process is still under control.

Figure 9-5
Typical distributed controls.



Control Room Instrumentation

Traditional control room instrumentation and control devices consist of controllers, relays, recorders, and annunciators in addition to the simple indicators, pushbuttons, and lights. Though this traditional instrumentation has now been replaced by computer-based systems, it is still in use in old control systems and in small applications.

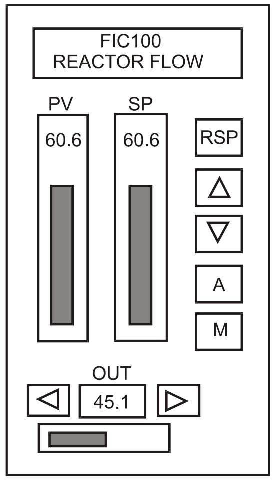
Controllers

Controllers evolved in the past fifty years from simple three-mode pneumatic controllers to powerful stand-alone units (see figure 9-6). The performance of the controller depends largely on the stability of the process, good-quality control equipment, and well-tuned control parameters (see the section "Controller Tuning" in chapter 8).

Controller indication generally takes the form of direct-reading scales that express output in engineering units for the process variable (PV) and the set point (SP). The controller's output (OUT) typically has a 0-100 percent scale. Level instruments normally indicate their PV and SP in a 0-100 percent range. The scale range is normally greater than the operating range. For example, if the process has an operating range of 0 to 70, then a 0-100 scale is required. Typically, the closest standard scale range is used.

Typically, the auto-to-manual (A/M) transfer function is available as a standard feature on electronic controllers. However, plants should tightly control the use of A/M transfer, and remaining in manual should be a temporary condition. When controllers are left in manual mode because “that’s the only way this loop will work,” the plant should recognize that a fix is needed either in the field devices or at the controller. In addition, all controllers that have remote set point (RSP) are equipped with a set-point transfer function that permits bumpless transfer between local and remote.

Figure 9-6
Typical electronic controller faceplate.



Typical standard controller capabilities include the following:

- Ability to manually drive the output signal when the controller is in the Manual mode.
- Communication to a PC should be within the capabilities of the selected controller, and the required communication software should be available as an off-the-shelf item.
- Built-in alarm annunciation is generally available in the form of front-mounted LED lights.
- Power to two-wire transmitters.
- Programming must be simple to understand and apply (however, training may be required).
- Configuration must be retained on power loss.
- The controller should be secure from tampering.

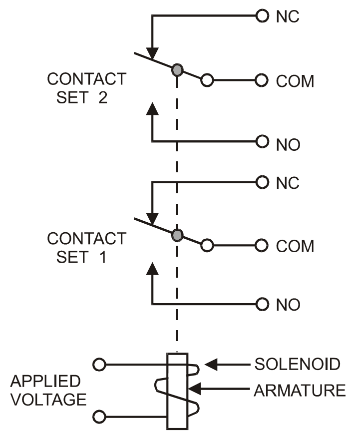
Relays

An electromechanical relay consists of an electrically operated solenoid in which a magnetic field is produced and mechanical contacts are used to make or break electrical circuits (see figure 9-7). When the coil is energized, the resulting magnetic force causes a mechanical movement that changes the status of the contacts. When the coil is deenergized, the contacts return to their “normal” status. This rapid movement occurs within 5 to 20 milliseconds after the coil is energized. Most relays used for industrial control systems are energized with either 120VAC or 24 VDC.

A contact that is open when it is deenergized (i.e., in its shelf condition) is called “normally open” (NO). If the contact is closed when its deenergized, it is called “normally closed” (NC). Where an NO and an NC contact are combined into one set of contacts with a common termination for power, it is referred to as a “form C contact.”

In spite of the widespread use of PESs, relays are still in demand for motor control circuits, for “permanent” simple logic circuits, and for critical trips. Relays provide adequate and reliable functionality for simple safety-instrumented system (SIS) logic. Emergency circuits that are used to stop the operation are typically routed outside the PES through relays. When well sized, the failure mode of relays is predictable, and hazard assessment is a lot simpler to accomplish.

Figure 9-7
Typical electrical relay with two sets of contacts.



With the proliferation of PLCs, the use of relays has dropped significantly. PLCs systems are preferable to relay systems because of their flexibility, reliability, and ease of implementation for complex logic and sequencing. Relays are a mature and simple-to-understand technology and are easy to troubleshoot. With a properly selected relay, the chance that the contacts will weld is remote. Relays have a “program” that is difficult to change (i.e., requires rewiring).

Relays have no memory integrity to worry about, and they will accept a wide range of operating temperature, moisture, corrosion, and vibration problems. In addition, relays are not sensitive to power problems, electrical noise (e.g., from walkie-talkies), poor grounding, or off-state leakage current on logic outputs. Also, relays have no program sequence problems (their logic is continuous and simultaneous), no need for additional protection such as master safety relays and watchdogs, and no need for specially trained personnel. However, relays are not suitable for complex logic, for analog measurements, and for applications that require diagnostics or reporting of the logic.

Relay contacts must be protected from excessive currents. Both the magnitude and the type of load must be considered. For example, a contact will not switch a 5 amp inductive load if it is only rated for a 5 amp resistive load, or if it is handling a device with an inrush current of 10 amp. Inductive loads require arc suppression because they create large instantaneous voltages (due to the building and the collapsing of magnetic fields). These arcs, if not suppressed, will harm the contacts. Arc suppression is typically required for DC circuits, whereas on AC circuits the arc is quenched when the alternating voltage passes through the zero point

Recorders

There are two main types of recorders: continuous trace (the conventional type) and digital (the microprocessor-based type). In continuous trace recorders, there should be a separate, non-clogging inking system for each pen, with sealed and replaceable ink cartridges. Preferably, the ink level in the cartridge should be visible when the door is open, and the ink cartridges should contain a four-month supply of ink. Also, cartridges should be fitted with means for starting the ink flow, and each pen circuit should be independent.

Digital recorders should typically display the point number that is being printed, and the descriptive data (date/time, scale range, messages) should be printed as the recorded value is being printed. These devices generally record points at a frequency of 6 sec./cycle or better and have self-diagnostics and math capabilities. Additional points plant personnel should consider are the need for averages or statistical functions, a connection between the recorder and a PC, and password protection.

For both recorder types, and depending on the process requirements, the chart scale should be linear, and the visible portion of the recorder should display at least eight hours of recording. Similarly, there should be enough paper for 32 days, and alarm switches should be independently adjustable, covering 100 percent of scale. When specifying recorders, consider the types of inputs the application requires (mA, mV, A, V, T/C, RTD, etc.) and the need for attenuation, linearization, computation, and so on.

Annunciators

Annunciators are generally used to call attention to abnormal process conditions through individual illuminated displays and audible devices. The standard definition of an annunciator is an enclosure in which lamps are located behind labeled translucent windows. Each window is labeled to correspond to a particular monitored variable or status. Colored lights are sometimes used to uniquely identify some of the alarms on the annunciator.

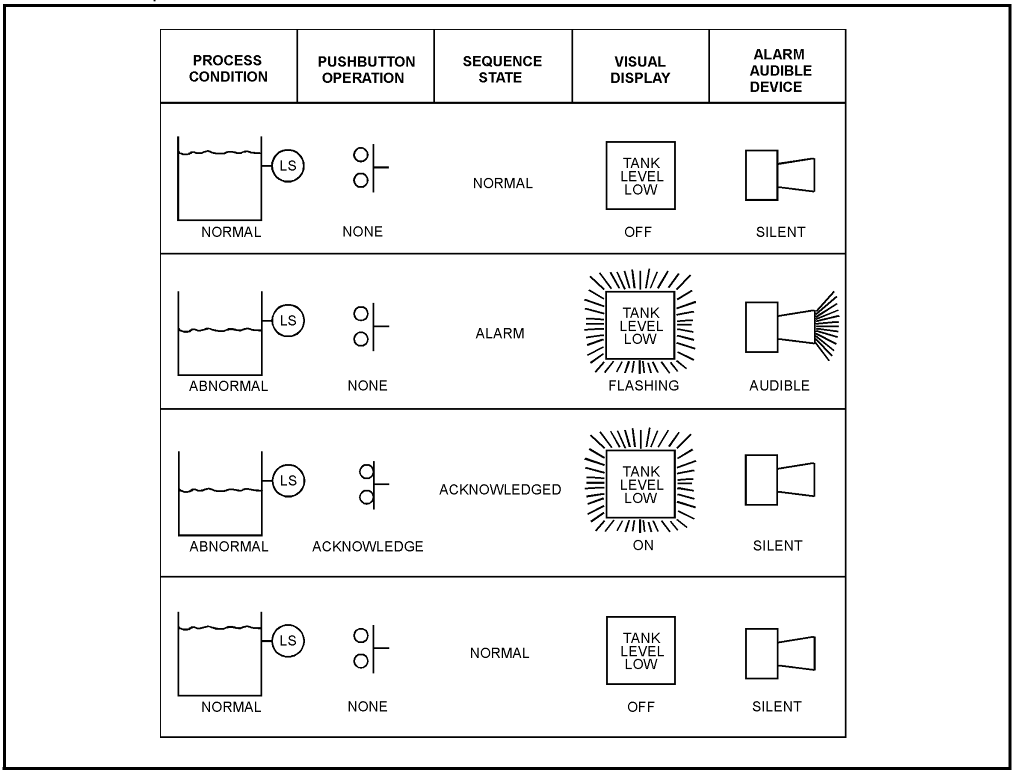
Annunciators come in a variety of physical arrangements, operating sequences, and special features. Plants typically implement annunciator sequences in accordance with the ANSI/ISA-18.1-1979 (R2004), Annunciator Sequences and Specifications standard.

Annunciators are typically operated from electric contacts that are usually part of a field-mounted sensing device. Two types of annunciator sequences are generally used, known as sequences A and M. The operation of each is different after process conditions return to normal.

Sequence A has an automatic reset (see figure 9-8). The sequence returns to the normal state automatically after the annunciated condition is acknowledged, when the process condition returns to normal. Sequence M has a manual reset. The sequence returns to the normal state after the annunciated condition is acknowledged, when the process condition returns to normal, and the reset push button is activated.

First-out annunciators are used to indicate which one of a group of alarm points is operated first. First-out sequences can be automatically reset or manually reset when alarms return to normal. Many methods for differentiating between first and subsequent alarms are used. Typically, when later alarms are activated, their visual displays do not flash, and their audible devices do not operate. The first-out indication is reset by pressing the Acknowledge button.

Figure 9-8
Annunciator sequence A, with automatic reset.



Programming Languages

The International Electrotechnical Commission (IEC) is a sister organization of the International Standards Organization (ISO) based in Geneva, Switzerland. It has produced a standard that describes the five programming languages plants should use for industrial control systems. The purpose of such a standard is

- to provide a consistent method for programming
- to develop languages to encourage the development of quality software for solving different types of control problems
- to meet the needs of different applications and industries

IEC standard 61131 provides three graphical languages (functional block diagram, ladder diagram, and sequential function chart) and two textual languages (structured text and instruction list). These languages are vendor independent and portable, and can run on PESs from different vendors.

Functional Block Diagram

The functional block diagram depicts signal and data flow by using function blocks. A function block consists of a rectangle whose inputs enter from the left and whose outputs exit from the right, as on an electronic circuit diagram. The outputs of a block may be inputs to another block, with the signals going from left to right (however, some signals are fed back). The functional block diagram employs reusable software elements, describes the program as a set of interconnected graphical blocks, and is typically used where the program involves the flow of signals between blocks (see figures 9-9 and 9-10). The functional block diagram can be used within the ladder logic or the sequential function charts and typically includes the following common blocks:

- PID controller, on-off controller, ramp generator, totalizer
- Equal, greater than or equal, less than or equal, greater than, less than
- And, or, xor, not, latching relay, on delay, off delay, up counter, down counter
- Math functions (add, subtract, multiply, divide, square root, average)

Figure 9-9
Function blocks.

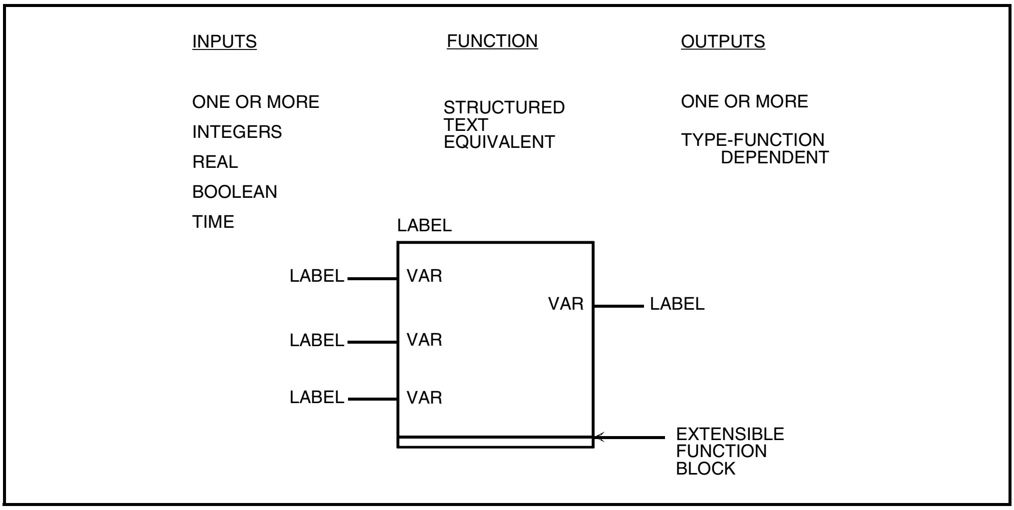
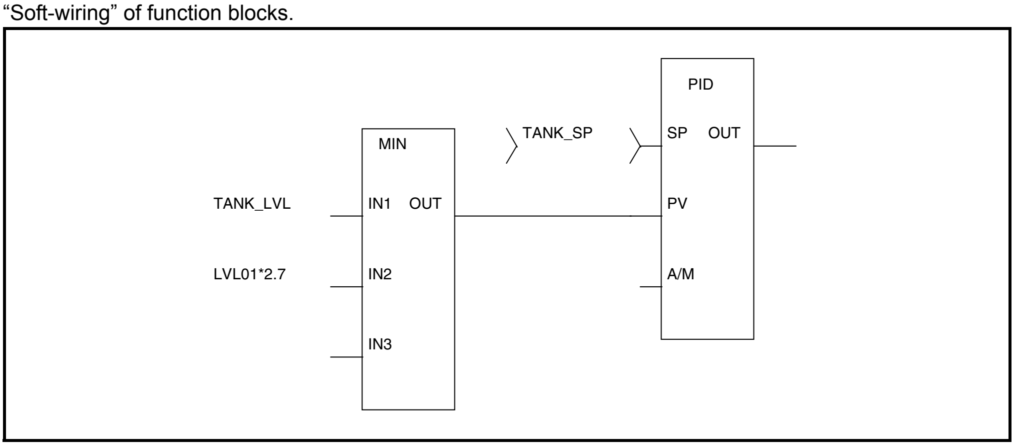


Figure 9-10
"Soft-wiring" of function blocks.



Ladder Diagram

Ladder programming evolved from the electrical wiring diagrams used to describe relay logic. It has a left-hand power rail that supplies "power" through software contacts along the horizontal rungs. Elements of the ladder logic provide connections between the power rails to software coils (see figure 9-11). The contacts represent the state of a Boolean variable. When all contacts in a rung are true, power will flow and operate a coil located on the right of the rung.

This programming language is typically used for logic involving AND, OR, and TIMER functions. Its graphical representation is easy to understand, can be learned relatively quickly, and is well accepted by maintenance personnel because it's similar to electrical wiring diagrams (see figure 9-12). Ladder programming clearly identifies the live state of contacts in the program while it's running and therefore provides powerful online diagnostics. However, using this programming language makes it harder to break a complex program down (especially if a large program is written by different programmers) or to implement complex math. The typical ladder functions are as follows: contacts normally open (NO), contacts normally closed (NC), coils (retentive or non-retentive), and timers.

Figure 9-11
Ladder logic diagram.

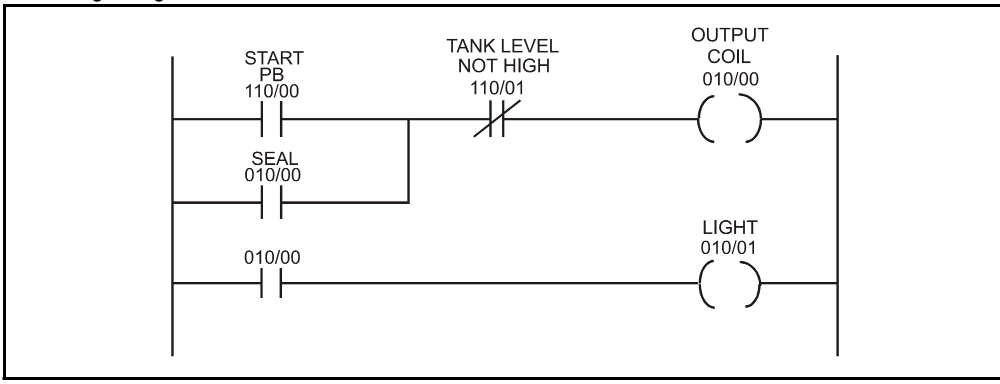
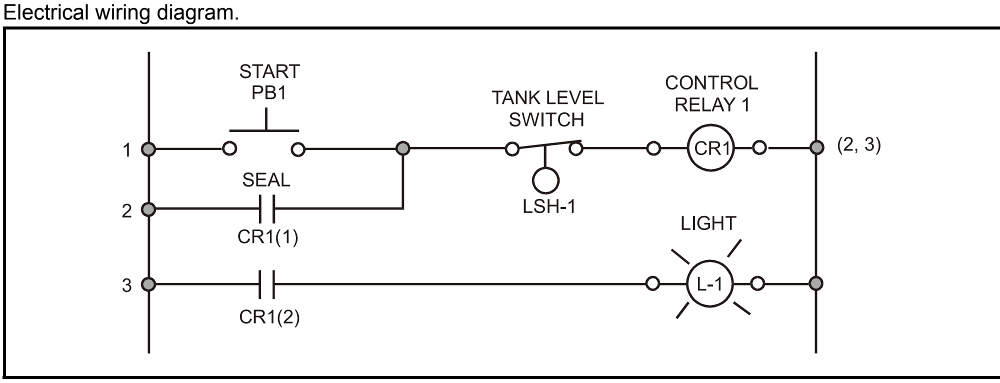


Figure 9-12
Electrical wiring diagram.



Sequential Function Chart

The sequential function chart depicts the sequential behavior of logic (for time- and event-driven sequences) and shows the main states of a program (see figure 9-13). It is used to represent a program's internal organization rather than being a true programming language. The sequential function chart is represented as a series of steps symbolized as rectangular boxes that are connected by vertical lines. Each step is a state of the system under control (with the initial step "Start"), each step is associated with one or more actions (each action has a unique name), and each connecting line has a horizontal bar that represents a transition (see figure 9-14).

The flow of control is typically from top to bottom, with branches that are used for the flow to go back up. The sequential function chart can be used to partition a program; that is, each phase can be considered/executed separately.

Structured Text

Structured text resembles the Pascal programming language (see figures 9-15 and 9-16). It was specifically developed for industrial control. Structured text is very useful for stating equations. It can be written with meaningful identifiers/comments and is useful for complex mathematical calculations. However, in structured text there are limitations on the length of expressions, statements, and comments.

Figure 9-13
Sequential function chart.

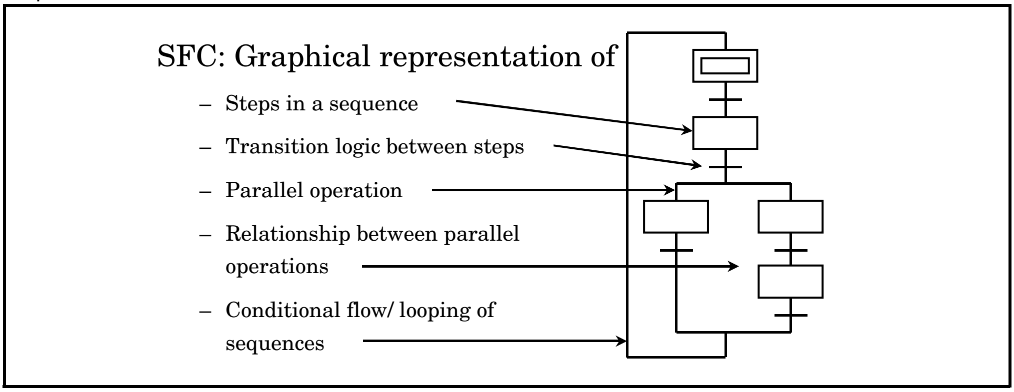


Figure 9-14
Example of a sequential function chart.

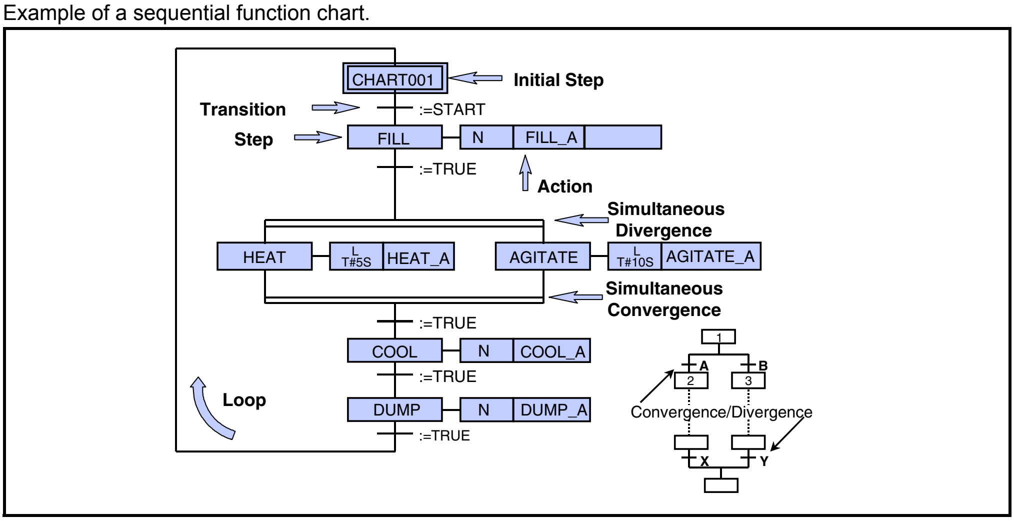


Figure 9-15
Structured text

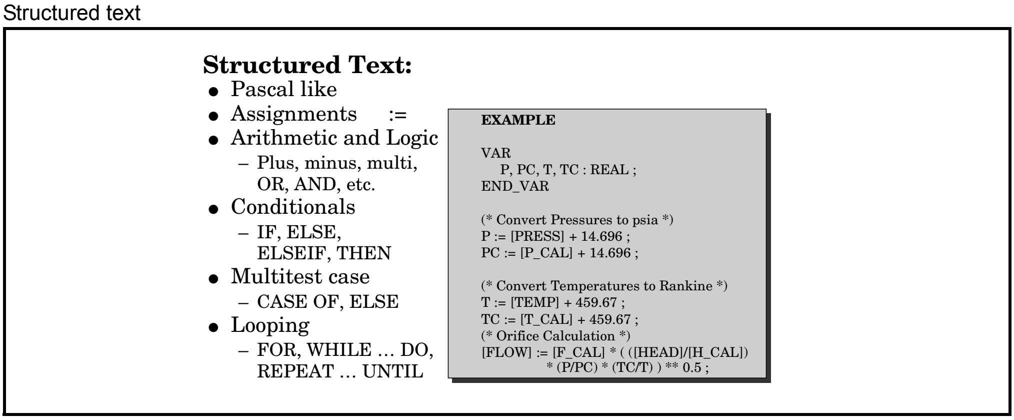


Figure 9-16
Structured text compared to the same expression in ladder logic

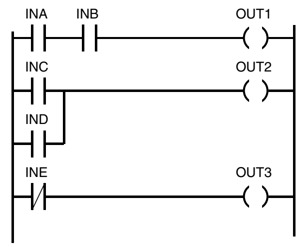
Ladder Logic simulates hard-wired relay logic

– Power rails on either side
– Contacts are inputs to logic
– Coils are outputs
– Rungs carry power (Boolean data)
– Branching and looping are provided by labels

OUT1 = INA AND INE

OUT2 = INC OR IND

OUT3 = NOT INE



Instruction List

The Instruction List is an assembly-like language and is not commonly used in the process industries.

Fieldbus

Fieldbus is a digital link that is starting to replace the conventional 4-20mA standard signal so familiar to industry. It connects several field devices in a multidrop network enabling these devices to share information (see figures 9-17, 9-18, and 9-19). Such a system offers tremendous economical benefits as well as operational advantages. Some large facilities have started implementing Fieldbus, and sooner or later every user will be facing the decision whether "to be or not to be Fieldbus." A control room operator familiar with DCSs or PC/PLC-based controls should have little difficulty migrating to Fieldbus systems.

Figure 9-17
Simple network with only one single element.

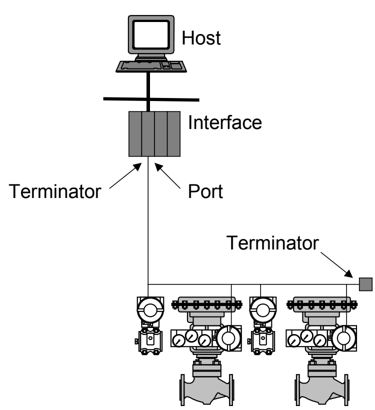


Figure 9-18
Network with multiple series segments used for long distance.

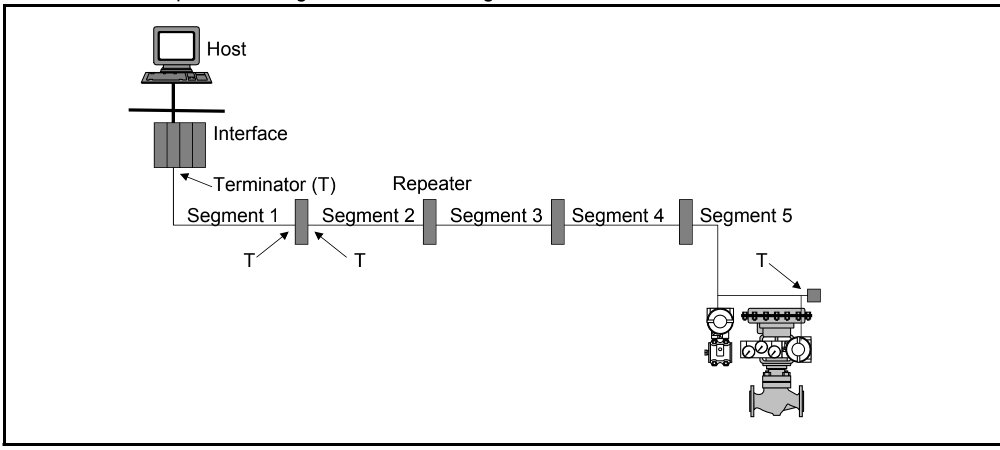
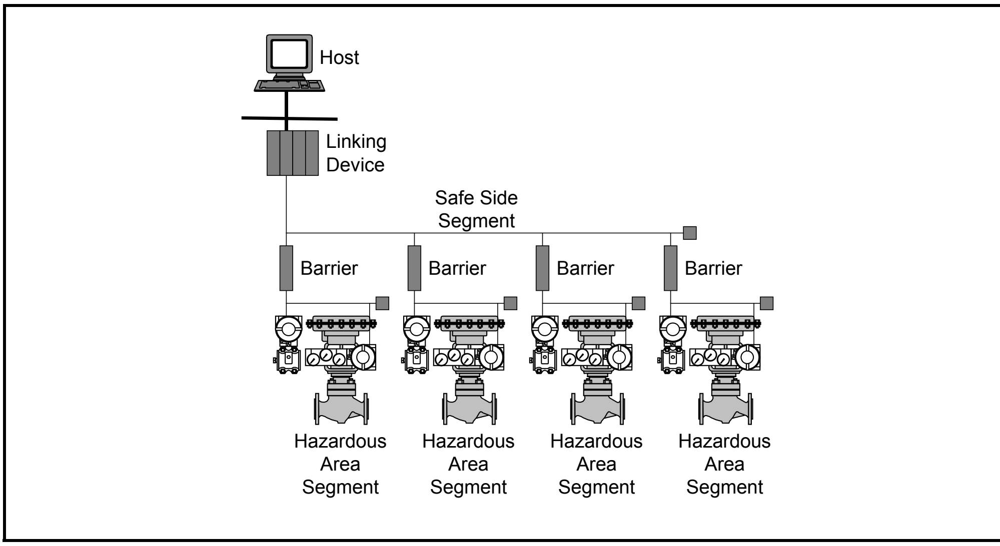


Figure 9-19
Several hazardous-area segments connect to a safe-side segment using repeating barriers forming a single network.



For the process industries there are three major Fieldbus systems on the market. They are Foundation Fieldbus (standardized by the ISA), Hart (which has been around for a while and is almost a true Fieldbus), and Profibus (a mainly European bus). The first two are the most common in North America, and each of the three has its pros and cons. This handbook will describe the first one only. Be very careful when you pick a Fieldbus system. You'll be stuck with it for a long time, so make sure it's the best one for your application. Additional information on the Fieldbus is available from the ISA-50.02 standards.

Fieldbus implementation has many benefits.

- Wiring (and labor) cost savings are greater than in conventional 4-20mA installation since Fieldbus does not require one-to-one wiring.
- Controlling can be done at the field device, which reduces the load on the “central” control system (i.e., faster control with smaller systems). This is a unique capability of Foundation Fieldbus.
- Non-proprietary programming means that once you learn it you've learned it for all systems.

- Fieldbus technologies work on the same type of wires as conventional instrumentation, which makes it easy to migrate from existing conventional systems to Fieldbus.
- Fieldbus offers very powerful diagnostics for field devices, which saves troubleshooting time and reduces commissioning and startup costs.
- Digital communication provides very high accuracies no longer limited by the 4-20 mA range. This applies to monitoring and controlling (see “Inputs and Outputs” in the following section “System Specification,” in this chapter).
- The control room can “write” to field devices, adjusting and changing calibration remotely (a function that can be write-protected).
- Individual field devices can measure and transmit more then one process variable. The savings from such multi-variable transmitters can be substantial.

Fieldbus implementation has also some drawbacks.

- If a network communication wire fails (a rare occurrence), the entire network fails. This takes down communication to many sensors and valves, and leaves the control room operator in total darkness. However, powerful diagnostics will immediately point to the failure. To avoid this, plants should consider redundancy for important loops.
- We're at present in a “transient mode,” where some field devices are Fieldbus compatible and some are not. Plants should allow for this in developing their estimate, design, procurement, and installation plan.
- Currently, Fieldbus field devices are about 25 percent more expensive then conventional devices. With time, however, it is expected that this cost difference will disappear and then reverse. Eventually, 4-20 mA field devices may become more expensive as they become less available, while Fieldbus types become the norm. It will take another few years before all devices and systems are Fieldbus compatible (and the control industry is moving quite fast on this). Meanwhile, we'll have hybrid systems that will accept both Fieldbus and the conventional 4-20 mA signal. At present, a Fieldbus installation is only slightly lower in total cost then a conventional installation. This cost includes hardware, engineering, installation, commissioning, and startup. This small gap will widen as more and more vendors switch to Fieldbus, making it much more economical to implement (in addition to its other advantages).

A note of caution here: When plants implement emergency shutdown systems, they need to be very careful when using digital systems instead of one-to-one wiring (see chapter 10). Personnel need to consider the code requirements, the system failure mode, the effects of common mode failure, and the final costs. Remember, safety comes first.

System Specification

A PES specification defines the key features of a potential control system and acts as a reference as the plant searches for the best PES for a particular application. Such a specification is a prerequisite for successful PES implementation; it should always precede the system-selection process. A specification covers many facets of a PES. The document content and size will vary with the application and its complexity. The following sections describe the typical components of a system specification.

Purpose and Overview

The PES specification should select the control philosophy, that is, centralized or distributed control, and define the line of demarcation between the different major components (e.g., PC for interface only and PLC for controls only). It should also define the interface with other control systems and/or instrumentation (existing and/or new) as well as the need for hardware and software to implement communication between devices from different suppliers. The specification should assess the number of operators, their location, computer skills (familiarity/interest), range of authority and responsibility, and their authorized access to control and/or trip system settings. Finally, the specification should forecast expected future expansion and needs.

Architecture

In terms of architecture, the PES specification should define the distribution of functions (controllers, operator interfaces, input and output modules, etc.), the number of nodes, and the distance between them. A system layout drawing showing all components and distances would be helpful in describing these requirements. The specification should also assess the redundancy requirements for communication, power, I/Os, processors, and so on. It should select the cabinets (type and rating) for all components in conformance with the vendor's requirements and assess the need for forced ventilation or HVAC for all cabinets.

Similarly, the specification should define the number and locations of terminals and printers (i.e., operator interface requirements), determine if maintenance should be done on line (while the control system is operational), and determine if this requirement applies to all inputs, outputs, operator interfaces, and so on.

The specification should also identify the control room’s location, space, environment, and whether an uninterruptible power supply (UPS) is needed. It should define the types of memory needed to store all programs and process information (i.e, disk drives, etc.). A PES is typically supplied with 100 percent spare memory capacity to handle future system requirements. In terms of security and access, the specification should assess the need for password protection to prevent unauthorized access.

Environmental Considerations

For environmental considerations, the specification should define the temperature, humidity, corrosion, vibration, dust, and area classification under which the components of the control system will operate. The ambient temperature range where a PES will be located should not exceed the vendor's recommendations. On high temperatures, solid-state devices will rapidly fail, while on very low temperatures these devices will cease to function. Solid-state devices should be allowed to stabilize to within the vendor's recommended temperature range, before these circuits are energized.

The specification should assess the potential of static electricity and electrical noise and the need for grounding and lightning arrestors. Electrical noise includes electro-magnetic interference (EMI) and radio frequency interference (RFI). Solid-state devices are susceptible to such noises. Electrical noise typically produces momentary energy in the signal wires and other undesirable effects in the PES circuits. It should be avoided by carefully following the vendor's recommended installation guidelines.

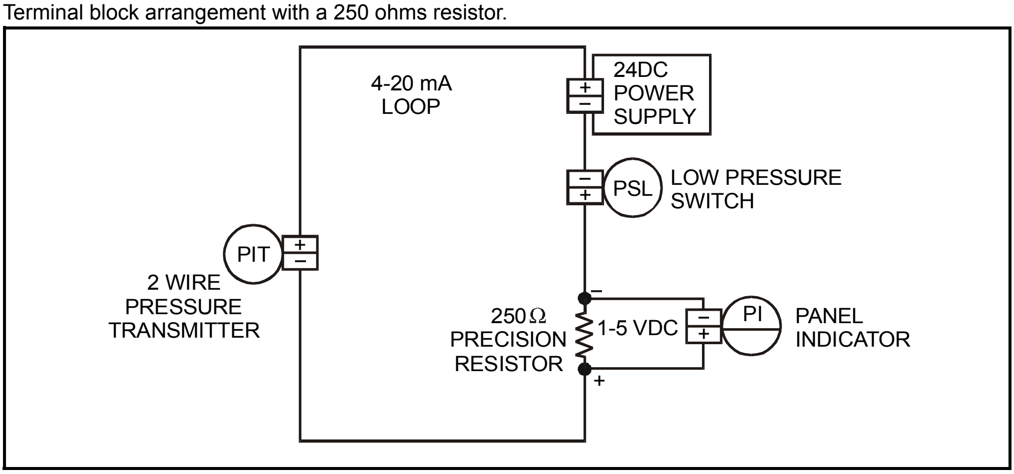
Inputs and Outputs

First, for analog signals, the specification should determine their distribution, types, need for current loop resistors, signal resolution (8 or 12 bits), and quantity (typically, 30 percent spare capacity is required to handle future system modifications).

Current loop resistors convert one type of analog signal into another. A conventional analog signal has a 4-20 mA range. However, some devices will only accept a voltage signal (typically, a 1 to 5 VDC). Signal conversion using a current loop resistor is required between the mA and VDC signals. Current loop resistors, sometimes called dropping resistors (see figure 9-20), are commonly installed directly on terminal blocks. According to Ohm’s law, R = V/I = 1-5 VDC / 4-20 mA = 4/0.016 = 250 ohms. Therefore, a 250 ohms resistor will convert a 4-20 mA signal into a 1-5 VDC signal. Using 4-20 mA loops offers two advantages over the use of voltage signals: a current loop is more immune to electrical noise than a voltage signal, and on two-wire transmitters only two wires are required to transmit the signal and carry the power source, saving on installation costs.

The higher the resolution of an analog signal, the more accurate a signal will be after it is converted into a digital value inside the PES. However, this means more expensive hardware. For example, an 8-bit digital resolution for a 4-20 mA analog signal means that the range is divided into $2^8 = 256$ steps for a 16 mA range (4-20 mA). The 4mA signal would correspond to step 0 and the 20 mA to step 255. Each 0.0625 mA (16/256) change in the analog signal would add or delete 1 from the digital range of 256 steps.

Figure 9-20
Terminal block arrangement with a 250 ohms resistor.



The specification should define analog input signals as single-ended or differential inputs. Differential inputs are more expensive than single-ended inputs, but they will tolerate differences in ground potential and are therefore used for low-level signals.

Second, for discrete inputs, the specification should determine their distribution and types, the need for high-speed inputs (pulses) or bar code readers, and the quantity if inputs (typically, 20 to 30 percent spare capacity is required to handle future system modifications).

Third, for discrete outputs, the specification should determine their distribution and types, any requirements for surge suppression, the need for outputs to bar code printers, and quantity of outputs (here again, 20 to 30 percent spare capacity is required to handle future system modifications).

Inductive equipment such as solenoid valves and relays generate a high-voltage transient when they change their mode from ON to OFF by switching hardwired contacts. This high insurgence of power drastically shortens the life of the switching contacts, damages the coil, and may generate interference with other nearby circuits. Voltage suppression diodes (also known as surge suppressors) are used in such a circuit to limit the effect of such transients. They are located in parallel with the wires to eliminate the surge. When the flow of current is interrupted, the diode conducts, providing a path for the current to decay to zero without generating a voltage surge. The correct suppressor must be properly selected since excessive suppression may cause a delayed release time. Surge suppressors are located typically at the inductive load. If they are located at the switching device, they may be less effective because the wires between the switching device and the load may act as antennas, emanating EMI. Inductive loads switched by solid-state outputs alone do not require surge suppression.

Control Functions

In terms of control functions, the specification should define the approximate number of PID functions and determine the required math and logic capability or any other special functions such as ramping and tracking.

The specification should also state the required sampling and execution time and list the critical loops. It should also define the implementation philosophy for such loops, that is, hardwired or PESs with "hot backup" or "triple redundancy fault tolerant" (see chapter 10 on alarm and trip systems). Finally, the specification should determine if controller redundancy is required.

Communication

For communication, the specification should determine if online communication maintenance is required and the acceptable update speed, define the link to other networks, and determine if communication redundancy is required.

Interface Functions

With respect to interface functions, the specification must determine the expected number of graphics and alarms (that is, identify priority levels, audible location, historical storage of info, etc.). It should also determine the trends and reports (that is, identify quantity, on-request or automatic printing, ability to include manual data in report, etc.). Refer to section "Operator Interface" later in this chapter for more on this.

The specification should determine if the operator interface unit needs to perform complex calculations or statistical process control (SPC). It should define the acceptable system update time and state if similar functionality will be available on all CRTs (i.e., provide full redundancy). Finally, the specification should determine all hardware requirements such as the enclosure rating (see chapter 12), mounting (desk or console-mounted), arrangement in control room, need for touch screen or membrane keyboards, requirements for a separate hardwired annunciator to handle critical alarms, monitor size, and the need for paper chart recorders (typically required for recording time increments of less than 1 sec).

Electrical Power

In terms of electrical power, the specification should identify an available quality and source and assess the effect of power failure on hardware, software, data retention, and data recovery. Also it should assess the effect of suddenly re-established power (i.e., auto start, operator reset command, uncontrolled action, etc.). It should then decide if a UPS is required and, if so, which type of UPS (e.g., online UPS). Both direct current (DC) and alternating current (AC) are encountered in process measurement and control (see figures 9-21 and 9-22).

Figure 9-21
Steady DC voltage.

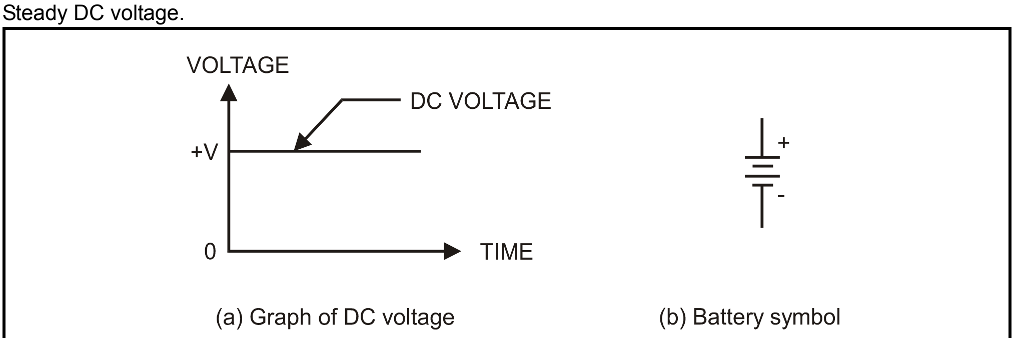
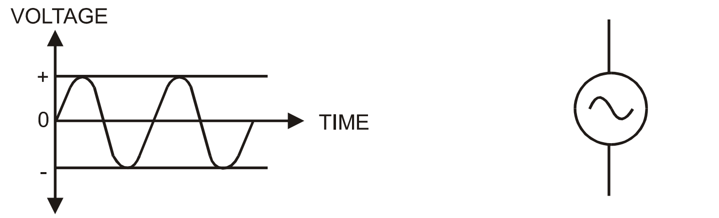


Figure 9-22
Sine-wave AC voltage.



(a) Graph of AC voltage

(b) Symbol for AC source

Manpower Requirements

For manpower, the specification should determine the requirements for engineering, operation, and maintenance, and identify a training program.

Startup/Shutdown Requirements

Regarding startup and shutdown, the specifications should define if these are manual activities or automatic functions performed by the control system, and therefore whether there is a need for feedback status for the sequenced startup and shutdown.

Shutdown Philosophy

The specification must define the shutdown philosophy and whether there is a need for separate push buttons, hardwired relays, or a separate PES for shutdown activities. It should assess the interaction with non-process alarms and systems (e.g., fire, gas emissions, lab results) and define the emergency shutdown requirements (manual and automatic) and their implications.

Motor Start/Stop

The specification should define a motor start/stop philosophy so as to maintain conformity among the various motors to minimize operator error. It should define the functionality of all controls (at the motor, at the motor control center [MCC], and in the control room) as well as their interaction and their priorities.

Operator Interface

The operators are the end users of a control system. Therefore, their needs should be met for all displays and controls. The implementation of an operator interface at a plant should be done in conjunction with the operators. If an operator is confused about the interface, the best PES in the world will not help. Under stress conditions, the operator must be capable of handling all the displayed information. It is important therefore that the operator be involved in developing the display and layout, including selecting colors. An operator interface provides a limited amount of available information at any one time, so the user must assess the distribution of information and its relevance as well as the number of monitors and their functionality. The typical monitor-based interface functions are graphics, alarms, trends, and reports. They are discussed in the following sections.

The performance of an operator interface can be gauged by its ability to quickly display large amounts of graphical and text information (i.e., call-up time and display refresh time) and at the same time providing this information clearly (i.e., screen resolution). When implementing an operator interface, the system designer should always assess the amount of data that an operator can monitor and the number of loops that he or she can control within a certain display.

The system designer needs to define, at the beginning of a project, the levels of data access and manipulation. Typically this information is available from the Control Scope Definition (see chapter 14). There are generally four main levels of data access and manipulation.

1. Monitoring, where information can be viewed but not modified
2. Operating, where the operator can modify set points, operating modes, outputs to process, and start/stop sequences
3. Tuning, where the setting of PID loops can be modified
4. Programming, where software changes to the control system are made (applies to both off-line and on-line programming)

The most common navigation tool is the keyboard. Some keyboards are sealed with a membrane and are commonly used on plant floors. In addition to keyboards, other system access devices commonly used to help the operator's eyes focus on the displayed data include touch screen and mouse (or similar device such as trackball). In comparison to a touch screen, a mouse (or trackball) requires smaller screen targets, does not experience parallax, and requires a more positive action. However, the ball picks up dirt more easily and requires more time from the operator to position the cursor correctly. Touch screens are easier to use and come more naturally to an operator. However, they require larger targets and fingers may smudge the screen and, after prolonged use, may damage some touch screen types.

When using a touch screen, the operator must know when the correct target has been reached—this is commonly done through reverse video. Another item to consider is target activation—i.e., should the target be activated when the operator's finger touches the screen or when the finger is removed. The second option allows the operator to correct his or her action. When designing touch screens, the designer should locate common targets where the operator expects them to be on the screen (such as for Alarm Acknowledge and Alarm Reset). In addition, the designer should allow sufficient space around each target, label each target with its tag number and/or function, and provide visible and/or auditory feedback when a target is activated.

ISA has developed a standard to indicate the requirements for symbolically representing the functions of distributed control or shared display systems (ISA-5.3-1983, Graphic Symbols for Distributed Control/Shared Display Instrumentation, Logic and Computer Systems). It is applicable to all industries that use process control and computer systems.

Graphics

Graphics display a pictorial view of the process. They should be easy to configure (i.e., do not require programming), should have a menu-driven construction, and should be easy to change. Password protection may be required on some graphics (e.g., PID tuning parameters and trip settings). When generating graphics, the system should display only what is needed.

Often, graphics are implemented so as to replace control panels. In such applications, the implementation requires that all panel functions be shown in the new system—that includes

- indicators, controllers, hand switches, lights, and mimic display (shown in the graphics),
- recorders (shown through the trending and reporting packages), and
- annunciators (shown through the alarm management package).

When implementing graphics, the designer should keep in mind that "information" is needed by the operator—not just data. When building graphics, the designer should present only the required information and avoid clutter. Congested displays are very hard to read and a rule of thumb is to leave at least a third of the display blank.

The mind of a human being translates incoming information in an analog way since most of the parameters encountered in daily life are analog—and not digital. Therefore, when showing the level in a tank, a bar graph (i.e., analog display) is more informative than, and as important as, the actual value of the level (i.e., digital value).

Analog values should be displayed in engineering units beside bar graphs, and the display terminology should be the same throughout. Error messages should be clear (e.g., not "entry error," but "entry error: allowable range is between 40 to 70%"). In addition, colors will not improve a badly formatted screen. If possible, start with a black-and-white screen, generate a legible layout, and then proceed with colors. Color blindness should be considered, that is, do not rely on color alone to indicate status or functions—add labels, change shapes, and so on.

Color provides more information in less space and helps improve visualization—for example by reducing the response time by drawing the operator's attention to a specific area. When using colors, the system designer should ensure that the meaning of colors is consistent throughout the facility, that large background areas have a neutral color (black or gray), and that no more than seven to ten colors are used.

If text is to be shown, it is generally limited to labels or brief messages. Text color should have a contrasting background to facilitate reading, i.e., dark text should have a light background and vice versa. Blinking messages are hard to read—blinking the background is a better option.

The system designer should label all the equipment with their corresponding tag numbers and mimic flow lines to show process flow.

Using the proper sequence in graphic displays facilitates the operator's reactions to process events. Typically, the first graphic is an index of all the graphics in the system, the second is an overview of the whole plant, the following graphics are more detailed, and so on. In some cases, a control loop overview is added. This graphic would group a large number (100 to 200) of important control functions showing only deviations from set point. It is recommended that one or more graphics be used to indicate PES health status. Such graphics take their information from various parts of the control system and its components.

When critical action keys are embedded in the graphics, they should always be in the same location, regardless of the displayed graphic. This minimizes the chance of operator error.

Alarms

Alarms display the process malfunctions. They should be date- and time-stamped when they occur (printing every alarm on occurrence), when they are acknowledged, and when they go back to normal. The last two (or sometimes more) unacknowledged alarms should be displayed at the bottom of any graphic display. Graphics and alarms should be integrated functionally, that is, graphic symbols are subject to standard alarm sequencing through the changing of color and/or shape.

Alarm occurrence, operator acknowledgement of the alarm condition, and the return to normal status should be reported to the screen (i.e., to the operator). The operator should be able to monitor the latest alarm activities from any screen he or she is looking at, and when an alarm occurs, the operator should be made aware of it immediately. As a result of an alarm condition, the operator should be able to switch the screen displays directly to the appropriate location to take corrective action. The switching should be made with a minimum number of key strokes or mouse clicks.

In some cases, alarms are triggered, not just on reaching a set point, but also when the rate of change of a process variable is exceeding an expected rate of change, even though the set point has not been reached yet. This allows the operator to take a corrective action before the actual alarm set point is reached.

At least three alarm priorities should be selectable for all alarm points. For example, red (or 1) should be for high priority, yellow (or 2) for medium, and white (or 3) for low priorities. On system startup, priorities 2 and 3 would be disabled to limit the display of abnormal conditions and to allow the operator to concentrate on the activities at hand. When startup is completed, all priorities can be reactivated. In addition, alarms should be grouped in "areas." This allows all alarms in an area to be isolated if this area is shut down, thus again avoiding an unnecessary flood of useless alarms into the control room. When this area is back in service, its alarms are reactivated.

Trends

Online trending displays the historical data. It should be available as part of the graphic display, and historical data should be accessible from disk and displayed with selectable time spans.

A high-end trending package has the capability of

- displaying either a single trend or multiple trends on one full screen view,
- embedding trends into graphics,
- placing analog and discrete values on the same display,
- displaying any value (e.g., variable inputs, set points, output values, discrete on/off statuses),
- changing the trend's color when it goes into alarm,
- using different colors to display different trended points,
- sampling points at small time intervals (this is dependent on the controller's scan time),
- changing the measured span and time span of individual points or of a whole group,
- zooming, through a cursor, to the lowest time increment (i.e., the sampling time), and
- storing large amounts of historical data for future retrieval (this is dependent on the system's memory and sometimes removable media is required for archiving large amounts of data).

When implementing trends and after deciding which points will be trended, the system designer should ensure that trend layouts, labeling, and color use are consistent throughout the system.

Reports

Reports may be triggered by events or by time and incorporate online (incoming) data or historical data (from disk). Reports should be simple to create.

Special Design Considerations

When implementing PESs, in addition to selecting the best system for the job, users must assess many other issues such as safety and system failure, software, and environmental conditions.

Safety and System Failure

Safety is a moral and legal issue. It is the system designer's responsibility to ensure that control systems are applied safely. Therefore, potentially hazardous conditions require reliable emergency circuits that are designed for such applications. It is difficult to anticipate the failure mode of a PES because of the nature of its components. Using a master safety relay and/or external watchdog may improve the PES's safety.

The master safety relay ensures instant control over the system's outputs. When deenergized, the relay cuts the power supply to the output modules with no effect on the remaining components. That is, the monitoring of process conditions remains in operation. Typically, the relay is deenergized by a resetable shutdown function (e.g., push/pull emergency shutdown pushbutton).

The external watchdog consists of a check function in the program that operates with an external timing function. The check function is a software exercise in which statuses are changing with each scan to ensure that the PES memory is not stuck in a logic state. The outside timer is adjusted to a time that corresponds to three or four scans of the program. If within these scans the timer does not reset, a set of contacts will open, deenergizing the master safety relay. Major PES vendors have a "standard design" for implementing external watchdogs.

In a PES, the inputs and outputs are the most vulnerable to damage because they are exposed to external influences. Typically, the failure mode of input modules cannot be ensured since they are solid-state devices. The designer may need to check if the failure of an input circuit causes a false input into the control system and therefore results in various outputs responding accordingly. Outputs, which are also normally solid-state devices, tend to fail shorted, which causes the external load to be continuously energized. Typically, the failure mode of loads (such as control valves) that are connected to the output of the control system should be fail-safe in the deenergized position. That is, on loss of signal or power, a valve would go to a position that is deemed safe from a process point of view. Both inputs and outputs are affected by transient voltage. Transient voltages are normally of very short duration, and if they exceed the specified peak voltage, sensitive electronics will be damaged. For example, the discrete solid-state output would no longer be capable of turning to the Off mode and would be stuck in the On mode.

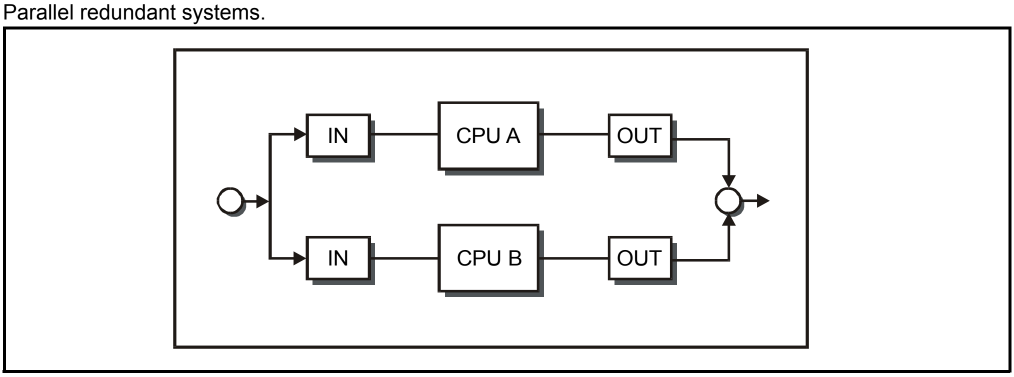
Control units, which are comprised of elements such as the processor and memory boards, may be affected and even destroyed by electromagnetic or electrostatic interference. This can cause a total shutdown, or worse, a partially defective program with the system still in operation. PES components may also pick up electric noise from their surroundings, causing erratic malfunctions (generally, a hard problem to diagnose).

Failure of the power supply can be easily assessed. However, it is important to assess the effect of the sudden reactivation of power. Would this cause erratic action at the output modules? The different components of a control system may functionally fail if they are removed or short-circuited while the system is powered. That's why some systems require the power to be off before devices are connected to or removed from them.

PESs in critical applications—that is, protecting safety and health—must be installed in compliance both with the regulations and codes in effect at the site (e.g., OSHA, ISA, NFPA, IEC, etc.) and the vendor's requirements (see chapter 10). Such systems should be protected from unauthorized changes, and the failure mode of loads should be fail-safe. Plants should avoid using conventional PESs such as regular PLCs for safety alarm and trip applications because of government regulations and because of such device's unpredictable failure modes. Quite often, plants must use redundant or triple fault-tolerant redundant systems to improve reliability and failure mode of PESs.

Control system duplication (i.e., redundant systems) consists of two computer-based systems operating in parallel, one controlling and one as a backup (see figure 9-23). The backup monitors the controlling one and determines its health. If the controlling one fails, the backup takes over immediately. In critical applications, shutdown is initiated if a disagreement develops between the two systems. It is good practice to ensure that the two systems are from different vendors and that the implementation is performed by two independent teams to avoid common mode failure.

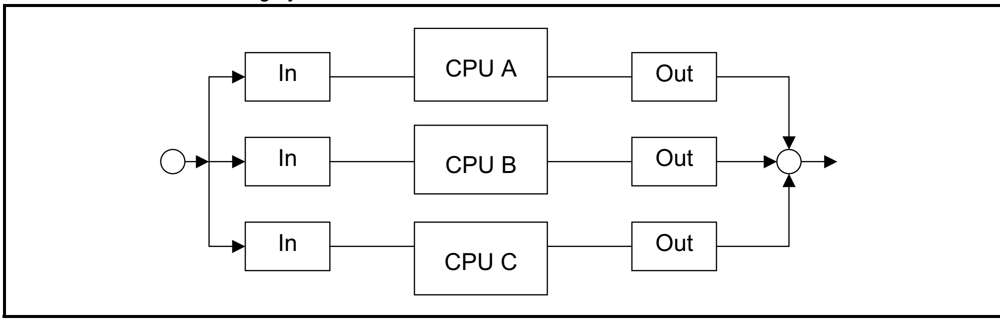
Figure 9-23
Parallel redundant systems.



Control system triplication (fault-tolerant triple redundancy) is used where the consequences of a shutdown are unacceptable. In such systems, three complete control systems operate in parallel using voting functions. The voting is done by software and hardware. If one system fails, the other(s) remain operational. If only one control system fails, safety shutdown does not occur (see figure 9-24). Control and I/O functions are a continuous two-out-of-three vote, and they are normally repaired on line without affecting the process. Control system triplication is the safest form of industrial "off-the-shelf" PESs.

PES-based fault-tolerant systems will keep operating correctly with an internal failure. They are normally used for high-reliability safety instrumented systems (SISs) that require the advantages of a PES. Fault-tolerant systems that employ two-out-of-three (2oo3) voting are also called "triple modular redundant" (TMR) systems. When three sensors are used, 2oo3 voting can determine the bad sensor, alarm this condition, and isolate it from the loop.

Figure 9-24
Two-out-of-three PES voting system.



In addition to regulations, the successful and safe implementation of PESs depend on good engineering practices. Typically, the following points are implemented:

- Use security keys and/or passwords to prevent easy access.
- Avoid first versions of new software and wait until the bugs are out.
- Write-protect all disks except those to be written to.
- Boot from hard disk or from the same write-protected disk.
- Never use pirated software; use only licensed software.
- Perform frequent backups.
- Keep system programs on program disks and production data on data disks.
- Grounding systems are critical when using PESs as logic solvers. They must be implemented in close compliance with the vendor's recommendations.

Software

Partial software failure is typically caused by erroneous programming or by an involuntarily introduced error (e.g., electrical noise transmitted to memory). This type of failure tends to be a lot more difficult to pinpoint and diagnose than total software failure or hardware problems.

Of all system components, software is the most prone to error. For that reason, it is good practice for plants to ensure that all software changes are closely controlled. This is sometimes a difficult task, particularly during plant startup. Software must be tested before a process is commissioned. This can be done with hardwired test equipment (test switches, lamps, etc.) or with computer-based simulation (for medium to large applications). When a subcontractor is developing software, the plant must transmit exact requirements to the subcontractor, and the quality of the final product should be checked at different stages of the development process.

Application software must be customized for each job. However, plants should try, as much as possible, to avoid custom software when off-the-shelf software is available (such as for communication software between different devices). Custom software always requires a debugging period, which increases in length with the complexity of the program. Murphy's laws on custom software speak volumes.

- "Nothing is as simple as it seems."
  (Software always ends up being larger than originally thought.)
- "Everything takes longer than expected."
  (Software always takes more time than estimated.)
- "When it fails, it's at the worst possible time."
  (This always happens at startup, so allow for a careful test period before implementation)

PES programs are executed according to a schedule that reflects priorities and intervals. The two most common types are non-preemptive scheduling and preemptive scheduling. In non-preemptive scheduling, a task will continue to execute until all its program functions are done. It is more straightforward than preemptive scheduling but tends to have poor control characteristics on fast processes (all tasks are delayed if one task takes longer). Moreover, with non-preemptive scheduling is not possible to predict exactly when a task will execute. This type of scheduling should not be used for time-critical applications.

In preemptive scheduling, program execution occurs on several priority levels. The higher-priority tasks will execute if a lower-priority task is not completed. When the high-priority task is completed, the lower-priority task will then resume.

A PES can be programmed off line or on line. Off-line programming is the most common programming method and is used for the initial creation and downloading of a program. Online programming provides the tools for testing, troubleshooting, and last-minute changes during commissioning and startup. Online programming takes effect immediately, so its implementation should be carefully thought out.

Environmental Conditions

Control systems are susceptible to poor grounding, temperature, dust, corrosion, humidity, shock, vibration, and electromagnetic and electrostatic energy. In addition, signal wiring inside and outside of most PESs may act as antennas and pick up electrical noise when they are not properly shielded or when walkie-talkies are used in the vicinity of the PESs (see also chapter 11 on control centers).

PESs must be grounded according to the code requirements and the vendor recommendations. This includes grounding and shielding process for both power and signal wiring as well as enclosures. Good grounding provides a safe path for faulty currents, minimizes electric shock hazard by reducing the potential differences between conductive surfaces, and protects the equipment from electrical noise and transients. A poorly grounded system is a continuous source of hard-to-detect problems.

Most PESs have an operating temperature range of 32 to 125°F (0 to 55°C). For that reason, heat must be dissipated properly and hot spots avoided. Air cooling can achieve this and is available in natural convection, fan-forced, or air conditioning methods.

Office-type PCs should not be used as operator workstations unless they are located in a clean environment. In spite of their additional cost (20% to 50% more), industrial-quality PCs are usually used in manufacturing facilities. The three most common types of enclosures for PESs are general-purpose for indoor applications (these are typically used in clean control rooms), drip-proof types for indoor applications (typically used in industrial-quality rooms such as motor control centers [MCCs]), and watertight/dust-tight types for in-plant and outdoor applications.

Network Topologies

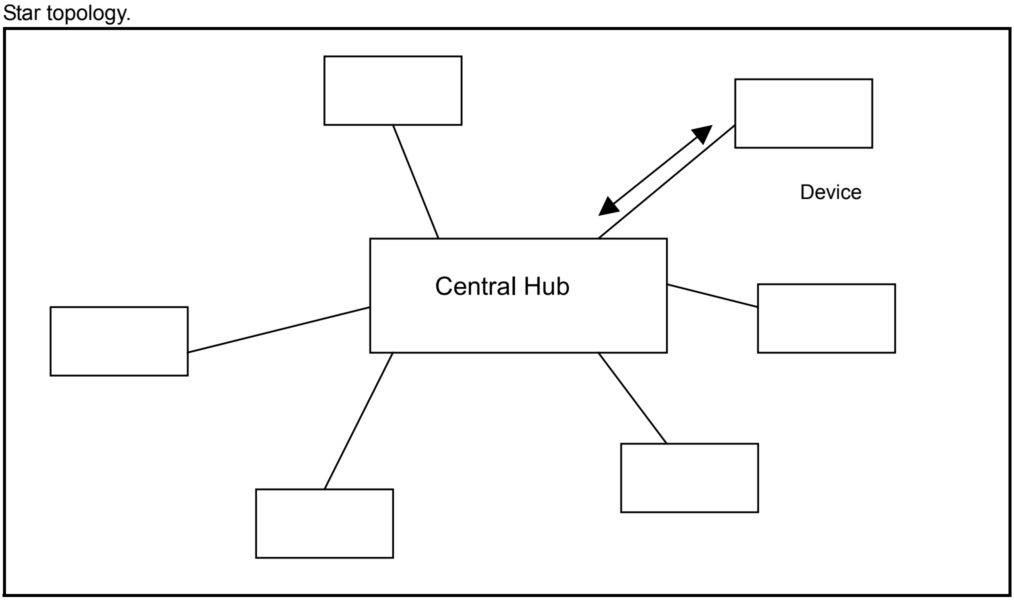
Network topologies connect individual devices. Such connections allow the devices to share and exchange information. The most frequently used in the process industries are the star, the bus, and the ring network systems.

Star Topology

In a star topology, each device is connected by a point-to-point link to a central hub that acts as the single switching device (see figure 9-25). The communication processing load is on that central hub. When a device wants to transmit data, it first sends a request to the central hub asking for a connection to a specific destination. Once the link is set by the central hub, data is exchanged between the two devices as if they were connected on a point-to-point link. The star topology is the most simple and least costly of the three topologies. Each device operates independently and loss of communication between a node and the central hub does not affect other nodes. Star topologies typically have no redundancy.

A variant of the star topology is the *mesh topology* where each device has its own switching device and therefore a one-to-one communication is provided. Each device has a single link to each of the other devices, hence the mesh look (and name). A mesh topology is expensive and complex.

Figure 9-25
Star topology.

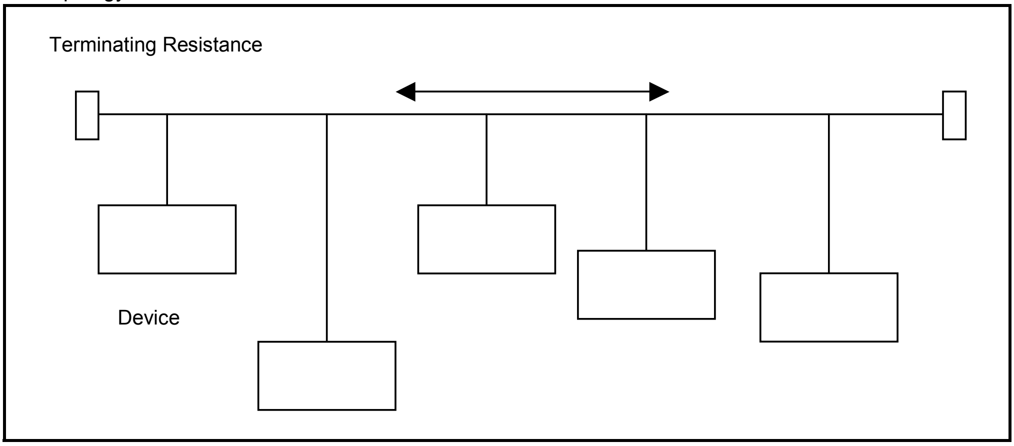


Bus Topology

In a bus topology, also known as a multi-drop topology, all devices are connected to a passive link (or bus), basically a cable (see figure 9-26). All devices on the network listen to all messages but a device will respond only to the messages addressed to it.

Bus failure will affect communication and therefore redundant buses are sometimes used. Since all devices on the bus share this common transmission link, only one device can transmit at any one time. Each device wishing to transmit data has to wait for its turn and then transmit. The receiving device recognizes its address from the traveling packet and copies it. This topology is very flexible and can handle a large number of devices with a variety of data types and data rates. However a cable break disables a large portion of the network.

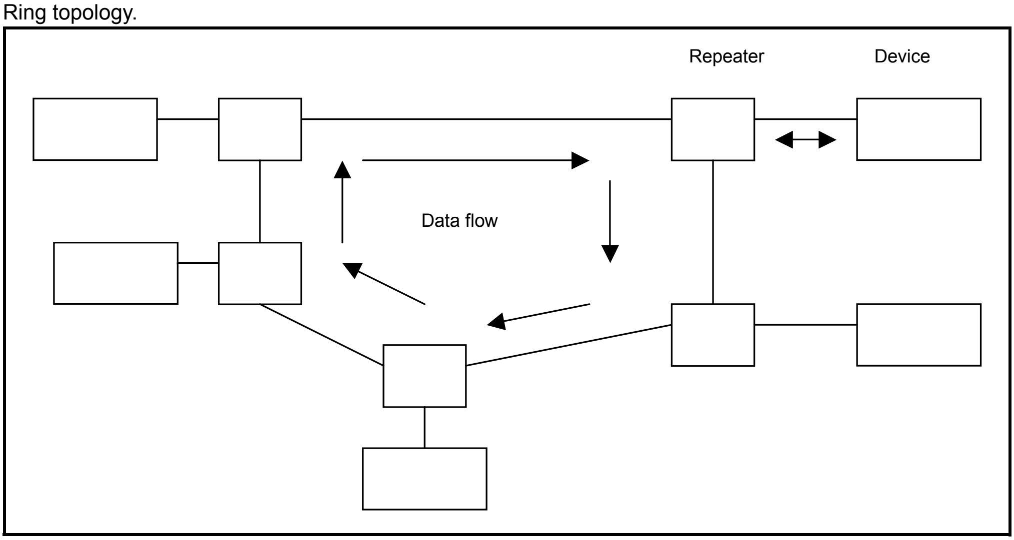
Figure 9-26
Bus topology.



Ring Topology

In a ring topology, also known as loop topology, repeaters are connected to each other in point-to-point links. Therefore, each repeater is connected to two other repeaters. Data is transmitted in packets circulating in one direction (see figure 9-27). Each packet contains the destination's address, some control information, and data to be transmitted. Each device attaches to a repeater. The ring topology provides excellent throughput, however it is limited to the number of devices on its network. Where redundancy is required, a second ring is implemented and communication moves in the opposite direction.

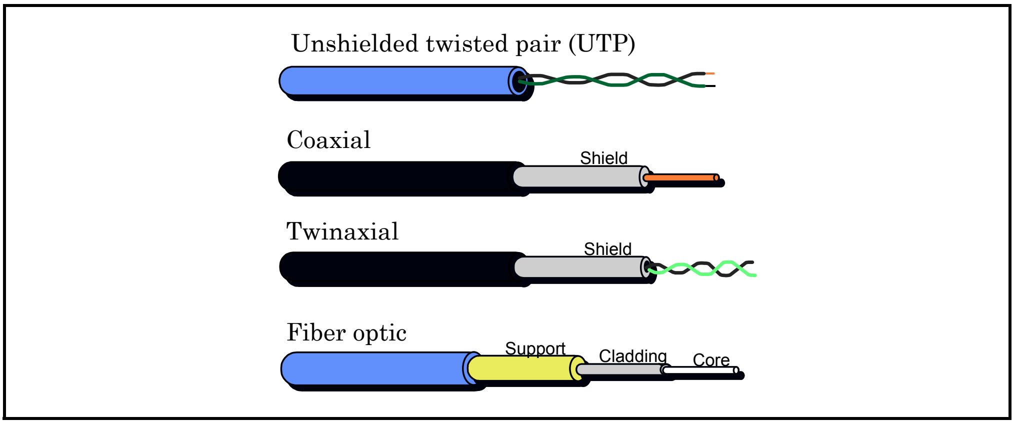
Figure 9-27
Ring topology.



Transmission Media

The most common transmission media for networks are twisted pair (shielded and unshielded), coaxial (and twin axial), and fiber optic (see figure 9-28).

Figure 9-28
Most common transmission media.



Twisted Pair (shielded and unshielded)

Twisted pair, as its name implies, consists of a pair of insulated copper wires twisted together to minimize the effects of electromagnetic interference. A cable is a number of such pairs grouped together in a bundle and wrapped in a protective sheath. A shielded pair of wires protects the signal from unwanted noise generated from electromagnetic interference (EMI) and radio frequency interference (RFI). The shield is made of metallized polyester or of a metallic woven material. EMI is created when the wires are in close proximity to electrical motors and fluorescent lighting. RFI is generated by radio equipment such as walkie-talkies.

Twisted pair is typically used in point-to-point wiring and within a single building. For longer distances, coaxial or fiber optic is used—however, they are more expensive than the twisted pair. Twisted pair can transmit both analog and digital signals and the shielded type has excellent noise immunity. The star, bus, and ring network topologies can all use twisted pair.

Coaxial (and twin axial)

The coaxial cable consists of two conductors, an outer cylinder that can be solid or braided, and an inner conductor that can be solid or stranded. In between the inner conductor and the outer cylinder is a solid dielectric material. The outer cylinder is covered by an insulating jacket. Coaxial cables must be handled carefully during installation. The twin axial is a variation of the coaxial cable. It has two coaxial cables inside a shield and an insulating jacket for overall protection.

Coaxial cable is a versatile transmission medium as it carries large amounts of data and can be used in point-to-point or multipoint configurations. It is commonly used for the bus network topology (and sometimes for the ring topology). Coaxial cabling is used for analog and digital signaling—known as broadband and baseband respectively. Its noise immunity is better than twisted pair. Coaxial cabling is more expensive than twisted pair but less expensive than fiber optic transmission.

Fiber Optic

A fiber optic cable consists of a glass or plastic core, a cladding, and a support with an outer protective jacket. The optical fiber transmits a modulated light wave signal by means of internal reflection. Light from a laser or light-emitting diode (LED) source enters the cylindrical core and is propagated. At the other end, the light signal is demodulated into an electronic signal. The laser light source is more efficient and provides greater data rates than the LED. However, the LED light source is less expensive, has a longer life span, and operates over a higher temperature range.

Fiber optic is commonly used in point-to-point links and the signal can travel over very long distances. Since it does not carry electrical signals, it is immune to electrical interference and ground loops. In addition, it can be safely routed through hazardous and explosive environments. Optical fiber links are more expensive than twisted pair or coaxial cables.

Selecting Vendors

Once a technical specification is prepared, the plant issues a request for quotation to potential suppliers. The number of suppliers bidding on the job will vary with the project requirements. However, two is a minimum, three to four is reasonable for a good and fair comparison, and five to six is a maximum. Beyond that, bidding becomes a monumental task, particularly on large projects.

Plant personnel can use the following checklist to assess potential suppliers and decide if they should be on the bidder's list. Note that this list should be used in addition to preparing a technical specification.

- What does this vendor offer over the competition?
- What experience does the vendor have in this type of application?
- How far is the vendor from the plant (i.e., availability of service, support, spares)?
- Does the vendor provide onsite commissioning and maintenance?
- What training does the vendor offer customers?
- Are maintenance contracts available?
- How many people are in the vendor’s service group? Is there an organization chart?
- What is the service facility like?
- What is the duration of the standard guarantee? Are any extensions available?
- Will the vendor guarantee the life cycle of this product? For how long?
- Does the vendor have a quality program? Is it available for review?
- Is the vendor accredited by a quality organization?
- How does the vendor test control systems?
- What documentation is supplied with the system? Are examples available for review?
- Is the software developed in house or is it contracted out?
- Will the vendor comply with all the requirements of the plant (including engineering documentation)?
- What is the vendor's capability in handling projects?
- Is the vendor willing to submit at the bidding stage the name and résumé of the control engineer assigned to the project? Will the vendor keep this person on the job until the end of the project?
- Which portion of the project (if any) may the vendor subcontract out?
- What is the vendor's financial health (the plant’s accounting and purchasing departments can help here)? How long has it been in business, and in this type of business?

Testing

PES systems must be tested before the process is commissioned and started up. Testing can be done either on site after the system is installed or at the vendor's facility. The latter approach is known as a factory acceptance test (FAT) and can save a lot of precious (and expensive) time on site. In FAT, all inputs should be simulated, and all outputs monitored.

Justification

Implementing a new computer-based control system to replace an old one, quite often an analog type, requires justifying the cost. The first step in the justification process is identifying the telltale signs that point to the need for a new control system. The next step is to justify the new system by determining the cost of implementation and deciding which of the quoted systems is best for the application.

A technical audit is a good starting point to identify the weak points of the existing control system. The following is a list of telltale signs that plant management should watch for:

- Sliding market share.
- Inability to keep up with the competition.
- Unhappy customers.
- Recurring emission problems.
- Large inventories of raw materials and finished products.
- Inconsistent and/or poor quality.
- Unreliable plant trip and alarm systems.
- Poor or nonexistent production data.
- Inflexible production capabilities and long startup times.
- Poor productivity with too many staff.
- Errors when production data are manually recorded.
- Many man-hours wasted in reading data from unreliable sources.
- Too much time wasted in checking manually copied data.
- Inability to obtain immediate feedback and production knowledge.
- Inflexible production facilities and customers who are pressing to accept low-volume, unprofitable orders.
- Existing facilities take a long time to set up.
- Production costs keep going up.
- Environmental regulations cannot be complied with.
- Budgets cuts prevent plant from making investments and improvements.
- Production priorities are constantly changing, startup and shutdown costs are heavy, and accommodating customer delivery requirements is difficult.
- Existing production facilities make it impossible to meet the required quality of service, introduce new products, and implement technological know-how, and the time available to respond to market demand is getting shorter.
- Customers are demanding, but the plant cannot deliver, more specialized products and specialized packaging, better quality and service, better delivery times, and specific delivery accommodations.

Many of these telltale signs are interrelated. For example, poor quality produces more scrap, increases pollution and the need for raw material, raises costs, and decreases profits.

Once the justification process has started it should move fast since delays generate hesitation, and hesitation generates doubt and uncertainty (and nothing in the end gets done). Restarting the whole process becomes even more difficult. It should be noted that the control system is not the only answer to all the problems just mentioned. Other key factors in improving production are the quality of raw materials, the capabilities of the process equipment, and employee morale. New control systems must be implemented into existing plants, where possible, with minimal interruption to plant production and with the knowledge that this investment is worth taking.

Problems encountered in the justification process are caused by difficulties in measuring and quantifying the real economic benefits. Management wonders: Is it worth it? Is the risk worth taking? Accountants are poor engineers (what cannot be justified has a value of 0), and engineers are poor accountants (they find it hard to generate those numbers for justification). PES decision makers are generally split into two camps: believers and nonbelievers. From the believers' standpoint, justification is generally not needed. Modern controls are a way of existence (the only way), and sometimes believers are convinced of unrealistic, unachievable savings levels (which adds fuel to the fire of the nonbelievers). On the nonbelievers' side, engineers' judgments are seen as only guesses. Nonbelievers usually have no experience with modern controls (or perhaps a bad experience), they tend to be distrustful of advanced controls, and they need proof in black and white.

The cost of implementation consists of an initial cost and an ongoing cost. The initial cost includes the cost of hardware and software, the control room building (if the existing one is not reusable), the engineering, the installation, and other miscellaneous costs encompassing training, travel costs, startup, and the like. Engineering costs may include project engineering, engineering contractors, programming, system checks, preparing manuals, and commissioning and startup assistance. Installation costs may include moving the control equipment to the plant and into the control room; wiring all inputs and outputs, the power supply, and the grounding; and testing the complete installation. The cost of ongoing maintenance covers system repairs and upgrades, training, new maintenance personnel, maintenance agreements available from system vendors (or third-party service companies), and hardware/software updates.

Benefits

A control system is implemented because it provides certain benefits, and these benefits dictate the requirements of the control system. For example, if increased productivity requires automatic plant startup, the control system should have the capability of doing just that. Both the benefits and the tools that provide such benefits form the core of a functional specification (i.e., the requirements are the basis upon which a system is selected and implemented). Many of the benefits of PESs are interrelated. For example, consistent quality reduces scrap, pollution, raw material usage, inventory, and setup time.

The following is a list of typical PES benefits:

1. Increased annual sales because delivery dates are reliable (the process is under good control).

2. Customers willing to pay extra for quality (which reduces their waste), generating a positive public relations image to customers, vendors, and the media.

3. Better market and customer response since PESs are easily reprogrammable (lowering the cost of new product introduction), provide greater production flexibility (allowing a variety of setups/products/production levels at a much lower setup and changeover time), and do not require rewiring (a disadvantage of relay-based systems).

4. Pollution reduction through improved control strategy and monitoring capability (meaning that action is taken before emissions occur by forecasting malfunctions). In addition, the PES stores the results of all analyzer data and retrieve them on demand (allowing practical handling of historical data).

5. Consistent quality by reducing scrap, minimizing problems related to waste disposal, and reducing production costs by reducing the interruption of production, warranty costs, costs for the investigation of defects, quality control costs, liability suits, product downgrading, downtime, and so on. This consistent quality will translate into increased sales to satisfied customers who have tracking capabilities (customers' requirements or specifications can be automatically tied to lot analyses).

6. Increased productivity through automatic startup and shutdown, faster and greater attention to detail, tracking of numerous conditions and reacting quickly and predictably to them, and maintaining the process within specific limits. As a result of this productivity, the operator can concentrate on important activities, gain the confidence to operate within a narrower range and tighter margins (pushing the process to higher limits of production),

and spend the necessary time to optimize production (especially in batch and new recipe environments).

7. Increased safety by decreasing accidents. This is done by forecasting process conditions, analyzing the types and occurrences of alarms, and tripping the production process before a catastrophe occurs.

8. Optimized production by maintaining in memory a database of production information, responding to process shifts before they affect product quality, using built-in statistical process control capabilities, forecasting delivery delays before they occur, providing a basis for training new operators and engineers, acting as a repository of knowledge from previous and present operators and engineers, providing modeling and simulation of production processes under different conditions, and aiding production and sales in the introduction of new products (which can be launched earlier and faster).

9. Inventory reduction by matching online raw material inventories with production requirements, reducing work-in-progress inventory, and reducing inventory space.

10. Accurate and timely information reporting, which is accomplished by analyzing and displaying real-time data (with reports) for evaluating performance, forecasting problems, generating statistics, and performing diagnostics. Also, a PES can enable better production data to be reported (improving the decision-making process), make it possible for production and environmental data with quality control results to be tracked, and enable full-time, online record keeping (for summarizing what and how much was produced, unit costs, raw material usage, etc.). The accurate information the plant needs is available when it is needed with minimal paperwork (eliminating clipboards, manual calculations, and human errors and freeing time for problem solving and improving management and the operation).

11. Long operating life since PESs have few or no moving parts (mainly disk drives). The PES's input/output modules, CRTs, and disk drives tend to be the weakest links.

12. Additional benefits, including built-in diagnostics to facilitate maintenance and troubleshooting, ease of modification and configuration, and competitive cost when compared to large analog/relay systems, which are not easily expandable. Also, the engineering does not need to be completed when ordering a PES; an approximate input/output count with spares and a functional specification should suffice.

Implementation

In existing plants with old control systems, implementing a modern control system is generally first done on a small scale for a part of the plant. This provides a learning curve with minimum impact. In existing plants, it is common to start with a process

- that is now driving the cost up.
- with as rapid a payback as possible.
- with the fewest number of people and equipment.
- that produces a large number of several end products.
- with a large price differential between the feed and end products.
- with expensive raw materials, expensive cleanup cost, or expensive operating cost.
- with high energy consumption.
- that is hazardous (operators are kept away from production).

Users should keep a few points in mind.

1. Management's support and commitment for the new system must be established. The management must ensure that the system's operators do not believe the new system will be

used to “beat on” them. Instead, the new system is to help everybody do a better job.

2. Assemble a dedicated team led by a champion who will devote his/her full time to the project.
3. It is preferable to acquire an off-the-shelf system that can be easily understood by plant personnel, is well supported by the vendor, and is easily expandable.
4. Always avoid islands of automation; communication problems can become expensive nightmares.
5. Do not automate chaos.
6. Implement where success is sure. Implementation can take as little as a few months or as long as several years; it all depends on the scope.
7. Involve operators and maintenance personnel in selecting the system.
8. In new plants, implementation will be done all at once, often on a large scale. In these cases, experience is needed because there is no room for error.

Maintenance

PES maintenance should be performed by trained personnel. It is normally carried out with the system’s power disconnected. If maintenance must be performed while the PES is energized, safety practices and the vendor's recommendations must be followed.

Enclosures are susceptible to contamination by dust. Dust buildup leads to lack of air flow and diminished performance by circulating fans and heat sinks. Dust also absorbs moisture, creating a conductive path rather than the expected isolation. Where fans are used make sure that the filters are kept clean to avoid restricting the cooling air. Also make sure the fans are in good shape, that is, no worn-out noisy bearings (you can hear this noise) and no foreign objects (e.g., paper clips, etc.) lodged near the fan's inlet. Bent or chipped blades must be replaced. Also, plant personnel should clean the fins of heat exchangers to maintain convection cooling.

Moisture corrodes unprotected circuit boards, particularly where other atmospheric contaminants are added, such as corrosive gases and vapors. Therefore, where air is used to cool enclosures, use clean, dry, and oil-free instrument air.

Connections for all components must be kept tight. Poor connections lead to poor system performance and arcing. Grounding connections must be secure. To help reduce maintenance costs, plant personnel should follow the vendor’s recommendations; avoid excessive temperature, dust, vibration, and humidity; never allow food or drinks at the operator's workstations; and ensure that power supply quality meets the vendor's recommendations.

CHAPTER 10

ALARM AND TRIP SYSTEMS

Overview

Plants that are implementing alarm and trip systems must follow the legislative and regulatory requirements in effect at the site. ANSI/ISA-84.01-1996, Application of Safety Instrumented Systems for the Process Industries provides detailed information on implementing critical trips for process applications, in particular where programmable electronic systems (PESs) are used as the logic function.

The purpose of a plant alarm system is to bring a malfunction to the attention of the operator(s), whereas a trip system takes protective or corrective action when a fault condition occurs. A plant trip system could shut down the process in an orderly fashion, or it could switch over from some defective unit (such as a pump) to a standby unit. In most cases, a trip system remains dormant and quite frequently unused until there is a demand on the system (or if it is being tested). Alarm and trip systems protect only when they work.

The reliability of alarm and trip systems is achieved through the following:

- Their fundamental design.
- The conditions under which they operate.
- The capabilities of properly trained plant personnel.
- The frequency at which they are tested.

Processes are generally provided with two trip systems. The first is a trip system for normal operation (commonly part of the control system) and typically related to production, quality, and financial issues. The second is a safety instrumented system (SIS) for handling critical trips. Additional categories can be generated to account for plant/process-related requirements. Critical trips protect the safety and health of people, and in many cases also environmental areas, by taking the process to a safe state when predetermined conditions are violated.

These two systems—the normal control system and the SIS—should be physically separate to maintain their independence. This will increase their reliability and minimize the possibility that they both fail as a result of a common cause. Separation, which includes the power supply circuits, reduces the probability that both the control system and the SIS are unavailable at the same time or that changes to the control system affect the functionality of the SIS. Where possible, different types of measurement should be used for each system of control. For example, if a capacitive probe is used for level control, then, if appropriate, a bubbler may be used for the SIS. It is imperative to ensure, particularly for the SIS, that the sensors selected are appropriate for the application.

A SIS system is composed of the sensors, logic, and final elements that are required to take the process to a safe state. Since the failure of a SIS could harm the environment and, more importantly, lead to loss of life, it is incumbent upon the plant to ensure that the SISs (including their power supply system) function properly and reliably. Therefore, SISs must be regularly tested, and their design must allow for such testing. Bypassing or forcing any function of the SIS can only be allowed by procedures and, where possible, should be annunciated to the operator.

Once a SIS places a process in a safe state by tripping it, it must maintain the process in that safe state until the hazard is removed and a reset has been initiated. This reset function is typically a manual action by an operator. In addition, manual means that are independent of the logic should be provided to actuate the SIS's final elements if manual operator intervention is required.

Fail-Safe and Deenergize-to-Trip

All systems will fail sooner or later. A fail-safe system will go to a predetermined safe state in the event of a failure. In a deenergize-to-trip system, the outputs and devices are energized under normal operation; removing the power source (electricity, air) causes a trip action. Where possible, it is preferable to implement all plant alarm and trip systems as fail-safe and deenergize-to-trip. For SISs in particular, implementing them as fail-safe and deenergize-to-trip is strongly recommended. Fail-safe and deenergize-to-trip implementation may not be possible or suitable for an application because of the severe consequence of a nuisance trip. In these cases, additional safeguards are required to maintain the safety of the process when the SIS malfunctions.

Where possible, the design should ensure

- that sensor failure or loss of electrical power or instrument air will activate the alarm or trip and go to a safe condition,
- that the initiating contacts energize to close during normal operation and deenergize to open when the alarm or trip condition occurs,
- that if a high process value is the trip condition, the sensor is reverse acting (i.e., a high value generates a low signal) so the trip occurs on the loss of signal,
- that solenoid valves are energized under normal operating conditions but deenergize to trip, and
- that pneumatically operated trip valves move to a safe trip position on air supply failure.

Safety Integrity Level

There are many types of integrity and criticality classifications which vary with the application. The process industries, have in general, adopted the Safety Integrity Level (per ANSI/ISA 84.01). The machinery industries and combustion systems have adopted different classifications and they will not be discussed in this book.

The safety integrity level (SIL) defines the level of performance that is needed to achieve a safety objective (see design section later on in this chapter). The higher the SIL, the better the safety performance of the SIS and the more available the safety function of the SIS (see table 10-1). Associated with the SIL is the "probability of failure on demand" (PFD). The desired SIL is met through a combination of design considerations. Two key considerations are separation and architecture.

Table 10-1
Safety integrity level performance requirements.

SAFETY INTEGRITY LEVEL	**1**	**2**	**3**
SIS PERFORMANCE REQUIREMENTS	Safety Availability Range		
	0.9 to 0.99	0.99 to 0.999	0.999 to 0.9999
	PFD Average Range		
	10^{-1} to 10^{-2}	10^{-2} to 10^{-3}	10^{-3} to 10^{-4}

Separation ensures that the process control system and SIS functions are independent so they don't fail from the same cause. For SIL1 applications, identical separation (i.e., each of the two systems uses similar equipment) is generally acceptable. However, diverse separation provides a more reliable system and is therefore recommended. For SIL2 applications, diverse separation is highly recommended, and for SIL3 applications diverse separation is generally required.

Where it is not possible to separate the SIS from the process control system (for example, in turbine control systems), additional considerations are required. These can include evaluating the failure of common components and their impact on the SIS, supporting the whole system as a SIS, and limiting access to the system to avoid tampering.

Separation should also be implemented at the design level. Preferably, the design team implementing the process control system should not be the same group implementing the SIS. This approach minimizes the effect of common mode faults from a design point of view.

Architecture that typically meets the SIL performance requirements are:

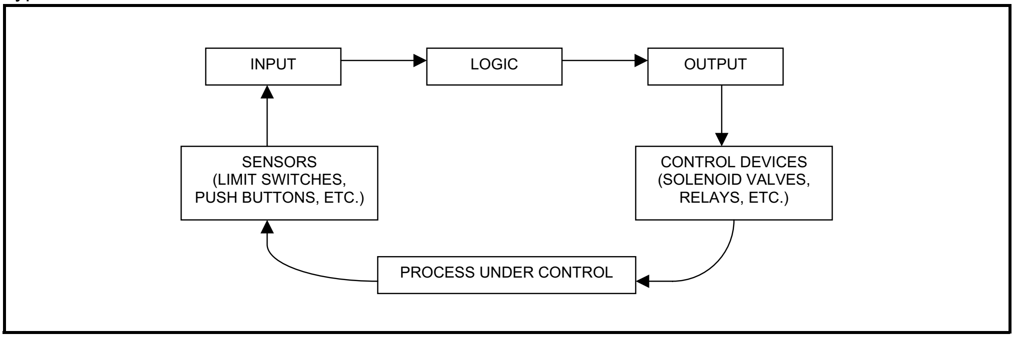
- For SIL1, a one-out-of-one architecture with a single sensor, single logic solver and a single final control element
- For SIL 2, more diagnostics than SIL 1 and may include redundancy for the sensors, logic solver, and/or final elements
- For SIL 3 applications, at least two separate, redundant, and diverse systems are required, each with its own sensor, logic solver, and final control element. Moreover, the two systems must be on a one-out-of-two ("1oo2") voting scheme. Sometimes three parallel systems are used with a two-out-of-three ("2oo3") voting arrangement.

The architecture a plant selects should in the end be based on the reliability of the system components and their test frequency.

Elements

A typical SIS consists of three basic elements: input, logic, and output. Other parts that have a potential impact on the safety function, such as power supply, are also considered part of the SIS (see figure 10-1). SISs require a dependable power supply, and quite often an online uninterruptible power supply (UPS) is added to ensure reliable operation. Deenergize-to-trip systems do not require electrical power to trip. They bring the process to a safe condition on power failure, and therefore, redundant power sources may not be required. However, they are required on energize-to-trip applications.

Figure 10-1
Typical SIS elements.

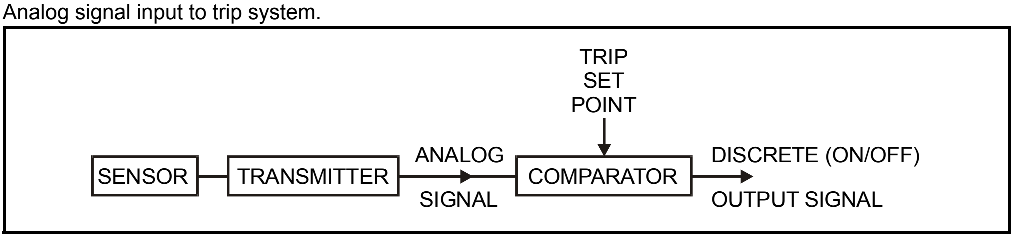


The failure of sensors (switches, transmitters, etc.) and control devices (solenoid valves, control valves, etc.) account for the majority of SIS equipment failures.

Input

The input converts process variables into the digital form required by the logic unit. For analog signals this conversion includes comparing the input to a trip set point to obtain a status. Typical forms of inputs include self-contained discrete devices, such as limit switches and push buttons, or analog systems, which consist of a measuring element, a transmitter, a comparator, and a discrete output (see figure 10-2). Whenever possible, sensing elements should be installed in such a way that they can be tested without disconnecting wires or loosening pipe or tubing fittings. As an example, the impulse line between the process and a pressure switch may include a tee and a shutoff valve between the isolation valve and the sensing element (see figure 10-10). This is used to be able to inject an appropriate test signal. In addition, it is good practice to use switches that have hermetically sealed contacts to avoid corrosion and contact film, thereby improving reliability.

Figure 10-2
Analog signal input to trip system.



In a system that is measuring levels, bouncing liquid levels may cause annoying alarms and trips. Introducing a few-second delay or dampening may solve this problem. When such time delays are employed, the designer should ensure that the delay is short enough that the process's safety time constraints are not violated. Also, where smart field devices are used, they should be write-protected and provided with read-only communication to prevent inadvertent modifications. In addition, if possible, calibration adjustments on the selected measuring instrument should be limited to prevent adjustments into the dangerous range. For example, if a trip point is set at 100 psig (700 Kpag) and the dangerous zone is reached at 150 psig (1050 Kpag), it would be prudent to select a pressure switch whose upper range is less than 150 psig (1050 Kpag). This would prevent an accidental setting at or above 150 psig (1050 Kpag).

If redundant sensors are used, they may be connected to both the process control system and the SIS, provided that the failure of the process control system will not affect the SIS's functionality. The reliability of SIS equipment is increased by using levels of redundancy and diversity in measuring sensors. Common-cause failures can be minimized by properly applying redundancy and diversity. For example, when using redundant sensors plants should use different principles of operation and different manufacturers and compare the outputs, alarming or shutting down on unacceptable deviations. In addition, the effectiveness of field devices can be enhanced by comparing two values, for example, flow measurement with the modulating valve position and analytical measurement with a basic measurement such as pressure and temperature.

Redundancy is applied to enhance safety integrity and improve fault tolerance. Redundant systems should be analyzed for common-mode faults such as plugging of shared process impulse lines, corrosion, hardware/software faults, and shared power sources. Diverse redundancy is recommended for SIS systems. However, redundancy should not be used where it will be a justification for using lower-reliability components.

Logic

The logic takes the input(s) and produces the output signal(s). The logic of a SIS must be designed with a manual reset function to prevent the process from initiating an automatic restart when power is restored or when the cause of the trip is removed. The three most common types of logic hardware are direct-wire systems, electromechanical relays, and programmable electronic systems (PESs). Other available types of logic are solid-state logic and motor-driven timers. The logic for a SIS can be implemented using any or a combination of these types. Generally, the latest technology is used to implement a process control system; however, SIS technology is typically implemented using a proven and mature product.

Direct-wire Systems

In direct-wire systems, the discrete sensor(s) is directly connected to the final control element. This approach can be used only for the simplest applications.

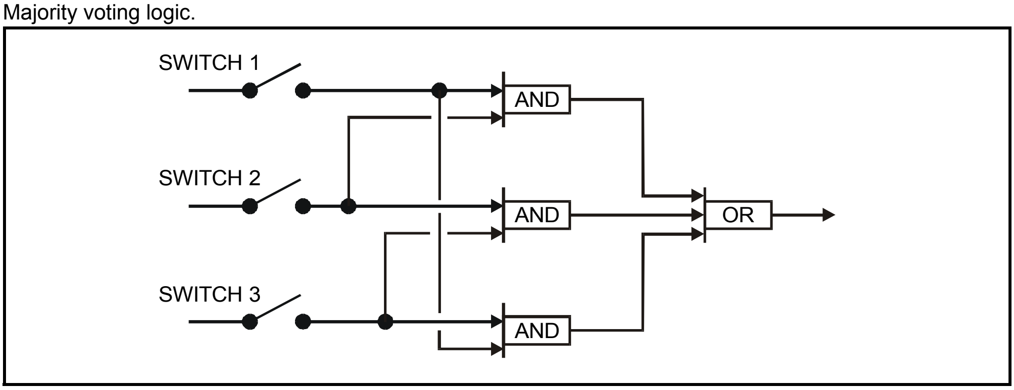
Electromechanical Relays

The acceptance of electromechanical relays is now widespread. They are commonly used for SIS applications. Additional information on relays is provided in chapter 9 in the section "Control Room Instrumentation." For SIS applications, some industries use safety relays. Such relays have many built-in features, such as mechanically interlocked contacts to ensure predefined behavior. The contacts are interlinked by a mechanical bar that ensures that all normally open (NO) contacts do not close if the normally closed (NC) contacts do not open. If either the NO or NC contacts are welded shut, the mechanical bar will prevent the opposing contact from operating. A minimum contact set for a safety relay consists of one NO contact and one NC contact.

Where safety relays are not used, consider the following requirements:

- Use industrial quality relays.
- Contacts should open on coil deenergization or failure.
- The coil has gravity dropout or dual springs.
- Proper arc suppression is provided for inductive loads.
- Consider the need for a hardwired two-out-of-three (2oo3) voting logic (see figure 10-3).

Figure 10-3
Majority voting logic.



Programmable Electronic Systems (PESs)

PESs are used in SISs when there are large numbers of inputs and outputs, where the logic is complex, where communication with the SIS is required, and where different trip point settings are required for different stages of an operation (e.g., in a batch control system). Plants considering the use of a PES for SIS applications should weigh the fact that the PES's solid-state nature means its failure mode is unpredictable and could be unsafe. When PESs are used in SIS applications, they should

1. Be approved for safety applications and implemented in compliance with the applicable codes.
2. Use extensive diagnostics and fault-tolerant architectures.
3. Use internal and external watchdog timers. The internal watchdog timer function is generally supplied within the PES. The limitations of the internal watchdog timer are that it may fail to monitor the complete application or it may fail for the same reason the PES fails. The external watchdog timer monitors an input and an output and ensures that they are continually being scanned by the processor (see the subsection “Safety and System Failure” in the “Special Design Considerations” section of chapter 9). Using an external watchdog timer does not eliminate the need for an internal watchdog timer. Some safety-certified PESs do not require external watchdog timers because of their voting technology.

PESs (see chapter 9) can be more reliable than relays if they are implemented with the appropriate redundancy and diagnosis. For complex systems, PESs are usually easier to use than relays. In addition, they produce clear and comprehensive information (i.e., they will log activities), and they easily monitor any SIS overrides or defeats. However, typical PESs have an unpredictable failure mode and are therefore not used in critical applications unless they are approved for such applications.

PESs are more susceptible than relays to electrical noise, and they can easily be modified without record update (creating an uncertain condition). Hardware and software modifications to PESs should be carefully controlled and their effects carefully studied. They should be implemented only by trained personnel. Where possible, alternate means, such as emergency shutdown push buttons wired directly to the output devices, are provided to the operator to bring the process to a safe state if the PES malfunctions.

Output

The output converts the results from the logic into one or more process variables. Typical forms of output devices include solenoid valves, trip relays, and the like. Most output devices should deenergize to trip. That is, a motor should stop on the loss of control signals, and a valve should fail in the safe process condition when the signal or power supply (electrical or air) fails. Users should carefully study the failure mode of output devices. Both signal and power failure must be taken into account as well as the behavior of output devices when signal or power suddenly resumes.

Users should consider the following points for control valves in SIS applications:

- The opening and closing speeds. They should ensure that these speeds match the process requirements.
- After long periods in the same position (opened or closed), an on-off valve may become stuck in a certain position. Therefore, where applicable, a modulating control valve may be desirable since its continuous operation confirms that the valve is operational. A safety review should be performed to assess the dual use of a modulating control valve for process control and for SIS. This dual functionality can be used for SIL 1 and 2 only. SIL 3 requires a separate trip valve(s).
- The need for valve position feedback to confirm the trip action.
- Where solenoid valves are used, the solenoid should be mounted between the positioner and the actuator. This approach bypasses the effect of a malfunctioning positioner.

In environments where leakage from a closed automatic trip valve may cause a dangerous condition, plants should implement double-block-and-bleed valves. Double-block-and-bleed valves consist of two valves in series with a bleed/vent valve between the two valves (see figure 3-1 in chapter 3). If the process fluid leaks through the first block valve, it will bleed or vent instead of going through the second block valve and into the process.

Design

A good design must consider the failure of alarms and trip systems and propose the simplest system that will meet the application's requirements. The equipment selected must be of good industrial quality and must operate under conditions well below its maximum limits.

Where appropriate, it is good practice to use prewarning alarms. These notify the operator before the trip point is reached triggering the shutdown. Especially in today's modern control systems, prewarning alarms can be easily implemented at a minimum cost.

The design should also reflect that common points (junction boxes, cable runs, etc.) are protected from outside hazards such as fire, heat sources, and the like. Common-cause failures can be caused by design errors, environmental over-stress (high/low temperature, pressure, vibration, etc.), single elements (common process taps, single energy sources, single field devices, etc.), process conditions (corrosion, fouling, etc.), and poor maintenance or operation (procedures, training, etc.). These common-cause failures must be closely assessed during the design stage and throughout the life cycle of the SIS.

To maintain the functionality of SISs and the safety of the plant, the designer should be very careful about implementing trip bypasses or, better still, avoid them. If they are implemented, they should be automatically reset by timers or be alarmed on a set frequency.

The design of SISs typically involves one of two methods: qualitative or quantitative.

Qualitative

In the qualitative approach, the design is based on the application of good engineering judgment, relative knowledge of the process risks, and experience. This method uses a series of company-dependent qualitative matrices. First, the severity of the consequences of process failure is determined (see table 10-2). Then, the likelihood of occurrence is determined (see table 10-3). Tables 10-2 and 10-3 show five occurrence likelihood levels each. The severity and likelihood of occurrence are then combined to assess the risk level (low, medium, or high), thereby determining the SIL levels (see table 10-4).

Table 10-2
Risk severity: Example.

Level	Descriptive Word	Potential Severity/Consequences		
		Personnel	Environment	Production/Equipment
V	Catastrophic	Death outside plant	Detrimental off-site release	Loss > $1.5M
IV	Severe	Death in plant	Nondetrimental off-site release	Loss between $1.5M and $500K
III	Serious	Lost time accident	Release on site - not immediately contained	Loss between $500K and $100K
II	Minor	Medical treatment	Release on site - immediately contained	Loss between $100K and $2,500
I	Negligible	First aid treatment	No release	Loss < $2,500

Table 10-3
Risk frequency: Example.

Level	Descriptive Word	Qualitative Frequency	Quantitative Frequency
5	Frequent	A failure that can reasonably be expected to occur more than once within the expected lifetime of the plant.	Freq > 1/10 per year
4	Probable	A failure that can reasonably be expected to occur within the expected lifetime of the plant.	1/100 < Freq < 1/10 per year
3	Occasional	A failure with a low probability of occurring within the expected lifetime of the plant.	1/1,000 < Freq < 1/100 per year
2	Remote	A series of failures with a low probability of occurring within the expected lifetime of the plant.	1/10,000 < Freq < 1/1,000 per year
1	Improbable	A series of failures with a very low probability of occurring within the expected lifetime of the plant.	Freq < 1/10,000 per year

Table 10-4
Overall risk: Example.

High Risk

	Frequency				
Severity	1	2	3	4	5
V	1-V	2-V	3-V	4-V	5-V
IV	1-IV	2-IV	3-IV	4-IV	5-IV
III	1-III	2-III	3-III	4-III	5-III
II	1-II	2-II	3-II	4-II	5-II
I	1-I	2-I	3-I	4-I	5-I

Low Risk Medium Risk

The next stage is to evaluate the effectiveness of the protection layers, other than the SIS under consideration. Using these qualitative evaluations, an SIL number is determined. The more layers, the lower the SIL required (see figure 10-4). Then, by following a company-set guideline (see figure 10-5), the process designers implement a design. For example, if a "serious" severity is selected with an "occasional" frequency, the overall risk is "medium." With only one layer of protection an SIL 2 is required, whereas with an extra protection layer an SIL 1 will meet the requirements.

Quantitative

In the quantitative approach, the design is based on numerical data and mathematical analysis. The SIS responds to a demand from the process and protects the plant from hazards. Since all components of a SIS are subject to the probability of failure, such failures may result in a hazardous condition. If the SIS is not functional, a demand from the process may result in a hazardous condition.

Figure 10-4
Qualitative matrix: Example.

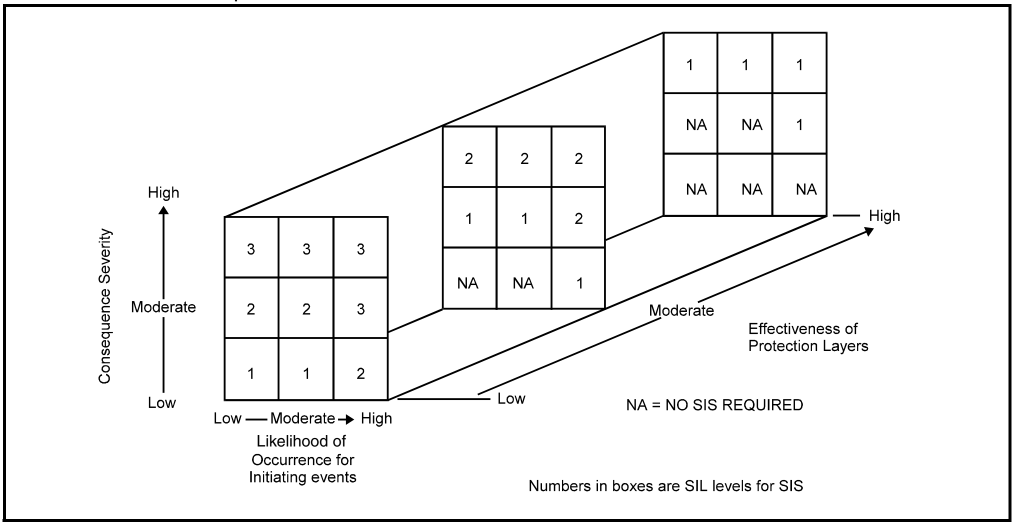
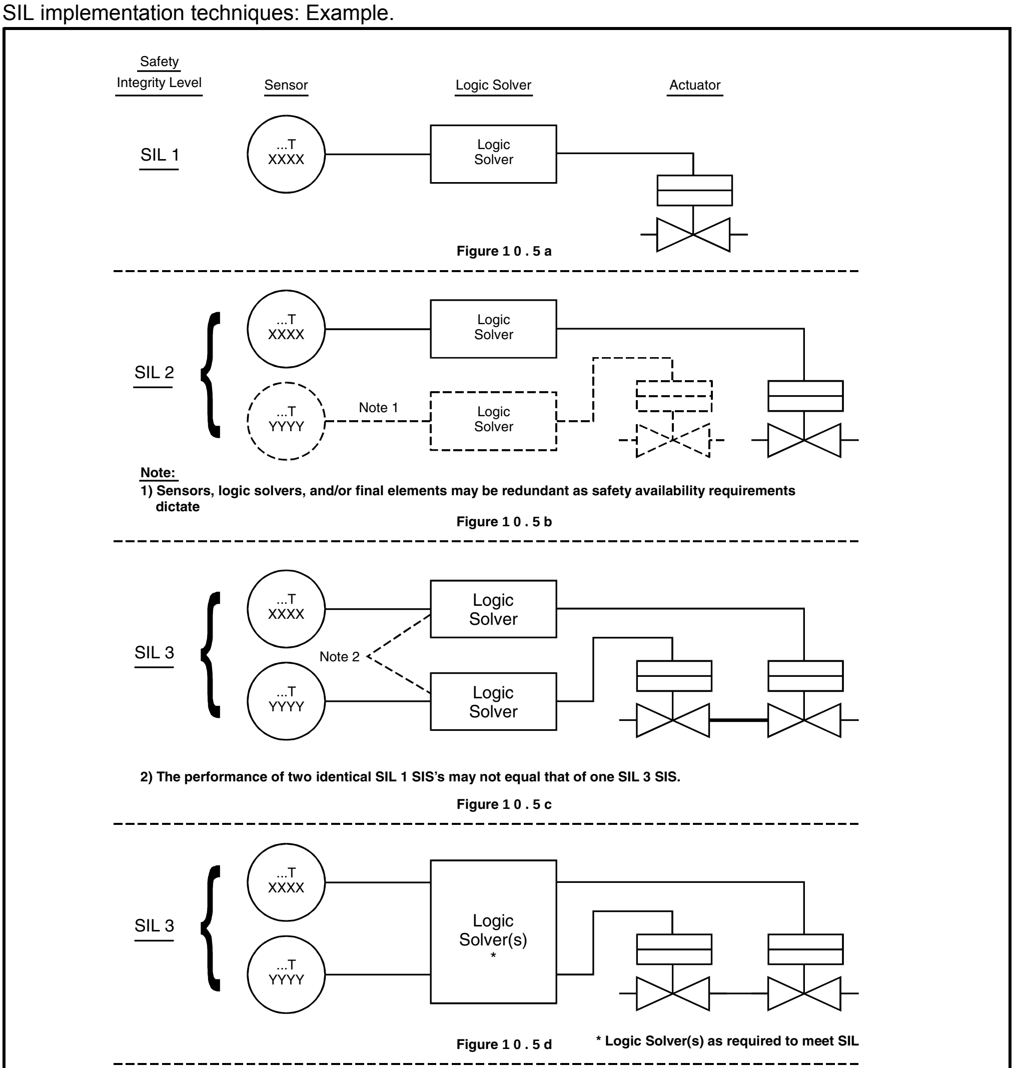


Figure 10-5
SIL implementation techniques: Example.



Without a SIS in place to prevent the hazard, the hazard rate equals the demand rate. In other words, a hazard may take place every time the conditions that would have activated a SIS occur. Typically, a SIS is down, that is, non-operational (and therefore not available) for only a relatively short time, known as the probability of failure on demand (also sometimes referred to as the "fractional dead time"). System availability is the probability that the SIS will effectively respond to a demand:

SIS availability = [1 – (hazard rate / demand rate)] x 100

Probability of Failure on Demand (PFD) =
Hazard rate / Demand rate = H / D

Typically, the demand rate is more frequent than the acceptable hazard rate. It should be mentioned at this point that a SIS is not required if D is less frequent than H, i.e., if the potential occurrence of a hazard is less frequent than the acceptable hazardous event rate. For example, if an environmental release is considered acceptable at a certain rate (say H = 0.01)—and at the same time, and due to non-instrumented layers, a demand can only occur at a lower rate (say 0.001)—then a SIS is not required.

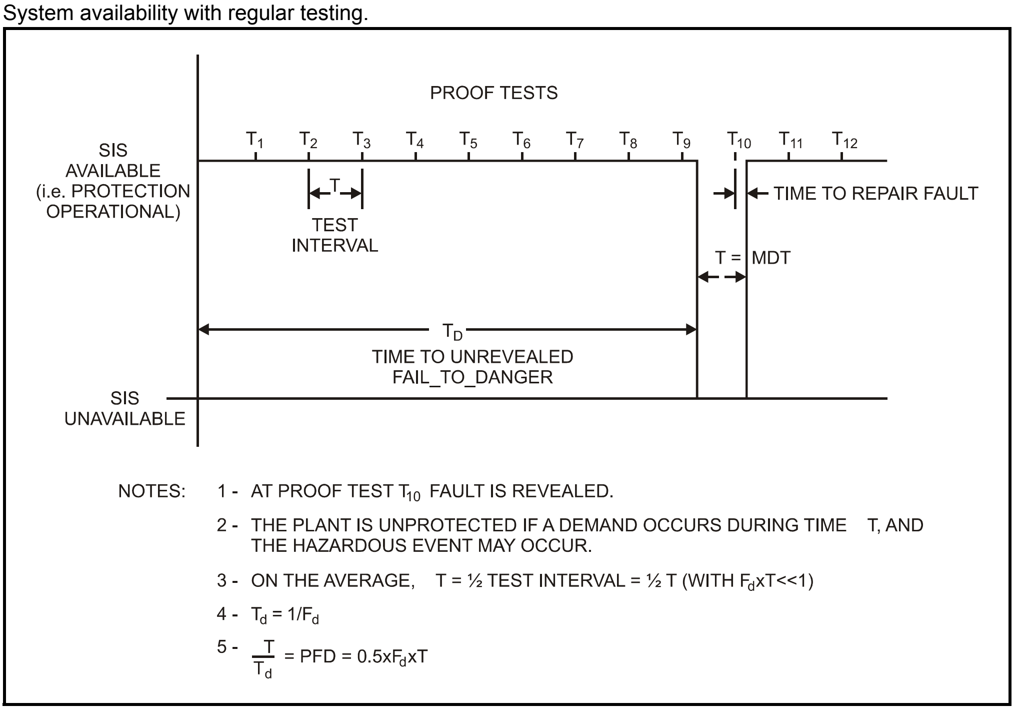
For a simple one-out-of-one trip system,

PFD = Fd x T/2 (see figure 10-6)

which means:

H = D x Fd x T/2

Figure 10-6
System availability with regular testing.



The hazardous event rate (H) is a small fractional number that represents the frequency at which a hazardous event may take place, expressed in occasions/year. This low value is specified by plant management (and generally not by the SIS designer). It is based on regulations, insurance guidelines, industry standards, and corporate guidelines.

Demand rate (D) is the frequency at which the SIS is required to perform, expressed in occasions/year. It is the frequency of a potentially hazardous event that would have occurred if the SIS was not providing protection.

Failure rate (F) is the rate at which the SIS develops a failure and becomes inoperative. The dangerous failures are the fail-to-danger (Fd), since the fail-to-safety (Fs) will reveal themselves and bring the process to a safe condition. Depending on the equipment used and on the application, the failure rate (F) of a SIS component may always fail-to-danger (Fd) or may never fail-to-danger (i.e., always fail in a safe mode). Some users have set a ratio of Fd to F (such as Fd = F / 3), while some others rely on collected data or other sources of information. F values are available from references, from compiled plant data, and from published references such as *Guidelines for Process Equipment Reliability Data* (Center for Chemical Process Safety / American Institute of Chemical Engineers, 1989) and *Offshore Reliability Data* (Det Norske Veritas, DNV Technica, 3d ed., 1997).

Test interval (T) is the time between tests. To be effective, T must be a lot less than the demand (D) on the system. On average, a failure occurs halfway between two tests; in other words, a component will be dead for T/2.

The five most commonly used equations are as follows:

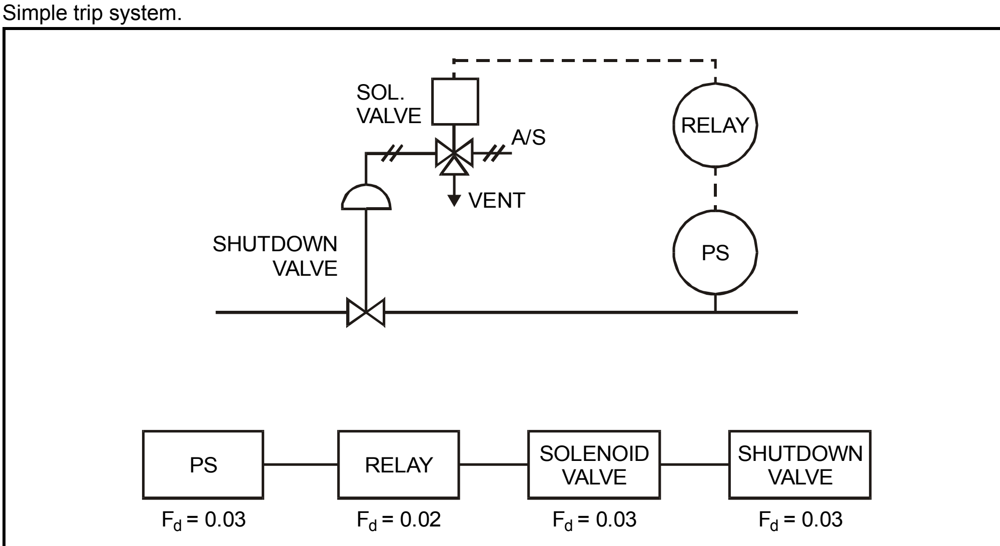
1. For simple 1oo1 (one-out-of-one) trips

$$H / D = PFD = 0.5 \times Fd \times T$$

   For example, if a SIS for environmental safety management consists of a pressure switch, relay, solenoid valve, and shutdown valve (see figure 10-7), then by adding each component's Fd rate:

$$0.03 + 0.02 + 0.03 + 0.03 = Fd\ total = 0.11$$

Figure 10-7
Simple trip system.



If T = twice a year = 6/12 = 0.5 yr, then

$$PFD = 0.5 \times 0.11 \times 0.5 = 0.0275$$

and that meets SIL 1 (which is 0.1 to 0.01).

With D = once every 2 years = 0.5 / yr

$$H = D \times PFD = 0.5 \times 0.0275 = 0.01375/\ yr$$

Or, once every seventy-three years. That is, it is expected that this SIS will fail on demand once every seventy-three years, releasing contaminants into the environment. This calculated hazard rate (H) should be compared with the hazard rate set by management.

It is not essential to test all the elements of a SIS at the same time. An average PFD can be calculated for different test frequencies, where;

$$PFD = 0.5 \times [(Fd_{sensor} \times T_{sensor}) + (Fd_{logic} \times T_{logic}) + (Fd_{valve} \times T_{valve})]$$

If, to improve the PFD, two components within a SIS are redundant, then the following 1oo2 equation should apply for these redundant components. This would apply to two switches in series where either one can trigger the trip logic or to two shutdown valves where either valve can trip the process. These redundant components should not have the potential of a common mode failure.

2. For 1oo2 (one-out-of-two) trips, that is, two parallel/redundant trips

$$PFD = (Fd^2 \times T^2)/3$$

3. For 2oo2 (two-out-of-two)

$$PFD = Fd \times T$$

4. For 2oo3 (two-out-of-three) trips

$$PFD = Fd^2 \times T^2$$

In industrial applications, 2oo3 logic provides a compromise between improved safety and reduced nuisance trips. For hardwired systems, this can be implemented as shown in figure 10-3.

5. For 2oo4 (two-out-of-four)

$$PFD = Fd^3 \times T^3$$

For other configurations, different equations apply.

Documentation

Good documentation begins at the design stage and continues through the commissioning, startup, and lifetime of a plant. During design, the hazards that require alarms or trips should be identified in the design notes, in the hazard analysis studies, and in drawings such as interlock diagrams and logic diagrams. SISs, in particular, should be clearly identified and should be kept up to date as the system evolves. The documentation of SIS should be under the control of a formal revision and release control program.

SIS implementation requires supporting documentation, such as the following examples:

- Safety requirement specifications
- A description of the logic (see figure 10-8 for a typical description)
- Design documentation, including quantitative or qualitative verification that the SIS meets the SIL
- A commissioning pre-startup acceptance test procedure
- SIS operating procedures
- Functional test procedures and maintenance procedures
- Management-of-change documentation

The plant should prepare the safety requirement specifications to identify both the functional and integrity requirements. These documents are needed for design activities, for normal plant operation, and for testing purposes. In most cases, safety requirement specifications are also incorporated into the plant operating manuals to provide quick and clear information to plant operating personnel the moment they need it. On very small applications, the SIS safety requirement specifications could be part of the logic diagrams (an example of a typical logic diagram is shown in figure 10-9).

The content of a typical safety requirement specifications encompasses the following:

- The definition of the safe state of the process for each of the identified events.
- The process inputs to the SIS and their trip points.
- The normal operating range of the process variables and their operating limits.
- The process outputs from the SIS and their actions.
- The functional relationship between the inputs, logic, and outputs.
- Selection of deenergized-to-trip or energized-to-trip (with the former the recommended method).
- Considerations for performing manual shutdown.
- Actions to be taken when the energy sources to the SIS are lost.
- Response time requirements for the SIS to bring the process to a safe state.
- The response action to any self-revealing faults.
- Operator interface requirements.
- Reset functions. A reset function is required in order for SIS systems to prevent an automatic restart once the process conditions have returned to normal. An operator intervention through the reset function ensures a safe condition before process restart.
- The required SIL for each safety function.
- The diagnostic, maintenance, and testing requirements to achieve the required SIL.
- Reliability requirements, where spurious trips may be hazardous.

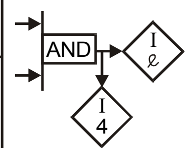
Testing

Every alarm and trip system will fail sooner or later. The primary purpose of testing is to uncover faults, and thus this activity is of prime importance in SIS applications. Testing should reveal all relevant faults, such as wear that prevents tight shutoff of a control valve or a plugged process isolation valve. According to its logic, a SIS must act when a hazardous condition is sensed. Therefore, the measurement, logic, and final element must all be functional—hence, all three components must be tested at regularly scheduled intervals.

The testing of SISs and the appropriate methods and equipment needed for testing should be considered at the design stage. The design documentation should provide a clear explanation of the intended method of testing and the assumptions on which the test method is based. The testing of SISs should, where possible, be designed to reveal all faults.

Figure 10-8
Logic description.

PLANT: *ABC Inc.* AT DESCRIPTION FOR: *FV - 128*

Measurement (Range)	Pre-alarm (Setting)	Trip (Setting)	Trip Logic	Trip Action (process effect)
FT - 127 (0-100 ℓ/h)	*FSL - 127 (15 ℓ/h)*	*FSLL - 127 (7 ℓ/h)*		*Close FV - 128 (Stop flow to tank T25)*
		PSL - 139 (5 kPa)		

COMMENTS:

This interlock is implemented to prevent a recurrence of the tank overflow that occurred on Feb. 12, 1982 (see accident report # 271 Ak7)

ATS Test Procedure Document Ref. Number: *ABC - 7 - 2*

Designed by: *J. Arnold* Date: *Feb. 20 / 82*

Checked by: *S. Black* Date: *Feb. 21 / 82*

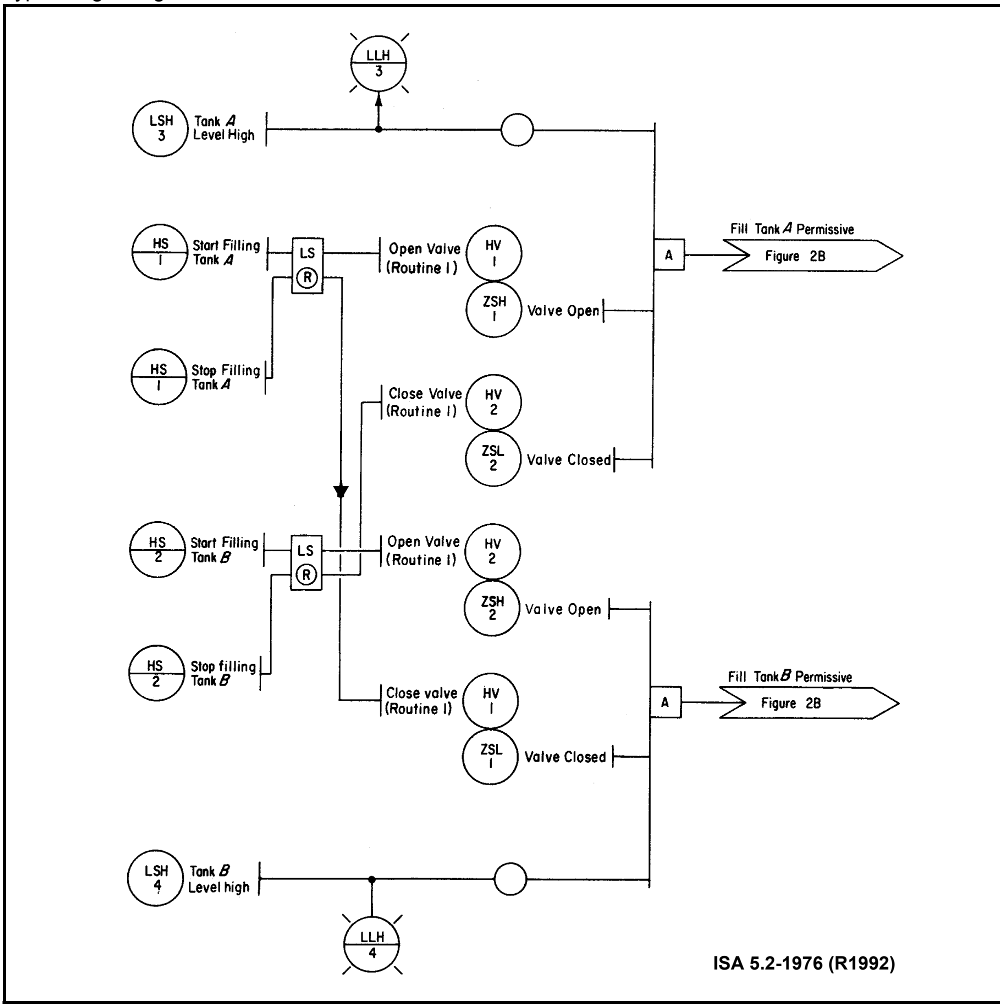
Approved by: *G. Khowy* Date: *Feb. 23 / 82*

The reliability of SISs is determined first through their fundamental design, then through the conditions under which they operate in the plant, and finally through the frequency by which they are tested. Sensors may be switches or transmitters. Switches are more direct, but they give no indication that they are functional. A transmitter, on the other hand, due to its continuous output is more likely to draw attention to its failure. Therefore, switches may require more frequent testing than transmitters.

Redundancy reduces the test frequency because the signals are valid as long as the two (or more) signals are identical. Diverse redundancy is preferred, for example, a pressure sensor backed up by a temperature sensor, both of which monitor the thermodynamic properties of a process.

Testing consists of creating an abnormal condition at the measurement point, observing the reaction of the final element, and ensuring that the logic has responded as expected. Testing should be done, where possible, using artificially generated process signals, since this checks the functionality of the SIS starting at the measuring element.

Figure 10-9
Typical logic diagram.



When the failure of a SIS causes a spurious alarm or trip, it is said to be "fail-safe" or "fail-to-safety." This is because its failure shuts the process down to a safe state and draws attention to its malfunction. If, however, a fault occurs that does not reveal itself, then when the system is called upon to alarm or trip, no alarm or trip will occur, and a sometimes dangerous occurrence may follow. Such faults are called "fail-to-danger." If a "fail-to-danger" fault occurs, the affected system will remain in a risk condition until the failure is revealed and corrected. A fail-to-danger fault may be revealed either by the system's failure to operate when required (an unwanted and hazardous condition in most cases) or by testing (obviously the preferred method).

Testing procedures should be, where possible, a simple and straightforward activity. Difficult and troublesome testing activities are quite often poorly performed or just ignored, which compromises the integrity of the SIS. SISs should be tested with minimal disturbance to the plant. The choice is between off-line testing, online testing— the two most common—and shutdown.

Off-line testing is performed while the process is off line, that is, not in operation. Off-line testing is the most common type of SIS testing. It has its limitations because scheduled shutdowns or turnarounds tend to be infrequent, of short duration, and very hectic, with the maintenance staff concentrating on scheduled repairs and readying equipment for production. Off-line testing is used before putting the SIS in service for the first time to confirm that the installed SIS meets the design requirements. The more frequent practice is to implement adequate testing during routine shutdowns.

Off-line testing must prove that the SIS can work under the required process conditions (e.g., at temperatures and pressures that will prevail when the plant must alarm or trip). This may be difficult if extreme conditions must be simulated by maintenance personnel, such as very high temperatures or pressures. Off-line testing may be an expensive proposition if the period between tests is shorter than the operating cycle. Therefore, SIS testing while the process is "on line" is sometimes required.

Online testing is performed while the process is on line, that is, operational. Online testing must be done under close supervision and in close cooperation with the operator. Great care must be exercised during online testing to avoid shutting down the plant by mistake. Even then, online testing is confined to those trips that can be defeated for a period of time without undue risk. During online testing, the operator should monitor the incoming data from the sensor(s) and be ready to manually shut down if the process deviates beyond a known limit, that is, a real demand on the now isolated SIS. Therefore, provisions must be in place for the operator's safe manual intervention should a genuine emergency arise while the testing is being performed.

Online testing of the final control elements is very difficult and must be carefully planned. A full test of a final control element can only be done at process shutdown, unless redundancy of that element is implemented. If it is, then procedures must be in place to ensure that the SIS with its redundant systems goes back on line when the testing is done. In critical cases, redundant output components, such as trip valves, are used. These allow one component to be tested while the other is fully functional. In some other cases, plants implement complete redundant SISs to provide very high reliabilities and to allow the full online testing of a SIS while the process is maintained under another SIS.

Shutdown testing is a form of online testing. Here, the testing of the trip actually shuts down the process. This type of trip is seldom used, except for batch systems, where the cycle frequency is relatively short. Shutdown trips do test the complete system and are usually done by (or under the guidance of) the operator. Shutdown testing intentionally brings the process to the actual trip condition to observe how the SIS responds. This method, if used, should be carefully evaluated before it is implemented, should be performed under controlled conditions, and should be avoided if it puts the whole process at risk.

After SIS equipment has been tested and repaired, it is a good and safe practice to have a second person inspect and approve the completed work. Also, the equipment operator must always be advised of (and agree to) an upcoming test.

Methods

SISs can be tested by breaking down the system into its three main elements (input, logic, and output) and testing them individually. Although the different elements can be tested at different intervals, a complete functional test of all elements as one unit should be done at a preset interval, for example, when the plant is shut down.

Inputs are tested by finding out if they respond correctly to a simulated or a real change in process conditions. The methods of testing in order of preference are as follows:

1. Isolating the impulse line to the measuring sensor, after closing the isolation valve, and injecting a simulated signal (while testing, the trip set point should be verified). See figure 10-10.

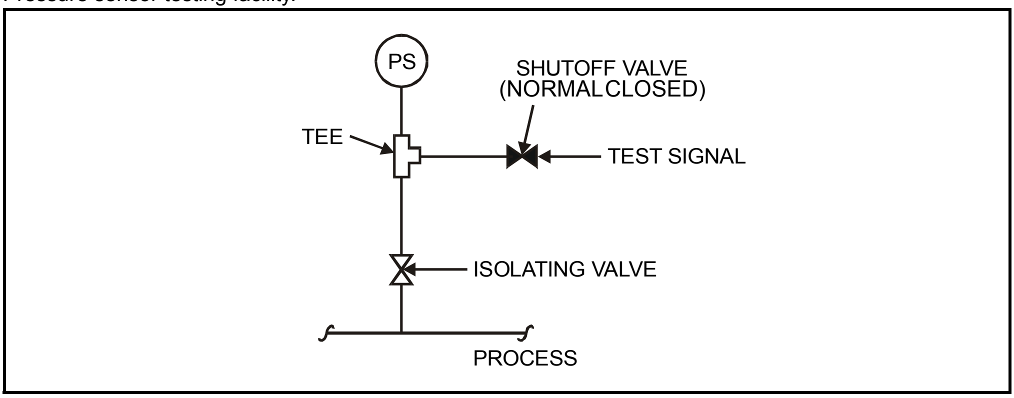
2. Altering the set point to cause a trip.

3. Altering the switch or transmitter output by altering its range or zero point.

Logic systems are tested by simulating action at the input and verifying that the output(s) respond correctly. This may require the use of defeat or bypass switches to enable section-by-section testing. When defeat or bypass switches are activated, an alarm in the plant control system should remind the operator at a set frequency (say, every hour) that the switch has not been reset yet. Logic testing should be done off line (where possible); online logic testing is difficult and may trip the plant.

Outputs are tested by finding out if they respond correctly to a simulated or a real command from the logic. The most common output devices for trip functions are motors and trip valves. Testing motors is a simple start/stop activity. Testing trip valves requires careful planning since a trip valve may also be a modulating control valve. The most common methods for testing valve-based trips, in order of preference, are as follows:

Figure 10-10
Pressure sensor testing facility.



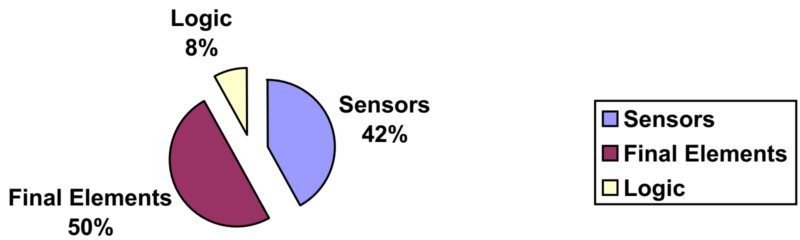
1. Allowing a valve to trip
2. Using a chock (a travel-limiting device) to limit valve movement and allow the valve to trip to chock
3. Injecting a suitable signal into the solenoid valve vent to control the movement of the main valve
4. Bypassing the action of the trip solenoid valve

Frequency

How often SISs should be tested is determined by codes and regulations, by the importance of a particular system to personnel safety or plant performance, by the calculations that were used to determine the required safety integrity level (in a quantified approach), and by the results of previous testing. In addition, testing must be done whenever changes are made to the SIS and also after the SIS has been down for an extended time. The reasons behind the plant's test frequency should be carefully recorded. In certain cases, the testing frequency may have to be modified, for example, where the process is harsher on the sensors and final elements than originally thought. When the frequency of testing is modified, all the modifications and reasons behind them should be carefully recorded.

As a starting point and in the absence of data, SIS testing can be set at a six- to twelve-month interval (but should not extend longer than once every three years). Analyzers are an exception and may need to be tested once per week, and sometimes once a day, depending on the analyzer and the expected accuracy. Sensors and control valves have the highest probability of failure. Therefore, the logic typically needs to be tested less frequently than the field devices that are facing the process conditions (see figure 10-11).

Figure 10-11
Typical breakdown of SIS failures.



Too much testing reduces availability and increases the probability that undetected human errors will be introduced. Insufficient testing reduces SIS reliability. A balanced approach is important. Where some plant production units run for long periods of time, their SISs must be tested while the plant is running. This is typically done without interrupting the process. Such online testing requirements should be considered at the detailed design stage. The SISs for processes that shut down relatively frequently can be tested off line.

Deferring a scheduled test to a later date is permissible either because the process is down or because the process shutdown is scheduled "shortly" after the SIS test is due. "Shortly" means when acceptable to safety, as determined through quantified data analysis, and typically within three months.

Procedures

Test procedures verify the operation and speed of response of all SIS components (including the logic sequence), the operation of all alarms, and the operation of the manual trips and system reset.

Test procedures must not jeopardize the safety of maintenance personnel or personnel of the production facilities. When implementing a test procedure, the designer should determine if such testing will reveal all possible faults, such as wear that prevents tight shutoff or plugged process isolation valves. The tests should be designed to minimize the risk of spurious trips and to allow safe manual overrides to intervene when plant emergency conditions develop during testing. The SIS test procedure is generally worked out and agreed upon by the various responsible persons in the plant and must be kept up to date. A test procedure is recommended for every alarm and trip in the plant, but is essential for all SISs.

A plant's process for preparing, reviewing, and approving the SIS test procedure should consider the following factors: the SIS test frequency, hazards to personnel and to equipment, reference information such as drawings and specifications, and the equipment and personnel who must do the testing. A simplified example of a completed SIS test procedure is shown in figure 10-12.

The following information should be indicated in the test procedure:

- Frequency of alarm/trip test
- Hazards to personnel and to equipment, required protection, and list of safety functions
- Reference information (i.e., drawings, specifications, etc.)
- Required test equipment and personnel
- Testing procedures
- Description and location of equipment to be tested

- Logic description
- Acceptable performance limits (e.g., +/- 2% of expected reading), where applicable
- The state of the process when the test is performed

The results of SIS testing and the corrective actions (where needed) are recorded on a document that is generally cross-referenced to the SIS description and the SIS test procedure. The document is completed by the person doing the testing and checked by a person responsible for SIS testing in the plant. This document should be available for future reviews, plant audits, or investigations should plant problems occur.

SIS test results typically show the following:

- The date of the test/inspection
- The name of the person(s) who performed the test/inspection
- The identification of the system (i.e., tag numbers)

Figure 10-12
Typical test procedure.

PLANT: ABC Inc. ATS TEST PROCEDURE FOR: *FV - 128*

Test Frequency: *Yearly*

Hazards: Highly corrosive (refer to safety procedures Sp7215)

Reference Information: Instrument Index sheet # *ABC - 7 - 2*

Requirements – Personnel: 2 maintenance (1 piping and 1 instrument);
Equipment: 2 pressure testers, model Ak78, and stand, tool box.

Test Procedures

1. Advise operator and get work permit.
2. Activate I2 bypass switch (SW7) on control panel and ensure bypass light is ON.
3. Isolate FSLL-127 (a diff. press. switch) from process, open tee shut-off valve V36 and drain fluid in impulse line.
4. Inject regulated air signal into FSLL-127, bring to diff. press. of 5” WC (= to 7 l/hr) – check that trip switch activates.
5. Isolate PSL-139 from process, open tee shut-off valve V37, and drain fluid in impulse line.
6. Inject regulated air into PSL-139 and bring to 5 kPa – check that trip switch activates.
7. Now that both switches are activated, check that logic has activated, and send a command to trip FV-128 (but bypassed by Sw7).
8. Close the two isolation valves for FSLL-17 and PSL-139 (V36 + V37) and reconnect to process.
9. Deactivate I2 bypass switch Sw7.
10. Advise control room operator of completion and return work permit.

End of Test Procedure.

ATS Description Document Ref. Number: *ABC - 7 - 1*

Designed by:	*S. Black*	Date:	*6 Mar. 82*
Checked by:	*K. Red*	Date:	*6 Mar. 82*
Approved by:	*J. Smith*	Date:	*10 Mar. 82*

- A description of the test/inspection to be performed and the identification of tested equipment
- The results of the test/inspection (both as-found and as-left conditions)
- Proof that the test/inspection was carried out
- A record showing the deficiencies and the required corrective actions
- A record to be used when reviewing testing frequency
- Confirmation that the SIS is operational after testing

Commissioning and Pre-startup

Commissioning encompasses the checking of installation and wiring work. An installation check confirms

- that all temporary supports, connections, and the like are removed,
- that impulse and air line tubing installations are properly routed and supported,
- that all instruments are installed correctly,
- that tagging and nameplate details are correct and details match the corresponding specification sheet,
- that pressure testing for tubing is successfully completed, and
- that regulator pressures and purge flows are correctly set.

A wiring check confirms

- that wiring is correct (through a continuity test),
- that power supply sources are operational and set per specifications,
- that grounding is implemented correctly, and
- that all SIS components and energy sources are operational.

Other checks confirm that

- all instruments are properly calibrated.
- all loops are functional.
- all documentation is available.

The pre-startup acceptance test (PSAT) ensures that the SIS as installed conforms with the design before hazards are introduced. Records must be kept to substantiate that the PSAT is completed. The PSAT confirms that

- all SIS components and links to other systems perform according to the design.
- safety devices are tripped at the defined set points.
- the proper shutdown sequence is activated.
- alarms are correctly displayed.
- the reset functions are operational.
- bypass functions and manual shutdowns operate correctly.
- all documentation (including test procedures) are consistent with the design and installation.

Management of Change

A written management-of-change procedure must be implemented to initiate, document, review, and approve all changes to the SIS other than replacement in kind. The review process must include personnel from appropriate disciplines including ownership (typically, operations), knowledge (typically, process and instrumentation engineers), and maintenance. In addition, the review stage of the change must ensure that the safety integrity of the SIS is maintained.

The management of change ensures that the following factors are considered before any change:

- The technical basis for the proposed change
- The impact of change on safety and health
- Modifications for operating procedures
- The time period needed for the change
- Authorization requirements for the proposed change
- Where applicable, the availability of memory space
- The effect of the change on response time
- Online versus off-line change, and the risks involved

CHAPTER 11

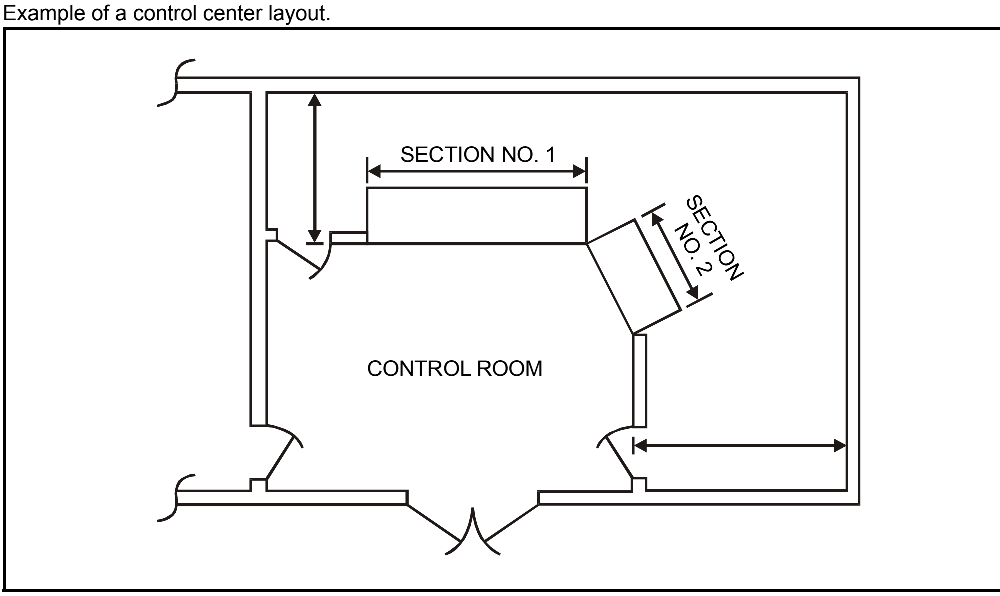
Control Centers

Overview

The design of control centers must meet the codes and regulations in effect at the site as well as the requirements for the plant's operation. Control centers, also commonly referred to as "control rooms," form the nerve center of a plant. They are generally air-conditioned, sometimes pressurized with clean air, and their temperature and humidity are controlled to preset conditions. Additional information is available from ISA-71.01-1985, Environmental Conditions for Process Measurement and Control Systems: Temperature and Humidity.

When designing a control center, the designer must develop a layout (see figure 11-1) and ensure that the center's design and use conforms to good engineering practice and standards. A good source of information on these is ISA's RP60 series of recommended practices for control centers. Some of the items that should be addressed when designing control centers are design, physical aspects, security, fire protection, air conditioning, electrical/electronic, and communication. These are discussed in this chapter.

Figure 11-1
Example of a control center layout.



Design

Many points should be considered when designing control centers. For example, the control room should be located, whenever possible, away from sources of vibration and completely protected from heavy rain, external fire-fighting water, and the like. In some cases, the control room must be earthquake-proof. For safety purposes, no process lines should enter the control room except for instrument air. The electrical area classification should be taken into account when locating and designing the control room.

Where required (and where economically justifiable), the control room may need a false floor for the passage of cables and/or tubing. In this case, smoke detectors should be installed underneath the false floor, and the floor should be made of a flame-resistant and anti-static material. Where equipment has to be accessed, space should be allowed between that access area and the nearest obstruction (such as a wall), with a minimum of 3 ft (1 m) clearance. In most cases, control room doors should be of the self-closing type.

To avoid electrical noise, high-voltage cabling should be routed at a 3 ft (1 m) distance from low-voltage cabling. Also, to avoid unnecessary noise, air conditioning units are typically kept outside the room. There should be a minimum of two sockets in the control room for portable power tools and other uses.

Easy and safe access must be available so the control room equipment can be brought into the room. As obvious as this may sound, many control rooms were completed before it was realized that the purchased equipment would not fit through the doors. Construction and warehousing personnel should coordinate to ensure that openings are left in walls so large equipment panels can be installed.

Physical Aspects

When designing control centers, the physical characteristics of the operators should be considered. For example, the distance the operator must move should be considered and reflected in the design. Locating controls in hard-to-reach areas that require extreme physical movement will produce fatigue and should be avoided. The dimensions shown in figures 11-2 and 11-3 as well as in tables 11-1 and 11-2, reflect the static anthropometric data. It may be refined to reflect the physical characteristics of a given plant's actual operators.

Control room design should have a good ergonomic layout. Details such as the type of chairs used, their ability to adjust height and tilt, and the type of armrests selected are all important factors. Operator comfort is directly related to operator performance and efficient plant operation.

Figure 11-2
Standing body dimensions.

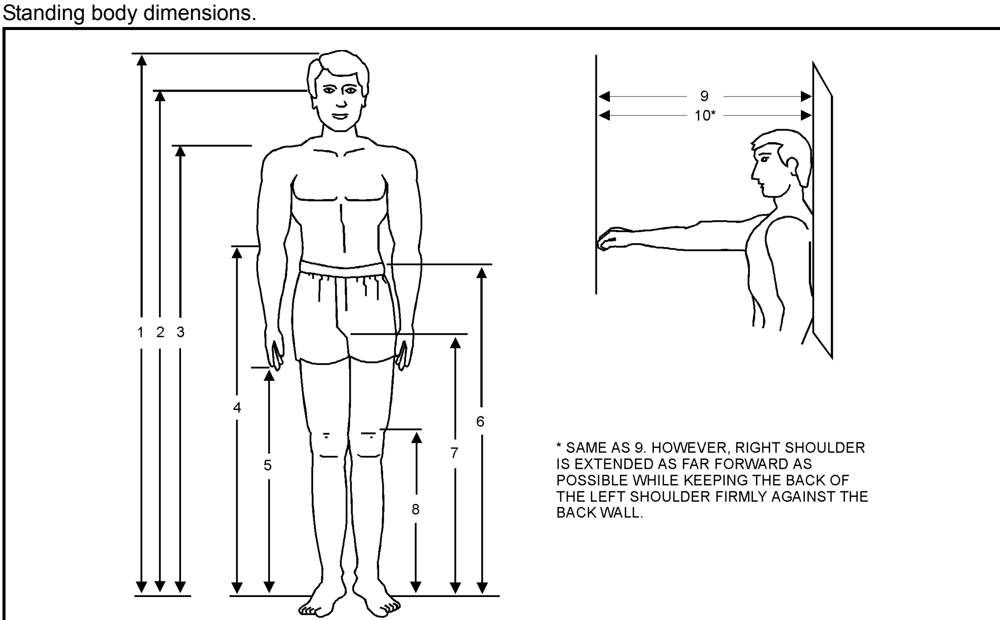


Table 11-1
Standing body dimensions.

	Percentile values in centimeters					
	5th percentile			95th percentile		
	Ground troops	Aviators	Women	Ground troops	Aviators	Women
Weight (kg)	55.5	60.4	46.4	91.6	96.0	74.5
Standing body dimensions						
1 Stature	162.8	164.2	152.4	185.6	187.7	174.1
2 Eye height (standing)	151.1	152.1	140.9	173.3	175.2	162.2
3 Shoulder (acromiale) height	133.6	133.3	123.0	154.2	154.8	143.7
4 Elbow (radiale) height	101.0	104.8	94.9	117.8	120.0	110.7
5 Fingertip (dactylion) height		61.5			73.2	
6 Waist height	96.6	97.6	93.1	115.2	115.1	110.3
7 Crotch height	76.3	74.7	68.1	91.8	92.0	83.9
8 Kneecap height	47.5	46.3	43.8	58.6	57.8	52.5
9 Functional reach	72.6	73.1	64.0	90.9	87.0	80.4
10 Functional reach, extended	84.2	82.3	73.5	101.2	97.3	92.7
	Percentile values in inches					
Weight (lb)	122.4	133.1	102.3	201.9	211.6	164.3
Standing body dimensions						
1 Stature	64.1	64.6	60.0	73.11	73.9	68.5
2 Eye height (standing)	59.5	59.9	55.5	68.2	69.0	63.9
3 Shoulder (acromiale) height	52.6	52.5	48.4	60.7	60.9	56.6
4 Elbow (radiale) height	39.8	41.3	37.4	46.4	47.2	43.6
5 Fingertip (dactylion) height		24.2			28.8	
6 Waist height	38.0	38.4	36.6	45.3	45.3	43.4
7 Crotch height	30.0	29.4	26.8	36.1	36.2	33.0
8 Kneecap height	18.7	18.4	17.2	23.1	22.8	20.7
9 Functional reach	28.6	28.8	25.2	35.8	34.3	31.7
10 Functional reach, extended	33.2	32.4	28.0	39.8	38.3	36.5

Figure 11-3
Seated body dimensions.

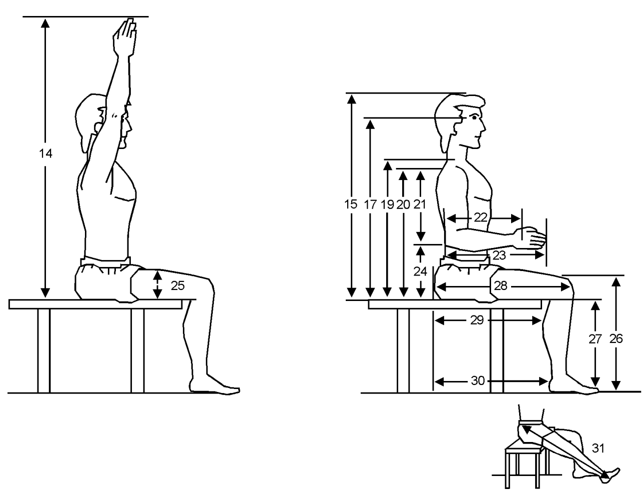


Table 11-2
Seated body dimensions.

	Percentile values in centimeters					
	5th percentile			95th percentile		
	Ground troops	Aviators	Women	Ground troops	Aviators	Women
Seated body dimensions						
14 Vertical arm reach, sitting	128.6	134.0	117.4	147.8	153.2	139.4
15 Sitting height, erect	83.5	85.7	79.0	96.9	98.6	90.9
16 Sitting height, relaxed	81.5	83.6	77.5	94.8	96.5	89.7
17 Eye height, sitting erect	72.0	73.6	67.7	84.6	86.1	79.1
18 Eye height, sitting relaxed	70.0	71.6	66.2	82.5	84.0	77.9
19 Mid-shoulder height	56.6	58.3	53.7	67.7	69.2	62.5
20 Shoulder height, sitting	54.2	54.6	49.9	65.4	65.9	60.3
21 Shoulder-elbow length	33.3	33.2	30.8	40.2	39.7	36.6
22 Elbow-grip length	31.7	32.6	29.6	38.3	37.9	35.4
23 Elbow-fingertip length	43.8	44.7	40.0	52.0	51.7	47.5
24 Elbow rest height	17.5	18.7	16.1	28.0	29.5	26.9
25 Thigh clearance height		12.4	10.4		18.8	17.5
26 Knee height, sitting	49.7	48.9	46.9	60.2	59.9	55.5
27 Popliteal height	39.7	38.4	38.0	50.0	47.7	45.7
28 Buttock-knee length	54.9	55.9	53.1	65.8	65.5	63.2
29 Buttock-popliteal length	45.8	44.9	43.4	54.5	54.6	52.6
30 Buttock-heel length		46.7			56.4	
31 Functional leg length	110.6	103.9	99.6	127.7	120.4	118.6
	Percentile values in inches					
Seated body dimensions						
14 Vertical arm reach, sitting	50.6	52.8	46.2	58.2	60.3	54.9
15 Sitting height, erect	32.9	33.7	31.1	38.2	38.8	35.8
16 Sitting height, relaxed	32.1	32.9	30.5	37.3	38.0	35.3
17 Eye height, sitting erect	28.3	30.0	26.6	33.3	33.9	31.2
18 Eye height, sitting relaxed	27.6	28.2	26.1	32.5	33.1	30.7
19 Mid-shoulder height	22.3	23.0	21.2	26.7	27.3	24.6
20 Shoulder height, sitting	21.3	21.5	19.6	25.7	25.9	23.7
21 Shoulder-elbow length	13.1	13.1	12.1	15.8	15.6	14.4
22 Elbow-grip length	12.5	12.8	11.6	15.1	14.9	14.0
23 Elbow-fingertip length	17.3	17.6	15.7	20.5	20.4	18.7
24 Elbow rest height	6.9	7.4	6.4	11.0	11.6	10.6
25 Thigh clearance height		4.9	4.1		7.4	6.9
26 Knee height, sitting	19.6	19.3	18.5	23.7	23.6	21.8
27 Popliteal height	15.6	15.1	15.0	19.7	18.8	18.0
28 Buttock-knee length	21.6	22.0	20.9	25.9	25.8	24.9
29 Buttock-popliteal length	17.9	17.7	17.1	21.5	21.5	20.7
30 Buttock-heel length		18.4			22.2	
31 Functional leg length	43.5	40.9	39.2	50.3	47.4	46.7

Security

If the control center is considered a high-security area, the entrance will have to be restricted and a means for maintaining this restrictiveness incorporated. This is generally accomplished by requiring the use of badges or magnetic cards and permitting only approved personnel into the control room.

Another aspect of security is access to software and software management. It is good practice to have duplicate copies of software stored in separate locations and to maintain control over who has access to these storage areas.

Fire Protection

The fire protection system in the control center must conform to the requirements of the local codes and regulations as well as the requirements of the insurance companies. The fire protection system must be designed by qualified fire protection specialists.

When plant designers assess the fire hazards, they must make a determined effort to reduce fire hazards by constructing the control room (including the floor) of noncombustible material and reducing stacks of paper. It is good practice to have a separate area for high-risk devices (such as printers) unless they must be in the control room. If they are, then the storage of paper in the room should be kept to a minimum. The designers should assess whether records (or tapes) should be stored in fire-proof safes, in the control room, or in a remote area.

The use of a safe fire-protection fluid will ensure that the fire protection system poses no harm to the control room operator. In addition, hand-operated fire extinguishers of dry CO_2 are usually stored near the exits of most control rooms. The room is usually designed with emergency lighting since non-essential power services will shut off during a fire, and means should be provided to ensure that power supplies can be manually or automatically isolated.

Placing basements below control rooms is not recommended because they may collect water from fire-fighting or even from rain. Also, in control rooms with false floors, water may accumulate under the floor. A water detector may therefore be required.

Air Conditioning

Air conditioning maintains a comfortable working environment for the operators while dissipating the heat that is released by all the equipment in a typical control center. The air-conditioning unit must be sized to maintain temperature and humidity within the requirements of the control systems, for example, around 75°F (24°C) and 50% RH.

The air conditioning air intake must be located where it will supply clean air to the control center even during an abnormal situation such as the discharge of a nearby relief valve. Under normal operating conditions, air conditioning maintains a comfortable working environment, but during a power failure the air-conditioning unit will stop. Heat will begin to build up because in most plants the control system will remain operational since it may be on stand-by power. Control room design for critically hot environments should consider installing more than one air-conditioning unit in case one unit fails. Additional information on control room temperature and humidity conditions is available from ISA-71.01-1985.

Pressurized rooms located in hazardous locations must conform to the code and statutory requirements in effect at the site (such as NFPA 496). They should be clearly marked with the following:

- a notice stating “WARNING - PRESSURIZED ROOM”;
- a warning located at both the control switch for the source of pressurization and at the relevant points of electrical isolation that indicates the time in minutes for which purging is to operate before the electrical supply can be switched on or restored; and
- a warning at all entrances to the pressurized room against introducing any flammable materials.

Electrical/Electronic Considerations

The design of a control center must ensure that all electrical peripheral functions such as grounding, lighting, and electronic interference suppression are correctly implemented. All power and chassis grounds and cable shields should be connected to the grounding electrode in conformance with the recommendations of the system vendor. Cabling in and out of the control room must go through wall penetrations and must be adequately sealed to prevent the entry of water.

In situations where both electrical power services and control signal cabling are distributed using subfloor cable trays, the design should ensure that the trays for electrical power distribution and for control and communication signals are kept a minimum of 3 ft (1 m) apart and cross at right angles only. This will minimize the potential of generating electrical noise. To prevent electronic interference, susceptible equipment (such as microcomputers and networks) should be kept far from high-power electrical equipment.

Lighting requirements should be evaluated. For instance, the lighting needed to monitor display areas is typically less than that required for printers and disk drives. However, for maintenance purposes, strong lighting is needed throughout the control center. Control center lighting may be provided by fluorescent fixtures mounted above parabolic egg-crate-type ceiling panels (to diffuse light and minimize glare on displays). Dimmers should be used to control different sections of the control center. There should be at least two independently controlled circuits: one for general room lighting and the second for monitor display lighting. And, if lighting is not supplied from the UPS, there should be a separate emergency light in the control center.

Communication

In many modern control centers walkie-talkies are not allowed. A sign to that effect may be installed on the control center door. This is done to avoid the effect of electrical noise that walkie-talkies generate. In such cases, an FM transceiver with a roof-top mounted antenna is supplied to make possible communication with field operators who are using walkie-talkies. Inside the control center, movable microphones (or telephone handsets with long cords) should be provided on each console. Walkie-talkies should operate on a unique assigned frequency to avoid interference from other nearby units and operations.

C H A P T E R 1 2

ENCLOSURES

Overview

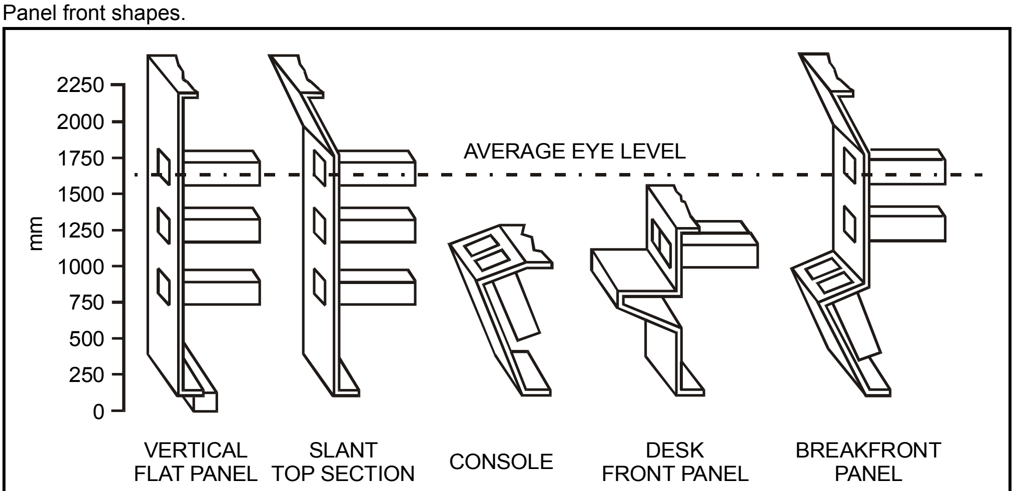
Enclosures, which include control panels and cabinets, house items of instrumentation and controls as well as their peripherals such as wiring, terminal blocks, power supplies, and the like. Enclosures are typically assembled in a panel assembly shop by professionals who should know in detail what the owner's requirements are. It is therefore important that the plant prepare a specification that covers the design, construction, assembly, testing, and shipping of the enclosure.

A typical specification should address the following topics: general requirements, documentation, fabrication, protection and rating, nameplates, electrical considerations, pneumatics, temperature and humidity control, inspection and testing, certification, and shipping. This chapter will address these topics.

There are many type of control panels (see figure 12-1).

- Vertical panels are simple in design and cost less than the others; they could be wall or floor mounted.
- Slant-top section panels use their top segment typically to mount annunciators or semi-graphic displays.
- Consoles are used to facilitate operator access to push buttons and indicator lights.
- Desk front panels are commonly used to provide an operator with a “look-over” capability.
- Breakfront panels provide good access and improve aesthetics. They tend to be custom built and therefore cost more than regular panels.

Figure 12-1
Panel front shapes.



General Requirements

One of the first rules in building control panels is to ensure that all electrical components comply with the requirements of the current edition of the electrical code in effect at the site and that they are approved by and bear the approval label of the testing organization (e.g., UL, FM, CSA, etc.).

In most cases, the panel assembly shop furnishes the panel completely fabricated and finished, with all components mounted, piped, wired, and tested. This work should be done in accordance with the requirements the owner identified in a specification. These requirements will vary with project needs, but typically a specification states that

- all instruments and equipment that the specification does not indicate the owner will supply to the panel assembly shop shall be supplied by the panel assembly shop. This ensures that no devices, however minor, are forgotten.
- the work of assembling the enclosure should be carried out by certified and trained tradesmen, who should have adequate supervision and the equipment necessary to complete the work. The panel assembly shop may also be required to produce evidence of tradesmen's certification and training to ensure that only qualified personnel assemble the panel.
- the panel assembly shop is responsible for correctly installing and assembling all items or equipment and for carefully reading and rigidly adhering to the manufacturer's instructions. Any damage caused by failure to observe the manufacturer's instructions must be the responsibility of the panel assembly shop.
- uniformity of manufacture is maintained for any particular item throughout the panel. This facilitates the inventorying of spare parts and reduces the need for training of on-site maintenance personnel.
- all instruments are installed and connected so they can be maintained and removed for servicing without having to break fittings, cut wires, or pull hot wires. This includes providing the necessary unions and tubing connections for all instruments (to facilitate their removal for maintenance).
- for enclosures that are located outdoors, rain shields are commonly required even if the enclosures are of weatherproof construction. This is because rainwater could drip inside the panel while the doors are open during construction or maintenance, and destroy the electronic equipment.

Additional information is available from ISA's recommended practice ISA-RP60.3-1985, Human Engineering for Control Centers.

Documentation

The owner (or his appointed representative, such as an engineering firm) should supply the panel assembly shop with the documentation to completely and correctly fabricate and assemble the enclosures. Such documentation typically includes instrument index, loop diagrams, electrical control schematics, instrument specifications, nameplate drawing (where applicable), certified vendor drawings (where applicable), and front-of-panel general layout.

The front-of-panel general layout normally shows the physical size of the control panel and the approximate positions of front-of-panel instruments, lights, switches, push buttons, and displays. This drawing may also give the approximate locations of cable and tube entries and electric/pneumatic supplies, while leaving the determination of the exact dimensions to the panel manufacturer.

Before construction begins, the panel manufacturer is expected to furnish detailed drawings to the owner for approval. These drawings typically include steel fabrication drawings (used only for custom panels); detailed front-of-panel layout; detailed back-of-panel layout; wiring diagram and terminal layout; and tubing, air header, and bulkhead layouts. Additional information is available from ISA's recommended practice ISA-RP60.4-1990, Documentation for Control Centers.

Fabrication

Standard off-the-shelf enclosures are used for most applications. Custom-built panels involve high cost, long delivery times, and relatively low quality control during fabrication. Given the diversity of available standard off-the-shelf enclosures and their modularity, custom panels have become a rarely supplied item.

When selecting standard enclosures, the users should keep in mind that they must comply with the codes and regulations in effect at the site, the area classification, the environmental requirements, and the application/plant requirements. In some applications, the content of an enclosure will need to be viewed regularly. To avoid having to frequently open and close the enclosure door, acrylic door panels are installed that enable the content to be viewed. Keep in mind, however, that non-metallic enclosures do not provide protection to noise-sensitive electronic equipment.

Sometimes for security reasons, locked enclosures are specified. Designers must give this careful consideration, since locking an enclosure may create problems in emergencies when immediate access is required. Examples include extinguishing a fire that is starting inside the enclosure or even performing regular maintenance when the key cannot be found. To avoid these situations, personnel may just leave the key on the panel—defeating its purpose.

It is a good practice to allow spare panel space (say 25 to 30%), thus allowing for the installation of future equipment without having to buy and install new panels. Unused panel areas should be kept free of wiring and terminals to facilitate the mounting and wiring of future equipment.

When designing a panel, the layout of incoming and outgoing wiring is closely related to the location of input/output modules. Therefore, input/output module placement determines the routing of wires.

Protection and Rating

Enclosure protection and rating is usually described according to one of two systems: the NEMA system (for National Electrical Manufacturers Association, the system common in North America) and the IEC/CENELEC Ingress Protection (IP) code (CENELEC is the European Committee for Electrotechnical Standardization). The NEMA system defines the characteristics of an enclosure according to certain tests and to their locations, indoor or outdoor (see tables 12-1 and 12-2).

The IEC/CENELEC approach commonly states the degree of protection in terms of a code “IPxy,” where *x* relates to the ingress of solid foreign objects and *y* for the ingress of liquids (see tables 12-3 and 12-4). There is no direct correlation between the two systems. However, table 12-5 shows a conversion from NEMA type numbers to IP codes.

Nameplates

Nameplates are required to identify panel equipment. For all panel instruments, the panel fabricator should supply and mount an engraved three-ply laminated plastic nameplate (for example, white-on-black core) that indicates the tag number as shown on the drawings. The characters must be big enough so the tag number can be read clearly from a reasonable distance. Nameplates for panel devices can be attached with adhesives only in air conditioned room environments, whereas in all other areas they are mechanically attached with rivets or screws. Additional information on nameplates is available from ISA's recommended practice ISA-RP60.6-1984, Nameplates, Labels, and Tags for Control Centers.

Table 12-1
Enclosures for indoor locations.

Provides some protection against these environmental conditions	Enclosure Type									
	1	2	4	4X	5	6	6P	12	12K	13
Incidental contact with enclosed equipment	*	*	*	*	*	*	*	*	*	*
Falling dirt	*	*	*	*	*	*	*	*	*	*
Falling liquids and light splashing		*	*	*	*	*	*	*	*	*
Circulating dust, lint, fibers, and flyings			*	*		*	*	*	*	*
Settling airborne dust, lint, fibers, and flyings			*	*	*	*	*	*	*	*
Hosedown and splashing water			*	*		*	*			
Oil and coolant seepage								*	*	*
Oil or coolant spraying and splashing										*
Corrosive agents				*			*			
Occasional temporary submersion						*	*			
Occasional prolonged submersion							*			

Table 12-2
Enclosures for outdoor locations.

Provides some protection against these environmental conditions	Enclosure Type						
	3	3R	3S	4	4X	6	6P
Incidental contact with the enclosed equipment	*	*	*	*	*	*	*
Rain, snow, and sleet	*	*	*	*	*	*	*
Sleet			*				
Windblown dust	*		*	*	*	*	*
Hosedown				*	*	*	*
Corrosive agents					*		*
Occasional temporary submersion						*	*
Occasional prolonged submersion							*

Table 12-3
Degree of protection against contact and entrance of solid foreign bodies.

Numeral	Degree of Protection	Type Test
0	No protection against contact or entry of solids	None
1	Protection against accidental contact by hand, but not deliberate contact. Protection against large bodies.	No touching of live or moving parts by a 50 mm-diameter sphere.
2	Protection against contact by fingers. Protection against medium-size foreign bodies.	No admission of 12.5-mm-diameter ball. No contact with a test finger of standardized design, roughly 80-mm long by 12-mm diameter.
3	Protection against contact by tools, wires, etc. Protection against small foreign bodies.	No entry by a 2.5-mm-diameter wire.
4	Protection against contact by small tools and wires. Protection against small foreign bodies.	No entry by a 1-mm-diameter wire
5	Complete protection against contact with live or moving parts. Protection against harmful deposits of dust.	Tested in dust chamber with vacuum applied to inside of enclosure, 200-mm H_2O approximately, to draw 80 enclosure volumes through enclosure. Dust may enter, presumably not enough to affect function.
6	Complete protection of live or moving parts. Protection against ingress of dust.	Same test as above, but no entry of dust permitted.

Table 12-4
Degree of protection against ingress of liquids.

Numeral	Degree of Protection	Type Test
0	No protection	None
1	Protection against drops of condensed water. Condensed water falling in enclosure shall have no effect.	Similar to that for Numeral 2, with enclosure on turntable for 10 minutes exposure in normal mounting position. Flow rate 1 mm/min.
2	Protection against drops of liquid. Drops of falling liquid shall have no effect when enclosure is tilted to 15° from vertical.	Tested with dripping reservoir for 2.5 min. in each of 9 positions of 15° tilt. Water shall not interfere with function or collect of cable entry. Drip rate 3 mm/min.
3	Protection against rain. No harmful effect from rain at angle less than 60° from vertical.	Oscillating spray head sprays enclosure for 10 min. from angle between ± 60°. Water shall not interfere with function or collect at cable entry.
4	Protection against splashing from any direction.	Same test as above, but angle is ± 180° from vertical. Water shall not interfere with function or collect at cable entry.
5	Protection against water jets from any direction.	6.3 mm nozzle, 12.5 l/min., 2.5-3 m from equipment from all directions for 1 min./m^2 area, 3 min. minimum. Water shall not interfere with function or collect at cable entry.
6	Protection against conditions on ships' decks. Water from heavy seas will not enter.	Same as 5 except 12.5 mm nozzle 2.5-3 m from equipment, 1001/min, and no water shall enter.
7	Protection against immersion in water. Water will not enter under stated conditions of pressure and time.	Immersion under head of 1-m for 30 min. No entry of water.
8	Protection against indefinite immersion in water under specified pressure.	Test to be agreed between manufacturer and user.

Table 12-5
Conversion of NEMA type numbers to IEC IP codes (Do not use this table to convert from IP codes into NEMA type numbers).

NEMA Enclosure Type Number	IEC/CENELEC IP Code
1	IP10
2	IP11
3	IP54
3R	IP14
3S	IP54
4 and 4X	IP56
5	IP52
6 and 6P	IP67
12 and 12K	IP52
13	IP54

Electrical

In a typical enclosure arrangement, the wiring is routed so that all wires connected to the panel go to individual terminals and the wire number is identified with a permanent marker reflecting the number shown on the drawings. Spare terminals should always be added. For example, a minimum of 25 percent or 10 spare terminal points, whichever is greater, should be provided on each strip. In addition, all terminals must be suitably protected so the accidental touching of live parts is unlikely.

Good engineering practice requires that no more than two wires go to one terminal point and that no wire splicing be permitted in cable ducts or anywhere in the panel except on identified terminal blocks. Some applications require weatherproof wire splices (instead of terminal blocks) to ensure no short circuits will occur if wire terminations get wet. In some cases, plants standardize on colors and wire gages. This allows maintenance personnel to identify the function of a wire just by looking at it.

Where a common 24-V DC power supply is needed to power many instrument loops, the panel manufacturer may be required to supply and install a dual power supply system. Such a system should be protected by diodes in case one of the two should fail. In addition, each power supply unit should have sufficient power for all the loops in the panel and still have at least 25 percent spare capacity. For each of the two power supplies it is helpful to have an output contact to alarm in case of failure.

It is a good practice for each instrument loop to have its own terminal-mounted power-supply disconnect switch, especially for startup and maintenance/troubleshooting activities. This enables each loop to be serviced individually without affecting other loops. This disconnect typically includes its own overload protection device rated for the low-power instrument loop (e.g., 0.5A fuse).

120-V AC wiring is typically run in cable ducts that are separate from low-voltage wiring. The panel assembly shop should furnish and install multiple circuit power distribution panels with circuit breakers. To avoid electrical noise problems, the plant must run thermocouple (and other very low-voltage signals), 24-V DC, and 120-V AC wiring in three separate cable ducts.

To facilitate the work of maintenance personnel, at least two tool receptacles (with ground fault protection) and overhead lighting should be provided for every eight feet (2.5 m) of panel length. Fluorescent lighting is a source of electromagnetic interference. If such lighting must be used then some precautions should be implemented to protect the panel-mounted electronic equipment. These precautions include enclosing the switch in a metal enclosure, shielding the cable between the lamp and the switch, and installing a shielding grid over the lamp. The power for panel-mounted instruments and back-of-panel instruments is sometimes provided by a three-prong grounded plug and flexible cord running to conveniently located receptacles, while all other wiring is hardwired to terminals.

To ensure that the safety of equipment used in hazardous areas is not jeopardized, the plant should install only certified equipment in hazardous areas and should strictly follow the code requirements. Where purging is required, it is normally done with clean, dry, oil-free instrument air. This purging should conform to the pressure-sensing and interlocking requirements of the electrical code in effect at the site.

Additional information on implementing electrical equipment in hazardous areas is available from ISA-12.

Pneumatics

Pneumatic tubing is not often implemented in the typical enclosure since most modern equipment is electronic. In applications where pneumatic tubing is required and in the absence of plant standards, the plant may use ISA-RP60.9-1981, Piping Guide for Control Centers.

It is a good practice to have all of the external connections terminate at a bulkhead plate. Also, each bulkhead termination should be permanently identified, and the tubing should be identified by permanent markers according to the instrument loop diagrams. This approach minimizes the chance of errors during maintenance or whenever the tubes are disconnected. To allow for future expansions and unforeseen modifications, the panel should have a minimum number of spare bulkhead connections, complete with their bulkhead union fittings, on the bulkhead plate (for example, 20 percent or six spare bulkhead connections, whichever is greater).

All tubing should be installed in a neat and orderly manner, free from distortions, and run with adequate support. Similarly, all tubing should be arranged so instruments and accessories can be easily removed and maintained. As with the wiring, the tubing may be color coded to facilitate identification of functions.

For the air supply system inside the panel, a 2-in. (50 mm) instrument air supply header is typically required. This header is supplied with ¼-in. takeoff points equipped with shutoff valves for each instrument and a ¼-in. drain valve at its lowest point. Again, the panel should have a number of spare takeoffs with shutoff valves (for example, 20 percent). In addition, the panel assembly shop should also supply and install a duplex air filter regulator, complete with an input and an output pressure gage. Each filter regulator should have a capacity at least 25 percent greater than that required by the instruments installed in the panel. The panel's air supply system should also have a pressure-relief valve that is capable of handling the combined maximum capacity of the two filter regulators. It should be located on the downstream side of the filter regulators.

After the enclosure is assembled, the panel assembly shop should ensure that all installed lines are clean, both internally and externally, and that all joints are free from leaks.

Temperature and Humidity Control

If temperature and humidity conditions are a concern, an HVAC or heating unit may have to be mounted in the enclosure. Instead of an expensive HVAC unit, plants sometimes purge with instrument air and maintain a slightly positive air pressure (about 0.1 inches of water column) to cool the inside of a panel.

Inspection and Testing

The owner's representative should be able to visit the panel assembly shop at any time to check progress and/or inspect the enclosure and its internal components. When all assembly work is completed, the panel assembly shop is expected to thoroughly check the enclosure mechanically and functionally before the owner's representative arrives. To avoid damaging sensitive electronic equipment, the shop should not use high-voltage insulation testing equipment. The assembly shop will, as a minimum, perform the following checks after the enclosure is completed:

1. The physical appearance and mechanical construction of the enclosure, inside and outside
2. All nameplates for correct location, spelling, wording, and letter size
3. Any signs of physical damage or negligence
4. All electrical power circuits needed for correct operation
5. All air supply lines required for correct operation
6. Leaks in pneumatic lines
7. All electrical and pneumatic circuits needed for correct functional operation, loop by loop
8. All alarm circuits required for correct operation

Certification

In situations where the enclosure must be certified, the assembly shop should obtain the necessary documents from the appropriate authorities for all inspections. The cost of all such inspections should be born by the panel assembly shop. Any deficiencies noted by such inspections should be corrected by the panel assembly shop at no cost to the owner. After all approvals have been obtained, the panel assembly shop should affix to the panel any labels (e.g., union labels) covering electrical and pipe fitting as required in the enclosure specification.

Shipping

To avoid damage during shipping to the plant, the panel assembly shop removes all tray-mounted and plug-in instruments from their manufacturer's boxes, reboxes them, and ships them separately to the plant in tagged boxes. The enclosure, suitably protected, should then be shipped by air-ride truck. Additional information is available from ISA's recommended practice, ISA-RP60.11-1991, Crating, Shipping, and Handling for Control Centers.

CHAPTER 13

CONTROL VALVES

Overview

Control valves are a continuously varying orifice in a fluid flow line that changes the value of a process variable by changing the rate of flow. The typical control valve consists of three main components: the body, the trim (usually consisting of a plug and seat), and the actuator.

In most applications, a control valve is the final element in a control loop. It provides the power needed to translate the controller's output to the process, either in a two-position (on-off) or proportional (throttling) control mode. Of the three basic components of a typical control loop (sensor, controller, and valve), the valve is subject to the harshest conditions and is the least understood. To complicate matters, the valve is also the most expensive and most likely to be selected incorrectly.

A successful control valve installation requires both knowledge and experience. First, personnel must gather the process information and then select the appropriate valve. Additional information on control valves is available from the ISA-75 series of standards.

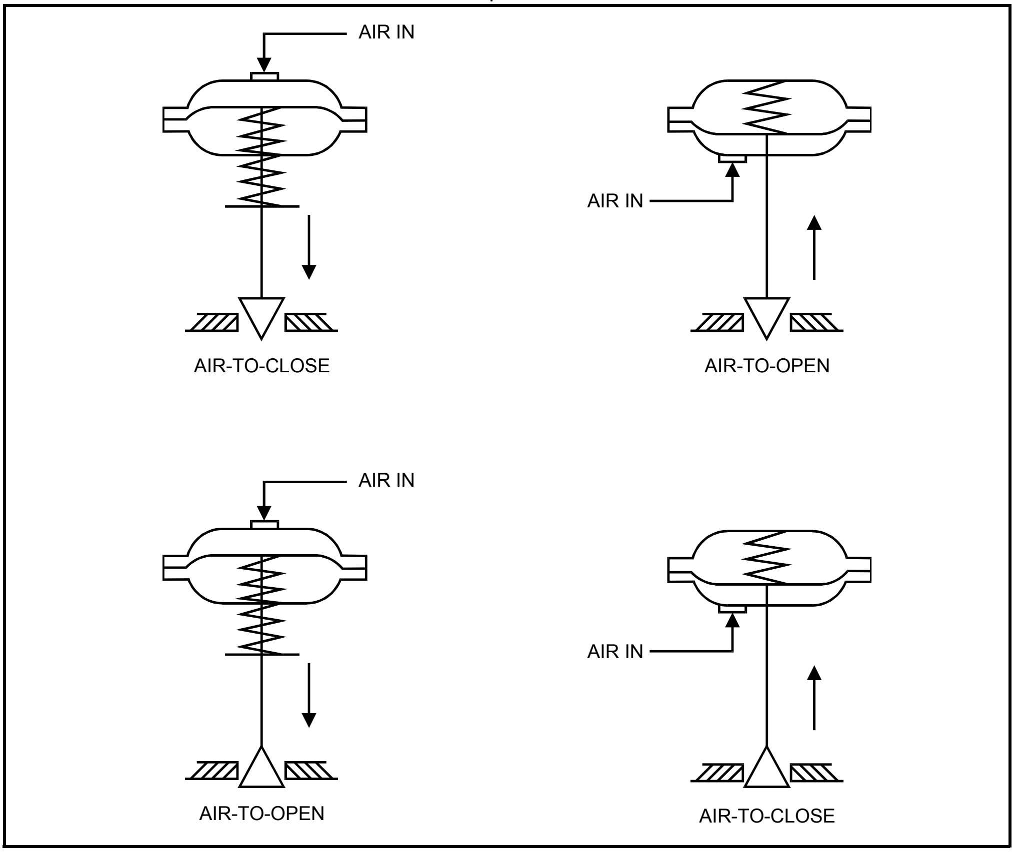
Selecting the right valves involves the following factors:

- Process requirements: The type of fluid passing through the valve, the inlet pressure and differential pressure (dp) across the valve, the maximum and minimum flows, the flowing temperature, and the degree of shutoff.
- Correct sizing of the valve: The valve must be able to handle its maximum design flow (say, at 75% fully open). However, the designer must avoid oversizing or undersizing since they degrade the valve's operation. Typically, a properly sized valve should not operate below the 10 percent or above the 90 percent travel position.
- Suitable flow characteristics: The valve's flow characteristics must match the process requirements (i.e., linear, equal percentage, or quick-opening)—refer to section on "Trim" in this chapter.
- Fail-safe mode (on air and/or signal failure): An air-to-open valve is a fail-closed valve (FC); a spring closes the valve on air failure, and air must open it. An air-to-close valve is a fail-open valve (FO); a spring opens the valve on air failure, and air must close it (see figure 13-1).
- Proper choice of valve body type (i.e., globe, ball, etc.) and accessories: For example, for applications that are toxic or environmentally hazardous, bellows seals may be required.
- Correct installation: always refer to the vendor's recommendations.

Shutoff

Control valves that are well designed provide stop valve tightness. However, a slight leakage will normally occur through the valve trim, particularly where a valve has been in service for a while. The amount of allowable valve leakage can be defined at the design stage. In accordance with ANSI/FCI 70-2, valve leakage is classified according to six classes, which are summarized as follows:

Figure 13-1
Valve failure mode with different valve/actuator setups.



Class I: no test required

Class II: 0.5 percent of rated valve capacity, tested with clean air or water at the maximum operating differential pressure or 45 to 60 psi (300 to 400 Kpa), whichever is less

Class III: 0.1 percent of rated valve capacity, tested with clean air or water at the maximum operating differential pressure or 45 to 60 psi (300 to 400 Kpa), whichever is less

Class IV: 0.01 percent of rated valve capacity, tested with clean air or water at the maximum operating differential pressure or 45 to 60 psi (300 to 400 Kpa), whichever is less

Class V: 0.0005 mL/min of water per inch of port diameter per psi differential, tested with clean water at the maximum operating differential pressure or 100 psi (700 Kpa), whichever is less

Class VI: bubble-tight, tested with clean air or nitrogen gas at the maximum operating differential pressure or 50 psi (350 Kpa), whichever is less. For example:

1 in. port diam.; leak rate = 0.15 mL/min or 1 bubble/min

2 in. port diam.; leak rate = 0.45 mL/min or 3 bubble/min

4 in. port diam.; leak rate = 1.7 mL/min or 11 bubble/min

8 in. port diam.; leak rate = 6.75 mL/min or 45 bubble/min

If tight shutoff is required, the plant may provide a tight shutoff isolation valve in series with the throttling valve. Otherwise, the soft seat on a throttling valve with tight shutoff may need frequent replacement.

Noise

Valve noise is caused by the mechanical vibration of valve components and by fluid noise. Fluid noise can, in turn, be generated by hydrodynamic and aerodynamic noise.

Mechanical noise is typically caused by the lateral movement of the valve plug in relation to the guide surfaces. It is generally not predictable and should not occur with a good valve design. If it is does occur, the plant can generally eliminate it by replacing the valve plug. Better plug guidance may also do the job.

Hydrodynamic noise is caused by cavitation or flashing. Aerodynamic noise is created by the deceleration of the fluid, or expansion immediately downstream of the vena contracta. Valve noise can be calculated, and if it is determined that it will occur, it can be reduced by one (or a combination) of the following methods:

- Specially designed valves with multiple paths: to drop the pressure in gradual steps
- Valves in series: to divide the pressure drop over two valves
- A valve with a downstream multiple orifice plate in series: to increase the valve's downstream pressure
- Silencers: to reduce noise
- Cover piping with insulation: to reduce noise traveling through the pipes

Flashing and Cavitation

Flashing and cavitation are detrimental to valves, drastically shortening their useful life. Cavitation progresses through two steps: (1) flashing, where the liquid becomes vapor, and (2) the vapor collapses back into liquid (an implosion). Cavitation sounds like a hissing noise on the downstream side of the valve when it starts. When fully developed, it sounds like gravel passing through the valve.

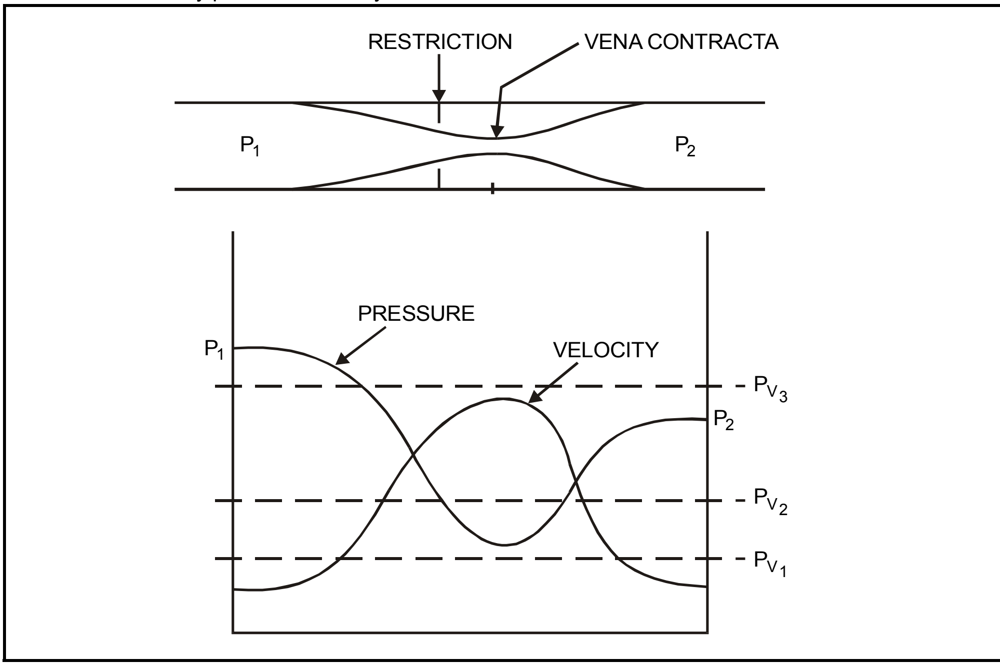
No cavitation or flashing occurs if the fluid's vapor pressure is lower than the pressure at the vena contracta (Pv_1 in figure 13-2). This is because the fluid started as a liquid and, through the vena contracta, remained a liquid. However, if the fluid's vapor pressure (Pv_3 in figure 13-2) is higher than the discharge pressure P_2, flashing will occur since the liquid turns into vapor and stays as such at pressure P_2. If P_2 is higher than the fluid's vapor pressure (Pv_2 in figure 13-2), then cavitation will occur. This is because the liquid becomes vapor as its pressure drops below Pv_2 and then returns back to liquid as it crosses Pv_2 to become P_2.

Mechanical damage is the main result of cavitation. Cavitation gives the trim assembly the appearance of eroded holes or a porous surface. Flashing can produce serious valve erosion, resulting in a fine, sanded surface with a smooth, polished finish. Where cavitation is expected, plants should select special trims or reduced pressure drop across the valve to reduce the effects of wear and noise.

Pressure Drop

All valves, because of their resistive nature, drop most of the pressure across their trim (see figure 13-2). The lowest pressure is located at a point just downstream of the trim, a point known as the vena contracta. The amount of pressure drop depends on the valve's geometry, and thus varies among valve types and even between two valves of the same type from different manufacturers. As the pressure drop across a valve increases, so does the flow. However, a point will be reached (the chocked-flow condition) where increasing the pressure drop, will not increase flow.

Figure 13-2
Pressure and velocity profiles caused by a restriction in a line.



When users must decide how much of the total pressure drop should be taken across the valve, some rules of thumb are helpful. The pressure drop across the valve, as a percentage of the dynamic losses of the system, could be around 10 to 20 percent (5% is an absolute minimum and only if the flow variations are minimal) or 5 to 10 psi (35 to 70 kPa), whichever is greater. It should be noted that if less than 30 to 40 percent of the total pressure drop is across the valve, the equal percentage will give better control than the linear.

Installation

Installing valves correctly is essential, and the user must always refer to the vendor's recommendations to ensure satisfactory performance. During pipeline pressure testing, the plant should keep the valves fully open to avoid high differential pressures across the valve. Pipe work on either side of the control valve should be supported, and eccentric reducers should be used where condensables or sludge could be trapped upstream of the valve (i.e., allow drainage). It is good practice to allow five pipe diameters upstream (and downstream) of the valve to minimize disturbances and achieve the stated flow characteristics. However, if space is restricted, allow one pipe diameter upstream (and downstream) as a minimum.

Usually, all actuators are mounted with their stems vertical above the valve body. If the valve will operate in a dusty environment, the plant should install a rubber boot around the stem to protect its polished finish. When removing valves from toxic, acid, or alkaline service, always flush and clean the valve to protect maintenance personnel and the environment.

The C_v

Valve sizing is based on the C_v, which is the number of U.S. gal/min of water at 60°F (15.5°C) when there is a 1 psi (6.9 kPa) differential pressure (dp) drop across the valve. A valve with a

C_v of 20 means that when fully open, the valve will pass 20 U.S. gal/min of water with a 1 psi (6.9 kPa) dp.

Valve C_v is determined through test results. For the same type of valve of the same size, different vendors may have different C_v values as a result of different valve designs and geometry. For liquids

$$C_v = Q(U.S.\ gal/min) \times \sqrt{\frac{specific\ gravity}{dp(psi)}}$$

Note: At extremely low Reynolds numbers (typically for small valves), the flow becomes laminar, and Q becomes proportional to dp rather than the square root of dp.

Generally, valves are selected so they pass a flow that is larger than the expected maximum design flow when they are wide open and at design pressure drop. However, the valve should not be oversized. Control valves, despite having sufficient capacity (C_v) to handle the flow, are typically one size smaller than the inlet and outlet piping or have reduced trim sizes. If for some reason (e.g., to handle future increases in flow) a plant's valve is specified to line size, the plant may need to reduce the trim to provide good control. The reduced trim can then be replaced in the future with a full-size trim to handle the larger flows.

Valve Bodies

Valve bodies can be classified into two types based on their motion: linear and rotary. Linear valves comprise globe (including three-way and angle), gate, diaphragm, and pinch types. Rotary valves include ball, butterfly, and plug types.

Line connections for control valves are available in a variety of configurations. They may be flanged, wafer-style, threaded, or welded. Flanged connections are used in most applications and also for toxic applications where threaded valves or valves clamped between flanges are unacceptable. Valves with wafer-style connections are clamped between the adjoining line flanges. This design provides a decrease in valve weight and space requirements and is simpler to install. Wafer-style connections are common with butterfly valves. Threaded connections are generally used for small sizes, typically under 1 to 2 in. (25 to 50 mm). Welded connections are generally used for highly toxic, very high-pressure flammable materials and some other specific applications. They are supplied as butt-weld (the valve ends are beveled to match the pipe bevel) or socket-weld (the valve ends have an inside diameter slightly larger then the pipe's outside diameter).

Rules of Thumb

Valve selection is application dependent. However, the following rules of thumb may help the user select a type of valve. The user's experience and the vendor's recommendations should also be carefully evaluated.

1. For most modulating control applications, and considering the effects of cost, controllability, and maintenance, the following guidelines apply:
   - Globe valves are used for up to 3 in. (80 mm) lines.
   - Globe, characterized ball, and eccentric rotary-plug valves are used for 3- to 6-in. (80 to 150 mm) lines.
   - Characterized ball, eccentric rotary-plug, and butterfly valves are used for 6- to 12-in. (150 to 300 mm) lines.
   - Butterfly valves are used for larger than 12-in. (300 mm) lines.

2. Ball, eccentric, butterfly, and diaphragm valves are used for most on-off applications.

Cooling Fins (Radiating Bonnet) and Bonnet Extensions

Cooling fins are used to protect the packing and actuator from extreme temperatures. They are typically required when fluid temperatures above 400°F (200°C) are handled. Bonnet extensions are generally required on temperature applications below -20°F (-30°C).

Bellows Seals and Packing

Bellows seals are used to prevent leakage when the packing fails or where standard packing may let noxious fluids leak into the surroundings. They are fragile and expensive and are generally limited to 150 psig (1 MPag) at 570°F (300 °C). In some cases, 500 psig (3.5 MPag) can be obtained with thicker bellows.

Sometimes sealing can also be obtained with double packing since this is less expensive than bellows sealing. Extra packing can also be used with bellows as a safety feature if the bellows fails. The space between the packings may have to be vented to a tank to capture any emissions. In certain cases, the space between the packings may have to be pressurized.

Valve packing isolates the process fluid from the outside world. The valve packing material under the operating conditions must remain elastic and easily deformable, must be chemically inert and as frictionless as possible, and must be easily accessible for maintenance.

Comparison Table

Table 13-1 summarizes the main types of control valves with respect to a set of common parameters. This comparison table can be used as a guide to selecting control valves. The information presented indicates typical values; vendors may have equipment that may exceed the limits shown.

Globe

Globe valves are the most versatile of all valves. They are ideal for high-pressure drop applications, are available with either single- or double-seated construction, and may have pressure-balanced trim. The single-seated valve (see figure 13-3) is typically used on all 1-in. (25 mm) and smaller valves and is usually top guided. The double-seated valve (see figure 13-4) requires fewer actuator forces and is top and bottom guided. However, it is more expensive; more difficult to service, maintain, and adjust; and does not provide tight shutoff. The double-seated valve is not commonly used. Three-way valves (see figure 13-5) are an extension of the typical double-seated globe valve.

Table 13-1
Control valve comparison.

Parameters / Body Types	Service (Y=Yes, N=No)						Sizes	Pressure ranges	Temperature ranges	Characteristic			Rangeability [1]	Capacity (C_V) [2]	Applicable to	
	General	Toxic	Corrosive	Erosive	Slurries	High pressure drop				Equal percentage	Linear	Quick-opening			Flashing service	Cavitating service
Globe	Y	Y[3]	Y	N	N[8]	Y	1–36″[4]	to ANSI 2500	-330–1000°F (-200–540°C)[5]	Y	Y	Y	20:1–100:1[6]	10–12 d^2	Y	Y
Diaphragm	Y	Y	Y	Y	Y	N	1–20″	to ANSI 150	-40–300°F (-40–150°C)	N	N	Y[10]	3:1–15:1	14–22 d^2	N	N
Ball	Y	N	Y	N	Y[13]	N	1–24″	to ANSI 600	-330– 750°F (-200–400°C)	Y	Y[9]	N	30:1–100:1	14–24 d^2	N	N[7]
Butterfly	Y	N	N	N	N[8]	N	2–36″	to ANSI 300	-60–480°F (-50– 250°C)[11]	Y	N	N	15:1– 50:1	12–35 d^2	N	N[7]
Eccentric Rotary Plug	Y	N	Y	Y[12]	Y[12]	N	1–12″	to ANSI 600	-330– 750°F (-200– 400°C)	Y	Y	N	30:1–100:1	12–14 d^2	N	N[7]

1. Valve rangeability is the ratio of maximum to minimum controllable flows
2. Where d equals valve diameter in inches, e.g., a 4 in. globe valve would have approximately a C_V of 11 x 16 = 176. This is an estimated value (refer to manufacturer's data for accurate C_V values).
3. On toxic, extremely valuable, or thermal cycling applications use with bellows seal
4. For needle valves; 1/8 to 1″
5. For needle valves; -5 to 1000°F (-20–540°C)
6. Depending on characteristics and type
7. Rotary valves are not used for cavitating service due to their high pressure recovery. It should be noted that the pressure recovery coefficient varies between valves and between manufacturers for the same type of valve.
8. Use ball and diaphragm valves on slurries.
9. Linear for low capacity characterized ball valves
10. Minimal flow increase at greater than 70% open
11. With metal seal
12. May require special trims - check with vendors
13. When using a straight-through design

Figure 13-3
Single-seated globe valve.

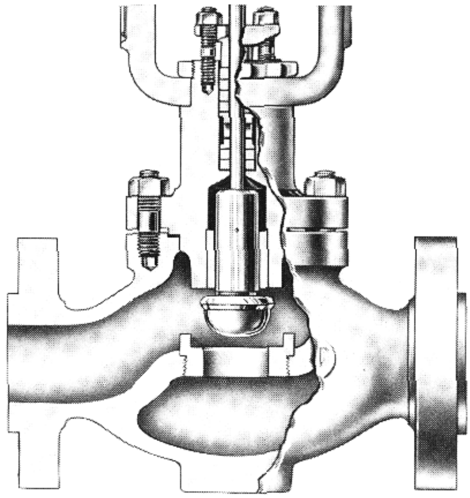


Figure 13-4
Double-seated globe valve.

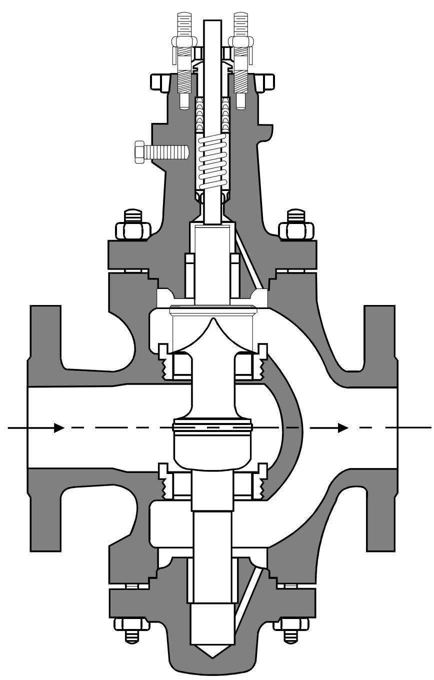
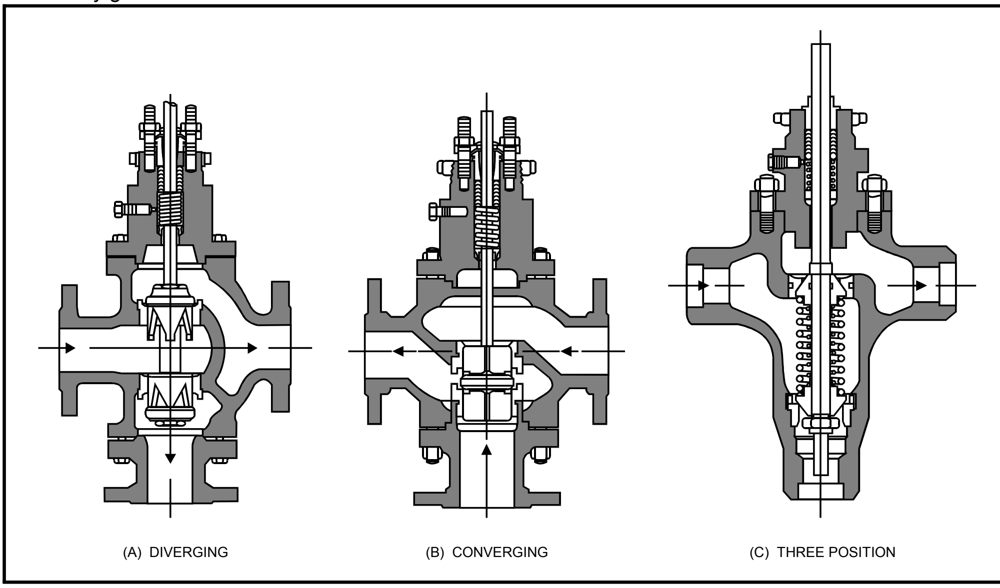
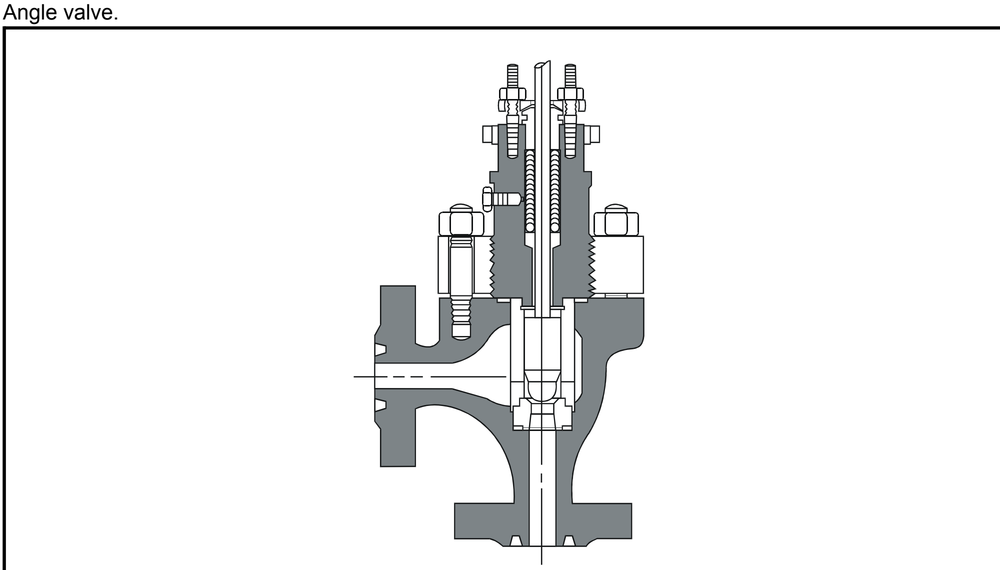


Figure 13-5
Three-way globe valves.



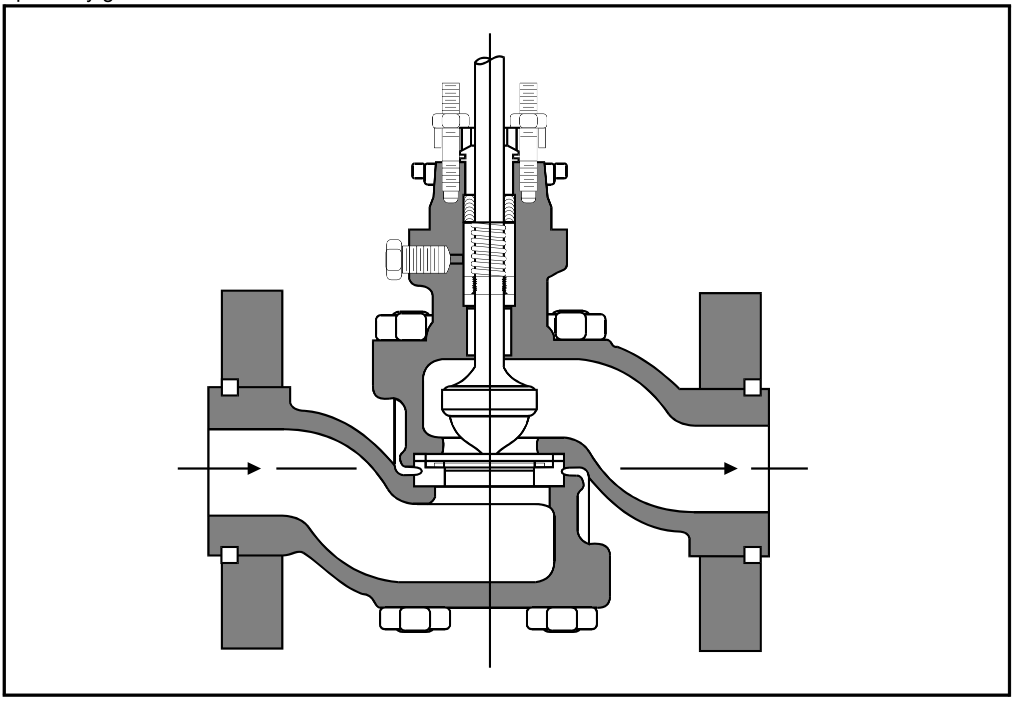
Another type of globe valve is the angle valve (see figure 13-6). This is considered a single-seated valve, and its streamlined interior, with its self-draining construction, tends to prevent solid buildup inside the body. These valves are also used for erosive fluids and in situations where the piping arrangement restricts the use of globe valves. Angle valves are typically offered in 1- to 6-in. (25 to 150 mm) sizes, but they are not available in jacketed construction. They are generally installed with the flow coming in on the side and exiting at the bottom. This configuration minimizes body erosion but will create a flow-to-close valve (i.e., it could slam shut) and a high-pressure recovery condition (i.e., it is prone to noise and cavitation).

Figure 13-6
Angle valve.



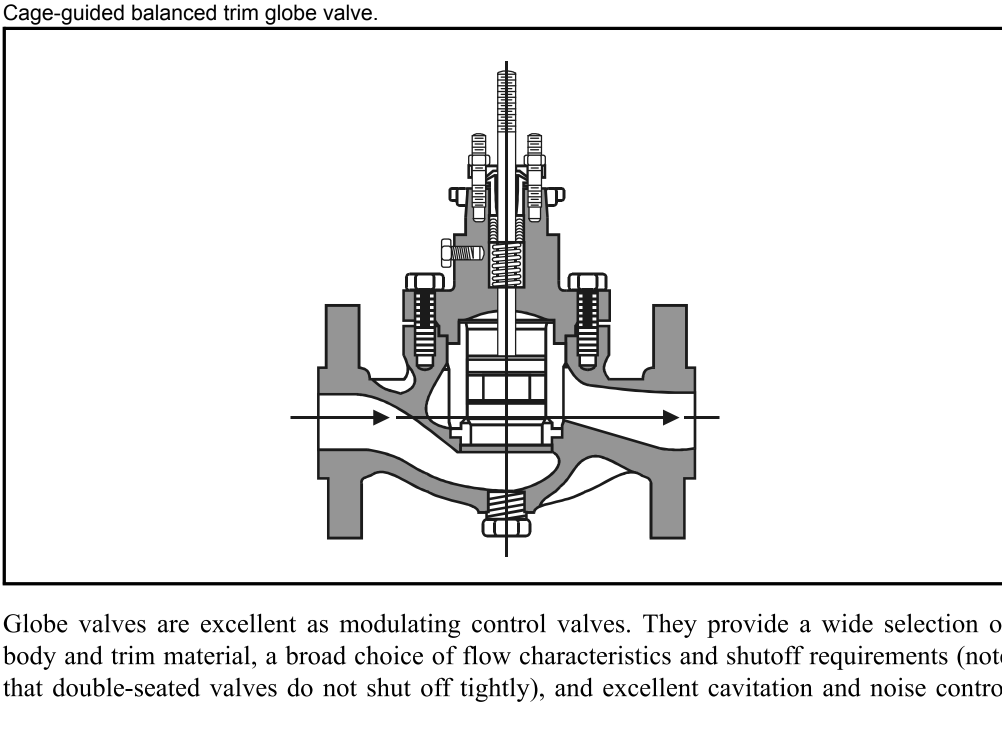
Globe valves are also available in a split-body configuration (see figure 13-7). This design is easily maintained and slightly less expensive than the regular globe valve. It is also relatively free of pockets in which sediments can settle. However, in the split-body configuration pipe, stresses are transmitted to the body bolting, which may cause misalignment and valve leakage.

Figure 13-7
Split-body globe valve.



Another type of globe valve that is very popular is the cage-guided balanced trim valve (see figure 13-8). This design uses the cage as a plug guide. The plug is grooved along its sides, which equalizes the pressure in the valve body. The cage-guided balanced trim valve provides a balanced valve plug, valve plug guiding, and excellent shutoff capabilities.

Figure 13-8
Cage-guided balanced trim globe valve.



Globe valves are excellent as modulating control valves. They provide a wide selection of body and trim material, a broad choice of flow characteristics and shutoff requirements (note that double-seated valves do not shut off tightly), and excellent cavitation and noise control with special trims. However, globe valves are the most expensive type of valve and should not be used on slurries or in dirty/solid-bearing fluids.

Globe valves can be either “flow to open” or “flow to close.” The flow-to-open design provides better stability, maximum capacity, and quieter, smoother operation. The flow-to-close design tends to slam shut near the seat position, and strong actuators are required to balance this effect. However, this consequence is minimal if the valve is under 1 in. (25 mm).

The typical globe valve can be steam-jacketed to provide heat that prevents the flowing fluid from freezing. Bellows are available where they are required. Globe valve designs of the bar-stock type are good for small flows and high-pressure drops.

Diaphragm (Saunders)

Diaphragm valves, also known as Saunders valves, are operated by forcing a flexible diaphragm against a bridge or weir to stop the flow. The weir-type design (see figure 13-9a) lasts longer than the straight-through type, but has less flow capacity. The straight-through valve, sometimes called a “pinch valve” (see figure 13-9b), is best suited for slurries but has a lower differential-pressure rating than the weir design.

Diaphragm valves are excellent for sanitary and slurry service as well as for liquids that contain solids or dirt. They are made of a packless construction (because fluid contacts only the liner) and are available as tight shutoff. Diaphragm valves are low-cost devices and their maintenance is simple. However, they have poor flow characteristics and are inadequate as modulating control valves. In addition, the diaphragm materials available are limited, and due to their application and construction, diaphragm valves tend to be a high-maintenance item.

Figure 13-9a
Weir-type diaphragm valve.

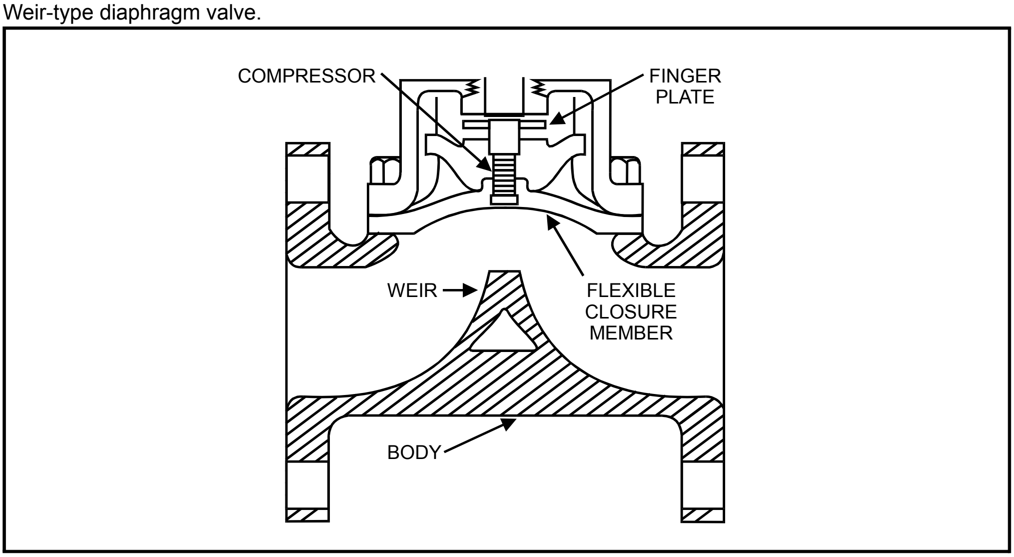
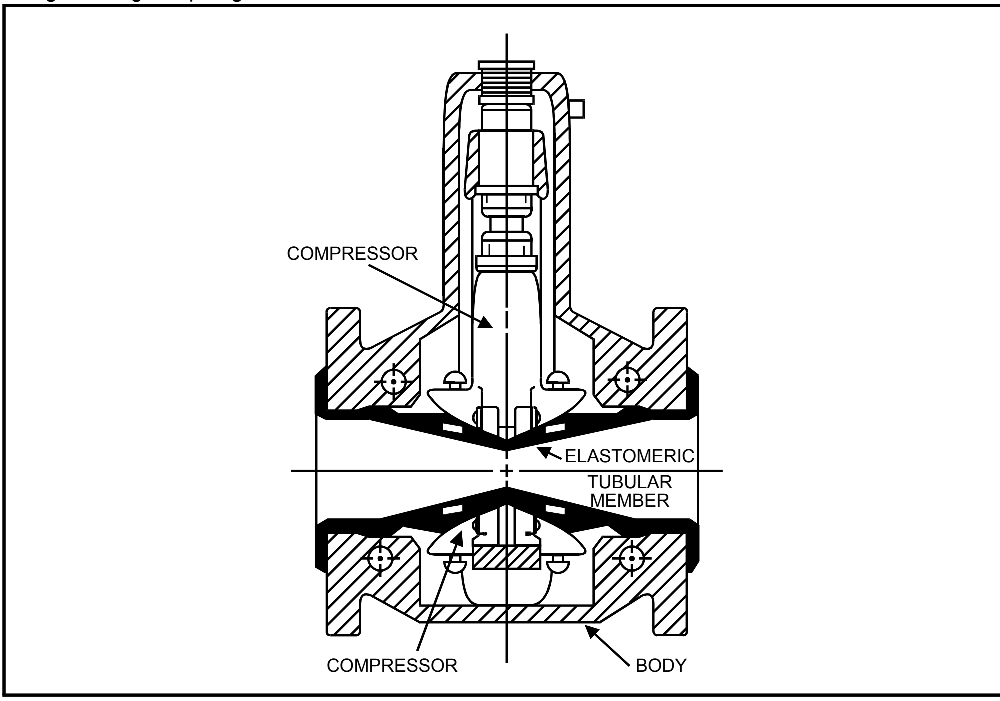


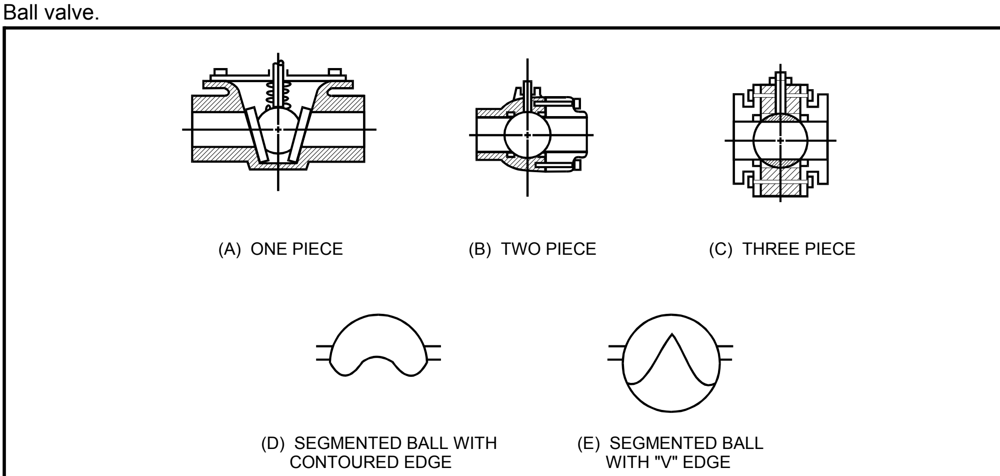
Figure 13-9b
Straight-through diaphragm valve.



Ball

The ball valve is a rotary-action valve (see figure 13-10). Some manufacturers mount the ball eccentrically so the face of the ball lifts when it rotates off the seat, thus preventing sliding (and erosion) across the seat.

Figure 13-10
Ball valve.



The ball valve has greater capacity and lower cost than a similar-sized globe valve, and its throughput is twice that of the same size globe valve when the pressure drop is low.

The full-bore ball valve is not used for throttling and control applications but generally for on-off applications. It has a sluggish response for the first 30 percent of its travel, but will operate at a higher dp than a partial ball valve since it divides the valve pressure drop into two steps.

The characterized ball valve consists of a partial sphere when it is opening up. It presents a triangular shape that makes it suitable for liquids that have solids in suspension. Its flow characteristics are equal percentage, and it provides good rangeability. This makes it an all-round general-duty valve, and it is actually taking over some of the globe valve's applications. The characterized ball valve is less expensive, lighter, and easier to install and maintain than a globe valve of similar duty. With its contoured notch shape, the characterized ball valve is used for modulation when the valve has a solid connection between the stem and the ball.

A variation of the ball valve is the plug valve. Plug valves are similar to ball valves, have linear or equal-percentage characteristics, and have a 1:10 to 1:100 rangeability. However, their high friction makes them less suitable for modulating service.

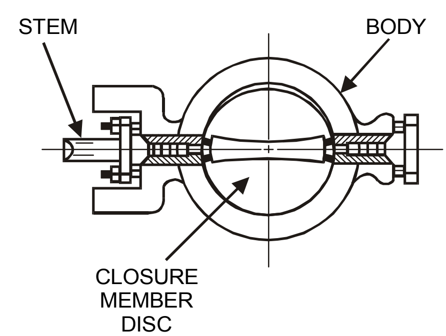
Ball valves are good for slurries and fluids with suspended solids because of their straight-through design and self-cleaning action. They have excellent packing sealability, low weight, a small number of parts, and a simple design. With these valves, the valve stem is not alternately wetted and exposed to air (due to the rotary motion), which minimizes the effect of corrosion. In addition, ball valves can provide tight shutoff (with PTFE seals).

However, ball valves have limited cavitation and noise protection, their pressure drop ratings are limited, and the dp across the valve generates a strong side thrust on the operating shaft.

Butterfly

The butterfly valve (see figure 13-11) consists of a cylindrical body with a disk (the closure member) mounted on a shaft that rotates perpendicularly to the axis of the valve body. Louvre dampers have the same characteristics as butterfly valves. Butterfly valves have large capacities, and the only obstruction to the flow is the disk. The torsional force on the shaft increases as the valve opens until it reaches 70 to 75° open; after that, it tends to reverse. Rubber seating gives butterfly valves tight closure. However, these valves may tend to stick in the closed position unless eccentric disks are used.

Figure 13-11
Butterfly valve.



The most common butterfly design is the flangeless (wafer) type. Typically, butterfly valves are limited in temperature range and should be sized so they can operate within 20 to 60° travel for good controllability. Butterfly valves offer high capacity at low cost. They have a small body mass (and so weigh little), are easy to install, and have an excellent packing sealability. In addition, they are simply designed and have a small number of parts. The butterfly valve's design eliminates the valve stem's alternate wetting and exposure to air, which minimizes corrosion. These valves have a tight shutoff capability (if they are lined) and can be used as a modulating control valve.

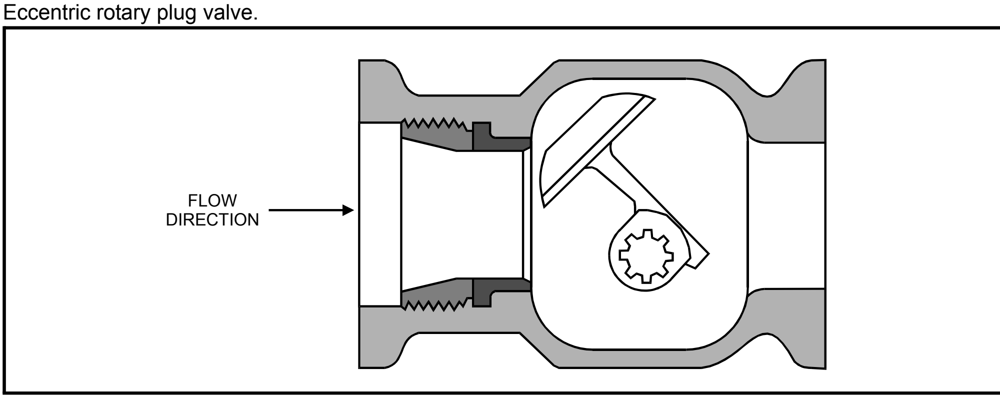
However, butterfly valves have a limited pressure-control range, and their pressure-drop ratings are limited. They are not used in cavitation or noise applications or for slurries or dirty/solid-bearing fluids. The dp across the valve generates a strong side thrust on the operating shaft.

Eccentric Rotary Plug

The rotary plug for this valve (see figure 13-12) provides an eccentric motion that produces capacities and performance close to those of the cage-guided globe valve. The eccentric rotary plug valve has a normal operating travel of 50° and is available in flanged or flangeless construction.

The eccentric rotary plug valve's metal-to-metal seating provides good shutoff, with no rubbing contact in the seat ring. The positive seating action and tight shutoff can be obtained with relatively low forces. This type of valve has a relatively high capacity, offers reasonable cost, and can handle corrosive fluids. The eccentric motion of the plug requires low actuating forces (as compared to butterfly valves), which reduces the torque requirements for the actuator. The eccentric rotary plug valve is available for flow in either direction, which provides a stable flow operation for either flow-to-open or flow-to-close.

Figure 13-12
Eccentric rotary plug valve.



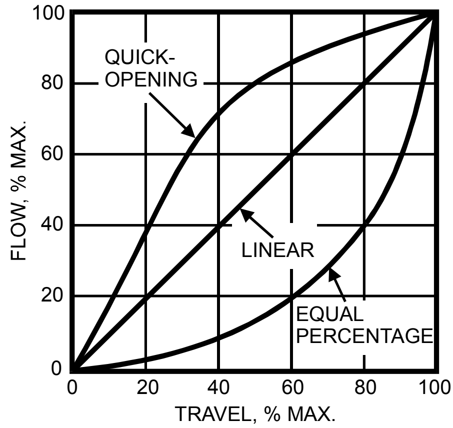
The eccentric rotary plug valve has some tendency to cavitate because of its high-pressure recovery in the "flow-to-close" mode. It also has some limitation in dp capability because of stability considerations. Typically, it requires a long-stroke, spring-opposed, rolling diaphragm actuator.

Trim

Valves control the rate of flow by introducing a pressure drop. Most of this pressure drop is developed across the valve trim. For a typical globe valve, the trim consists of the seat and plug. The seat, plug, and stem are generally made of 316 SS for pressure drops up to 100 psi (700 kPa) and hardened alloy steel for higher pressure drops, unless the process specifications require materials of higher quality.

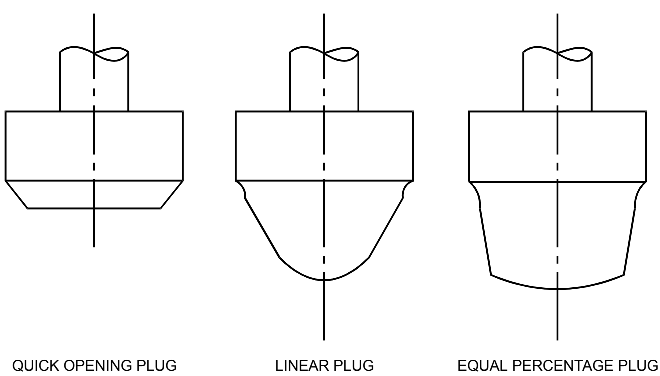
The valve trim provides the valve shutoff capability as well as its flow characteristics. A valve's flow characteristics involve the relationship between the stem position and the flow through the valve (i.e., the flow behavior of the valve as it is stroked). The theoretical flow characteristics of a valve are known as the "inherent flow characteristics" (see figure 13-13). They are determined by the design of the plug under test conditions and are based on a constant pressure drop. The actual flow characteristics under operating conditions are known as the "installed flow characteristics." They are subject to the varying pressure drops that occur in the line as the flow varies. Typically, under the varying differential pressures that result from varying flows, the inherent equal-percentage characterized valve will behave like a linear valve, and the linear valve will tend to behave like a quick-opening valve.

Figure 13-13
Inherent flow characteristics.



The three most common trims are the linear, the equal percentage, and the quick-opening (see figure 13-14). With the linear trim, the flow coefficient (C_v) is directly proportional to the valve opening. With the equal-percentage trim, equal increments of valve travel provide an equal-percentage change in flow coefficient. For example, if when the valve opens from 40 percent to 60 percent the C_v doubles, then when the valve opens from 60 percent to 80 percent, the C_v will also double. With the quick-opening trim, large increases in C_v occur as the valve opens, and only small C_v increases will occur as the valve reaches its fully open position.

Figure 13-14
Profiles of different plugs for globe valves.



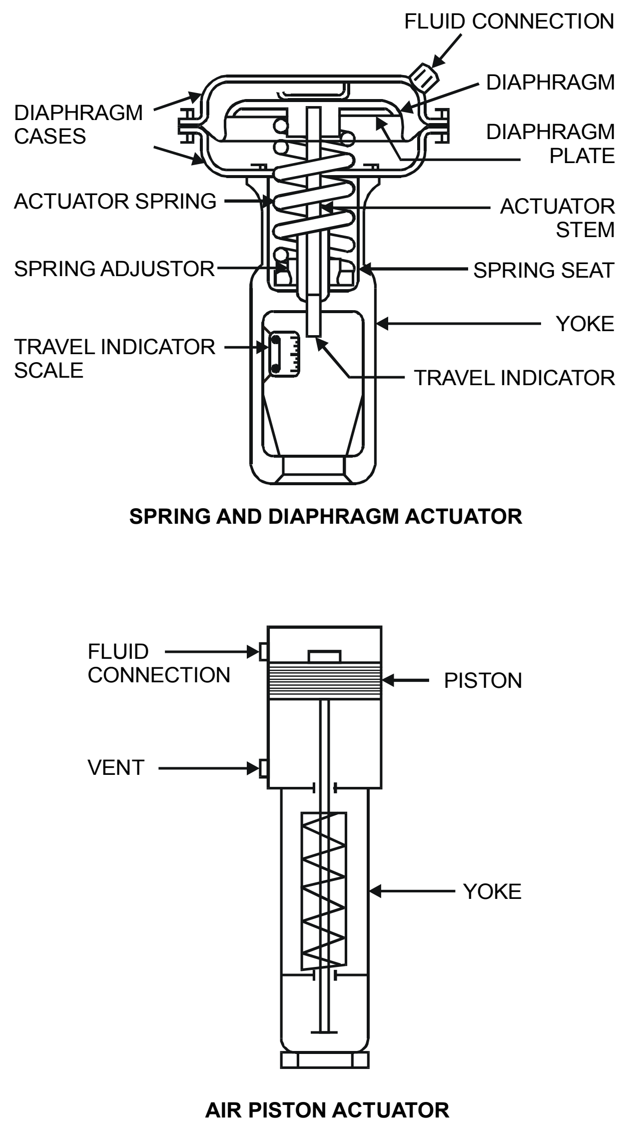
In general, linear valves are used in situations where the controlled process variable is proportional to the flow and where the pressure drop across the valve is relatively constant. Equal-percentage valves are used where the valve pressure drop decreases as the flow increases. They are also used in situations where the major system pressure drop is not across the valve, or when valve oversizing will occur. Quick-opening valves are typically used for on-off operations only.

Actuators

The actuator provides the power to vary the orifice area of the valve (i.e., opening and closing the valve) in response to a signal received. The stem carries the load from the actuator to the trim assembly. Actuators are typically selected by the valve vendor who supplies them pre-mounted to the valve. There are two types of actuators: linear and rotary.

The three most common types of linear actuators are the spring and diaphragm assembly, the air piston, and the electric motor. The spring and diaphragm (see figure 13-15) is relatively low in cost, inherently fail-safe, and simple and reliable, with few moving parts. However, it has limited power, limited seat shutoff capabilities, and slow operating speed. In addition, the spring and diaphragm may not handle high variations in stem load (i.e., it lacks stiffness).

Figure 13-15
Linear Actuators.



The air piston (see figure 13-15) provides high torque (or force) and has a fast stroking speed. In addition, it provides a high power-to-weight ratio, has few moving parts, and has an excellent dynamic response. It will also handle high differential pressures and provide high shutoff capability. However, the air piston typically requires a valve positioner.

The electric motor is generally used with a gear box and does not need air or a current-to-pneumatic converter (I/P). In addition, it provides a high force and is reversible. This type of actuator generally requires that the end-of-travel be adjusted and that torque-cutout limit switches be installed in order to avoid damaging valve parts.

The two most common types of rotary actuators are the rack and pinion and the quarter turn rotary. The rack and pinion type uses a linear actuator and translates its linear motion to a rotary motion. This can be done by mounting a rack on the actuator's stem and a pinion on the valve's stem.

The quarter turn rotary actuator, also known as the vane type actuator, consists of a vane enclosed in 90º pie shaped casing. Air pressure on one side of the vane will move the vane, which in turn will rotate the stem. An opposing spring counteracts the vane's moving action. Quarter turn rotary actuators are used in applications where high forces for valve movement are not required.

Response Time

Actuator response time varies according to the size and type of the actuator. For example, a spring diaphragm with a positioner may require 8 seconds for a 2-in. (50 mm) valve and 1 minute for valves larger than 6 in. (150 mm). These values are reduced if a booster is added. A piston actuator may require 0.2 seconds for a 2-in. (50 mm) valve and 2.5 seconds for valves larger than 6 in. (150 mm).

Air Volume Boosters

Air-volume boosters are used to supply air where high-speed or high air pressure (up to 250 psig [1700 kPag]) action is required. For example, a valve with a booster will increase performance speed three to four times when compared to a valve with a positioner only.

Valve Positioners

Despite its name, a valve positioner is in reality an actuator's "position controller" that acts as a secondary controller whose feedback is the position of the stem (refer to chapter 8 for more on cascade loops). Positioners are typically supplied with three pressure gages (supply, input, and output). Valve positioners are generally used in the following cases:

- To accurately position the valve stem; for example, when the pressure differential is 200 psi (1400 kPa) and higher
- When the stem-packing friction has an effect on the valve's response to an input signal
- To change the control valve's characteristics
- To provide split-range operation (use the same characteristics and travel for both valves)
- To increase the valve's speed of response
- To provide necessary air pressure for high-pressure applications
- To reverse the valve's action (direct or reverse)
- To increase shutoff capability
- To control springless actuators (double-acting pistons)
- For three-way and rotary throttling valves
- On valves that are 4 in. (100 mm) and larger

Handwheels

Handwheels are used as a way to provide manual control, such as for overrides or in case of power or signal failure. In most loops they are not required. If a handwheel is essential to an operation, the plant should ensure that it is accessible and can be maneuvered by a single person.

CHAPTER 14

Engineering Design and Documentation

Overview

Engineering design and documentation activities can be split broadly into two parts: front-end engineering and detailed engineering. Front-end engineering will vary according to the project size and conditions, but in the end, its content must define the project requirements, engineering standards, plant guidelines, and statutory requirements that are in effect at the site, setting the foundation for a successful detailed engineering.

Detailed engineering encompasses the preparation of all the detailed documentation necessary to support bid requests, construction, commissioning, and maintenance of the plant. In the present business environment, the size of corporate and plant engineering staff are generally at minimum levels, so the detailed engineering phase on large projects is frequently given to an engineering contractor or to an equipment supplier. In some cases, the instrumentation and control (I&C) engineering portion of a project is contracted out as part of a larger engineering package that includes other disciplines such as civil, electrical, mechanical, and the like.

Front-end Engineering

Front-end engineering is the first step in engineering design. It defines the I&C requirements and covers the preparation of the engineering data that is needed to start detail design. This phase, from an I&C point of view, typically parallels the preparation of preliminary process and instrumentation diagrams (P&IDs)—sometimes known as engineering flow diagrams—and the completion of hazard analysis for the process under control.

The hazard analysis is an essential part of the design activities. However, since it is not normally an activity led by I&C engineering, it will not be discussed in this handbook. If the reader requires additional information on this subject, it can be found in OSHA's Part 1910, Appendix D, and in other pertinent publications.

In general, three documents should be prepared during the front-end engineering phase and completed before the start of detailed design. They are: the P&IDs, the control system definition (which may include a preliminary instrument index), and the logic diagrams. On large projects, two additional documents may be required: a scope-of-work definition for the engineering contractor that will do the detailed engineering (see appendix C), and a scope-of-work definition for the supplier of packaged equipment, such as water treatment facilities, boilers, compressors, and so on (see appendix D).

Front-end engineering documents must be updated as changes are made during the project, and changes do occur. Once these documents are approved and agreed upon, no changes should be implemented without prior approval from the project manager and the assigned control engineer (or control supervisor, depending on company policy). The reason for this is to maintain control of changes, since these documents are the guidelines for the detailed engineering that affects contractors and vendors, and therefore impacts the schedule and budget.

Detailed Engineering

Detailed engineering must be based on the statutory requirements in effect at the site and on the front-end engineering. The documentation produced under detailed engineering will vary with the complexity of the process, the project's requirements, and the plant's philosophy and culture. The following is considered to be the minimum technical information for the field of I&C; engineering management must decide whether any additional documents are required:

- Instrument index
- Process data sheets
- Instrument specification sheets, including calculations (for control valves, orifice plates, etc.)
- Loop diagrams
- Interlock diagrams
- Control panel specifications (including an overall layout; see chapter 12 on enclosures)
- Control room requirements (see chapter 11 on control centers)
- Manuals for programmable electronic systems (DCS, PLC, PC, etc.)
- Alarm and trip-system documentation and testing procedures (see chapter 10 on alarm and trip systems)
- Installation specification (see chapter 15 for further details on installing instruments)

In addition to these documents, a location drawing is prepared that shows the location of all I&C devices (for further information, see figure 15-1 in chapter 15). Also, two additional documents that are generally not prepared by the I&C discipline but are of prime importance to the I&C detailed design phase: piping drawings and location and conduit layout drawings. They are described in chapter 15 under "Installation Details" and "Wiring."

Document Quality

The front-end and detailed engineering must meet and maintain a certain level of document quality. As a starting point, the plant must ensure that each document carries the required identification and cross-reference information. Common practice is to show drawing identification information in the bottom-right corner of a drawing in an area called the title block. For a specification, this information is typically shown on the front page.

Document identification typically consists of the following content:

- Plant name and location
- Process area (or name)
- Document number
- Document title
- Date document originated and name of the person approving it
- Date of revision, name of person approving the revision, and a condensed revision description

When the document is revised, it is also recommended that the nature of any changes be identified. The changes should be listed chronologically, so future users can understand the purpose and scope of previous modifications. Typically, when documents are issued for construction the revision number starts at 0. Before that they tend to have letters (A, B, C, etc.), reflecting the engineering revisions. If a section is not finalized, it could be circled and the word *Hold* written inside the marked area. This "Hold" should be resolved and removed before the document is issued for construction.

To conform to the quality standard, such as ISO 9000, that some plants adhere to, the plant must have a system of documentation control in place for identifying, collecting, indexing, filing, storing, maintaining, retrieving, and disposing of pertinent engineering records. This applies to both front-end and detailed engineering documentation. Using some of the ISO 9000 guidelines as general rules

- the latest issues of the appropriate documents must be available at all pertinent locations.
- documents must be reviewed and approved by authorized personnel before they are issued and according to a procedure. Authorized personnel must have access to the background information upon which they may base their decisions.
- obsolete documents should be clearly identified and quickly removed from all users.

Following the plant's construction, commissioning, and startup, a complete set of documentation should be revised, reflecting the "as-built" condition, for the purposes of operating and maintaining the plant. In addition, all documentation should be maintained as changes occur throughout the life of a plant's control system.

Process and Instrumentation Diagrams (P&IDs)

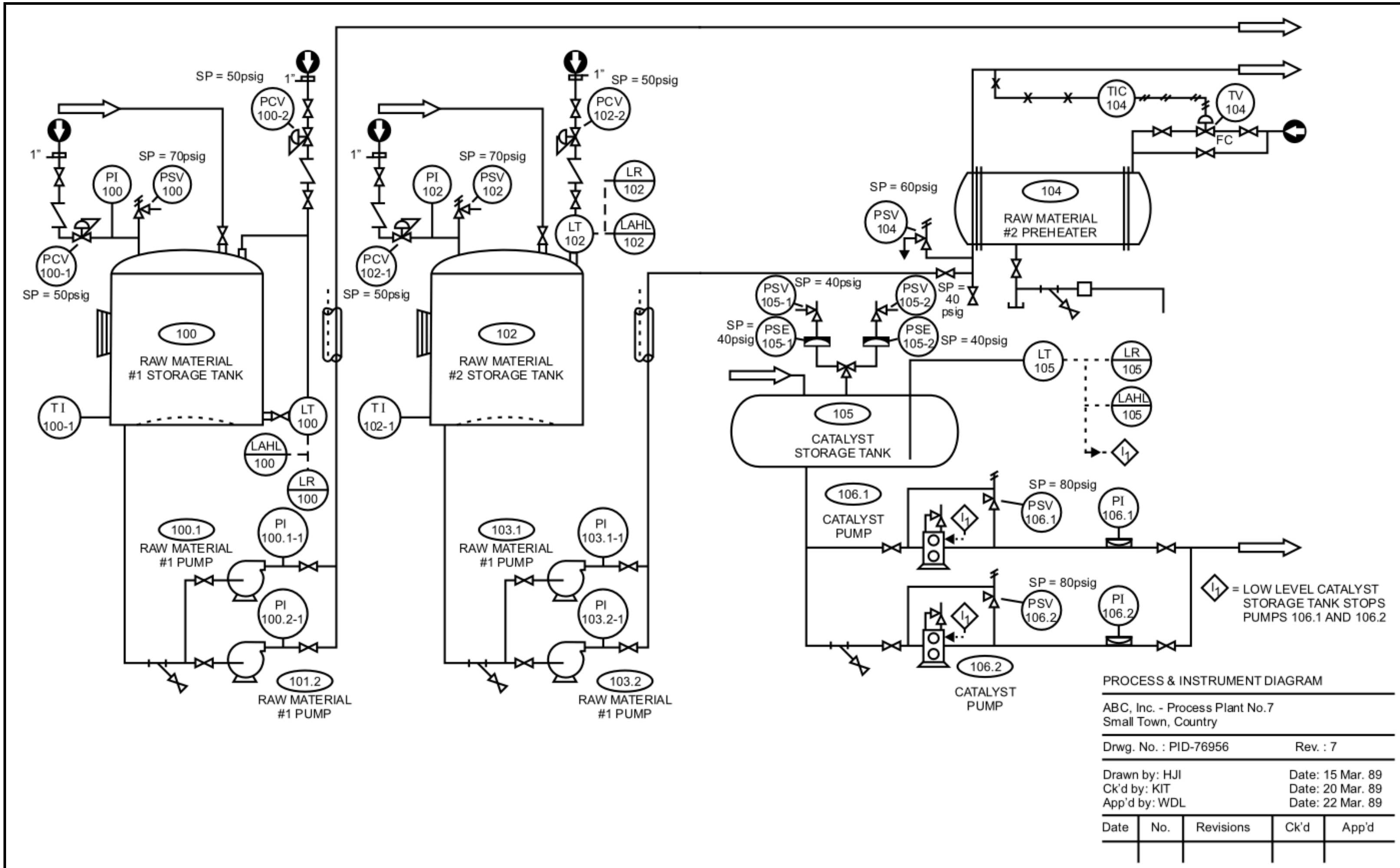
The P&ID is an essential document in process industries, whether it goes under the name "engineering flow diagram" or "piping and instrumentation diagram." It is a drawing that represents the process in the plant and how the major components (equipment, piping, and instruments) are connected together. It defines the scope of a project, acts as the foundation for all design activities, and is the basis for the detailed design and operating documents. P&IDs are used to aid communication within the engineering team, plant operation, maintenance personnel, and contractors.

P&IDs are usually developed from process flow diagrams, mass balances, and the plant control requirements. They are generally created by a team that consists of at least a process engineer and a control engineer. However, the process engineer is typically the "owner" of the P&IDs and the one who controls all approvals and modifications to the document. It is very confusing (not to mention wasting money and time) to have users work from different versions of the same P&ID. Good engineering practice requires that a hazard and operability study (or similar exercise) follows drawing generation and changes, and that procedures exist for handling revisions effectively.

P&IDs typically show the following types of information:

- Plant equipment, including maximum, normal, and minimum levels in vessels. Where possible, it is good practice to represent the relative size, shape, and location of the actual equipment in the plant, including the location and size of tank nozzles, manways, connections, and the like.
- All pipelines, valves, bypasses, relief valves, vents, drains, and in-line devices such as check valves, filters, and reducers. Also, sloping lines (showing the amount of slope), insulation, and tracing (showing the type—steam or electrical). If heat tracing is self-limiting or thermostatically controlled, it should be noted on the P&ID.
- The set pressure for all relief valves, rupture disks, pressure regulators, and temperature regulators.
- All motors (and in some cases their voltage and horsepower) and interlocks. A description of the motor start/stop philosophy for the plant should be included in the control scope definition or in the notes section of the P&IDs.
- Controls and instrumentation, including—
    - indication of whether the instruments are in-line devices or remote mounted (and in some cases showing the instruments' connections to the process)
    - instrument purging, tracing, and insulation
    - the major function of the instrument loop (leaving the details to other documents to preserve precious P&ID drawing space)
    - the signal transmission method and control valve actions on air/electrical failure, that is, fail-open (FO), fail-closed (FC), or fail-locked in last position (FL)

Figure 14-1
Process and Instrumentation Diagram.



- all interlocks, with their descriptions shown in other documents such as logic diagrams unless they are simple enough to describe in writing.

The equipment layout on a P&ID usually follows a left-to-right sequence on the drawing (see figure 14-1). Notes are typically added on the right side of a P&ID above the title block. Notes are used to describe items on the P&ID, to refer to other documents, and to provide guidance in understanding the information on the P&ID.

For clarity, P&IDs showing the supply and distribution of utilities and services such as instrument air, steam, and cooling water are normally drawn separately from the main process P&IDs. The cut point on each utility line is marked where it becomes part of the process P&ID. Vendor-supplied packages are drawn as rectangles that contain references to the detailed vendor drawing(s).This approach is essential on P&IDs that are loaded with too much information and where drawing space is at a premium.

Any item should be shown only once on the P&IDs. If, for clarity, an item needs to be shown twice or more on different P&IDs, then on the other P&IDs it should be shown in dotted lines.

From an I&C point of view, the symbols used on P&IDs should be based on an established corporate standard. If none exist, the symbols should then be based on ISA-5.1-1984 (R1992), Instrumentation Symbols and Identification (refer to chapter 2 for further details). ISA-5.1-1984 (R1992) acknowledges that it is at the discretion of the user how much detail should be applied to a document. Generally, a P&ID should have sufficient detail to convey the functional intent of the loop and to enable the viewer to understand the means of measurement and control for the process. Because of space limitations on P&IDs, the full complement of instruments in a loop should be shown on other documents, such as loop diagrams and interlock diagrams.

As a rule, the control functions that must be shown on the P&IDs as separate elements are all in-line instruments, all hardwired interlocks and alarms, and all connections to the control system. Functions that need not be shown on the P&IDs as separate elements are any elements that are not needed to convey the functional intent of a loop (but are sometimes shown for clarity or because of corporate culture). Examples include I-to-P and P-to-I converters (if they are part of the final control element) and intrinsic safety barriers.

To save precious P&ID drawing space, complex logic is kept outside P&IDs. Instead, logic diagrams are used to describe the detail logic of the trips and interlocks. See "Logic Diagrams" later in this chapter for information on preparing logic diagrams.

A master P&ID or legend sheet is required to explain line identifications and describe all the symbols used on P&IDs. The detail shown on such a master P&ID will vary with corporate culture, but typically includes three main sections

- A description of the symbols used for process equipment
- A description of the numbering system and identification used for the lines and for all process equipment
- A description of the symbols and designations used to describe the instrumentation and control functions. See chapter 2 on identification and symbols for further details on this subject.

Control System Definition

The control system definition is intended to ensure that all key aspects of measurement and control engineering are clearly and formally documented and agreed upon before detailed design starts and before the instrumentation and control equipment is purchased. The control system definition should be available for review by all concerned. This document provides a clear basis for the detailed design phase of a project, especially when that phase is undertaken by firms outside the organization such as engineering companies. Another major advantage of the control system definition is that it leads to a more accurate cost-estimating process.

The control system definition typically includes: a general description of the process, a description of the potential control system, the safety requirements for the particular application, a list of recommended vendors, and any other miscellaneous considerations such as electrical area classification and reliability requirements. The amount of information contained in a control system definition will change depending on a project's complexity and the corporate culture. Its size may vary from a few pages to a few hundred pages.

Process Description and Overall Plant Control Philosophy

The type of process to be controlled should be described, i.e., continuous, batch, manufacturing, or a combination. Management's requirements for data logging, production reports, efficiency reports, or links to other management information systems should be identified since they affect the potential control system from a hardware and software point of view. The number of operators who will be in the control room and in the plant, with their responsibilities, must be determined—this information will help define the extent of the operator interface via monitors and control panels. Even such detail as the expected response time by the operator should be established—this will allow a rational estimate of the number of alarms and of the expected operator response time in case of emergency or plant shut-down.

The operation's requirements for startup and shutdowns, for automatic versus manual operation, and for the location and function of operator interface equipment (e.g., main control room versus field control centers) must also be determined when the control system definition is prepared.

Control System Description

The control system description section describes the potential control system (see chapter 9 for further details on programmable electronic systems). First and foremost, the description must pay careful consideration to safety requirements so it complies with codes and good engineering practice. If special safety features are required, they may have to be implemented outside the basic control system, particularly where emergency stop circuits are implemented (see chapter 10). Then, the system (being centralized or distributed) must meet the requirements of the process and of the operators. At this point, the control system designer should consult with plant operation personnel (the eventual system user) to understand their needs and problems.

The control system must be capable of accommodating future expansions and modifications, so these requirements must be estimated. In some applications, the effects of system malfunction (including failure of individual components, e.g., inputs, outputs, power supply) must be assessed. Therefore, the system's capabilities may include the need for redundancy at various levels of the control system, that is, at the controller, input/output, communication, and so on.

The control system must be capable of handling all the incoming data and outgoing controlled outputs at an acceptable rate. The control system may also have to interface with other systems such as vibration-monitoring systems, bar code readers, analyzer systems, and the like. As a result, the control system will require this interface capability both from a hardware and software point of view.

In the event of major malfunction, the operator must be capable of sorting out incoming alarms and trips as they start actuating in series (some people call it a "domino effect," others a "ricochet effect"). Therefore, the plant must consider categorizing and prioritizing alarms even for small control systems. They must be implemented for large ones. The designer of the control system also needs to assess if alarm and trip functions (and controller set points) should be protected from uncontrolled modifications or if the operator will be allowed to change such parameters at will.

The control system needs power to operate, therefore, the reliability and quality of the electrical power supply and of the instrument air supply are vital. If required, a backup must be implemented. In this case, an uninterruptible power supply (UPS) for the electrical power is required. For the instrument air, an air tank with sufficient retentive time would be added to the instrument air header system.

Another point to consider is how the operator will communicate with the plant. In some facilities where electronic equipment is susceptible to EMF noises, walkie-talkies are not allowed. Signs to that effect are posted in the control room and near all control panels that house electronic equipment. Also, if computers and networks are to be installed and operated under unacceptable environmental conditions (temperature, humidity, vibration, and static), the plant must provide proper equipment protection (see chapter 11).

And finally comes training. The level, quantity, and timing of training for involved staff (engineering, supervision, operations, maintenance) must be determined at the beginning of a project and funds allocated for it. At this point, a decision should be taken regarding the configuration and programming. Will these activities be performed by in-house personnel or will they be contracted out? Each option has its pros and cons, both in the short and long terms.

It is worth noting that programmable electronic systems (PESs) provide tremendous capabilities for control but require that precautions be taken to minimize specific risks, such as system failure, environmental effects detrimental to the system, and uncontrolled hardware or software modifications. All these risks can be minimized and in many cases almost eliminated with a well-designed, properly installed, and well-managed application (see chapter 9).

Safety Considerations

The safety considerations section of the control system definition addresses the safety aspects of the control system (refer to chapter 10 for further details). The exercise should start by identifying the main process hazards. It then looks at the required reliability of the control system, determines its failure mode, and deems it acceptable. Another item to consider in safety considerations is how quickly the plant wants the operator to respond in the event that the alarm/trip is activated.

Recommended Suppliers

Quite often, certain suppliers will be recommended because of the plant's past experience with equipment reliability and vendor service. To facilitate plant maintenance, it is good practice to maintain uniformity of manufacture for any particular item throughout the project. Therefore, a list of approved vendors is typically generated at the early stages of design before contracts are awarded.

Other Considerations

This section considers the area classifications for a plant's different locations and any specific code requirements that are peculiar to a project such as environmental regulations. Also, if the plant's control center will be considered an emergency center, it should be built and equipped for that function (for example, by making bottled air available to pressurize the control center. Refer to chapter 11 for further information on control centers. The environment under which all the instruments and control system will operate (dust, humidity, corrosive atmosphere) must be stated in the control system description.

Another point to consider is the reliability and testing frequency of critical measurements and control loops that the plant requires to protect personnel and the environment from dangerous hazards (see chapter 10 on alarm and trip systems). Is there a need for duplicated or triplicated control systems to handle critical loops, or will the logic be implemented using hardwired safety relays?

Logic Diagrams

Logic diagrams are another set of front-end engineering documents that get updated throughout the project as the control logic is modified. Logic diagrams define discrete (on-off) controls that cover all time-based and state-based logic. This includes programmable logic controller sequences and hardwired trip systems. Logic controls must be well described to allow hazard analysis studies to be performed and information to be clearly transferred between engineering disciplines as well as between engineering, contractors, maintenance, and operations.

If the logic is very simple, a written description in the control system definition or a description on the P&IDs is generally adequate. However, in the majority of cases intricate logic is required. When it is, logic diagrams could be produced in conformance with ISA-5.2-1976 (R1992), a standard intended to facilitate the understanding of the operation of binary systems and improve communications among the users of such data. This ISA standard provides symbols for binary operating functions that can be applied to any class of hardware whether it be programmable, electronic, mechanical, hydraulic, manual, or other (see figure 14-2).

Figure 14-2a
Logic diagram symbology.

FUNCTION	SYMBOL	DEFINITION	EXAMPLE
4.1 INPUT	Statement of Input Alternatively: Statement of Input Initiating instrument or device number, if known	An input to the logic sequence	The start position of a hand switch *HS-1*, is actuated to provide an input to start a conveyor. Alternative diagrams: a) HS-1 Start Conveyor Manually b) HS 1 Start Conveyor Manually
4.2 OUTPUT	Statement of Output Alternatively: Statement of Output Operated instrument or device number, if known	An output from the logic sequence.	An output from the logic sequence commands valve *HV-2* to open. Alternative diagrams: a) Open Valve HV-2 b) Open Valve HV 2
4.3 AND	BASIC A, B, C → A → D	Logic output *D* exists if and only if all logic inputs *A*, *B*, and *C* exist.	Operate pump if suction tank level is high and discharge valve is open. Tank Level High, Valve Open → A → Operate Pump
4.4 OR	BASIC A, B, C → OR → D	Logic output *D* exists if and only if one or more of logic inputs *A*, *B*, and *C* exist.	Stop compressor if cooling water pressure is low or bearing temperature is high. Water Pressure Low, Bearing Temperature High → OR → Stop Compressor

Figure 14-2b Logic diagram symbology.

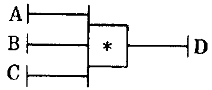
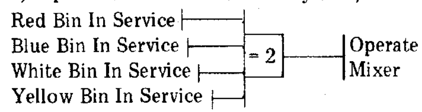
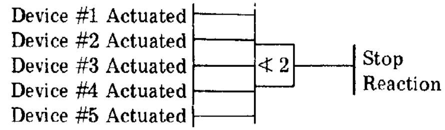
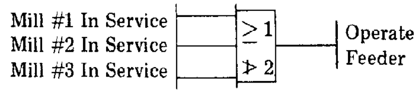
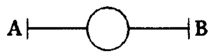
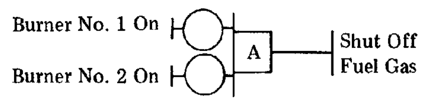
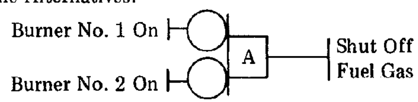
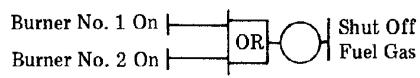
FUNCTION	SYMBOL	DEFINITION	EXAMPLE
4.5 QUALIFIED OR	 *Internal details represent numerical quantities (see "Definition").	Logic output *D* exists if and only if a specified number of logic inputs *A*, *B*, and *C* exist. Mathematical symbols, including the following, shall be used, as appropriate, in specifying the number: a. = equal to b. ≠ not equal to c. < less than d. > greater than e. ≮ not less than f. ≯ not greater than g. ≤ less than or equal to [equivalent to *f*] h. ≥ greater than or equal to [equivalent to *e*]	a) Operate mixer if two, and only two, bins are in service.  b) Stop reaction if at least two safety devices call for stop.  c) Operate materials feeder if at least one and no more than two mills are in service. 
4.6 NOT BASIC	 **The *NOT* symbol may be drawn tangent to an adjacent logic symbol.**	**Logic output *B* exists if and only if logic input *A* does not exist.**	Shut off fuel gas if burners no. 1 and no. 2 are not on.  Some Alternatives:  

Figure 14-2c
Logic diagram symbology.

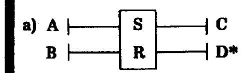
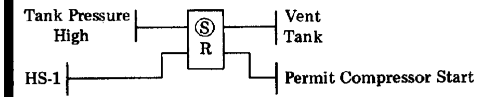
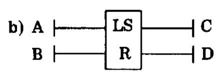
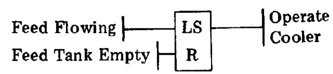
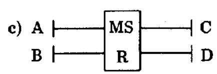
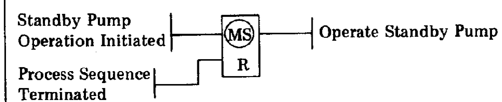
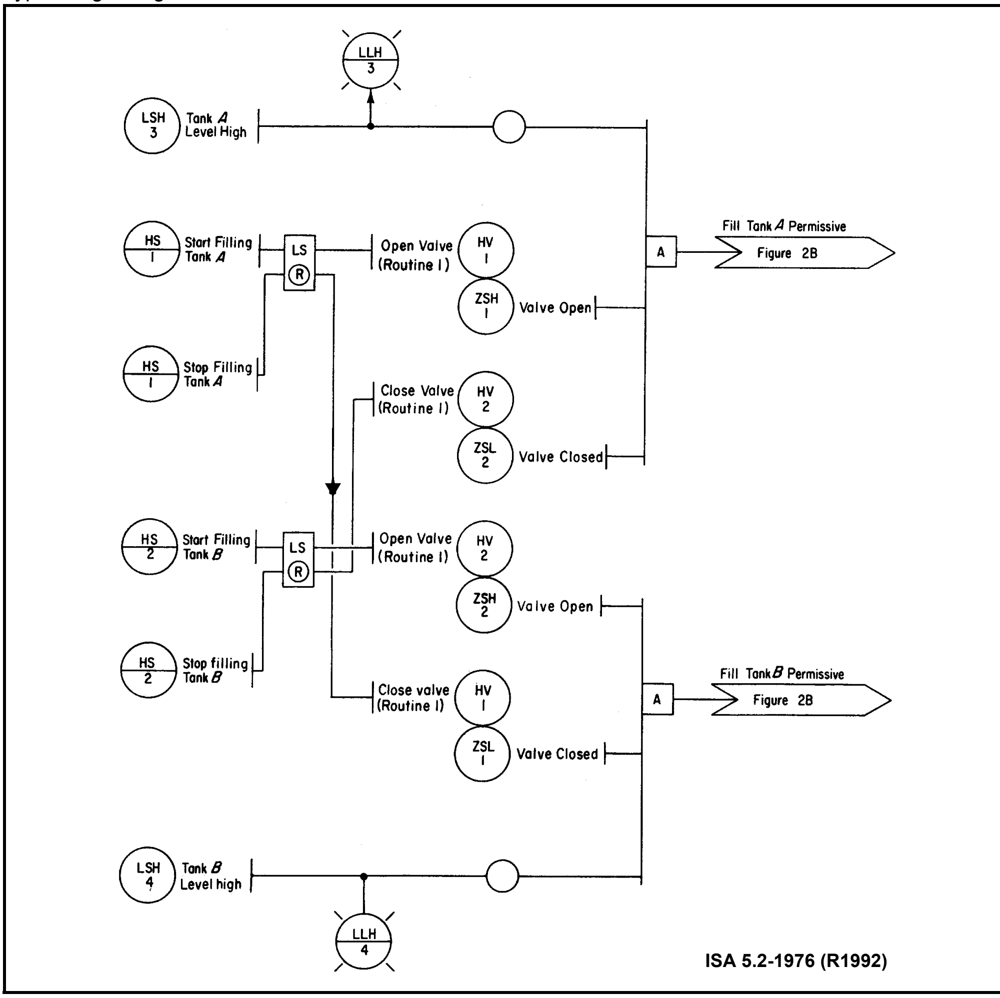
FUNCTION	SYMBOL	DEFINITION	EXAMPLE
4.7 MEMORY (Flip-Flop)	BASIC  *Output *D* shall not be shown if it is not used.	S represents *set memory* and R represents *reset memory*. Logic output *C* exists as soon as logic input *A* exists. *C* continues to exist, regardless of the subsequent state of *A*, until the memory is reset, i.e., terminated by logic input *B* existing. *C* remains terminated regardless of the subsequent state of *B*, until *A* causes the memory to be set. Logic output *D*, if used, exists when *C* does not exist, and *D* does not exist when *C* exists.	If tank pressure becomes high, vent tank and continue venting, regardless of pressure, until venting is stopped by manual actuation of hand switch, HS-1, provided that the pressure is not high. If the venting is stopped, a compressor may be started. 
		Input-Override Option If inputs *A* and *B* exist simultaneously, and if it is desired to have *A* override *B*, then *S* should be encircled, i.e., Ⓢ ; if *B* is to override *A*, then *R* should be encircled, i.e., Ⓡ *Loss-Of-Power-Supply Option* The unmodified letter *S* denotes that *no consideration* has been given to the action of the memory on loss of the logic power supply. See paragraphs 4.7 b, c, and d, below, and 3.8.	
		Similar to definition of symbol (a) except that the memory shall be *lost* in the event of loss of the logic power supply.	If feed begins to flow, the cooler shall operate until the feed tank is empty. In the event of loss of the logic power supply, the cooler shall not operate 
(cont'd)		Similar to definition of symbol (a) except that the memory shall be *maintained* in the event of loss of the logic power supply.	If standby pump operation is initiated, the pump shall operate, even on loss of the logic power supply, until the process sequence is terminated. The pump shall operate if start and stop commands exist simultaneously. 

Figure 14-2d
Logic diagram symbology.

FUNCTION	SYMBOL	DEFINITION	EXAMPLE
4.7 (cont'd)	d) A ⊢ NS / R ⊣ C; B ⊢ ⊣ D	Similar to definition of symbol (a) except that *after consideration* it is deemed *not significant*, so far as the process is concerned, whether the memory is maintained or lost in the event of loss of power supply.	If reservoir level is low, operate fill pump until either level is high or water quality is unsatisfactory. It is not significant to the process what happens to the pump on loss of the logic supply. If start and stop commands are simultaneous, the pump shall stop. Reservoir Level Low ⊢ NS Ⓡ ⊣ Operate Fill Pump Reservoir Level High ⊢, Water Quality Unsatisfactory ⊢ OR → Ⓡ
4.8 TIME ELEMENT	a) A ⊢ * ⊣ B *For functional details, see the following (also see Section 3.9):	Logic output *B* exists with a time relationship to logic input *A* as specified.	
BASIC	b) A ⊢ DI t ⊣ B (Delay Initiation of output)	The continuous existence of logic input *A* for time *t* causes logic output *B* to exist when *t* expires. *B* terminates when *A* terminates.	If reactor temperature exceeds a high limit continuously for 10 seconds, block catalyst flow. Resume flow when temperature does not exceed the limit. Reactor Temp. High ⊢ DI 10 s ⊣ Block Catalyst Flow
BASIC	c) A ⊢ DT t ⊣ B (Delay Termination of output)	The existence of logic input *A* causes logic output *B* to exist immediately. *B* terminates when *A* has terminated and has not again existed for time *t*.	If system pressure falls below a low limit, operate compressor at once. Stop the compressor when pressure is not low continuously for one minute. System Press. Low ⊢ DT 1 min. ⊣ Operate Compressor
BASIC (cont'd)	d) A ⊢ PO t ⊣ B (Pulse Output)	The existence of logic input *A*, regardless of its subsequent state, causes logic output *B* to exist immediately. *B* exists for time *t* and then terminates.	If vessel purge fails for any period of time, operate evacuation pump for 3 minutes and then stop the pump. Vessel Purge Fails ⊢ PO 3 min. ⊣ Operate Evacuation Pump

An example of a logic diagram is shown in figure 14-3. In typical logic diagrams, the inputs are shown on the left-hand side of the drawings and the outputs on the right-hand side. A master logic diagram or legend sheet is required to explain line identifications and describe all the symbols used to create such diagrams.

Figure 14-3
Typical logic diagram.



Process Data Sheets

Process data sheets contain the process data related to a particular instrument. They form the base upon which the process information is relayed from the process engineer to the instrument engineer. Specification sheets are then prepared and instruments selected. Figure 14-4a is an example of a process data sheet showing the operating parameters and is taken from ISA-TR20.00.01-2001, Specification Forms for Process Measurement and Control Instruments. The simplified process data sheet shown in figure 14-4b will in most cases have additional columns focusing on fluid viscosity, conductivity, vapor pressure, and the like.

Typically, process data sheets are generated after the P&IDs are prepared and the control equipment defined. It is of prime importance that these process data sheets be completed before instrument specification sheets are prepared. Verbal communications and assumptions made by the person completing the instrument specification sheets can be a source of misunderstanding, trouble, and expensive errors.

Figure 14-4a

Process data sheet (detailed format).

1	RESPONSIBLE ORGANIZATION	FLOW DEVICE	6	SPECIFICATION IDENTIFICATIONS	
2			7	Document no	
3	ISA	Operating Parameters	8	Latest revision	Date
4			9	Issue status	
5			10		

11	ADMINISTRATIVE IDENTIFICATIONS		40	SERVICE IDENTIFICATIONS Continued		
12	Project number	Sub project no	41	Inline hazardous area cl	Div/Zone	Group
13	Project		42	Inline area min ign temp	Temp ident number	
14	Enterprise		43	Remote hazardous area cl	Div/Zone	Group
15	Site		44	Remote area min ign temp	Temp ident number	
16	Area	Cell / Unit	45			
17			46			
18	SERVICE IDENTIFICATIONS		47	COMPONENT DESIGN CRITERIA		
19	Tag no/Functional ident		48	Component type		
20	Related equipment		49	Component style		
21	Service		50	Output signal type		
22			51	Characteristic curve		
23	P&ID/Reference dwg number		52	Compensation style		
24	Upstr line/nozzle number		53	Type of protection		
25	Upstream line pipe spec		54	Criticality code		
26	Upstr line nominal size	Rating	55	Max EMI susceptibility	Ref	
27	Upstr line conn type	Style	56	Max temperature effect		
28	Upstr line schedule no	Wall thickness	57	Min diameter ratio (d/D)	Max	
29	Upstr conn orientation		58	Max response time		
30	Upstr line material type		59	Min required accuracy	Ref	
31	Connection design code		60	Avail nom power supply	Number wires	
32	Dnstr line/nozzle number		61	Min load capability		
33	Downstream line pipe spec		62	Testing/Listing agency		
34	Dnstr line nominal size	Rating	63	Test requirements		
35	Dnstr line conn type	Style	64	Supply loss failure mode		
36	Dnstr line schedule no	Wall thickness	65	Signal loss failure mode		
37	Dnstr conn orientation		66			
38	Dnstr line material type		67			
39	Avail upstr straight lg	Dnstr lg	68			

69	PROCESS VARIABLES	MATERIAL FLOW CONDITIONS				101	PROCESS DESIGN CONDITIONS			
70	Flow Case Identification				Units	102	Minimum	Maximum	Units	
71	Inlet pressure					103				
72	Outlet pressure					104				
73	Inlet temperature					105				
74	Inlet phase type					106				
75	Mass fraction vapor					107				
76	Total mass flow rate					108				
77	Liquid mass flow rate					109				
78	Liquid actual flow rate					110				
79	Liquid standard flow rate					111				
80	Liquid density					112				
81	Liquid specific gravity					113				
82	Liquid viscosity					114				
83	Absolute vapor pressure					115				
84	Vapor mass flow rate					116				
85	Vapor actual flow rate					117				
86	Vapor standard flow rate					118				
87	Vapor density					119				
88	Vapor specific gravity					120				
89	Vapor molecular weight					121				
90	Vapor viscosity					122				
91	Inlet compressibility					123				
92						124				
93	CALCULATED VARIABLES					125				
94	Pressure differential					126				
95	Perm pressure drop					127				
96	Line fluid velocity					128				
97	Line Reynolds number					129				
98	Calculated uncertainty					130				
99						131				

132	MATERIAL PROPERTIES		138	MATERIAL PROPERTIES Continued		
133	Name		139	Abs critical pressure		
134	Composition		140	Critical temperature		
135	Density at ref temp	At	141	NFPA health hazard	Flammability	Reactivity
136	Ratio sp heat capacity		142			
137	Conductivity		143			

Rev	Date	Revision Description	By	Appv1	Appv2	Appv3	REMARKS

Form: 20F1001 Rev 0

Figure 14-4b
Process data sheet (table format).

PROCESS DATA SHEET
ABC Inc. - Process Plant No. 7
Small Town, Country
Drwg. No. : IED-96256 Rev. : 2

PROCESS DATA SHEET FOR INSTRUMENTATION

Prep'd by: HJI	Date: 11 May 89
Ck'd by: PTC	Date: 24 May 89
App'd by: WDL	Date: 27 May 89

Date	No.	Revisions	Ck'd	App'd

TAG NO. OF INSTRUMENT	MATERIAL FLOWING (INCLUDING SPECIFIC GRAVITY CONDITIONS)	FLOW RANGE UNITS: NOM. MAX.	PRESS. RANGE UNITS: NOM. MAX.	TEMP. RANGE UNITS: NOM. MAX.	VALVE FLOW DATA INLET PRESS.	OUTLET PRESS.	SHUT OFF P	MIN. P AT MAX. FLOW	PSE, PSV, PCV SET PRESS.	ALARM OR SWITCH SETPOINT	NOTES AND REMARKS

Instrument Index

The instrument index document is an index of all items of instrumentation on a specific project or for a particular plant. Its main purpose is to act as a cross-reference between all items of instrumentation and their related documents (see figure 14-5). The instrument index is commonly generated and maintained on personal computers using a database manager, a spreadsheet, or a word processing file. This computerized approach makes it easier to update the instrument index and is strongly recommended for facilities that have a large number of instrumentation devices.

Figure 14-5
Content of a typical instrument index.

Tag #	Description	P&ID #	Line / Equipmt. #	Spec. Sht #	Mfg. Docum. #	Wiring Diag. #	Location Dwg. #	Notes
FIT-123	Tank 65 discharge	12-8664	4″-IA-1256	8363 Sht.68	AB-27	3728 Sht.45	7258 Sht. 90	Supplied with tank
Notes:								

The instrument index is normally in tabular form. Typically, the following items are representative of the content listed on an instrument index:

1. Tag Number—This is a unique instrument identification (e.g., “TT-238”) shown on the P&ID, and its allocation, in most cases, is based on ISA-5.1-1984 (R1992) (refer to chapter 2 of this handbook for further information).
2. Description—The function/purpose of the instrument is described here (e.g., cooling tower inlet temperature).
3. P&ID—The process and instrument diagram (P&ID) that contains that tag number is referenced here.
4. Line/Equip.—The number of the line or equipment onto which the instrument is mounted is identified. This facilitates the search for an instrument on a particular P&ID and also simplifies the search for piping, mechanical, and vessel drawings.
5. Spec. Sheet—The specification sheet number for a particular device is listed.
6. Manufacturer's Drawings—Vendor-supplied drawings and manuals are cross-referenced here to facilitate future retrieval. In many cases, these drawings and manuals are numbered to conform to plant-produced documents that follow an established numbering system.
7. Loop Drawing—The wiring or tubing of the instrument is shown and referenced on this drawing.
8. Interlock Diagram—The interlock diagram in which an instrument is present is identified here.
9. Location Drawings—The location of the instrument on a line (or vessel) is referenced for future use at installation time or later on during maintenance. This drawing could also be a piping drawing (see chapter 15 on installation).
10. Notes—Any notes or remarks related to instruments are listed (e.g., “Instr. supplied with cooling tower”).

Some additional data that can be found on an instrument index are the following:

- Other drawings that relate to a specific instrument (e.g., typical installation details, other electrical drawings)
- Equipment supplier and model number
- Purchase order number, etc.

Instrument Specification Sheets

The purpose of the instrument specification sheets is to list the pertinent details of a particular instrument (i.e., a record for the functionality and description of that instrument). It is intended for use by engineers and vendors as well as by installation and maintenance personnel. Specification sheets provide uniformity in content, form, and terminology, which, in turn, saves time and minimizes errors for designers and users of such data.

When preparing instrument specification sheets, refer to ISA TR20.00.01 for existing forms, with instructions. Figure 14-6 shows a typical instrument specification sheet using one such ISA standard form. Some corporations develop their own set of specification sheet forms to meet their specific needs. Remember that a process data sheet must exist for every instrument that is in contact with the process.

Figure 14-6
Instrument specification sheet.

1	RESPONSIBLE ORGANIZATION	VORTEX OR SWIRL FLOWMETER w/wo TOTALIZER INDICATOR Device Specification	6	SPECIFICATION IDENTIFICATIONS
2	ISA		7	Document no
3			8	Latest revision — Date
4			9	Issue status
5			10	

11	FLOWMETER BODY		58	TOTALIZER INDICATOR	
12	Body type		59	Totalizer type	
13	End conn nominal size	Rating	60	Enclosure type no/class	
14	End conn termn type	Style	61	Signal power source	
15	Seal type		62	Contacts arrangement	Quantity
16	Mounting hardware		63	Totalizer reset style	
17	Body wetted material		64	Integral indicator style	
18	End termination material		65	Cert/Approval type	
19	Gasket/Seal material		66	Mounting location/type	
20			67	Enclosure material	
21			68		
22			69	PERFORMANCE CHARACTERISTICS	
23	SENSING ELEMENT		70	Max press at design temp	At
24	Sensor type		71	Min working temperature	Max
25	Sensor wetted material		72	Flow rate accuracy rating	
26	Fill fluid material		73	Density accuracy rating	
27			74	Min velocity URL	Max
28			75	Density LRL	URL
29			76	Min reqd back press	
30	CONNECTION HEAD		77	Pressure drop at flow URL	
31	Housing type		78	Min ambient working temp	Max
32	Enclosure type no/class		79	Contacts ac rating	At max
33	Signal termination type		80	Contacts dc rating	At max
34	Cert/Approval type		81	Max sensor to receiver lg	
35	Enclosure material		82		
36			83	ACCESSORIES	
37			84	Connecting cables length	
38	TRANSMITTER OR COMPUTER		85	Isolation manifold	
39	Housing type		86	Remote indicator style	
40	Measurement compensation		87	Calibrator adapter	
41	Output signal type		88		
42	Enclosure type no/class		89	SPECIAL REQUIREMENTS	
43	Span-zero adjustment		90	Custom tag	
44	Characteristic curve		91	Reference specification	
45	Digital communication std		92	Special preparation	
46	Signal power source		93	Compliance standard	
47	Failsafe style		94	Calibration report	
48	Integral indicator style		95	Software configuration	
49	Signal termination type		96		
50	Cert/Approval type		97	PHYSICAL DATA	
51	Mounting location/type		98	Estimated weight	
52	Calibration type		99	Face-to-face dimension	
53	Failure/Diagnostic action		100	Overall height	
54	Enclosure material		101	Removal clearance	
55			102	Signal conn nominal size	Style
56			103	Mfr reference dwg	
57			104		

110	CALIBRATIONS AND TEST		INPUT OR TEST			OUTPUT OR SCALE	
111	TAG NO/FUNCTIONAL IDENT	MEAS/SIGNAL/TEST	LRV	URV	ACTION	LRV	URV
112		Flow rate-Analog output					
113		Mass flow-Analog output					
114		Meas-Analog output					
115		Meas-Freq output 1					
116		Meas-Freq output 2					
117		Measurement-Scale					
118		Temp-Digital output					
119		Meas-Digital output					
120		Density-Digital output					
121		Test pressure					

122	COMPONENT IDENTIFICATIONS		
123	COMPONENT TYPE	MANUFACTURER	MODEL NUMBER
124			
125			
126			
127			

Rev	Date	Revision Description	By	Appv1	Appv2	Appv3	REMARKS

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The specification sheets must show compliance with the electrical code in effect at the site. This equipment must be approved and bear the approval label (e.g., UL, FM, or CSA), or, at a minimum, it must have the approval of the electric power authority in the region in which the equipment is installed. Non-approved equipment should not be installed, or liability, legal, and insurance problems may arise. For control equipment located in hazardous locations, the ISA has published a series of standards on this subject. Intrinsic safety (IS) through the use of barriers is the preferred method of protection in hazardous environments for many plants. However, other plants still prefer explosion-proof or purged enclosures. In any case, compliance with the code requirements is a must.

Loop Diagrams

The loop diagrams show the detailed arrangement of instrumentation components in a loop. They are used during design, construction, startup, and maintenance. All devices, pneumatic and electronic, that carry the same loop number are generally shown on the same loop diagram. This makes the loop diagram an ideal tool for troubleshooting. At a minimum, the loop diagram will show the interconnection of the devices, their locations, their power sources, and their control actions.

In general, a loop diagram should be prepared for each instrument loop that contains more than a single instrument. Normally, the only instruments that do not require loop diagrams are interlock systems (which are shown on the interlock diagrams) and local devices such as gages, regulators, and relief valves. For these local devices, an entry in the instrument index should be sufficient. A master drawing (or legend sheet) should be generated to explain all the symbols used in loop diagrams.

The content and format of the loop diagram should conform to a plant standard or, if one doesn't exist, to ISA-5.4-1991, Instrument Loop Diagrams. Figures 14-7 and 14-8 are reprints from this standard. ISA-5.4-1991 was published to provide guidelines for preparing and understanding loop diagrams and to identify optional information that may be shown on them. This ISA standard closely relates to ISA-5.1-1984 (R1992).

Some organizations keep track of the instrument loops by using tables generated through a database manager instead of loop drawings. This practice is more suited to modern distributed control systems than to analog instrumentation. While it reduces the number of drawings generated, it may not be acceptable to the installing contractor or to maintenance personnel. Many engineers, contractors, and maintenance personnel still prefer the "old-fashioned" loop diagrams over tables.

The following points are considered as good engineering practice when preparing loop diagrams:

- The electrical and pneumatic details of a single loop are not separated; rather, they are shown on the same loop diagram.
- Each instrument signal must be grounded at one point only, preferably in the control room.
- All cable shields must be continuous (connected across junction boxes, etc.) and care must be taken to adequately insulate the shield over its entire length so as to maintain the one point connection (see the section on grounding in chapter 1 of this handbook for further information).

Loop diagrams are generally the source of the wire numbers for all analog devices and for discrete devices that are not shown on any interlock diagram. The same rules apply for creating wire numbers on loop diagrams as for interlock diagrams. The only difference is that since there are no rung numbers, loop numbers are used. Each wire in the plant should have a unique number. The wire number is typically composed of a loop number followed by a dash and a sequential number starting with 1.

Loop diagrams were originally developed based on the concept of physical connections between individual devices, each performing a specific function. Modern control systems tend to have a measurement, a final control element, and a computer-based control system that performs most of the monitoring and control functions. The representation on the loop diagram in this case would not generally show the functions of the monitoring and control function. On the other hand, to show all this detail on the P&ID may, in some cases, overload the P&ID. Some corporations have adapted PMC 22.1, the function diagramming standard of the former SAMA (Scientific Apparatus Makers Association) organization, or have developed their own symbology to represent the control function. The functions performed in software may be shown on dedicated drawings or even described in the control scope definition. The final decision regarding where the functionality of the software should be shown depends on the complexity of the loop and the corporate culture. If separate drawings are used to describe the monitoring and control functions, they could be part of the control system definition document, with a master drawing generated to describe the symbology used.

Figure 14-7
Loop diagram (with stand-alone controller).

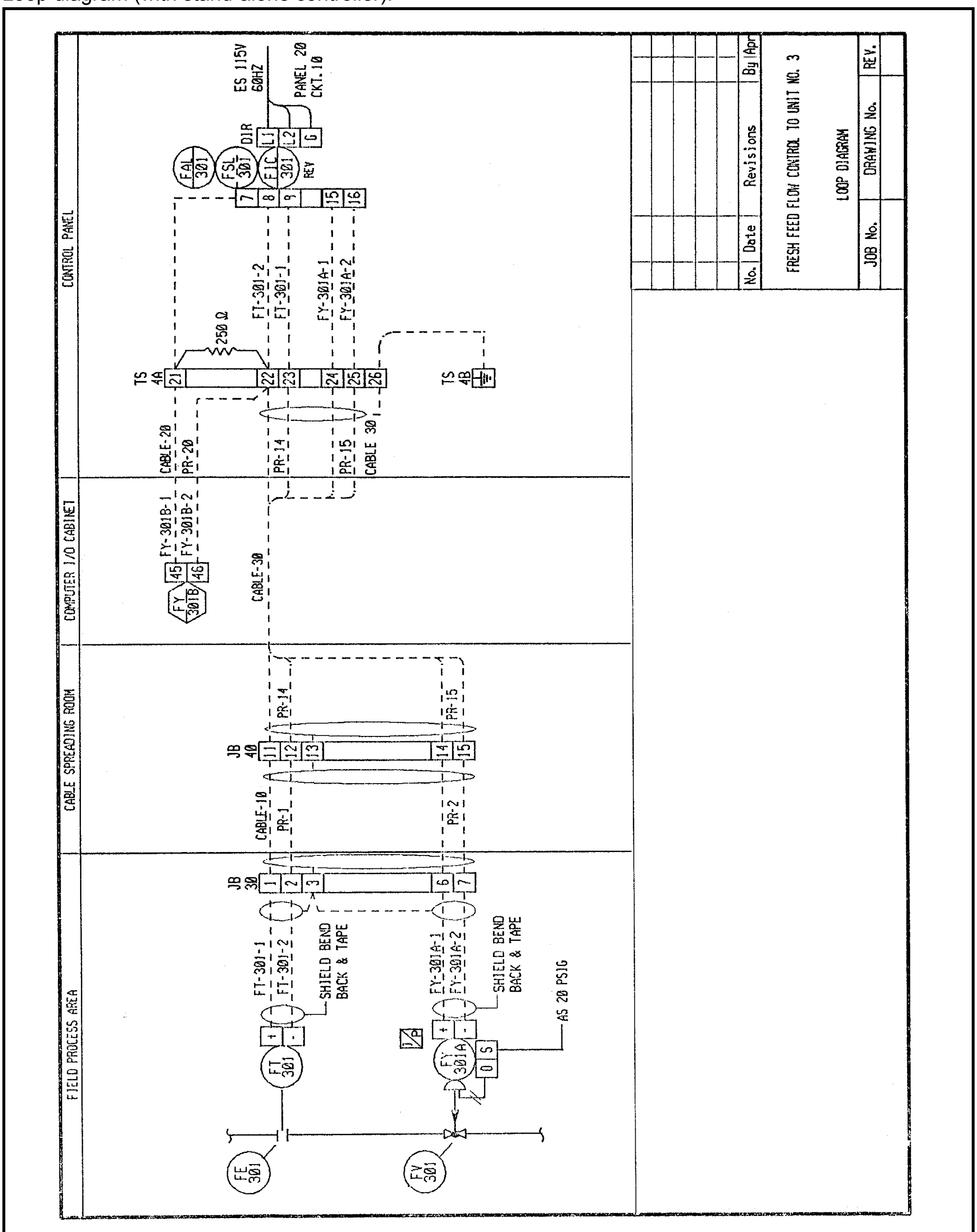
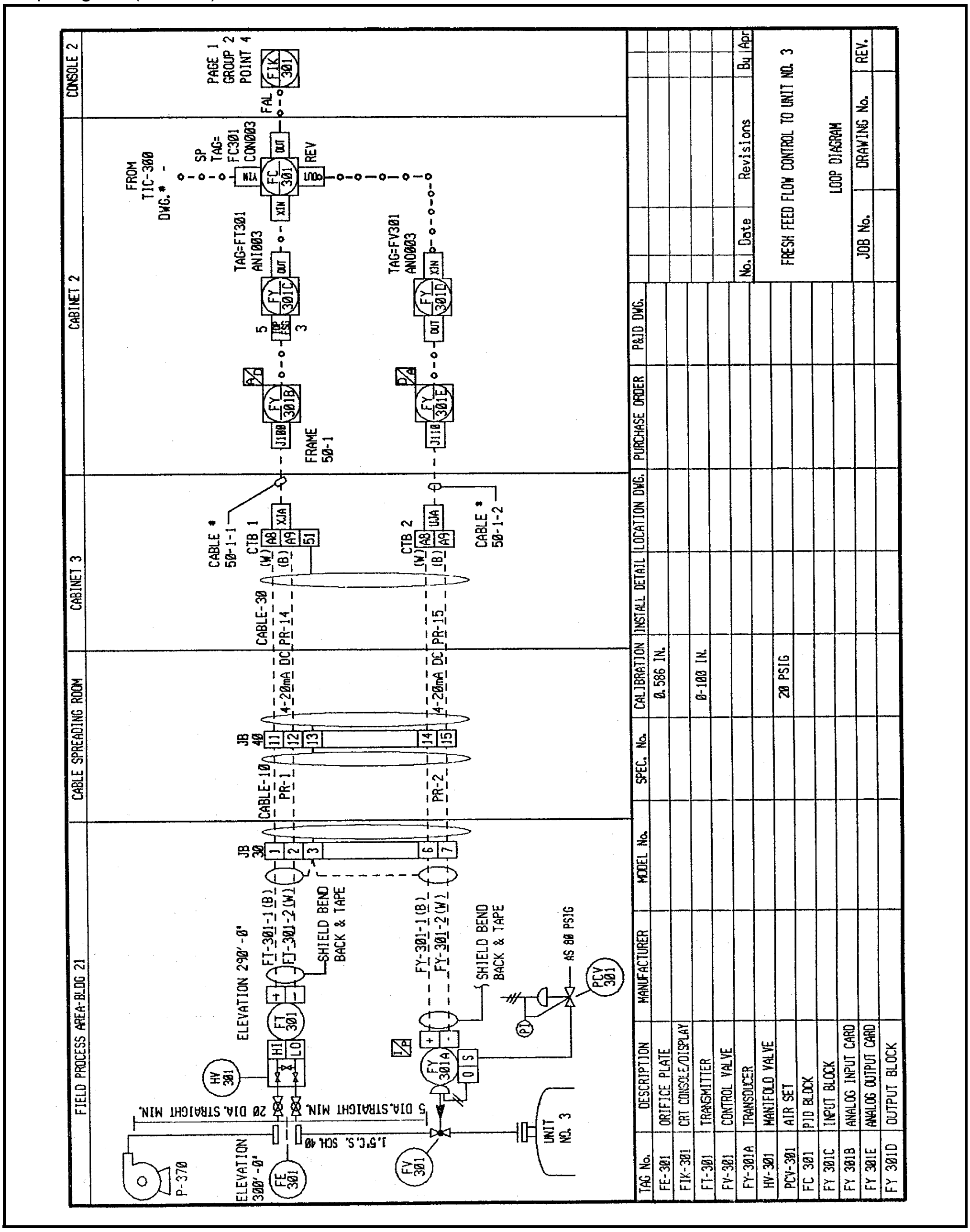


Figure 14-8
Loop diagram (for PES).

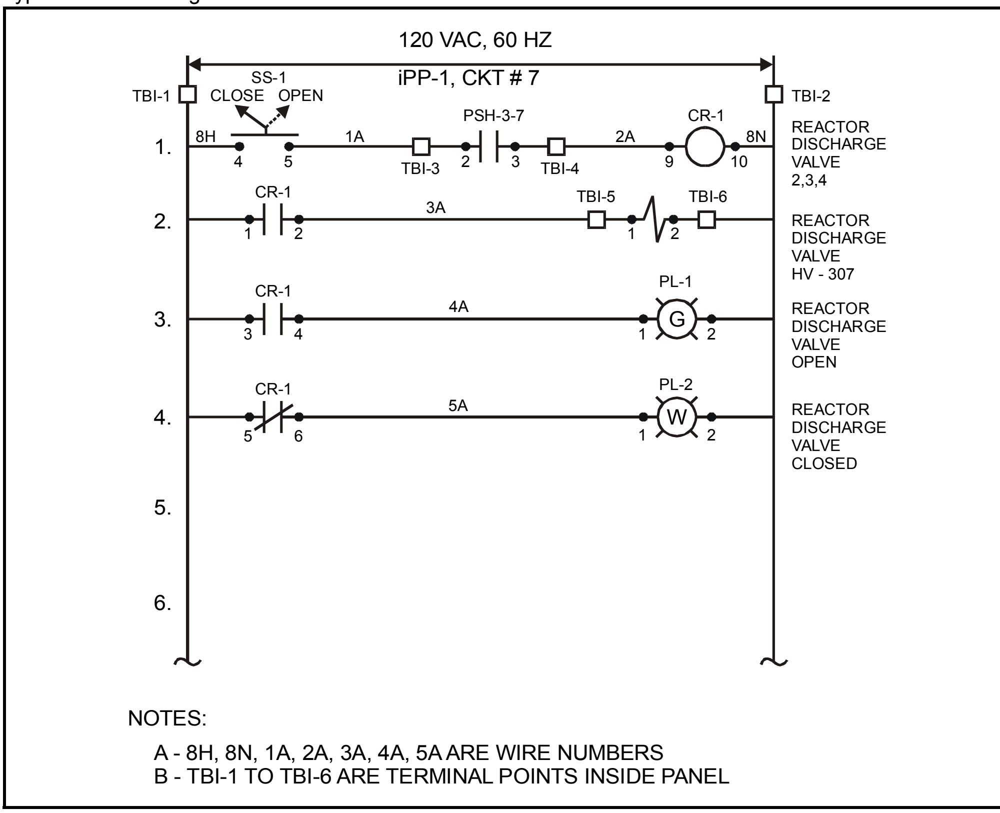


Interlock Diagrams

The interlock diagram (also known as "electrical control schematic" or "electrical wiring diagram") shows the detailed wiring arrangement for discrete (on-off) control (see figure 14-9). Generally, the only control circuits that do not require interlock diagrams are analog loops, which are shown on loop diagrams. With the extensive use of programmable electronic systems for performing logic functions, the use of the interlock diagram is not as widespread as it was years ago. However, some applications still require such drawings, such as hardwired safety trips and motor controls. A good quality interlock diagram will always be in agreement with the corresponding logic diagrams.

All devices on interlock diagrams will generally have a tag number, location, and service description. In addition, all rungs on these diagrams are numbered sequentially. The numbers start from the top of the diagram and increase, going down the ladder and continuing through all the diagrams created for the project. In North America, the symbols used are based on IEEE Standard 315A-1986. Each rung on a project should have a unique number, and each wire in a plant should have a unique number. These diagrams are the source of wire numbers for discrete control, which begin with the rung number, followed by a dash and a sequential number on the rung, starting with 1. Typically, the wire number does not change after it goes through a terminal block unless it is a fused terminal block. It changes only after a switching device or load, that is, fuse, switch, or coil. A master drawing (or legend sheet) should be generated to explain all the symbols used.

Figure 14-9
Typical interlock diagram.



Manual for Programmable Electronic Systems

The primary purpose of a programmable electronic system (PES) manual is to serve as a reference for the ongoing support and maintenance of the PES system after final commissioning and startup have taken place. This section will provide a framework and checklist from which a plant can produce the manual for (PES), such as PLCs and PCs. The exact layout of the manual will depend on the plant's needs, the level of training, the corporate culture, and the system selected. The information contained in such manual spans the hardware and software, including the input/output modules and the operator interface and/or supervisory computer. Typically, the manual may be broken down into the following sections, with each showing its contents:

- Overview and General Information
    - Manual layout description and index

    - Brief description of the PES
    - PES design philosophy (such as failure modes, etc.)
    - PES modification history
- System Startup Procedure
    - Overview, in which critical process and personal safety information must be highlighted
    - Specific startup instructions
    - List of control set points and parameters
- PES Communications
    - Data communication overview (include block diagram)
    - Network information
    - Cabling and connection information (pinouts, jumpering, shielding requirements, dip switch settings)
    - List of available reference manuals
- Input and Output, including Programmable Controllers (PLCs) and Standalone Controllers
    - Input and output cross-reference list
    - Program structure overview
    - Annotated program file listings
    - Device memory allocation listing
    - Program backup procedure
    - General information; software versions, dip switch setting, jumper configurations, electrostatic damage prevention, etc.
    - List of available reference manuals
    - Operator Interface
        - System screen layout and listing
        - Operator keyboard functional description, complete with function key index, if applicable
        - Full database listing, including link structure, if any
        - Input-output scanner(s) configuration and listings
        - Backup procedure
        - Host computer general information (operating system and version, directory structure, description of hardware components, dip switch settings, jumper configurations, electrostatic damage prevention, etc.)
        - List of available reference manuals
- Reference documents
    - Index
    - Equipment manufacturer's product data sheets for all components
- Miscellaneous
    - Index
    - List of support persons, including manufacturer's “hot line” support
    - System backup disk(s).

The writing style of this manual should be clear and concise. Descriptive sections should avoid excessive technical jargon, and acronyms should have their meaning spelled out on first occurrence (e.g., RAM = random access memory). In addition, the group that will be responsible for PES support and maintenance at the plant should be consulted regarding the number of manual sets required. The manual(s) should be updated to incorporate any system modifications that take place and should include a modification history that documents the nature of the modification, the date of changes, and the name of the person responsible for the change. The content of such a manual must comply with the regulations in effect at the site and is particularly applicable to critical loops.

PLC Program Documentation

An important part of any documentation package is the PLC program (where PLCs are used). With the proliferation of PLCs, the format in which the program (generally ladder logic, but also any other IEC-approved language) is described should be agreed upon. Without such a description, the review and editing, especially on large programs, becomes an impossible task. PLC program documentation may, for example, conform to the following requirements:

- The programming should be written in the format requested by the plant and comply with the existing plant software.
- The individual I/O description should show:
  - the tag number (e.g., LSH-123);
  - a description (e.g., TANK 17);
  - any notes (e.g., instrument location or PLC I/O address, etc.);
  - in addition, for ladder logic, all outputs/inputs should be cross-referenced to the rung(s) to which they connect.
- Each section of the program should be clearly explained. The ability to display or not display the rung descriptions should be available to speed up the programming and troubleshooting activities.
- The PLC program may be simulated on a personal computer (PC) prior to commissioning, and the software used should have the ability to compare two programs and flag differences. This is a useful feature when comparing the latest running program with the master or "approved" program.

In situations where the program is developed and implemented by outside contracting firms, the owner may want to include a sample PLC program. However, even in spite of such a sample program, it should be kept in mind that different programmers do not have exactly the same approach and format style, even while using the same example as a format. So the owner should coordinate and continuously review all programming during program development to ensure quality.

CHAPTER 15

INSTALLATION

Overview

The installation of instruments, control systems, and their accessories follows the final stage of the engineering design. The installation is then followed by commissioning and plant startup. It is important to prepare an installation specification that defines the owner's requirements—this prevents misunderstandings, extra costs, and construction delays. The content of such a specification typically covers the following topics: code compliance, scope of work, installation details, equipment identification, equipment storage, work specifically excluded, approved products, pre-installation testing, execution, wiring, tubing, and checkout. All of these are discussed in this chapter. It should be noted that the following guidelines apply to the majority of installations. Certain harsh or special environments may need additional requirements.

Code Compliance

It should be the responsibility of the installing contractor to ensure compliance even though the owner produced all engineering documentation and may be reviewing and approving all installation. All equipment and installation must comply with the codes in effect at the site. There will be cases where the drawings or specifications call for material, workmanship, arrangement, or construction of quality that is superior to that required by any applicable codes. In such cases, the drawings and specifications should prevail. Otherwise, the applicable codes and standards must always prevail.

To comply with local codes and especially with insurance requirements, all electrically operated instruments or the electrical components incorporated in an instrument should be approved and bear the approval label (UL, FM, CSA, etc.). Modifications to an approved piece of equipment may void the approval.

Scope of Work

An installation contractor's scope of work typically includes all items of instrumentation and control systems shown in the documentation supplied with the installation specification. Depending on the size and complexity of the project this set of documents typically includes the following: P&IDs, instrument index, instrument specification sheets, loop drawings, interlock diagrams, installation details, vendors' data, location drawings, related piping drawings, and location and conduit layout drawings. This documentation is used by the installing contractor to bid on the job and to do the work. In addition, to avoid future unwanted surprises, it is strongly recommended that the contractor visit the site before tendering a bid to understand all conditions and requirements that must be met in carrying out the work. This includes reviewing and accepting the safety requirements in effect at the plant. The contractor is responsible for reviewing all documentation and equipment received before commencing the installation work. Should there be inconsistencies (and there normally are), the contractor should immediately notify the owner, who then should decide on a solution.

All instrumentation devices listed in the instrument index should be mounted and connected by the contractor to form a complete operating system. A manufacturer, such as a panel assembly shop, may ship pieces of the equipment and instrumentation separately, but these pieces should be installed and connected by the contractor.

It is expected that the installation work will be carried out by certified and trained personnel with adequate supervision and the equipment necessary to complete the work. The owner may require the contractor to produce evidence of the personnel's certification and training and to ensure that the construction crew (and in particular their supervisor) will remain on the job until completion.

In situations where an electrical certificate of final inspection must be furnished to the plant, the contractor should apply for it and pay all fees required for the certificate.

During construction and commissioning, changes to the original drawings do occur. They must be recorded by the contractor on a set of drawings that is handed over to the owner before final inspection of the work. These marked-up drawings and documents form the basis of the future "as-built" documentation.

Installation Details

All field-mounted instruments should be installed and connected in such a way that the instrument can be maintained and removed for servicing without having to break fittings, cut wires, or pull hot wires through rigid or flexible metal conduit. Sufficient clearance around the instruments must be allowed to permit them to be removed without disturbing other equipment. It is also expected that the contractor will provide the necessary unions and tubing connections to all instruments. In addition, to prevent debris or paint from getting at the instrument, all field-mounted instruments, once installed, should be protected by heavy plastic bags until the owner gives final acceptance. Wherever dry air purging and/or heating are specified for an outdoor instrument enclosure, they should be activated as early as possible to protect the instruments.

The location of instruments and control equipment is generally identified on a location drawing (see figure 15-1). This drawing is generally a plan view of the facility, showing the location of individual I&C equipment with their respective elevations. Some companies use the piping drawings (instead of separate location drawings) to indicate the location of I&C equipment.

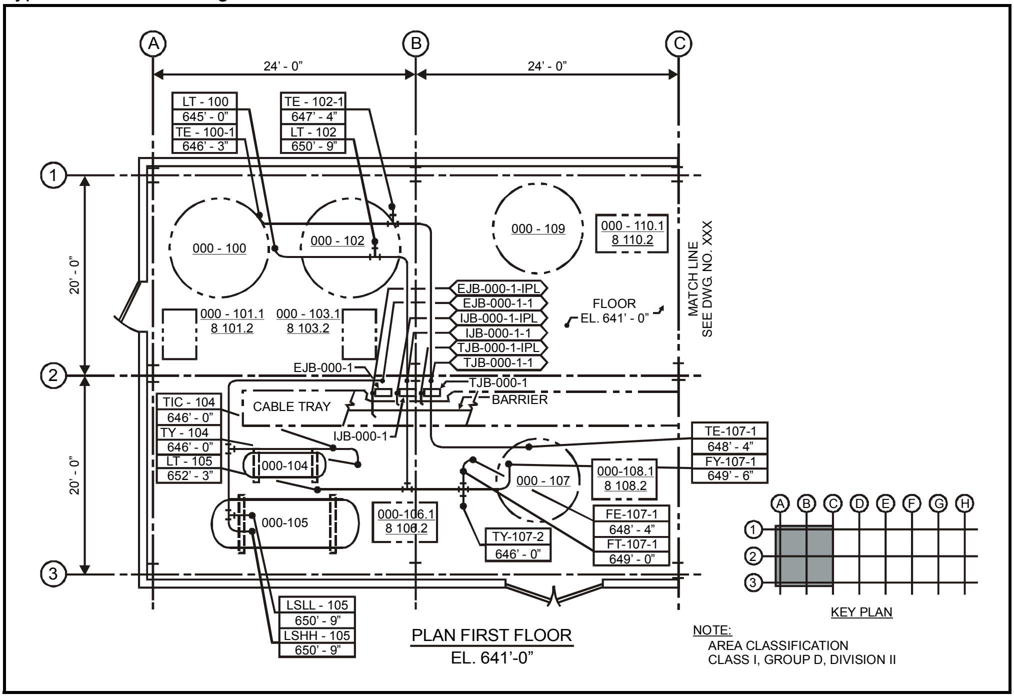
Piping drawings are typically not produced by the I&C discipline (it's a piping/mechanical engineering document). These drawings normally show the equipment and process lines as well as the connection to all field instruments (complete with elevations and tag numbers). The information on these drawings can be used in the instrumentation and control activities. This approach has two main advantages. First, fewer drawings are prepared and cost is reduced. Second, having only one drawing that shows both process equipment and instrument location and process connection avoids errors that occur when two drawings show the same information.

The details of the instrument connections (i.e., instrument air, power, wiring, etc.) are shown on the appropriate drawings, such as the instrument loop diagrams or specific instrument installation details.

The following points should be considered when installing I&C equipment:

- Plant maintenance personnel must have access to the instruments. Therefore, all instruments, including vessel or piping connections for sampling or for sensing elements, are located so they are accessible from structural platforms or grade.
- Access from permanent ladders should be restricted to small instruments (such as pressure gages, dial thermometers, or thermocouples), to cases where location cannot be changed to permit access from a platform or grade, and to cases where one person can easily carry the instrument.
- Process tubing should be designed and routed to prevent sediments from being deposited inside the tube or in the sensor housing (also refer to section "Tubing" later on in this chapter).

Figure 15-1
Typical location drawing.



Equipment Identification

All instruments and control equipment, including junction boxes, should be identified by the equipment tag number. This should read the same as the number that is shown on the documentation (see chapter 2 for further information on equipment identification). Tags are generally affixed to the instrument body or housing wherever possible and to the instrument support or adjacent tubing only when unavoidable. The tag should not be placed where routine maintenance would require that the tag be removed. In addition, all wiring should be identified with suitable nonconductive and abrasion- and solvent-resistant markers, with the wire numbers as shown on the documentation (i.e., on loop diagrams and interlock diagrams).

Most plants have their individual way of color coding the wires, from a simplified black (for phase or positive conductors) and white (for neutral or negative conductors) to a more complex coding system where each voltage and application has an individual color. However, in all cases, earth ground (if insulated) is green, and thermocouple extension wires use the ANSI color code. For intrinsically safe (IS) wiring, a bright blue color is the norm, so this color should not be used on any other circuits. This color may be take the form of a blue stripe on wires whose colors follow the general scheme described earlier. Conduits, cable trays, terminal blocks, and field junction boxes must also be identified with a bright blue label bearing the legend “INTRINSICALLY SAFE.”

Finally, all temporary jumpers that must be removed when commissioning, testing, or startup is completed must have a unique color, for example, an orange colored wire, for identification purposes.

Equipment Storage

On some construction sites, the installation contractor is expected to provide a separate adequate indoor storage space for instruments that require protection from excessive temperature or humidity. This space sometimes must be heated or air conditioned. Instruments, wherever possible, are kept in their original shipping cartons until installed. It is good practice to maintain a separate storage space apart from the areas where non-instrumentation equipment is stored.

Depending on the project's management and scope, the installation contractor may be responsible for receiving, unloading, safekeeping, and storing all materials and equipment supplied. When accepting deliveries, the contractor should inspect the equipment and materials against the instrument index, specifications, and purchase orders to ensure that quantity, type, ranges, and so on, are as specified. If there are discrepancies, they should be immediately rectified since at this stage, time is of the essence.

Work Specifically Excluded

The owner should clearly and separately identify exceptions to the scope of work. It is common practice on construction sites to have the piping/mechanical contractor install all in-line devices, such as control valves, orifice flanges and plates, in-line flowmeters, thermowells, as well as all impulse piping from the process up to and including the first block valve. This information should be detailed on the piping drawings to avoid misunderstandings, project delays, and extra costs.

To prevent damage to the instruments, most of which are relatively delicate (and expensive), all in-line devices must be removed when the piping is being flushed and cleaned and then reinstalled. In addition, during hydraulic tests on the process pipework, instruments should be disconnected to ensure that the isolating valves are leak proof. In no case should any instrument, other than control valves and thermowells, be subject to test pressures.

Approved Products

It is quite common for a client to specifically state to the contractor which products are approved for use on the client's project. Such a list of products can include electrical and pneumatic junction boxes, power and control cabling, terminal strips, rigid conduits and flexible conduits, conduit fittings, tubing, tube fittings, and so on. An actual list of approved products is typically included in the installation specification to guide the contractor.

Pre-installation Testing

Pre-installation testing ensures that each instrument as received from the vendor is supplied in accordance with its specifications, is functionally correct, and is in working order. To maintain control of a project, it is good practice for a client to require a schedule from the contractor that defines the overall sequence of instrument testing on a project.

With a few exceptions, instruments should be subjected to a pre-installation test that commences as soon as practicable after the instrument is received. The tests, when done on site, should be performed in the manner described by the manufacturer's documentation, with any adjustments also made in accordance with the manufacturer's instructions. The pre-installation calibration of instruments requires the availability of a fully equipped lockable workshop and a clean dry environment for the equipment. In some cases, instead of on-site pre-installation testing, the owner may rely on a certified test done by the vendor before the instruments are shipped to the site.

Before calibration commences, a comprehensive list of the test equipment to be used must be assembled. This test equipment should have a standard of accuracy at least ten times better than the manufacturer's stated accuracy for the instrument to be tested and be backed with calibration certificates that are up to date and available for inspection.

The owner should be immediately informed of any defects that cannot be rectified or any instrument that cannot be calibrated within a reasonable time. In areas with cold temperatures, the tests should be carried out on electronic instruments only after an adequate warm-up period.

Instruments are in most cases tested at 0 percent, 25 percent, 50 percent, 75 percent, and 100 percent in the up-scale and down-scale directions. If necessary, they are adjusted until the accuracy conforms to those limits stated by the manufacturer. After testing, all connections and entries must be sealed to prevent moisture and dirt ingress.

Execution

It is extremely difficult for an installation specification and its reference documents to cover each and every installation detail. The installing contractor is expected to be familiar with the codes and current good practices for the installation of instruments and their related hardware. The contractor is also typically expected to provide and install all peripheral items such as clips, supports, clamps, brackets, and stands as well as all necessary welding, painting, wiring, junction boxes, tubing, and fittings that are required to complete the installation and connect instruments as required by suppliers and by the owner's installation specification.

Instruments should only be mounted when all heavy mechanical work adjacent to the location of their installation has been completed. This should be clearly stated in the installation specification. Instruments and junction boxes should be mounted level and plumb and so as to provide accessibility and protection from mechanical damage, heat, shock, and vibration. They should not interfere with any structure, other equipment, piping, or electrical work. In addition, instruments once installed should not create an unsafe condition (such as sharp edges or protrusions) and should not obstruct walkways or other means of access provided for maintenance or process use, such as access for forklift trucks and cranes.

Instruments, impulse lines, tubing, or wiring should not be attached to process lines or process equipment except for equipment designed for process connection, such as in-line transmitters, gages, or control valves. Where instrument items are connected to piping or equipment, they should not be installed so damaging or undesirable stress is placed on the piping, equipment, or instruments. Most important, piping and equipment must not be supported by items of instrumentation or their accessories. Brackets and supports must be used where needed.

Field-mounted instrumentation and junction boxes are frequently mounted on building columns and walls. All mounting must be done in compliance with the equipment vendor's recommendations and quite often it is done through the use of metal framing (such as Unistrut's ®). Support stands made of painted mild steel pipe are provided when it is impractical to mount instruments on columns and walls. Such support stands should be attached to the building structure, beams, columns, or other permanent structural members and should not be attached to handrails, floor grating, process equipment, piping, vessels, conduit, or instruments. Where drilling in concrete, the contractor must avoid reinforcing steel and embedded conduits. If in doubt, the contractor must contact the plant engineer before any drilling starts.

Painting should be done according to existing plant specifications (typically, first primed then followed by two coats of paint).

Wiring

In the world of instrumentation and control, electrical power is provided at a relatively low voltage, typically 120V AC or 24V DC. In most cases, there are four types of instrumentation and control wiring.

1. Very low-level DC analog signals, such as for thermocouples, strain gages, pH sensing, etc.
2. Low-level DC analog signals (4-20 mA at 24V DC)
3. Low-voltage power wiring and low-voltage discrete signals (at 24V DC)
4. High-voltage power wiring and high-voltage discrete signals (at120V AC)

The installing contractor should run each of these four types in a dedicated multiconductor or conduit. Shielded wiring should be used for types 1 and 2. A gap should be maintained between each of the four types. This gap may be set by plant standards, and some plants have determined that a 1 ½ ft (0.5 m) is a safe and conservative distance for all applications under 100 kVA—an assumption valid to most instrumentation and control applications. Other plants abide by the following rules:

- In a contiguous metallic raceway or conduit, allow a minimum of
    - 3 in. (0.08 m) if the 120V AC wiring carries less than 20A,
    - 6 in. (0.15 m) if more than 20 A but less than 100 kVA, and
    - 1 ft (0.3 m) if more than 100 kVA.
- In a non-contiguous metallic raceway or conduit allow a minimum of
    - 6 in. (0.15 m) if the 120V AC wiring carries less than 20A,
    - 1 ft (0.3 m) if more than 20 A but less than 100 kVA, and
    - 2 ft (0.6 m) if more than 100 kVA.

In addition, a minimum distance of 5 ft (2 m) should be maintained between power transformers (and switchgear) and Types 1, 2, and 3 instrumentation and control wiring.

Quite often, types 2 and 3 can be run in the same conduit. In that case, type 3 wiring should be shielded as well. To avoid interferences arising between low-voltage and high-voltage cables, they should cross only at right angles and be kept physically separate on cable trays. For any other type of wiring, such as fieldbus or data highway, the installation must closely follow the vendor's recommendation.

Good grounding is vital to the installation of modern electronic-based equipment. First, individual shields in a multiconductor cable must be connected to the shields of the individual pair of cable to which they connect. The shields must not be grounded to the structure or to each other at the junction box. At the instrument end, no connection should be made to any shield, foil, or drain wire. In addition, the shield is typically not connected to the signal ground as this would introduce noise to the signal. In all cases, the designer should carefully follow the recommendations of the equipment vendor. The contractor must follow the grounding requirements as shown on the loop drawings, which typically show the grounding at the input/output cabinets. Sometimes field grounding exists, as designed by the equipment vendor, typically on analyzer systems. In these situations, a loop isolator is required to prevent ground loops from forming. (See “Grounding” in chapter 1 for further information.)

Cable runs should be positioned clear of process pipes, service pipes, ventilation ducts, hoist blocks, overhead cranes, and other similar equipment. They should be routed neatly to run either vertically or horizontally and not diagonally across walls, ceilings, or floors. Cables should enter into panels on the panels’ underside to reduce the risk of water or other liquids seeping into the panel and damaging the electronic equipment. Where side entry is unavoidable, these cables should incline downward away from the equipment to ensure that water does not flow toward the cable entry point. Cable entry into the panel from its top must be avoided. Also, drilling in a control cabinet should be avoided since metal chips can land on the electronics, causing short circuits. If drilling is unavoidable, then the installer should ensure that all electronic components are well covered (e.g., with a plastic sheet) before drilling starts.

All field-run conduits and cables are generally shown on the location and conduit layout drawings, which include details on the identification and number of wires. These drawings typically also show the location, elevation, and size of cable trays, junction boxes, and control/interlock panels.

Where redundant or triplicate channels are implemented, the different components (cable pans, conduits, junction boxes, equipment racks, etc.) should be physically separate. A minimum distance of 12 to 20 inches (0.3 to 0.5 m) is typically required between the different channels

Tubing

In electronic-based modern control systems, tubing is typically used for supplying instrument air to control valves and for process connections (also known as process tubing). Other tubing is used in hydraulic systems, but this topic is outside the scope of this handbook.

Air-actuated control valves require an air supply that is typically supplied by an individual shutoff valve that allows independent shutoff. The air supply take-off from the major supply header should be made from the top or side of the header or branch. To avoid leakage problems, tube connections and fittings should be kept to a minimum and preferably should not be permitted in tubing runs.

Process tubing must conform to, or exceed, the process/utility piping code specification with respect to design temperature and pressure as well as materials of construction. In most applications, process tubing is made of stainless steel and either 1/2 or 3/4 in. (10 to 20 mm) in size, depending on the application. On gas and liquid lines, the tubing is sloped continuously, with an appropriate grade of one in ten or greater. Sloping ensures that the gas and liquid go to predictable locations in the tubing. On steam lines, the tubing must remain horizontal to ensure a steady liquid head.

Tubing should be sufficiently supported to avoid vibrations and sagging. The support interval is typically every 3 ft (0.9 m) as well as before and after each bend. Where concentrated load exists on the tubing (such as valves)—supports should be located as close as possible to that load. Where straight runs exist, the supports should permit tubing movement. Exhaust tubing should always be routed downward.

Straight tube runs should not be installed between fixed fittings. At least one 90º bend is required to allow for motion and thermal expansion. A flexible hose should be used where too much vibration or relative motion exists.

Tube bending should be done with a tube bender and the tube should not be kinked or flattened. The minimum bend radius varies with the tube material, thickness, and diameter (refer to the vendor's recommendations).

Tube cutting should be done with a sharp tube cutter and the end of each cut should be square. No cutting oil should be used in the cutting process. All tube cuts should be deburred on the inside and outside of the tube and the exterior surface of the first two inches (5 cm) should be free of any visible defects (e.g., kinks, flat spots, and scratches). Male pipe threads should have a sealant—however, the use of thread tapes should not be allowed.

For a typical gas installation with no condensable fluids, the measuring device should be located above the process line and the process tap on the top or side of the line (see figure 15-2). All horizontal lines should be sloped to allow any trapped liquids to flow back to the process. For typical liquid installations or condensables such as steam, the measuring device should be located below the process line and the process taps to the side of the line (see figure 15-3). All horizontal lines should be sloped to allow trapped gases to flow back to the process. On condensable fluids, filling tees are required to allow a stable static head to be created. Some corporations will develop individual installation detail drawings that give a detailed description of the material needed for the installation (see figure 15-4). Other corporations generate a handful of “typical installation details” and rely on the capabilities and experience of the installing contractor.

Process tubing that contains liquids that can freeze should be protected by heat tracing. Tubing susceptible to plugging should be provided with suitable connections for cleaning, while tubing that handles gases that contain moisture should be provided with suitable drains, settling chambers, or traps. So that calibration and occasional checks on the instrument's output may be made without disconnecting the instrument, a tee may be located between the instrument shut-off valve and the instrument, with a threaded plug (or shut-off valve) on the vent side.

Figure 15-2
Typical gas installation.

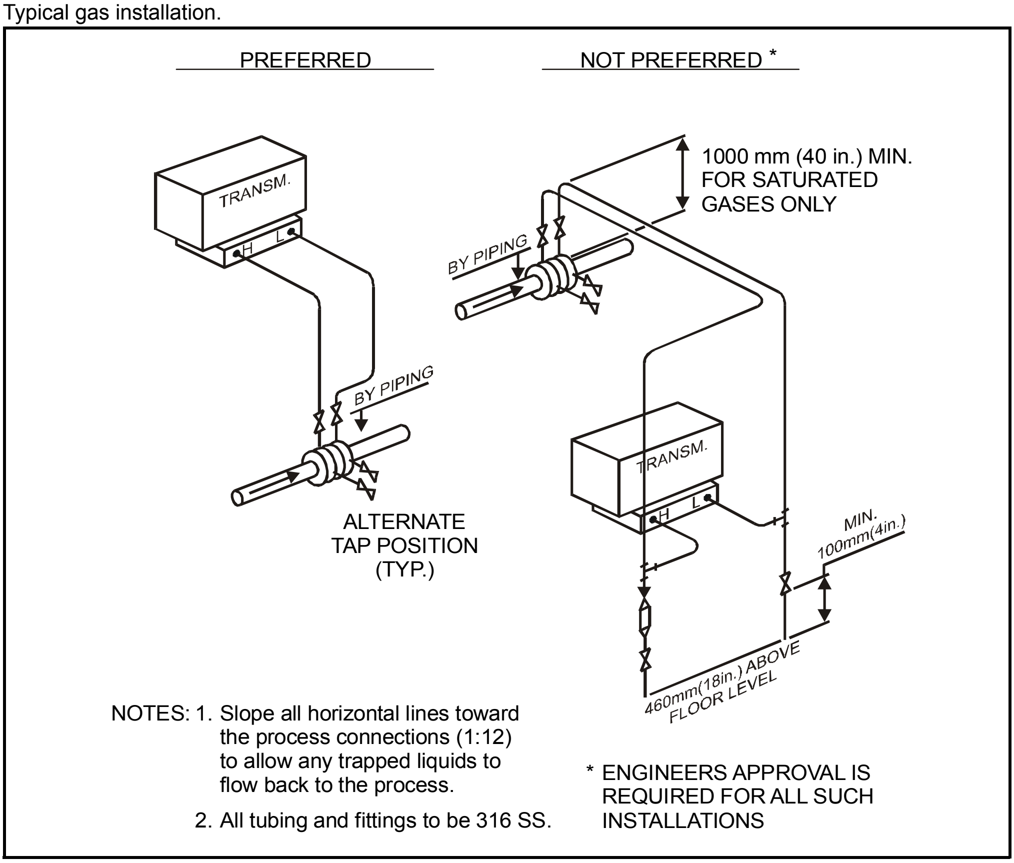
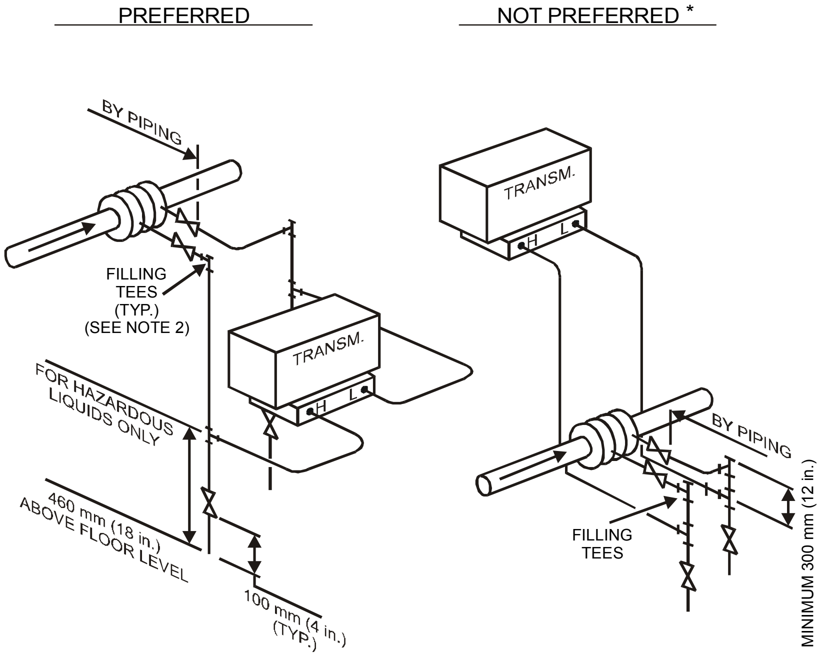


Figure 15-3
Typical liquid installation.



NOTES: 1. Slope all horizontal lines toward the process connections (1:12) to allow any trapped liquids to flow back to the process.

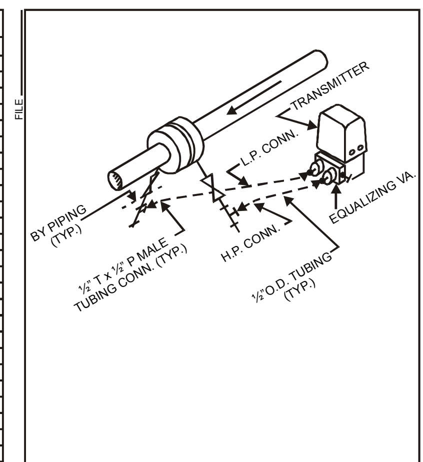
2. Use filling for condensable fluids only.

3. All tubing and fittings to be 316 SS.

* ENGINEERS APPROVAL IS REQUIRED FOR ALL SUCH INSTALLATIONS

Figure 15-4
Typical installation detail.

REV. NO.	ITEM CODE	QUANTITY	SIZE	DESCRIPTION
				** FIELD INSTRUMENT MATERIAL **
		2	1 / 2	TEE 3000# SCRD 316 SS
		2	1 / 2	PLUG SQUARE HEAD SCRD 316 SS
		2	1 / 2	NIPPLE XS 316 SS TBE
		10	1 / 2	TUBING SMLS 316 SS .035 WALL, A269
		4	1 / 2 x 1 / 2	MALE TUBE CONN. 316 SS, TXMPT
		2	1 / 2	BYPASS BLOCK EQL. VA 5000# 316 SS, SCRD
				* * * * *
				TUBING AND PIPE LENGTH ON THIS
				BILL OF MATERIAL IS AN AVERAGE
				LENGTH ONLY. LENGTH WILL VARY
				WITH EACH INDIVIDUAL INSTALLATION.
				* * * * *



MK	REVISION	APP.	MATERIAL PACKAGE NO.
SUPR.			CONTROL SYSTEM INSTALLATION PROCESS PIPING D/P TYPE INSTRUMENT LINE MOUNTED
SUPR. ENG.			
SCALE			

Process tubing is tested as part of and under the same conditions as the process/utility piping system. Before and after testing, impulse lines should be flushed and blown down with water or air to remove all contamination.

Checkout

After the installation and before the owner has accepted the system, a "checkout" is performed. The installing contractor should check the operation of each completed loop by simulating the process and events. Loop checking is performed from the process sensor to the control room and out from the control room to the final control element. Records should be kept of the final checks to instruments and control systems. These records could take the form of individual signed-off instrument specification sheets or loop diagrams.

Loop checkout also includes visually checking that

- accessibility to equipment is adequate.
- equipment is correctly supported.
- painting and protection against corrosion is complete.
- correct materials are used.
- terminal, cables, tubes, and equipment are identified and labeled correctly.
- segregation and minimum bending requirements are implemented.
- all cables and wires are properly terminated and supported.
- correct cable glands (type and material) are used.
- all equipment covers are in position and all unused ports are plugged.
- all equipment is properly grounded and connected to the correct supply voltage.
- the complete electrical installation complies with the appropriate codes and standards.
- the requirements for the installation are met (e.g., meter-run straight lengths, location and orientation of instrument process tapping points, etc.).

Loop check activities also include the following:

- Cleaning the air tubing by blowing it out with clean, dry instrument air
- Performing tubing pressure tests and ensuring that all connections have been made correctly
- Checking all field instruments at three points (0%, 50%, 100%) and ensuring that each individual instrument is in good working order. For thermal systems, a two-point check should be sufficient (one or two temperature baths may be required).

After the installation and checkout are completed, the installing contractor should compile the certificates, records, manuals, instruction sheets, as-built drawings, sketches and diagrams, and other relevant data applicable to the completed work and hand them to the owner. Upon receipt of the signed-off records, the owner completes the acceptance stage, signifying the completion of the installation work.

CHAPTER 16

MAINTENANCE

Overview

Now that the instruments and control systems are installed and operating, the responsibility reverts to maintenance for keeping the control equipment in good working condition and for ensuring that the operation of these systems meets the design intent. In addition, keep in mind that not only is the maintenance to be done correctly but also that any alterations must comply with all established codes, such as the electrical code in effect at the site.

It is imperative to underline that the content of this chapter is only a memory jogger and should not be taken "as is" because statutory, technical, and corporate needs vary from one site to the other. Post-installation and maintenance requirements vary with plant needs and specifics.

Maintenance activities in general, and in particular for instruments and control systems, consist of a large portion of human interrelations and teamwork. The two main activities of the maintenance team are

1. plant improvements and modifications (generally a pre-planned activity) and

2. plant maintenance (corrective and preventive types).

Maintenance is typically done by plant personnel; however, the help of outside contractors is sometimes needed. In such cases, contract maintenance programs with outside contractors are generally implemented.

Maintenance must at all times be kept in the designer's mind when instruments and control systems are being specified and designed. Items that are inaccessible, badly designed, or difficult to calibrate will be poorly maintained, eventually deteriorate, adversely affect process performance, and may end up in the garbage—a waste of time and money and a poor design effort.

Management has a few basic responsibilities to maintenance personnel and to the public at large. They include ensuring and maintaining a safe work environment, as well as providing maintenance personnel with the proper training, tools, and procedures to work safely and efficiently.

Because no product is absolutely perfect, everything eventually fails. The function of maintenance is to ensure the continued, reliable operation of the equipment on demand. It should be mentioned at this point that ISO 9000 states: "Sufficient control should be maintained over all measurement systems used in the development, manufacture, installation, and servicing of a product to provide confidence in decisions or actions based on measurement data." The above definition of measurement systems includes related computer software.

A maintenance shop should be clean and have sufficient tools in good condition to perform the required work. Generally, maintenance personnel will assess their needs based on the scope of their work and responsibilities. Maintenance personnel should always remember that modifications to approved equipment may void the approval of such equipment.

Maintenance activities can be broken down into different steps. This breakdown may be required for estimates, scope of work, and job descriptions. The breakdown shown in figure 16-1 is an example that should be adjusted to fit particular applications.

Figure 16-1
Example of a typical maintenance activity.

1) Receive a request for maintenance.
2) Select the required procedures, tools, and manpower to do the job.
3) Get a work permit from the operator.
4) Isolate the process.
5) Remove the instrument from the process.
6) Decontaminate the instrument.
7) Perform the maintenance activity, part of which is the diagnosis of the problem.
8) Recalibrate the instrument, which includes
    - collecting the required technical information,
    - ensuring it is the correct information for the instrument in question,
    - selecting the calibration equipment,
    - connecting the instrument to be calibrated,
    - calibrating, and
    - disconnecting the calibrated instrument.
9) Prepare for instrument reinstallation.
10) Reinstall the instrument.
11) Check its correct operation.
12) Advise the operator.
13) Complete the required paperwork.

The following topics cover common maintenance items. Obviously, not all maintenance items can be covered in this chapter. However, the selected items in this chapter give a good understanding of the requirements to be covered.

Implementation

Maintenance is successfully accomplished through a combination of technical know-how and experience. Maintenance and post-installation activities will widely vary from corporation to corporation.

Even within the same corporation, variations from site to site will occur. However, a good maintenance program generally includes

- an understanding of the maintenance activities,
- a clear definition of the maintenance organization,
- a set of procedures, in conformance with the vendors' recommendations, to maintain all equipment, in particular those performing critical and safety functions or located in hazardous areas,
- a system for the maintenance of records, where engineering data is always kept up to date with the site modifications,
- training (to be provided where needed),
- the availability of required spare parts,

- cost monitoring,
- accessibility to maintenance manuals for all items of control, and
- an analysis of equipment histories, accessible through records of calibration and maintenance results, that examines repeated failures.

Types of Maintenance

The two main types of maintenance are *corrective maintenance* and *preventive maintenance*.

Corrective maintenance is performed when breakdowns occur (or are about to occur). It is an unscheduled activity. Another type of maintenance, known as predictive maintenance, relies on the monitoring of sensors (e.g., vibration, temperature, pressure) to warn that a breakdown will soon occur. In many cases, predictive maintenance is considered part of corrective maintenance.

Preventive maintenance is predictable because it is scheduled ahead of time and performed generally at preset time intervals. Preventive maintenance reduces downtime by avoiding or reducing the unexpected problems. This type of maintenance requires a set frequency generally linked to scheduled shutdowns.

The debate over the advantages and disadvantages of corrective maintenance vs. preventive maintenance is interesting and ongoing in many plants. On one hand, failures that could occur at the wrong time (as they generally do) can result in the loss of production or, even more importantly, affect human safety. On the other hand, if preventive maintenance is scheduled over too long a period, a breakdown will occur before the preset maintenance interval. If it is scheduled over too short a period, it will waste money and can even increase the chances of a breakdown due to the increased potential of introducing human errors or defective components. To have the preventive maintenance set at the correct schedule is quite difficult; therefore, the dilemma still exists, and the debate goes on. In any case, preventive maintenance should not be established just for the sake of implementing this method. It should be based on facts and figures.

Preventive maintenance is based on frequency that requires review on a regular basis (annually seems to be a norm). In most cases, the frequency of maintenance is based on the equipment manufacturer's recommendations and past experience through the analysis of maintenance records. If, after a number of consecutive inspections, the equipment is consistently in good condition, then the frequency of maintenance can be eased. A good maintenance program should indicate how preventive maintenance is scheduled and planned (including identifying the need for spare parts).

Personnel

Some corporations find it essential to identify the maintenance organization. This is done by establishing who does what, how they interface, and what the official lines of authority and responsibility are. This need depends on the corporate philosophy and on the way a company does business. When identifying a maintenance organization, detailed job requirements and necessary skills are defined and can include, for example, loop-tuning skills (see appendix G for job descriptions).

All maintenance activities, including inspection and testing, must be performed by competent personnel. Competency is achieved through proper training that includes instructions on the various types of protection and installation practices and on the general principles of electrical area classification. In addition, suitable refresher training must be provided as needed.

Maintenance personnel have a variety of duties. These include troubleshooting control loops and the removal, repair, calibration, and reinstallation of many components of instrumentation and control hardware.

Training

Through proper training, the maintenance of control equipment can be correctly accomplished. Maintenance should be performed according to the vendors' maintenance manuals. Training includes both classroom and supervised hands-on experience at the plant with qualified personnel. Specialized equipment, such as analyzers and programmable electronic systems, require specific training. In addition, specialized skills, such as loop-tuning capabilities, are obtained through training and hands-on experience acquired over the years.

Training of maintenance personnel includes many components. Some are obvious, such as technical know-how, while others have more to do with safety. Safety training can include

- understanding and implementing work permit procedures,
- identifying work hazards and eliminating them where possible,
- mastering the use of tools and protective clothing,
- understanding the function of safety guards, interlocks, safety signs, tags, and barriers,
- avoiding loose clothing, jewelry, and long hair that can entangle in equipment, and
- reporting accidents and emergency conditions, as well as identifying any limitations that can reduce the safety of a job to be done (including any unsafe activities and any hazards).

Records

Maintenance records are required to support all maintenance activities, regardless of whether they are corrective or preventive. They are used as historical data for reasons that vary from setting the frequency of preventive maintenance to providing legal and insurance documentation. Sometimes maintenance records are coded to facilitate entry into computer systems, where database managers or spreadsheets handle data collection and retrieval.

ISO 9000 states: "Procedures should be established to monitor and maintain the measurement process itself under statistical control, including equipment, procedures, and operator skills."

Maintenance documentation requirements vary from plant to plant, but in general, the minimum includes a copy of maintenance records, all process and instrumentation diagrams (P&IDs), all instrumentation and control documentation, and the area classification documents, as well as a set of vendor manuals.

Maintenance records vary from one organization to the other, but required maintenance data, regardless of the format, includes

- the tag number or description of the device,

- corrective/maintenance actions on the device,
- spare parts used,
- the name of the person performing the maintenance, and
- the date of the maintenance.

In the case of corrective maintenance, two additional items are needed: a description of the complaint (or failure) and a description of the diagnostics.

Figure 16-2 shows a typical example of a completed form used for corrective maintenance.

Figure 16-2
A typical corrective maintenance form.

PLANT: ABC Inc. INSTRUMENT TAG NUMBER: PV 33-1

Complaint/Behavior of instrument:
PV 33-1 unstable at low flows

Date: June 13/88 by: H J Smith

Diagnostics/Symptoms:
Valve checked - all components functioning as per specifications

Setup time [S]: 1:10 (hrs:min) Diagnostic time [D]: 0:20 (hrs:min)

Corrective action: 1 - recalculate valve sizing 2 - valve oversized 3 - change valve trim to correct size 4 - valve tested and works O.K. through full range

Repair time [R]: 4:50 (hrs:min)

Total maintenance time [T]=S+D+R= 6:20 (hrs:min)

Parts used: New trim kit part # 72158HV9

Comments: None

Maintenance by: Doug White Date: June 18/88

Approved by: Joe Doe Date: June 18/88

Hazards

Maintenance personnel encounter numerous hazards in their day-to-day activities. Some of these hazards are described in the following pages and are summarized in figure 16-3.

Figure 16-3
Some of the hazards encountered in a plant environment.

Improper lifting
Falls
Slips
Falling objects
Defective tools
Noise
Adverse weather conditions
Spray painting
Fire
Poor ventilation
Hazardous locations
Confined space
Live and exposed equipment

Training, constant awareness, and compliance with the code requirements greatly minimize accidents. Before work begins, hazards should be identified, and if they cannot be eliminated, safety barriers should be implemented. The following represents a number of potential hazards facing plant personnel.

General Hazards

The most common injuries occur due to improper lifting, falls, slips, and falling objects. Maintenance personnel should assess the weight to be moved and be trained on how it should be carried. Where the potential of falling exists, fall-arrest or travel-restraint systems should be used. Falling objects should be prevented by securing items located overhead (such as on scaffolding and roofs), and where this is not possible, the area should be barricaded to prevent access. Maintenance personnel should avoid shortcuts—an accident could be a lifetime of suffering and frustration.

The presence of buried cables and utility lines must be verified before any drilling, excavation, or driving ground rods is started. The use of tools must always be in accordance with the tool manufacturer, including the use of eye-, face-, and hand-protective equipment.

In noisy environments (where the noise level is above 85dBA), hearing protection must be used. In adverse weather conditions (e.g., high winds, snow storms, and electrical storms) outside work should immediately stop.

When spray painting, personnel should ensure good ventilation. Where air breathing is required, only equipment approved for that purpose can be used, and breathing air systems must not be mixed with any other system.

Maintenance personnel should keep fixed and portable fire equipment, as well as all emergency access routes, free from obstructions, such as ladders, scaffolds, and tools. They should not work alone in a battery room (where hydrogen is produced when wet cells are charged), and they should check that the ventilation is working properly before entering.

Compressed gas cylinders should be stored and secured in approved racks designed for this purpose. Cylinders should be capped when not in use. Leaky or damaged cylinders should not be used and must be immediately returned to the supplier.

When temporary electrical cables are used, they should be protected from physical damage and, if exposed to traffic, should clearly be identified and protected.

Hazardous Locations

The requirements and precautions for maintenance in hazardous locations must be kept in mind when setting the guidelines for maintenance. A work permit approved by the operator must always be obtained.

Maintenance work in hazardous areas is generally limited to disconnection, removal, or replacement of control equipment and cabling. Whenever possible, the repair, calibration, and testing of equipment should be performed in a safe area.

Because equipment used in hazardous environments possesses special features, the features must be maintained (e.g., explosion-proof boxes should not be altered or repaired on-site, and intrinsic barriers should be used as recommended by the vendor). The seemingly correct operation of such equipment does not mean that its integrity is protected (e.g., explosion-proof boxes may have dirty or corroded joints, and intrinsic barriers may not be grounded). It is advisable that the repair of devices that provide safety in hazardous environments be performed only by the original manufacturer of such devices.

Where repair has been done on safety-related equipment, it is a good plant policy to have a second person (such as a supervisor) inspect the work. If this is not done, the safety and the quality of work cannot be ensured. After all, anyone can make a mistake, but no one can afford deadly ones.

Uncertified electrically powered test equipment (including uncertified batteries) should not be used in a hazardous area unless (and if permitted by code)

- the route is covered by a hazard-free work permit,
- the equipment is adequately protected (e.g., equipment switched off with leads disconnected), or
- the equipment is so enclosed that the risk of it being surrounded by a hazardous atmosphere is insignificant (e.g., by enclosing it in a sealed bag).

It should be noted that it may be permissible to use an uncertified voltage indicator to prove the effectiveness of an isolation, providing that the voltage indicator does not contain a voltage source.

Batteries (including lithium batteries commonly used for memory retention) should be handled according to the vendor's recommendations and disposed off in compliance with all the environmental regulations.

Confined Space

A confined space is a location where the build-up of dangerous gases, vapors, fumes, and dusts or the formation of an oxygen-deficient condition can occur. Maintenance personnel must follow established confined-space entry procedures.

The environment of a confined space must be considered hazardous until proven otherwise by a competent person. Such a person must be trained and capable of identifying and assessing the hazards in a confined space and allow entry after the space is deemed safe or under special controlled conditions. In addition, such a person must have a rescue plan ready in case a dangerous situation suddenly develops.

A trained observer must be assigned whenever maintenance personnel are in a confined space. The observer must advise the personnel of the potential hazards, remain outside the confined space, and stay in constant communication with the personnel in the confined space, ready to tell them to evacuate at the first sign of unusual symptoms.

Electrical Isolation

Except for intrinsically safe circuits, instruments and control systems that contain electrically energized components and are located in a hazardous environment should not be opened. To be opened, the electrical energy should first be isolated through either fuse removal or by opening and locking the breaker in the open position.

Maintenance personnel should not work alone near live and exposed electrical equipment. When protective electrical equipment (e.g., insulator covers and rubber gloves) is used, it should be evaluated by a certified testing laboratory, show no defects, and be used only within the approved voltage rating.

Circuit identification is essential. The necessary up-to-date documentation must ensure that the circuit identification is shown and is correct. This information provides the ability to safely isolate the equipment whenever maintenance is done. Maintenance personnel should always check that the actual tag numbers on the equipment and cables conform to the available documentation.

When equipment is withdrawn from service, exposed wires should not be left hanging loose. They should be terminated in an appropriate enclosure and insulated. In addition, lock-out and tag-out procedures must be carefully followed.

Lock-out means that the motor starter and/or other sources of power are actually locked with a padlock and the energy source is isolated. Maintenance personnel working on locked-out equipment have their own locks and keys. Tag-out means that a tag is attached to the lock identifying the duration of the lock-out with signatures and dates.

Maintenance personnel should ensure that all activities (including alterations and repairs) comply with the local electrical code. It must be kept in mind that modifications to approved equipment can void original equipment or system approval and should always be reviewed with the manufacturer.

Programmable Electronic Systems

The maintenance of programmable electronic systems, including the replacement of components and modules, should be done in accordance with the vendor's recommendations, using competent personnel trained to do this type of work. Maintenance of some equipment can be performed with the equipment online and the power supply connected. This reduces shutdowns and saves maintenance time.

Common maintenance issues related to programmable electronic systems (see chapter 9) should be part of routine maintenance. They include making sure that ventilation passages are clean and clear of obstructions, monitoring the condition of enclosures, and checking the condition of all grounding.

Alarm and Trip Systems

In the maintenance of alarm and trip systems, in particular the critical ones, adequate training is essential to ensure their correct operation (see chapter 10). Maintenance personnel should have access to procedures and maintenance manuals. The manuals should indicate how the system operates, what its set points are, and what risks are associated with such a trip and its testing and maintenance.

It is recommended to have another person, such as a supervisor, check all completed work. This minimizes the possibility of errors, a vital requirement where safety is involved.

Sometimes, a safety trip must be bypassed—for example, when testing it or calibrating its components. In such cases, safety must be maintained. The bypass function should be clearly and constantly indicated to the operator. And all such activities must conform with set procedures.

Safety procedures related to the maintenance of critical alarms and trips should be reviewed on a regular basis to ensure their adequacy. These procedures should have sufficient details and not leave the interpretation of unclear information to maintenance personnel.

The maintenance of critical alarm and trips should include

- a fault reporting system,
- the as-found and as-left condition of the system,
- the means to verify the calibration of the test equipment, and
- a record of all maintenance activities.

Calibration

Overview

Calibration of control equipment is a key maintenance activity. It is needed to ensure that the accuracy designed into the control system as a whole is maintained.

Typically, this activity is performed in a calibration shop, where most of the calibrating equipment is located. The quality of the calibration shop, the quality and accuracy of the instruments used for calibration, and the calibration records kept for all instruments are important facets of calibration activities.

Calibration is performed in accordance with written procedures. It compares a measurement made by an instrument being tested to that of a more accurate instrument to detect errors in the instrument being tested. Errors are acceptable if they are within a permissible limit.

Instrument calibration should be done for all instruments prior to first use to confirm all settings. This can be done either by the equipment vendor (who will issue a calibration certificate with the instrument) or by the calibration shop at the plant upon receipt of the instrument. Vendors generally charge a fee for this activity.

Most analog instruments have adjustable zeros and spans. In most cases, calibration consists of correcting the zero and span errors to an acceptable tolerance (see figure 17-1 and 17-2).

Figure 17-1
Zero errors.

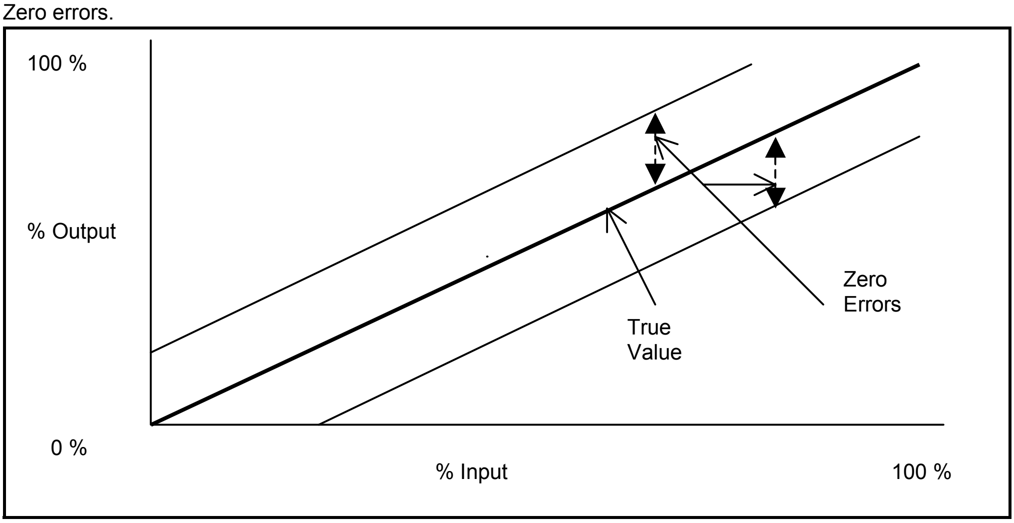
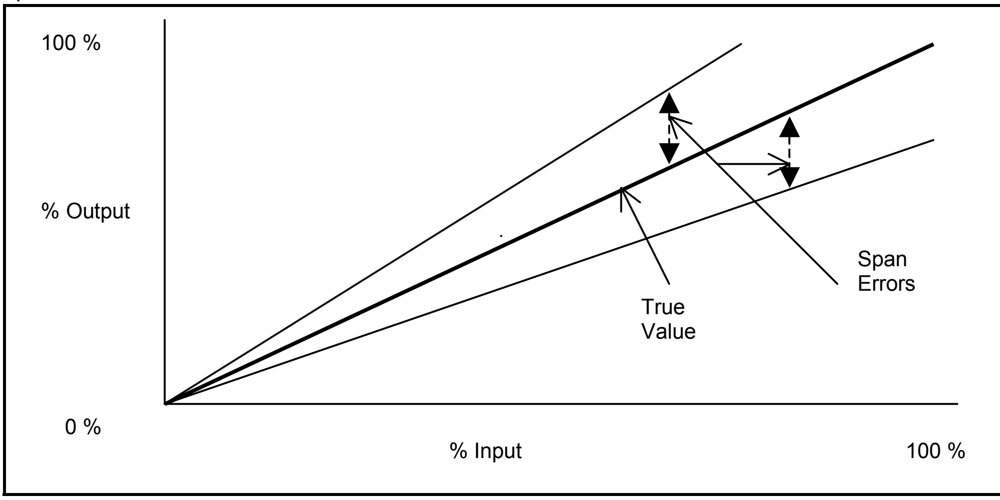


Figure 17-2
Span errors.



Typically, an instrument is checked at a number of points through its calibration range, i.e., from the lower end of its range (the zero point) to the upper end of its range. The zero point is a value assigned to a point within the measured range and does not need to be an actual zero. The difference between the lower end and upper end is known as the span. The calibrated span of an instrument is in most cases less than the available range of the instrument (i.e., the instrument's capability). In other words, an instrument is calibrated to function within the workable range of an instrument.

The calibration of instruments in a loop should be done one instrument at a time. This approach ensures that any instrument with an error (i.e., an instrument that is out-of-tolerance) will be corrected.

When a number of instruments are in a loop, the combined accuracy of these instruments is equal to the square root of the sum of the square. For example,

$$\text{Loop total error} = \sqrt{(\text{Sensor Error})^2 + (\text{Transmitter Error})^2 + (\text{Indicator Error})^2}$$

A calibration management system is generally required to provide calibration data and procedures to plant personnel, to record and store calibration data, and to ensure that calibration conforms to specifications. In addition, a calibration management system should define what will be calibrated, by whom, and where the calibration will be done. Technicians need to be trained and available, and records should be kept for further reference.

Procedures

Procedures establish the guidelines for the calibration of plant instruments. They ensure good maintenance and the preservation of the control functions as intended. Their detail varies considerably among plants. A typical procedure includes sections to cover the purpose and scope of the procedure, safety guidelines, explanation of the calibration sheets, definitions of key terminology, and references. Often, and depending on the corporate philosophy, procedures may incorporate specific details and instructions. For example, some procedures may state that

1. Each week a list of instruments to be calibrated will be issued. The maintenance supervisor will then assign the calibration to a trained instrument mechanic.

2. Each month, a list of instruments that were not calibrated, as per the set schedule, will be issued and immediate action taken to tag the equipment out of service until such time that calibration is correctly performed.

3. The maintenance foreman and the quality manager shall semi-annually review the calibration schedule and decide, based on past instrument performance, whether the calibration frequency should be changed.

4. Every calibrated instrument should have a calibration sticker, indicating the equipment tag number, the name of the person that did the calibration, the date of calibration, and the due date for the next calibration (see figure 17-3). It is preferable, where possible, to place the calibration sticker across the seal or over the calibration access to the equipment. When calibration is completed, maintenance personnel should remove the old calibration sticker and affix a new one to the calibrated instrument.

Figure 17-3
Typical calibration sticker.

CALIBRATION
TAG NUMBER: ………………………..
CALIBRATED BY: ……………………..
CALIBRATION DATE: ………………..
NEXT CALIBRATION DATE: ………..

5. No instrument should be put back in service if it does not meet the calibration requirements.

6. On all calibration reports, the instrument mechanic will note on the completed form the “as found” and “as left” conditions. If the “as found” condition deviates by more than the specified acceptable value, the quality manager will try to assess the time during which the instrument was out of calibration and the effect this may have had on the process. This information must then be immediately provided in writing to the maintenance foreman and the production manager. The quality manager and the maintenance foreman will then review the maintenance and calibration records for the instrument in question and decide whether the calibration frequency should be changed or any corrective action is needed.

7. All records pertaining to instrument calibration must be retained for a period of six years.

8. All manufacturers’ maintenance manuals will be kept in the maintenance shop in a dedicated area.

9. All calibrating equipment must be identified by individual tag numbers to facilitate identification and historical record keeping.

Instrument Classification

Instrument classification categorizes instruments according to their function. Their classification acts as a reference when such instruments are selected, purchased, tested, and used because each may have different criteria. Such a classification typically covers the identification of critical (as they relate to safety, health, and the environment) and non-critical equipment. The classification may also consider the results due to loss of performance and loss of the instrument's required accuracy. Sometimes such a classification resides in a plant's quality assurance manual. It all depends on the way a plant does business and runs its operation.

In this chapter, and as an example, instruments are divided into four classes. Plant management and maintenance personnel may decide that a different classification of instruments is required.

Class 1 Instruments

Class 1 instruments are the plant calibration standards. These types of instruments are used to calibrate Class 2 instruments and are generally traceable to an outside, nationally recognized standards or calibration organization. These instruments are kept in the maintenance shop in an environmentally controlled area that meets the manufacturer's specifications.

Class 1 instruments are calibrated annually by an independent calibration lab. After each calibration, they are returned to the plant with a certificate approved by the calibration lab. They are typically sent and received back within 30 days of the anniversary due date. The anniversary date of these instruments is staggered to ensure the presence of a working and calibrated set in the maintenance shop at all times.

In the event that a Class 1 instrument is found out of tolerance, the calibration lab should immediately advise the plant. The maintenance supervisor at the plant will then assess the effect this out of tolerance may have had on Types 2, 3, and 4 instruments.

When the calibration equipment is received back, it is checked for obvious shipping damage. If there is damage, the equipment must not be used and must be immediately returned to the calibration lab for repair and recalibration.

Class 2 Instruments

Class 2 instruments are the plant instrument calibration standards. These instruments are used by maintenance personnel to calibrate Class 3 and 4 instruments.

Class 2 instruments are calibrated semi-annually by plant maintenance using Class 1 instruments. In addition to the scheduled semi-annual check, calibration may be performed whenever the accuracy of a Class 2 instrument is questionable.

Calibration forms must be completed for each Class 2 instrument every time a calibration is performed. These forms are then signed by and filed with the supervisor of plant maintenance.

Class 3 Instruments

Class 3 instruments are critical process instruments that prevent situations that are either threatening to safety, health, or the environment or that have been defined as critical to plant operation or to product quality. The calibration frequency of Class 3 instruments is based on their required reliability—for critical trips, it is defined by the calculated Trip Testing frequency (T) (see chapter 10). Class 3 instruments may also require calibration when the instrument is replaced or when its accuracy is questioned (e.g., when its reading is compared with other indicators).

Calibration sheets are completed for each instrument every time a calibration is performed. These sheets are then signed by and filed with the supervisor of plant maintenance.

Class 4 Instruments

Class 4 instruments are used for production and represent the majority of the instrumentation and control equipment in a plant.

Calibration of Class 4 instruments is done when required, when an instrument is replaced, or when the instrument's accuracy is questioned (e.g., when its reading is compared with other indicators). After a certain time in service, the records are checked to determine if this approach is adequate.

Calibration sheets are completed for each instrument every time a calibration is performed, and these sheets are then signed by and filed with the supervisor of plant maintenance.

Calibration Sheets

Calibration sheets should be provided for all instruments requiring calibration. They are typically generated from a set form (e.g., database, spreadsheet, or word processing) using a generic template. Calibration sheets should contain all the necessary data related to the instrument to be calibrated (see figure 17-4). The level of detail in a calibration sheet varies from plant to plant. Calibration sheets are typically prepared, reviewed, and approved in accordance with a corporate standard.

A typical calibration sheet has the following four main sections:

- header,
- issue and revision information,
- notes and comments, and
- calibration data.

The header shows the plant name, equipment tag number, manufacturer's model number, and reference documentation.

Issue and revision information describes who prepared and approved the calibration sheet and when the activities were done. This section also lists the revision dates, a brief description of each revision, and the name of the persons that prepared and approved the revision.

The notes and comments section describes all the information related to the calibration of the device in question. For example, the sources of calibration data, special directives to maintenance personnel, etc.

Calibration data shows the information required to perform the calibration: the input range, output range, required equipment accuracy, and the set point(s) for discrete devices. Ranges and set-point information is commonly based on the process requirements and should include corrections for elevation and/or suppression (typically obtained from installation drawings). Calculations for calibrations should be recorded on the calibration sheets for future reference (typically in the previous notes and comments section). Set points should allow for possible errors to ensure operation within the required process limits, allowing a delay in switch response time.

Some instruments have a time response—for example, where damping or time delay are required. The time response should be identified on the calibration sheets and checked as part of the calibration process, particularly where time is critical in loop response performance.

As-left (AL) and as-found (AF) tolerances are important values in instrument calibration. They represent the post- and pre-calibration tolerances.

The as-left (AL) tolerance is the required accuracy range within which the instrument must be calibrated. The AL tolerance is based on the process requirements and on the equipment's capability as described in the manufacturer’s specifications. No further calibration is required if, after checking the equipment calibration, it is found to be within the AL tolerance.

Figure 17-4
Typical format for a calibration sheet.

INSTRUCTIONS CALIBRATION SHEET

Header Information:

Issue and Revision Information:

Notes and Comments:

Calibration Data:
(See examples in figures 17-7 and 17-8.)

Common process requirements for AL tolerances are shown in figure 17-5. However, each application should be assessed for its own requirements.

Figure 17-5
Common process requirements for AL tolerances.

Device	Common Process Requirements
Transmitters (including pressure, differential pressure, flow, level, and temperature)	±0.5% of calibrated span
Switches (including pressure, differential pressure, flow, level, and temperature)	±1% of calibrated span (or sometimes a percentage of set point)
Gauges (including pressure, differential pressure, flow, level, and temperature)	±5% of calibrated span
Controllers and other similar electronic devices (including indicators, transducers, isolators, and alarm units)	±0.5% of calibrated span
Analyzers, control valves, and other devices	Refer to process requirements and vendor data.

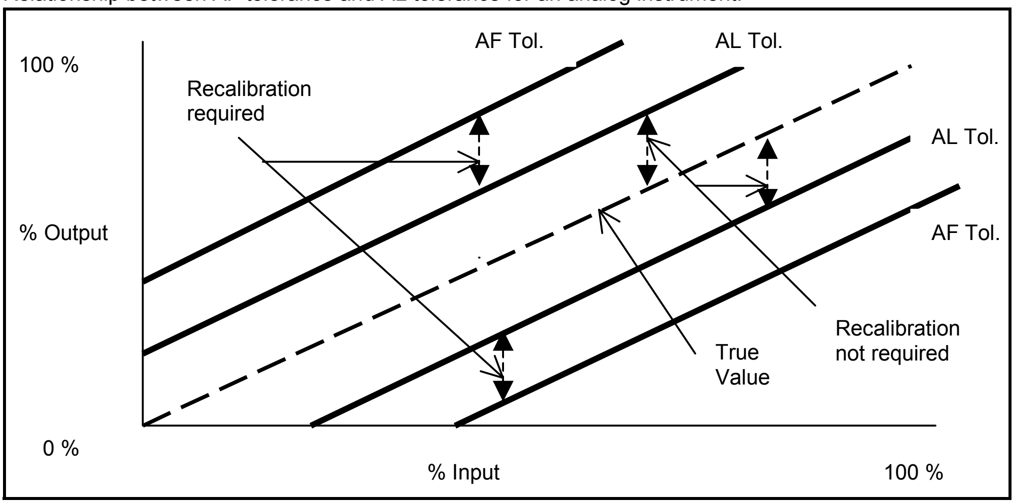
The AF tolerance sets the acceptable limits for drift that the instrument can encounter between calibration checks. Drift is defined as the change in output over time (not due to input or load).

Calibration is required if, after checking the equipment calibration, it is found to be within the AF tolerances but outside the AL tolerances. The AF tolerance is always greater than the AL tolerance (see figure 17-6).

Some plants would replace an instrument if the allowable drift limits have been exceeded (i.e., if the instrument is found outside the AF tolerances). Whereas, other facilities would recalibrate the instrument, put it back in service, and check it again at a later time before discarding it if still found outside the AF tolerances.

The ratio of AF tolerance to AL tolerance is known as the AF multiplier. For example, if an AL tolerance of 0.5% is required, then with an AF multiplier of 2, the AF tolerance is 1%.

Figure 17-6
Relationship between AF tolerance and AL tolerance for an analog instrument.



The calibrator's accuracy must be higher than the accuracy of the equipment being calibrated. This ensures that no significant errors are introduced by the calibrator. It is recommended to use a calibrator with an accuracy of at least four times the accuracy of the instrument being calibrated. For example, if a transmitter has a required accuracy of ±0.2%, then the minimum accuracy of the calibrator should be ±0.2% / 4 = ±0.05%

In some applications, it is required to include the accuracy of the calibrating equipment in the overall AL tolerance. In such cases, the overall AL tolerance, including the calibrator's accuracy equals

$$\pm\sqrt{(\text{Instruments AL tolerance})^2 + (\text{Calibrators total tolerance})^2}$$

It should be noted that this requirement is not commonly implemented because the calibrator's tolerance is very small in comparison with the instrument's tolerance.

When calibrating modulating devices, such as transmitters and controllers, nine calibration points are commonly used—five points up and four points down. This checks the effect of hysteresis and linearity. The nine points are 0, 25, 50, 75, 100, 75, 50, 25, 0%. In some cases, five points (0, 50, 100, 50, 0%) are considered an acceptable alternative. Hysteresis is the measured separation between upscale-going and downscale-going indications of a measured value—it is sometimes called hysteresis error. Linearity is defined as the closeness to which a curve approximates a straight line—it is usually measured as non-linearity.

For discrete devices, calibration consists of checking the set point with AF and AL minimum and maximum tolerances and defining if the contacts should open or close (on decreasing or increasing process input). Calibration data examples for a differential pressure transmitter and a pressure switch are shown in figures 17-7 and 17-8, respectively.

In figure 17-7, the differential pressure transmitter has an input range of 0 to 7.3 KPad and a 10 to 50 mAdc output. It is calibrated at nine points. The required tolerance for the transmitter is ±0.5% of span, and an AF Multiplier of 2 is used. Therefore,

AL Tolerance = Span x Tolerance = 40 mAdc x 0.5% = 0.2

AF Tolerance = AL Tolerance x AF Multiplier = 0.2 x 2 = 0.4

Figure 17-7
Calibration data example for a transmitter.

Point Number	Percent Value	Input in KPad	AF Output in KPad	AL Output in KPad
1	0	0.00	10.00 ± 0.40	10.00 ± 0.20
2	25	1.83	20.00 ± 0.40	20.00 ± 0.20
3	50	3.65	30.00 ± 0.40	30.00 ± 0.20
4	75	5.48	40.00 ± 0.40	40.00 ± 0.20
5	100	7.30	50.00 ± 0.40	50.00 ± 0.20
6	75	5.48	40.00 ± 0.40	40.00 ± 0.20
7	50	3.65	30.00 ± 0.40	30.00 ± 0.20
8	25	1.83	20.00 ± 0.40	20.00 ± 0.20
9	0	0.00	10.00 ± 0.40	10.00 ± 0.20

In figure 17-8, the pressure switch is to be set with contacts closing (CC) at 800 KPag falling pressure and contacts opening (CO) at 900 KPag rising pressure (i.e., the differential is adjustable). The required tolerance for the switch is ±3% of set point.

Figure 17-8
Calibration data example for a two-position pressure switch.

Description	Contact Status (CC or CO)	Process Direction (Falling or Rising)	Switch Set Point in KPag
Low-Pressure Switch Setting	CC	Falling	800.00 ± 24.00
Pressure Switch Reset Point	CO	Rising	900.00 ± 27.00

PROJECT IMPLEMENTATION AND MANAGEMENT

Overview

This chapter covers project implementation and management for process control systems. It should not be taken "as is" because statutory, technical, and corporate needs vary from one project to the other and from one site to the other. Also, this chapter cannot cover all possibilities because every project is different—however, it will attempt to take a start-to-finish approach.

All projects require careful planning, particularly when control systems are complex and implemented with tight budgets and short schedules. For all projects, documents are vital. Reference documents should show how, why, and when a decision was reached and by whom. This makes it easier for others to pick up later and provides all the reasons and history behind technical decisions.

Project personnel typically consist of a client, engineering personnel, equipment suppliers, and contractors. The client's work should be clearly defined through documents (e.g., specifications and drawings). The project manager must coordinate the activities of the client, engineering personnel, suppliers, and contractors. Engineering personnel, suppliers, and contractors should conform to the client's requirements (as identified in all the documents produced) and be in compliance with the required codes and standards.

Generally, a project starts because of the following:

- potential market opportunities, or
- disposal (or conversion) of a process by-product is required, or
- compliance with regulatory requirements is needed (e.g., reduced emissions), or
- replacement of obsolete equipment is required to meet new plant needs.

The lifecycle of a project goes through many stages. The importance of each stage and its duration will vary with the project. In most cases, a project's lifecycle consists of the following processes:

- define the scope and activities,
- define the sequence of activities and their duration and then develop a schedule,
- allocate human resources, assign roles and responsibilities, and develop an organizational chart,
- estimate project cost and obtain budgets,
- plan purchasing schedule to coincide with budget availability,
- develop team and supply training where required,
- start project and ensure proper coordination (this may involve compromises, tradeoffs, and alternatives),
- complete project, and
- close project (resolve open items, project evaluation, and identify lessons learned for future projects).

Quite often, once process engineering and/or researchers develop the required process, it is tested in a lab and then implemented—first in a small-scale pilot plant and then in a full-scale plant. When it is fully defined and the main problems are resolved, the feasibility of such a project is assessed, and if it is successful, budgets are allocated before the work in the full-scale plant starts. Once the budgets are approved, a multi-disciplinary team is assembled to design the plant.

Projects are managed by project managers who generally use proven methods when managing a project. Some of these methods are published, and some are just common sense, based on experience. A successful project manager will customize his or her project management method to the task at hand.

A project manager assigns roles to the team members, allocating responsibilities and authorities and identifying the reporting relationships in a project. He or she should ensure that the group works as a team and that interaction between the different disciplines is proceeding as planned. In addition, he or she should be familiar with the technical aspects of the work to be done. A project manager should be a knowledgeable leader, a fair and dependable person, an honest and energetic individual, and a skilled negotiator.

Two key limited resources control projects—budget and time. By definition, a project has a limited life span (a start and a finish) and each project is unique. Typically, in a process plant, process engineering defines the process, which becomes the basis of design. To control a project, project managers must understand the process (and project) very well. The project manager then divides the project into clear project phases or milestones. Each phase is identified with a deliverable—such as a product resulting from engineering work or construction activity. This approach creates a measurable and logical sequence in the life of a project. The scope of a project can be modified because of new government regulations or an error or omission in the original concept. These types of unforeseen delays affect budget and time and should always be allowed for.

For international projects, it is prudent to allow for extra costs and time to cover cultural and political differences, communication delays due to different time zones, different languages and the need for translation (and the possibility of misunderstandings), and the availability of on-site local technical experience.

Process Control

If a comparison is made between the human body and a typical plant, the following functional similarities are found. The bones are similar to a plant's structure. The muscles are the equivalent of electrical motors (taking their command for action from the brain and the nervous system). The veins correspond to the electrical wires (carrying the energy). The organs are similar to process equipment, such as reactors. The senses are the equivalent of industrial sensors (measuring the process conditions). The brain and the body's nervous system correspond to the plant's control system (a blend of human operators and control equipment). In other words, control system personnel implement and maintain the senses, nervous system, and brain of an industrial plant.

Modern control systems have been accused of eliminating jobs and creating unemployment. The reply is yes and no. Fewer people are needed to do tedious repetitive operations, but such control systems actually secure jobs by preventing plant closures through the maintenance of plant efficiency and competitiveness. In the end, and in most cases, modern control systems increase the number of jobs because of the increased market, both national and international.

The implementation of process control systems depends on the corporate culture and the needs of the plant, but it typically includes

- defining the project and developing a plan of action,
- designing the control system,
- installing the equipment,
- starting the control system, and
- providing all information to maintenance personnel.

See figure 18-1 for an overview of a typical lifecycle of a process control project, with all its activities in their proper sequence.

Modern industry in today's global competition requires modern and powerful systems that provide precise controls that are relatively simple to implement and operate. This requires planning and project control that must meet schedule and cost budgets. Process control is involved in most industrial applications, and this requires knowledge and experience. A correct thought process is essential to correctly implement a project, and a successful project will correctly match the process requirements with the control system.

The quality of the documentation produced by engineering is vital in the construction and maintenance of a facility. It allows others to pick up the project where designers left off, and it provides the reasoning as to why a decision was made (keeping in mind that hundreds or even thousands of different components form the ingredients of a control system). Unfortunately, it is quite common that project descriptions are not sufficiently detailed, and therefore, many reviews, evaluations, and revisions typically occur.

A final document is never really final. It is vital for the success of a project to allow sufficient time to clearly agree on the scope of a project and confirm that agreement in a document. For process control, the scope of a project is confirmed in the scope definition, P&IDs, and logic diagrams.

Engineering activities for process control typically start at the beginning of a project with the development of P&IDs, control philosophies, and logic diagrams. Also, process control typically is last to finish in the construction schedule, after most civil, mechanical, and piping work is completed. This situation creates excessive pressure on the process control construction and commissioning teams as the end approaches. This situation occurs because of a lack of funds as the project nears completion and delays generated from other disciplines. Therefore, good planning and engineering (both front-end and detailed) are vital to a successful implementation.

On a typical multi-disciplinary project, process control interfaces with many disciplines. At the onset of a project, most of the interface is with process engineering for the development of all the front-engineering activities and with project management for budgeting and scheduling. Later on, when detailed engineering starts, process control interfaces with all other disciplines, such as mechanical (e.g., for connecting and mounting the equipment), electrical (e.g., for wiring and conduit runs), and even civil (e.g., for control room requirements). It is strongly recommended that data transfer (e.g., obtaining process condition at instruments) and important communications be always done in writing.

Figure 18-1
Typical lifecycle of a process control project.

1st phase:

1. Project manager assigned, preliminary project (and budget) defined, feasibility studies completed.
2. Preliminary project approved and budgets allocated.
3. Process engineering develops material balance sheets.
4. Project manager assigns lead engineers for all disciplines.
5. Process engineering and process control engineering personnel develop preliminary P&IDs and logic diagrams.
6. Lead engineers review the scope of the project and change scope where required.
7. Electrical engineering establishes electrical area classification.
8. Project manager submits to management an overall project schedule, a reviewed project definition, and a project budget (at ± 30%).

2nd phase:

9. Management approves a ± 30% budget.
10. Preliminary (front-end) engineering starts to
    - prepare process control schedule,
    - prepare control scope definition and identify preferred vendors,
    - prepare preliminary instrument index,
    - update P&IDs and logic diagrams as required, and
    - review cost estimate and resubmit at ± 20%.
11. Management approves a ± 20% budget.
12. Detailed process control engineering starts to
    - prepare process data sheets and forwards to the process engineer to complete process information,
    - review mechanical and piping specifications,
    - prepare all detailed design documentation (see chapter 14),
    - establish interface between process control engineering and electrical engineering,
    - supply information to electrical engineering (e.g., power supply requirements and cable runs),
    - supply information to mechanical engineering (to mount in-line devices), and
    - prepare requisitions, evaluate bids, select vendors, and place orders.
13. Check completed systems (e.g., control systems, analyzer systems, and panels and cabinets) at vendor's facility.
14. Equipment delivery
15. Construction starts instrument installation, checkout, commissioning, and loop tuning.

3rd phase:

16. Plant startup
17. Engineering is completed.
18. Control system is handed over to operations.

Communication

Good communication is vital to the success of a project. Each project manager has his or her own style. The following points are described because they summarize key ingredients of good communication in project management and engineering.

Written agreements record what was said and decided, where as verbal agreements may be forgotten, misunderstood, or modified (intentionally or not) to suit a person's interest. Verbal agreements may result in expensive corrections meaning additional money and delays. This approach to written records should apply not only to decisions made but also to the transfer of data and documents.

It is preferred that discussions occur with a recipient before a memo is sent to him/her. Receiving an unexpected memo can in some cases create unhappy and uncooperative relationships between the members of a project team.

A written document typically should start with a reference subject. Such a document, in addition to indicating who the sender and recipient are, often indicates who it should be copied to, including if a copy should be sent to "file." Do not copy persons that have no interest in the subject matter. Typically, reports have a front cover and should be reviewed by another person or by manager, especially in the case of

- new designs,
- safety-related design,
- items of high economic importance, or
- information affecting the management of the facility.

It is common that multi-disciplinary documents require more than one review and signatures.

Standard and Code Compliance

Different standards and codes are applied when implementing a project. It should be determined at the beginning of a project which standards and codes apply. Some of them are corporate (or plant), and some are from external organizations. It is a good practice to establish a list of such standards and codes at the onset of a project. Later on, it will be a lot simpler to ensure project compliance.

Design standards and codes are generally grouped under a general umbrella for a particular country; for example, ANSI in the U.S., CSA in Canada, DIN in Germany, and IEC for Europe. In North America, the main standard and code developing organizations are:

ANSI = American National Standards Institute
API = American Petroleum Institute
ASME = American Society of Mechanical Engineers
ASTM = American Society for Testing Materials
CSA = Canadian Standards Association
FM = Factory Mutual
IEEE = Institute of Electrical and Electronic Engineers
ISA = The Instrumentation, Systems, and Automation Society
NEMA = National Electrical Manufacturers Association
NFPA = National Fire Protection Association
OSHA = Occupational Safety and Health Association
UL = Underwriter's Laboratory
ULC = Underwriter's Laboratory of Canada

At the international level, ISO and IEC are developing standards that are gradually being adopted worldwide. This will simplify engineering and equipment production. The world is getting smaller; global trade is on the increase; and accordingly, engineering and equipment is being sourced and used worldwide.

Control Strategy

"Should our control strategy be reviewed?" This question has crossed the minds of many managers, engineers, and operators. A need for a technical audit of the existing control system is the starting point (see chapter 19). The result of a technical audit is then compared with the plant business strategy. That becomes the base from which a control strategy for the plant is developed.

The plant business strategy should be expressed in terms of market and product needs. It should provide a plan for the present and the future, and it should identify the domain in which the organization operates now and into the future. The control strategy should be directly related to the plant's present and future business needs. It should be based on customer requirements, the competition, and the products being manufactured.

Once a strategy is in place, a plan is created to identify the steps that must be taken to reach the goal of the organization. A balance must always be maintained between the control strategy and the plan because knowledge gained through the implementation of the control system and the plan will need to be updated. None of the parameters are static; every parameter is in continuous evolution and change—the market, customer needs, technology, competition, and government regulations. Note that once the process has started, it should move fast. Delays generate hesitation, and hesitation generates doubt and uncertainty. Eventually nothing gets done, and to restart the whole process becomes even more difficult.

Going back to the original question of when to review the existing control strategy, the following telltale signs may provide an indication. Note that in most cases the control system is not the only answer to all problems. The quality of raw materials, the capabilities of the process equipment, and employee morale are but a few examples of additional key ingredients for a successful plant operation.

The review of the control strategy typically occurs following telltale signs such as

- sliding market share,
- unhappy customers,
- inability to keep up with the competition,
- recurring emission problems,
- large inventories of raw materials and finished products,
- inconsistent and/or poor quality,
- unreliable plant trip and alarm systems,
- poor or nonexistent production data,
- inflexible production and long start-up time,
- poor productivity, with too much staff and high wages,
- errors in transferring production data to paper,
- many man-hours wasted in reading data from unreliable sources,
- too much time wasted in checking manually copied data,
- inability to obtain immediate feedback and production knowledge,
- inflexible existing production facilities,
- long setup of existing facilities,
- large support staffs required for the production facilities,
- increasing production costs,

- inability to comply with environmental regulations, which are a top priority,
- budgets cuts that prevent plant investments and improvements,
- constantly changing production priorities, with heavy start-up and shutdown costs to accommodate customer delivery requirements,
- inability of existing production facilities to meet the required quality of service, new product introduction, and technological know-how that are key to price setting, profitability, and business survival,
- less time to respond to market demand,
- inability to deliver more specialized products, better quality, better service, better delivery times, and specialized packaging with specific delivery constraints,
- customers that press the plant to accept low-volume, unprofitable orders, and
- the need for quick response to market demands and changes, keeping in mind equipment failure, set-up times, operating costs, and inventory costs.

It should be noted that many of these telltale signs are interrelated. For example, poor quality will produce more scrap, which increases pollution, which increases the need for raw material, which increases cost and decreases profits. Some industries have these problems and do nothing about them. They do not survive. Others take the bull by the horns and are selling successfully to an ever expanding world market.

Plant Business Strategy

The plant business strategy, as was mentioned earlier, is the base of the plant control strategy. In other words, what is the control strategy really trying to achieve relative to the business side of things?

The following nine points serve as a guideline (or a starting point) for developing plant business and control strategies.

1. In general, if targeted growth and profitability are to be achieved, then several major changes may be required. There is an immediate need to get control over inventories, production, and delivery performance (including finished goods, raw materials, intermediates, and packaging).

2. For management, real-time data must be available at the plant floor level, immediately accessible to plant management, and integrated into the management information system at the plant. Also, there is a need to capture the knowledge of existing (and close to retirement) personnel in an "intelligent" system. The plant must be managed from minute-to-minute not from month-to-month. Management must be able to react to the present and plan for the future instead of reacting to the past. Problems must be detected and rectified before they occur.

3. From a customer point of view, the plant must be able to compare customer complaints with the production of the different shifts. In addition, customer orders must be tracked through the on-going production.

4. Plant emissions must be reduced by a stated percentage at the end of one year and by a higher percentage by the end of the following year.

5. Production must strive for zero defects, identify those processes that add value (to be enhanced) and those that add only cost (to be eliminated), and provide production information accurately when needed (no guessing, telephoning, working with old info, or manual collection of data). For all products, on-line knowledge of quality control analysis must be available on demand.

6. The plant must improve its ability to introduce new applications, produce an increasing proportion of proprietary products, and quickly and efficiently develop new products and processes.
7. The use of modern control systems should abide by the following guidelines:
   A. Implement first on a small scale (i.e., a relatively low-cost and acceptable learning curve) then expand plant-wide (perhaps seek government credit through R&D for pilot application).
   B. Start with a process that is now driving the cost up and look for a process
      - with as rapid a payback as possible,
      - that involves the fewest number of people with the least equipment,
      - that produces a large amount of several end products with different market values,
      - with a large price differential between the feed and end products,
      - with expensive raw materials (or expensive cleanup cost or expensive operating cost),
      - with high-energy consumption, and
      - that is hazardous and where the operators need to be kept away from the production process.
   C. Start in the plant automation process to get on the automation learning curve before the competition gets so far ahead that the plant can never catch up.
   D. The control system is required to reduce product cost and, at the same time, increase productivity and improve quality. Using production trends (good and bad), quickly identify any deviation and then correct the situation.
   E. The approval and implementation of a control system must be preceded by:
      - a scope definition (shows benefits, justification),
      - a description of the control system features,
      - an equipment list (for the potential control system), and
      - manpower requirements (including training needs and re-allocation).
8. Acquire an off-the-shelf system that can be easily understood by plant personnel and well supported by the vendor.
9. The management must ensure that the operators do not get the impression that the new system will be used to “beat on” them; it is there to help everybody do a better job. Get the operators involved in the decision making process.

Implementation of a New Control System

The first step is to start with a business strategy or mission. This is a management responsibility. The business strategy is used as a reference further along the process. Before further activities are carried out, management's support and commitment to improvement must be established. Without this support and commitment, activities down the line will probably be a waste of time, the concept will not be implemented, and future efforts toward implementation will be regarded with distrust.

The next step is to assemble a dedicated team that is led by a champion. The champion will probably devote all of his or her time to the project. The team's key word is “dedicated.” In other words, when the need arises for action, the team must find the time to take action. The team must not be too large. It should be multidisciplinary to benefit from different fields of knowledge. For example, a representative from management, two from engineering (one from process, one from controls), one from operations, and one from maintenance.

With the champion and the team in place, the justification process can start (see chapter 19). It will consist of three parts:

1. Identification of the plant needs based on the benefits obtainable from the control system. This activity will highlight the main features of the control system to be installed.

2. Specification of a control system based on the needs previously identified. This activity is closely followed by vendor selection. Vendors are requested to bid on the potential control system. Following the receipt of all bids, a decision analysis is performed to evaluate all control systems considered and decide which meets the plant’s needs most closely.

3. Totalization of all possible costs and performance of a cost justification for the project based on the benefits received and the payback achieved.

The champion then draws up an implementation plan. One word of caution: Do not automate the easiest application; look at where the benefits are needed and where the implementation is sure of being accomplished successfully.

Once the budget is approved and following the decision to implement, the problem becomes to implement it in the most effective manner. Management must be involved because resources (financial and human) will have to be allocated until completion of the project.

Throughout the justification/implementation process, it may be necessary to seek advice and guidance from experienced consultants. It will also be necessary to involve operators and maintenance personnel in system selection. This is good for morale and ensures support during and after implementation. Management should assure all employees that the new system guarantees business instead of taking jobs away. Employees must be kept informed of progress.

In most cases, the implementation for existing plants is first done on a small scale, which gives the benefit of going through the learning curve with minimum impact. Also, it allows management to check the justification through a follow-up before jumping into a plant-wide implementation.

In some cases implementation will be done on a large scale. This is especially true in new plants. Here, experience is needed because there is no room for error. It must be done right the first time!

It is important to remember the following points:

A. Implementation could take as little as a few months or as much as several years; it all depends on the scope.

B. Always avoid islands of automation. Communication problems can become expensive nightmares.

C. Do not automate chaos.

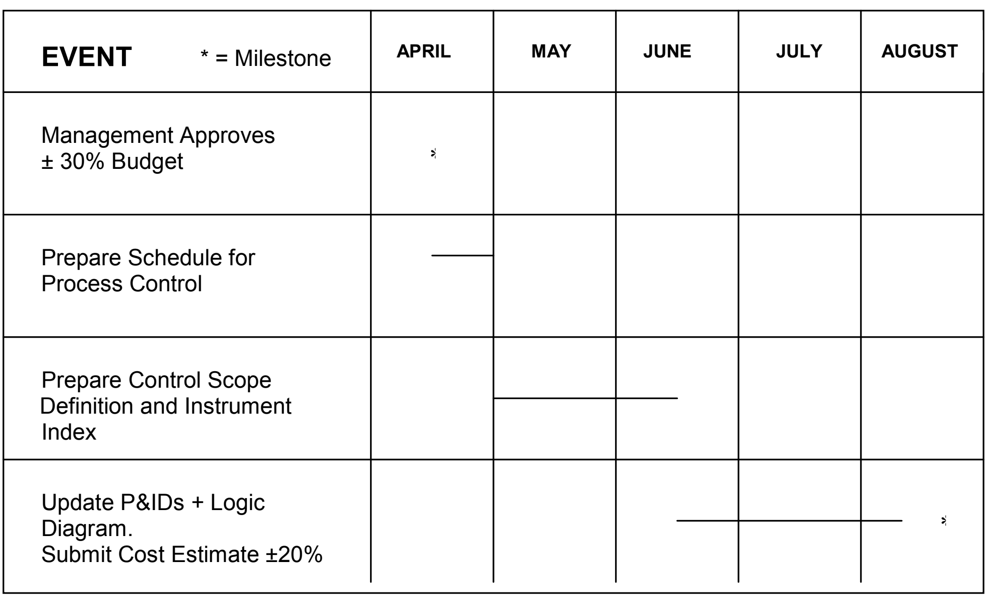
Scheduling and Time Management

Project scheduling comes in different formats. Regardless of the format used, the purpose of scheduling is to keep control of the project by breaking down the overall project into smaller manageable activities. Complex activities should be broken down into even smaller activities. Scheduling is an on-going activity that requires updating on a regular basis. The update frequency depends on the project and its complexity. A schedule is not only used by project management but is also used by engineering to monitor deliverables and interact with other disciplines, and by purchasing to plan their work, buy material, and schedule delivery.

A schedule defines different stages and milestones in a project. It is an essential tool to manage activities. For example, figure 18-2 shows a schedule for preliminary engineering activities as they apply to process control. Each stage may need to define

- its inputs, such as documents required and standards and codes applicable,
- the tools and methods required to get things done, and
- its outputs, such as documents produced and activities completed.

Figure 18-2
Simplified schedule for preliminary engineering activities showing two milestones.



In addition, the schedule may need to define who will do the work, when will it start and finish, what milestones are to be reached, and what is required to get an activity started to reach the milestone. Typically, events and activities are drawn on the left-hand side, and time is at the bottom (or top). When well prepared, the schedule should identify the requirements for, and effective use of, available human resources and show the activities that need to be completed before some others can start.

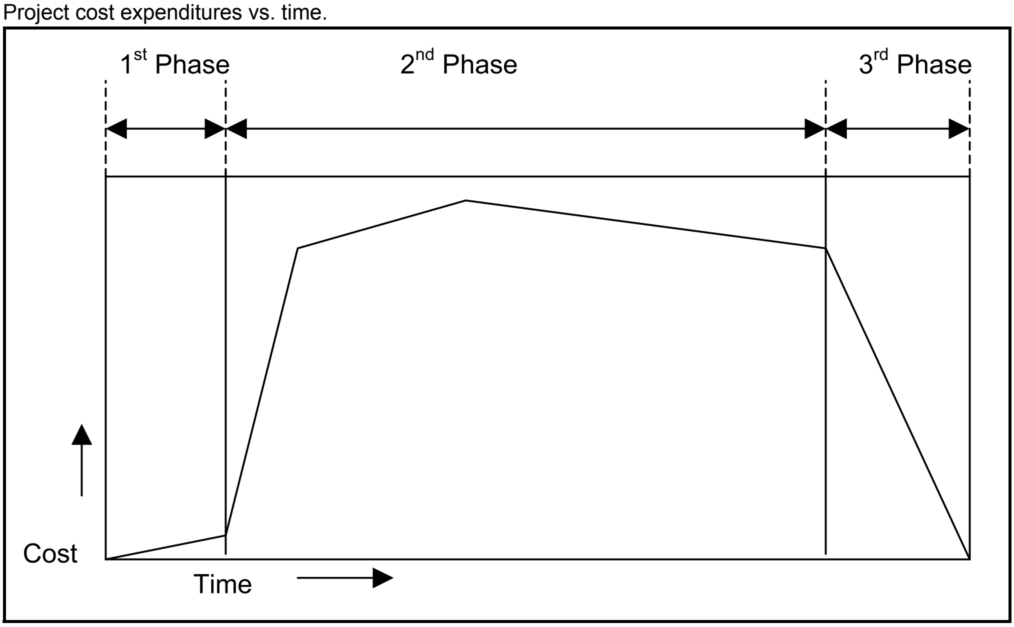
A preliminary schedule should be generated at the start of a project (having a bird's eye view of the project), including project definition, preliminary engineering, detailed engineering, construction, commissioning, and start-up. As the project evolves and its scope becomes clearly defined, the schedule is then broken down into detail activities. The detail of the schedule is in relation to the size of the project, its importance, and its complexity.

Cost Estimate

Estimating the cost of a project is essential to obtaining approved budgets. The accuracy of an estimate depends on the stage of a project. At the start of a project and until preliminary engineering is completed, a ±30% is acceptable. Past experience and previous data is typically used to fill in incomplete information. On completion of preliminary engineering, a ±20% is expected—here again, a combination of past knowledge and estimates from vendors is used to reach this level of accuracy. On completion of detailed engineering, a ±10% accurate estimate can be reached. At this point, and to reach this level of accuracy, bids have been received from vendors and contractors.

Typically a project goes through three basic phases. The first phase covers the start of the project, and costs start rising but generally at a low rate. Once the project is approved, the second phase starts, and costs increase significantly over time (see figure 18-3). In this phase, engineering personnel are mobilized, work starts, and equipment is purchased and installed. The third phase typically follows the completion of construction work on site, and cost diminishes until the project is closed.

Figure 18-3
Project cost expenditures vs. time.



Cost estimates typically include engineering and equipment costs—and quite often installation, commissioning, and startup costs. Costs are difficult to estimate for an old plant to be retrofitted. This is due to unreliable documentation that does not reflect plant conditions and to the uncertainty of existing equipment condition and capability.

From a process control point of view, an estimate is frequently generated from a list. The instrument list is a good starting point. The list can be broken down as follows:

- 1st column, the equipment tag number (i.e., one line per item),

- 2^{nd} column, the engineering costs,
- 3^{rd} column, hardware costs,
- 4^{th} column, installation costs (including installation material), and
- 5^{th} column, total for each line.

Additional lines would cover commissioning and startup on a loop-by-loop basis. Finally, a grand total to cover the total costs. Often a safety factor is added to cover unknowns (10% to 30%, depending on the project). The safety factor includes such unknowns as out-of-country projects, expertise of project personnel, and foreign languages. A budget review typically occurs as the project progresses—confirming the previously approved budgets—or when additional funds are requested (a situation often frowned upon by management).

Document Control

A project manager should ensure that all project documents (e.g., specifications and drawings) are generated and checked on schedule. These documents must be maintained as revisions are implemented because they become the reference data for project personnel. As reference data, these documents must be accessible to all who require them, but the changing of data on these documents must be closely controlled.

The storage of documents is another responsibility for the project manager. The documents must be accessible when technical data is required. When they are not easily accessible, the eventual user may make an assumption about the data (it's quicker, you know), eventually discover that his or her assumption was an error, then start looking for the documents. Quite often, he or she will not be sure if the document finally found is up to date. This will require a search for another person who "knows" where the latest information is, which is a tremendous waste of time, manpower, and money. As strange as this scenario may sound, it actually does happen.

Documents will sooner or later become obsolete if they are not maintained to the latest revisions. The users become aware of this situation very quickly and usually the hard way. To avoid this situation, documents must be checked continuously to ensure that they are not obsolete. The project manager, by doing a random check on a few items now and then, should be able to identify this condition.

One or more persons are usually responsible for the condition and maintenance of plant documents and drawings. This responsibility must be clearly identified. The project manager must determine the procedures for document and drawing revisions, whether they are closely and carefully monitored or whether every Tom, Dick or Harry can pick up the master set, mark them up, and simply file them back. With the appointment of a custodian(s) of the documents, the responsibility to ensure that all required design information and revisions are on the documentation becomes clearly identified. The project manager needs to recognize whether a custodian exists, whether the responsibility is established, and whether the authority is enforced.

A system should be implemented by the project manager to keep track of all documentation (e.g., specifications, drawings, and reports). The system should be simple and effective. Each document should as a minimum show the document number, title, type of drawing, date originated, and latest revision with date of revision.

Engineering

The purpose of engineering in general is to provide safe, cost-effective, and quality technical services to the end user. In industry, engineering is the first phase of technical activities and provides services for the production of a product (or products). Such services vary from the typical engineering design work to many other activities, such as:

- guidance on the application of codes and regulations,
- supervision of the work of others,
- estimating,
- planning,
- scheduling,
- advising and maintaining relationships with other disciplines,
- training of personnel,
- inspections,
- assistance to maintenance, and
- procurement of contracting resources.

Engineering, as described in this book, is broken down into two distinct activities: front-end engineering and detailed design. Each of these activities has its specific functions. Sometimes there is the temptation to skip the front-end part and jump directly into the detailed design. However, this short-cut approach creates delays, errors, and the need for corrections that eventually take more time than was supposed to have been saved by skipping the front-end part.

Front-End Engineering

Front-end engineering is the first step in engineering design. It defines the process control requirements, states the major aspects of the control scope of a project, and covers the preparation of the engineering data required to start the detail design. This phase follows (and sometimes parallels) the preparation of preliminary P&IDs and process hazard analysis for the process under control.

The process hazard analysis is an essential part of the design activities. It identifies weak points in the system and their effect on safety and operation. It can be performed using at least one of the following methodologies:

- what-if,
- checklist,
- what-if/checklist,
- hazard and operability study (HAZOP),
- failure mode and effects analysis (FMEA), and
- fault tree analysis.

The subject of process hazard analysis is outside the scope of this handbook. Additional information on each of these methods can be found in OSHA's Part 1910, Appendix D, or in other pertinent publications.

The preparation of front-end engineering will vary according to the requirements of a corporation. The activities of front-end engineering are generally carried out by the user (or by the appointed representative), based on the project requirements, engineering standards, and statutory requirements in effect at the site.

In general, the three documents that are prepared under this phase and must be ready before the start of detailed design are the P&ID, the control system definition, and the logic diagrams (see chapter 14). It is important to ensure that the symbols used for all items of process control are the same throughout the project and in compliance with existing plant standards or with ISA-5.1, which is an internationally adopted standard (see chapter 2).

These documents must be updated when changes are made during the course of the project, and changes do occur. Once approved and agreed upon, no changes to these documents should be implemented without prior approval from the project manager and the assigned control engineer (or control supervisor, depending on company policy).

When the content of these documents becomes final, they must be marked as such. Following installation, commissioning, and successful start-up, all engineering documentation should be updated to an as-built form and must be maintained as changes occur throughout the life of a plant's control system.

Front-end engineering may take 10% to 20% of the overall engineering budget, and yet it is an essential step in any project. When preparing front-end engineering documents, it is advisable to communicate with all involved in the project, including operators (the final client) and maintenance personnel (who will have to calibrate and repair the system for years to come), to understand their needs and preferences. At this stage, differences of opinion should be resolved, and the engineer may have to use a quantified approach to resolve tough issues, such as implementing DCS vs. PLC/PC (see chapter 19 on Decision Making Tools). All requirements are summarized in the control scope definition: give it the necessary time; it is the basis of all design to follow.

The requirements of the work to be done are captured in the front-end-engineering documents. The engineers preparing these documents should discuss the upcoming project with people who have been through a similar application and learned from previous mistakes. They should also collect all necessary technical information. This includes assessing the existing corporate standards and identifying the need to develop new standards or revise existing ones.

When preparing front-end engineering, certain items and/or conditions can increase difficulty and therefore require more time and money for project completion. They include

- distance between plant and engineering office: meaning more time spent traveling, lower engineering productivity/efficiency, plant personnel not immediately available,
- productivity of local personnel: productivity of engineering and construction personnel varies from country to country and even within the same country and must be included as a factor when assessing costs and schedules,
- installation season if outdoors—cold winters, hot/humid summers, rainy seasons—all affect the installation efficiency/productivity,
- contractors not familiar with industrial work and installations,
- handling toxic and hazardous production materials,
- age of existing plant; the older a plant, the more difficult it is to find up-to-date documentation, the more time consuming to fit new instrumentation into existing equipment, the more the costs increase in comparison with engineering and installing equipment in a new facility,
- unexpected surprises requiring modifications and/or additions to existing facility and equipment,
- careful planning if upgrading or modifying part of an existing control system to prevent shut down and allow a gradual switch to the new system (without shut downs),

- obsolete or reconditioned equipment (with missing maintenance manuals or where the vendor no longer supports old equipment), and
- incomplete existing documentation.

When the front-end engineering is completed, a technical review by all involved is required to ensure that common agreement has been reached before the start of detail-design activities. To reach consensus, sometimes more than one review is required.

Detailed Engineering

Detailed engineering covers the preparation of all the detailed-design documentation necessary to support bid requests, construction, commissioning, and maintenance of the plant.

Since the 1990s, due to the business environment, corporate and plant engineering staff are being reduced to a minimum, and the detail engineering phase is now frequently given to an engineering contractor or an equipment supplier. In most cases in which an engineering contractor is doing the detail work, the instrumentation and control engineering portion is contracted out as part of a larger engineering package that would include other disciplines, such as electrical, mechanical, and civil. Detail engineering must be based on all statutory requirements in effect at the site, the front-end engineering, the project requirements, and the engineering standards.

When the detailed engineering is given to an engineering contractor, a definition of the scope of that contractor is required to avoid misunderstandings and future additional costs. Appendix C can be used as a guide for such conditions. In other cases, such as when the detailed engineering is done by the supplier of packaged equipment, Appendix D can be used as a guide.

The detail-design documentation covered under detailed engineering includes drawings and documents as required to meet the needs of the legislative requirements in effect at the site and the plant (see chapter 14).

When selecting process control equipment, it is recommended to select the simplest device that meets the job requirements. Fancy devices with unwanted features add unnecessary cost and complexity. When selecting equipment, the engineer should consider cost, expense of installation, and maintenance. Also, he or she should check the reliability of the potential equipment, based on past experience and in comparison with other devices, for the ease of maintenance by plant personnel and the availability of technical vendor support and spare parts.

Detailed engineering should be based on the front-end engineering and should be completed based on the schedule and budget. Detailed engineering consumes the majority of engineering man-hours on a project. When an engineering contractor does the work, it is advisable to prepare the requirements (a specification) for engineering tender and after contract award. Start with a technical review meeting to explain and ensure understanding of the requirements described in the front-end engineering package.

Manpower requirements are typically based on the scope of work and the schedule. It is important to have a competent lead process control engineer, who will stay on the project until completion. The project manager should monitor the on-going performance and adherence to the schedule and scope of work.

Detailed engineering typically covers the preparation of all technical documents (see chapter 14). It also includes:

- design review of packages to ensure they meet the design requirements,

- preparation of tenders for completed technical specs,

- receipt and evaluation of bids, including meetings with vendors as required for clarifications and confirmation of all agreements in writing,

- recommend a vendor and advise purchasing group,

- review schedules submitted by suppliers to ensure that they match the existing project schedule, and

- review and comment on the documents submitted by vendors (with may be more than one go-round).

When the detailed engineering is completed, a technical review by all involved is required to ensure that the work done is in compliance with the front-end engineering and that no errors exist in the completed package before construction starts on site. Sometimes more than one review is required. The correctness of the package will ensure minimum delays and costs during the equipment installation phase.

Quality

The detailed engineering, along with all other documentation, must maintain a certain level of quality. As a starting point, it must be ensured that each document carries the required reference information. The following is a typical example of such information:

- drawing number,
- drawing title,
- type of drawing,
- date originated, and
- latest revision, date of revision, approved revision.

In addition, it is strongly recommended, where practical, that the nature of any changes be identified if the document is revised.

As a general rule and by using some of the ISO 9000 guidelines,

1. the latest issues of appropriate documents must be available at all pertinent locations.

2. documents must be reviewed and approved for adequacy by authorized personnel prior to issue and according to a procedure; such personnel must have access to background information upon which they can base their decisions.

3. obsolete documents must be quickly removed from all users.

True quality control is an ongoing activity and checks done at different steps of the project as it evolves ensure that the final product achieves a good quality level. Document review should not create a bottleneck; it should be part of the overall project schedule.

Some plants have adopted a coloring scheme to identify document modifications. For example, they use green to mark what should be deleted, red to show what should be added, and blue is used for comments to drafting or CAD operators.

Purchasing Equipment

Equipment purchasing follows the detailed engineering phase and precedes the installation of control equipment. The project manager, based on the schedule, knows what should be purchased and when. The vendors' terms and conditions should be reviewed by the project manager and/or by the purchasing department because quite often those commercial and legal requirements are ignored by engineering personnel, who are more interested in the technical details and compliance with their specifications.

The involvement of the project manager in the work done by engineering will vary based on the project itself, the personalities involved, and the company culture. The project manager can review the equipment specifications and confirm that they are sufficiently detailed, and he or she can inquire about vendor's technical support, training, and spare-parts availability. In addition, he or she can check the required condition to store the received equipment, the resources required for equipment programming (e.g., manpower, training, vendor support, cost, and availability), field service cost and availability, and the extent of the warranty and its duration. On the other hand, he or she can delegate all these activities to lead engineers and rely on their decisions.

After bids are received and vendors are selected, quite often the engineering specifications need readjustment to incorporate some minor data to meet the specifications of the selected vendors. Expediting is required to ensure on-time delivery of vendor data and equipment and is commonly linked to the schedule. This activity is typically done by the purchasing group, and it may have to be monitored by the project manager.

Vendor Documents

Vendor documents are essential in providing the detailed information required by engineering to complete their work. Therefore, when placing an order it is good practice to set delivery dates for vendor documentation and have progress payments linked to the delivery of the required vendor documents.

Prior to placing an order, the project manager should ensure that sufficient copies of vendor documents are available to all concerned. Typically three copies are required, one for engineering to finish their work, one for the installing contractor to know the required details to properly install the equipment, and one for maintenance to know how to properly maintain the equipment. With the advent of the Internet and vendor Web sites, many of the vendor manuals are available electronically, reducing the amount of paper involved.

Vendor document review is typically done by engineering personnel to ensure that the equipment to be supplied is exactly what the plant requires. Some companies will not return the documents to the vendor as "approved." They believe that "approval" is the vendor's responsibility. Instead, they use "reviewed" or "reviewed with comments."

Training

Operators with the best of production and process equipment cannot produce high-quality products without proper training. Getting into the leading edge of technology includes bringing personnel to that level of know-how. We are living in a world of continuous improvement. If we stop improving, we fall behind. Training is not an overnight process but an ongoing activity. Technology and methods are changing at an outstanding pace. If we do not keep up, we cannot survive. The plant cannot always draw the skilled resources from the outside on demand.

Training is one of the key elements of productivity. Without proper training, employees become frustrated when trying to make decisions about unfamiliar problems, which can lead to errors and discouragement. The result is twofold: wasted time and poor productivity. In addition, as the condition builds up, morale starts dropping, good employees quit for better opportunities, and the condition gets worse in a never-ending closed loop.

In many cases, training is a low priority. A problem to resolve first, a cut in the budget, or some other good excuse always takes precedence. Recall the quite apropos bumper sticker that reads, “If you think education is expensive, try ignorance.”

Training could be as basic as learning the fundamentals of process instrumentation and control systems, or it could be quite specialized, such as advanced PLC programming at a vendor's training center.

One of the first steps in training is the implementation of a training program, following a review of the plant’s needs. The program should be closely linked to the development of employees. It should be known to all employees to improve morale and encourage employee development. The project manager must identify the training program and affirm that the personnel department knows it.

It is advisable that detailed records of all training be retained, either in employee files or in a separate record. Some companies keep employee feedback on courses they have attended. This provides good information if additional employees need to attend the same types of courses.

When installing new equipment, particularly when a new technology is being introduced, training is a must and should occur before rather than after the implementation. Yet, it is amazing how often the famous “we've-got-no-money-left-in-the-budget” routine is used, and as a result, training is cancelled. Training is not just the problem of the project team installing the new equipment; it affects everyone.

Equipment Installation

With the detailed engineering now completed and checked, the project manager must have a contractor ready to install all the purchased equipment. The project manager typically selects a few bidders and asks for pricing. When selecting bidders, the project manager will assess the size of the contractor, their experience in similar work, and the supervisor’s experience and knowledge. In addition, three or four references of similar facilities are typically required from all contractors.

Depending on the project and the plant’s way of doing things, subcontractors are generally managed by the main contractor. This avoids finger pointing as the construction project comes to an end. In addition, the main contractor should also coordinate trade activities (e.g., pipe fitters install control valves, whereas electricians connect the 4-20 mA signals to the control valve positioner).

The bid package normally includes the detail-design documentation (see chapter 14). It also includes all commercial and contractual requirements. Therefore, the purchasing department is involved for such things as the terms and conditions and payment schedules. All documents in the bid package must be clear. Do not use words such as “best quality” or “good enough.” What is good quality for the contractor may not be acceptable to the client.

The quality of the installation depends on the quality of documentation, equipment, and the knowledge and expertise of your contractor. The bid package should clearly state that the installation must be done in strict compliance with the installation specification and all the engineering documentation supplied.

An installation specification (see chapter 15) is typically supplied with every installation bid package. The installation specification should identify who will receive, store, and retrieve the equipment. Some equipment may require special storage conditions, and some may have to be in lockable facilities (to prevent “borrowing”). Storage responsibility includes protection from rough handling, falling devices, or strong impact. In addition, equipment should be kept in its original shipping boxes where possible.

The bid package should also identify who will check that the equipment received is in compliance with the specifications and purchase orders, and if site calibration is required, who will do the calibration and who will provide the calibration facilities. The site engineer should be notified immediately of any discrepancy between what was ordered and what was received.

Many types of contracts are available, each with its advantages and disadvantages, and each dependent on the project in question and available technical documentation at bidding time (see chapter 20 on the subject of contracting).

It is good practice to review all design documentation with the potential contractors prior to bidding and then again with the selected contractor following award of contract. This prevents misunderstandings because the documentation provided with the bid package may not have sufficient details or the contractor may misunderstand some requirements.

Once the contract is awarded, the project manager should monitor progress of all installation activities through progress reports submitted weekly, from receiving the equipment to completing and checking the installation. The requirement and frequency of the progress reports are generally defined in the bid package.

The project manager maintains constant contact with the contractor, clearing all problems as soon as they occur. The project manager and the site engineers are expected to make daily rounds to assess project completion, and they must be available to answer all questions and make decisions on the spot to allow construction to proceed without interruption, otherwise delays will occur. A typical issue is resolving discrepancies between the documents and the reality of field installation and accessibility.

Checkout of the installed control systems follows the installation of all equipment. The project manager would at this stage appoint site engineers to verify that all control equipment is installed exactly as described in the specifications and drawings supplied with the bid package and as agreed with the contractor. Checkout includes installing all software then testing the whole system loop by loop (i.e., a signal from the field device, such as transmitters and switches, is received correctly in the control room, and a signal from the control room is received correctly at the field device, such as control valves and motors start/stop).

When the checkout of a loop is completed, it is tagged in the field and marked as completed either on the loop diagrams (see Chapter 14) or in a punch list. The punch list is typically generated from the instrument list and consists of a list of all loops to be checked.

Loop checking should confirm that all the components in a loop function correctly, including all wiring between the field devices and the control room. The loop-checking method varies with the equipment being tested. For certain modulating field sensors, such as pressure transmitters, an air pressure signal is generated between the process connection and the transmitter after isolating the process (see figure 10-10). That signal is set at 0%, 50%, and 100% of calibrated range and for each of the three points a corresponding signal is generated at the receiving end (indicator, recorder, or controller input). That loop is now checked if the received signal is correct (see figure 18-4). Otherwise corrections are required.

It is strongly recommended that control panels and control room equipment, such as DCSs, be fully tested at the vendor’s facility prior to being shipped to the site. This approach minimizes loop-checking time on site and facilitates identifying the source of problems when a loop is not operating properly.

Other modulating field sensors may not be tested at three points. For example, temperature transmitters are often tested at two points—ambient temperature and another point generated by a portable temperature bath. Other devices can only generate a signal when the process is in operation, such as magnetic flowmeters. In such cases, only a zero value can be read, and if desired, a modulating signal can be generated at the transmitter output to confirm signal continuity.

Discrete on/off input field devices, such as switches and pushbuttons, are whenever possible tested at two points on and off.

Figure 18-4
Loop testing for a pressure transmitter.

Tag Number: PIT-157

	0%	50%	100%	Units
Input Air Signal	0	300	600	KPag
Output from Transmitter	4	12	20	mA
Reading at DCS Monitor	0	300	600	Kpag

Loop Checked: OK — Notes: ……………………………………………

Date: Sept. 23, 2005 — By: CLC

Modulating field devices that receive their signals from the control room, such as control valves, are also tested at three points (see figure 18-5). Discrete devices, such as solenoid valves, are tested at two points, on and off.

Figure 18-5
Loop testing for a modulating control valve.

Tag Number: PV-157

	0%	50%	100%	Units
Output Signal from DCS:	0	300	600	KPag
Output to Control Valve:	4	12	20	mA
Valve Position:	0	50	100	Open

Loop Checked: OK — Notes: ………………………………………………

Date: Sept. 23, 2005 — By: CLC

Loop checking can be part of the installing contractor's responsibility, but it should be done in the presence of plant personnel. Loop checking requires more than one person. Typically two are in the field sending to and receiving signals from the control room, and in the control room, a person receives from and sends a signal to field personnel. Communication between the control room and field activities must be maintained at all times to ensure the successful completion of loop-by-loop checking.

With the completion of the instrument and loop checking, the equipment installation is now complete. All systems are connected, checked, operational, and ready for commissioning.

Commissioning

Commissioning follows the completion of all installation work and precedes plant startup (i.e., before process materials are introduced into the system). In commissioning, and where feasible, water and/or air are introduced in the process to test the operation of the complete process, including all process control loops and process equipment.

Commissioning is performed and controlled by plant personnel and process engineers. At this stage, process control personnel are basically standing by, ready to correct any deficiencies that have gone unnoticed.

The installing contractor may still be required to be on site for immediate repairs or adjustments. At this stage, the contractor will be working hand in hand with plant maintenance personnel. Vendors may be required on site to help test equipment and put them in service. This is common for complex systems, such as analyzer systems. Vendor presence should be planned in advance to ensure their availability at the required time and for a set duration.

Before commissioning starts, site maintenance personnel should have been trained on the operation and maintenance of all new equipment because they will be part of the commissioning team. As commissioning starts a full set of up-to-date documentation should be available. As the commissioning proceeds, problems are identified, and solutions are implemented.

With the commissioning completed, the plant is ready for startup and for the introduction of the process materials for actual production.

Startup

Start-up follows the completion of commissioning. And as was the case with commissioning, start-up is performed and controlled by plant personnel and process engineers. Process control personnel, contractors, and vendors are basically standing-by, ready to correct any deficiencies and make last-minute adjustments and repairs.

Prior to start-up, maintenance and engineering personnel should ensure the following:

- all control equipment is powered up,
- all control systems (e.g., DCSs, PLCs) are operational,
- all loops have been checked, and all deficiencies corrected,
- all safety checks are complete,
- all safety/critical trips are operational, and
- all required documentation is available and reflects the actual plant condition.

Startup is done under guarded conditions and is the beginning of full operating conditions (i.e., actual production). Process materials are introduced gradually.

Process control responsibilities during startup include monitoring all control systems, PID controller tuning (see chapter 8), assisting operations, and resolving issues quickly. At this stage, all personnel are under pressure to ensure a smooth and quick plant startup because the project may be running behind schedule and management is demanding immediate production.

Initial equipment failures tend to occur at this stage. The project manager should keep track of identified problems and implemented solutions.

With the completion of startup, the plant is handed over to operation and maintenance, and the project manager will direct his or her attention to closing the project.

Project Closing

Project closing marks the end of a project. It is a relatively easy activity if the project was under control from the start.

The contractor should by now have submitted all engineering and vendor documentation in their possession, including all marked-up documents, to the project manager. All documentation is then updated to an as-built condition to reflect the changes that were done during construction, commissioning, and startup.

The project manager issues a final report with the lessons learned and the status of budgets. The project is now completed.

CHAPTER 19

DECISION-MAKING TOOLS

Overview

Managers and users of process control systems are quite often faced with a situation where a decision is required on matters involving large sums of money. In today's economy, the game is survival of the fittest, and the game has a set of rules that is played on the global scene (some say there are no rules). If you lose, you're out. Markets that were guaranteed few decades ago are now threatened by international competition.

Product life cycles are much shorter, and technology is changing at an unwavering rate. In addition, production needs to be faster, less expensive on a per unit basis, and of high quality. The olden days, when products had a long life cycle, the domestic market was secure, and the economical conditions could be predicted, are all gone. We are in a new world, a world of international competition, where survival is a daily issue and vital decisions are frequently required.

A mismatch of process, production capabilities, and customer requirements generally results in poor quality, high cost, and low morale. On the other hand, success not only means survival but also increased markets and increased profits. From a process control point of view, one of the main tools in achieving success is the proper implementation of modern process control systems (see chapter 9 for further details). These systems are, when well applied, an aid to cost-effective, reliable, high-quality, pollution-reducing, and flexible production (i.e., an aid to survival).

In existing plants, the implementation of modern control systems consists of replacing existing obsolete controls. The replacement must be done with the minimum of interruption to plant production and with the knowledge that the investment is worth taking.

When decisions are made, they must be the correct ones. The techniques learned in this chapter should help the decision-making process by justifying certain major modifications. Some basic tools commonly used in the decision-making process are:

- auditing,
- evaluation of plant needs,
- justification, and
- system evaluation.

In many plants, the auditing of industrial control systems is becoming a requirement to ensure proper operation and the maintenance of corporate assets. In today's economy, control systems are becoming more and more vital to plant operation, and therefore, their functionality must be ensured. The failure of control systems could be a sizeable financial loss, and, even more dangerously, it could be hazardous to life and to the environment. On the other hand, their efficient functionality will provide safety and quality products and will handle fast, complex, and hazardous processes. Auditing may be defined as a form of quality assurance for the control system to evaluate its intended functionality.

The evaluation of plant needs is an activity that identifies the needs of the plant. These needs, once identified, typically become the basis of the control system specification. This is a process in which decisions regarding the plant needs must be made. These decisions must consider the available choices and should be based on facts, not on the opinion of the person (or persons) with the loudest voice or the highest authority. Evaluation of plant needs is generally done following an audit or sometimes instead of an audit.

Justification assesses the need to invest, helps establish the objectives, and identifies the profitability of the investment. Without it, the investment could be unprofitable, or the system selected may not meet the intended application. In many cases, the funds required for large investments in process control systems need to be borrowed, while at the same time, management has many other needs for funds in the plant. The decision on where to invest funds and which improvement project or expansion is to be chosen depends on the return on that investment and the amount of risk involved. In general, this is a difficult decision that must be substantiated, thus the need for justification.

System evaluation is a tool commonly used to evaluate bids following the submittals from different vendors, and a decision must be made concerning which one most closely meets the plant needs. This is done through a quantified system evaluation.

These four decision tools are actually interrelated and are often used together (see figure 19-1).

Figure 19-1
Relationship between different decision tools.

1. AUDITING
   (to verify the status of the existing control system and decide what to do next)
2. EVALUATION OF PLANT NEEDS
   (to identify the needs of a plant and decide what is required)
3. JUSTIFICATION
   (to ensure that the money to be spent is worth it and that the investment will resolve the issues raised by the audit and the evaluation of plant needs)
4. SYSTEM EVALUATION
   (to decide which of the systems submitted by vendors is the best for the application; this decision is based on a quantified approach)

Auditing

The auditing function is a systematic and independent activity that provides plant personnel with the status of the control systems and the condition of the technical data related to these systems. In other words, and according to ISO 9000, the purpose of an audit is to evaluate the need for improvement or corrective action. It also determines compliance with regulations and corporate standards. The result of the audit is provided in the form of an audit report.

Each company has its own auditing methods and standards, which vary from strict point-by-point procedures to very loose personal judgments. The ISO 9000 International Standard, which is one of the references for this text, has basic auditing guidelines. They are, however, non-disciplinary and do not look at the specific needs of control technology. There are many types of audits; this chapter will deal only with the auditing of industrial process control systems. Other forms of audits, such as environmental, safety, and accounting, are outside its scope and are specialties within their own disciplines.

Control personnel sooner or later may become involved in an audit, either as part of an auditing team or as part of the plant personnel being interviewed by an auditing team. If selected as an auditor, a control engineer needs to be experienced in the technology of industrial control systems and be aware of the regulations and standards. Sometimes the engineer will be familiar with the plant being audited; in other situations, that will not be the case.

Auditing the functionality of the existing control system determines whether the present system meets the needs of the plant. The ISO 9000 International Standard recommends that "design requalification" be performed to ensure that the design is still valid with respect to all specified requirements.

To audit the functionality of control systems, the auditor must understand the needs of the different plant functions: management, engineering, customer requirements, legislation, operations, maintenance, and, in many cases, other support services, such as purchasing, stores, and receiving.

Two points to keep in mind:

1. The auditing of control systems must be an objective activity.

2. In an effort to take some of the burden from the shoulders of future auditors, it should be pointed out that not every detail, important or not, can be audited. Verification of existing technical data can be performed only on a random basis, and considering the amount of data available, it is expected that some important details will be missed. However, every effort should be attempted to minimize this.

The Auditing Function

This chapter will provide the general guidelines for conducting an audit. Obviously, this text cannot cover all the details; the control engineer's knowledge and experience will play a key role in customizing an audit for a particular case, keeping in mind that no two audits are alike.

The audit function has, in addition to being a technical activity, a sometimes difficult aspect known as human emotions. An auditor interfaces extensively with plant personnel, who may sometimes consider this an intrusion, a person who will report to management their inabilities. This human side of the audit should be handled tactfully, yet objectively. For the well-prepared, experienced control engineer, with good interpersonal skills, it is feasible to conduct a control system audit the first time one is selected for this activity.

As a starting point, plant management should inform relevant plant personnel about the upcoming audit, cooperate with the auditor, and provide the required resources.

Scope of Work and Time Required

Audits by nature are disruptive to the workplace; they take the time of key personnel, who quite often wonder about the purpose of the activity. As far as they are concerned, everything is operating OK, considering the working conditions, which won't be changed anyway.

To minimize the disruption, the auditor should perform the audit quickly and efficiently. To assess the scope of work, some careful planning is necessary. In most cases, especially for plants being audited for the first time, lengthy pre-auditing activities are required.

Plants that are audited for the first time or plants that need many improvements will obviously require more auditing time than other plants. A typical medium-sized plant with an average amount of control systems would need, as a rule, about 10 man-days of on-site auditing activities (note that these on-site auditing activities do not include pre-auditing and post-auditing activities). On the other hand, a small plant would take about 5 man-days, and a large plant, about 20 to 30 man-days.

In the case of a medium-sized plant, the total man-days for auditing the plant could more or less be distributed as follows:

A Pre-auditing activities may require about 5 man-days of an auditor's time to prepare an audit protocol and review.

- plant P&IDs,
- job descriptions of control personnel,
- previous audit reports,
- plant layouts,
- operating procedures,
- administrative practices,
- regulatory requirements in effect at the site, and
- plant standards.

B On-site auditing may require about 10 man-days of an auditor's time to conclude.

- initial meeting with management and key personnel, explaining the upcoming audit activities (half a day),
- plant visit and review of existing plant technical data (2 days), interviews (2 days),
- actual auditing and verification of interview findings (3 days or more),
- preparation of preliminary audit report (1.5 days), and
- discussion of preliminary audit report with management (1 day).

Further discussion on some of these activities will be presented later on in this chapter.

C Post-auditing activities may require about 3 man-days of an auditor's time to

- clean up and file all audit data (for future reference) (1.5 days), and
- prepare and send final audit report (1.5 days).

Protocol

The auditing activities are guided by the audit protocol. This document, prepared prior to the start of an audit, helps the auditor plan and conduct the auditing activities and can be defined as the auditor's road map or audit plan. It is generally in the form of a questionnaire that serves as a continuous reminder of what needs to be done in step-by-step form. Without it, the auditor may forget what to ask, waste time, duplicate questions, and eventually end up with little significant data to report. A sample protocol is shown in Appendix H.

Pre-auditing activities, such as reviewing plant data before going to the plant are essential to fine tuning the protocol. The auditor will find that the core of the protocol tends to repeat from audit to audit, but the details must be customized for each audit. Generally, there is about a 50/50 split between core and details.

Auditors

The auditor is expected to be familiar with the regulations and plant standards in effect at the facility. In addition, he or she is expected to be well experienced in the field of process control systems and have the necessary degree of independence from the plant being audited.

Auditors of process control systems normally come from one of three sources

1. From within the plant. This approach is the least recommended because it is quite difficult to self-audit or to audit a colleague's work. The ISO 9000 International Standards recommend that auditors should not have a direct responsibility in the areas being audited.

2. From another plant (or office) belonging to the same organization. This is a much better approach than the first because it satisfies two conditions: some familiarity with the plant and a relatively arms-length approach (i.e., reasonable independence).

3. From an outside firm specializing in the auditing of control systems. This approach allows the auditing function to be carried out with a minimum of interference to plant personnel and at the same time allows an objective, experienced, and fresh approach to the auditing process. In addition, an outsider can in many cases communicate better because plant personnel do not have to worry about personalities and internal politics.

The auditing function, depending on the size of the task and on the available time, could be performed either by a single auditor or by a group of auditors. In the latter case, the group requires a leader to select an auditing team, coordinate the activities, review the progress, avoid duplication of activities, prepare the draft audit report, and so on.

Interviews

A key part of the in-plant auditing process is one-on-one interviews between the auditors and key members of the plant's process control team. These interviews give the auditor a good understanding of the day-to-day performance, as well as a chance to collect information that would have been otherwise hard to identify by just looking at documents.

The results of these interviews will become part of the audit report, with the source of information always confidential and never revealed. The confidentiality of these interviews must be understood and accepted by management, the interviewer, and the interviewee.

Before starting an interview, the auditor needs to be prepared by becoming familiar with the interviewee's functions at the plant and by listing the important points for discussion with the interviewee. It is important to plan enough time for the interview because rushing this activity will present the wrong impression. It is important to schedule time, place, and approximate duration of the interview.

At the interview, the auditor needs to establish a good rapport with the interviewee by arriving on time; introducing himself or herself; being friendly and courteous (it is not always easy to open up to an auditor who is a stranger); explaining the purpose of the interview and the benefit of the audit to all personnel; and informing the interviewee that the source of all audit information will remain confidential.

As the interview starts, the auditor should

- keep note taking to a minimum,
- distinguish between facts and personal opinions,
- look for specific examples,
- always be clear when asking questions (avoid the use of fancy technical terms or buzz words),
- ask one question at a time, and
- allow the interviewee enough time to answer the question and listen carefully.

A good interviewer will look at the other person, be genuinely interested in what is being said, and ask questions, keeping "why" last (start with who, what, where, when). The interviewer should not rush or cut the interviewee off and should keep on the subject until it has been completely covered.

The main purpose of the interview is to gather information; therefore, the auditor should, with the help of the audit protocol, be able to ask the necessary questions and understand the answers received. This is the reason the auditor must be an expert in the field of process control systems in addition to being a skilled interviewer.

Interviews can become difficult if shyness, nervousness, talkativeness, aggressiveness, lack of trust, and defensive attitudes are allowed. The auditor must avoid them.

As the interview draws to an end, the auditor should hold to the schedule, ask the interviewee if he or she has any questions, thank him or her for the time, and try to end on a positive note.

After the interview, the auditor should immediately summarize the discussion and write down the results. In some cases, the auditor may need to contact the interviewee once more for further clarification or for additional information.

Searching and Checking of Drawings and Documents

By now, the auditor has completed the interviews and has learned quite a bit about the plant—its problems, the way things are done, and what people like and dislike about the plant operation. The next step is a search-and-check mission.

The auditor starts by looking at documents and drawings to determine whether they are kept updated, and then tracks a number of items on the P&IDs to the instrument list, the loop diagrams, and the actual plant installation. Is it all there? Is it correct? This random check of detailed data should encompass other items, such as the control part of the operating instructions, computer systems, software documentation, and so on.

Such a search must be systematic, and shortcuts are not recommended. The auditor may be astonished at what can be discovered by taking the long route. It is generally quite informative, and it may lead to points never thought of or mentioned previously (intentionally or unintentionally).

The notes collected should be assembled and summarized at the end of each audit day. The audit process is not an 8 to 5 job. Long night hours are spent reviewing, finalizing, summarizing, and monitoring the progress. In the case of an audit team, the next day's activities must be coordinated and reviewed with the group, typically at dinner time.

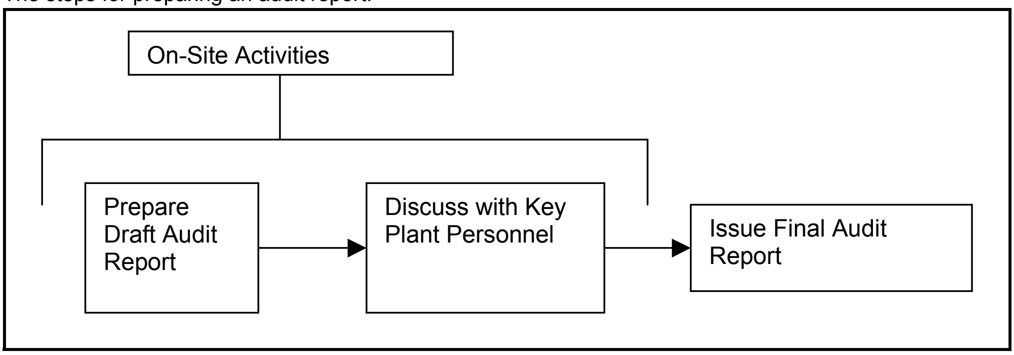
Report

The audit report provides the significant findings of the audit to help the plant achieve compliance with regulations and plant requirements. However, the auditor should not forget the confidentiality factor. The report should include all of the good practices in use at the plant, all the exceptions, and all the strengths and weaknesses.

An additional item, recommendations, can be added in the report. Whether to include recommendations or not has been the subject of numerous debates. Some auditors claim that it is not their function to recommend solutions but only to pinpoint problems. This approach results from the question of the auditor's liability and the reasoning that plant personnel are more knowledgeable when it comes to solving problems in their own plant. On the other hand, some auditors take the approach that the auditor, with his or her vast experience, needs to suggest solutions, particularly if the auditor belongs to the same organization. In any case, the addition of recommendations to the report should be decided between plant management and the auditor when the scope of the audit is being defined. Generally, plant management asks for the addition of recommendations from the auditor.

The audit report (see figure 19-2) goes through two stages. The first stage is the draft audit report, which is usually prepared on-site at the end of the auditing process. Its content must be discussed with the key plant personnel and, in most cases, the plant manager as well. The second stage is the final report, which is prepared within a month or so after the draft report. The final report, as a rule, does not include any new findings beyond the draft report. The final report is usually addressed to the plant manager, with copies to key plant personnel. It is recommended that this distribution list be agreed upon at the beginning of the audit.

Figure 19-2
The steps for preparing an audit report.



In some cases, when recommendations are part of the report, a follow-up activity (perhaps 3 to 6 months later) may be needed to check the implementation of the recommendations.

A typical audit report consists of two main sections: an introduction and the findings (and recommendations if required).

The Introduction covers some basic elements, such as

- the purpose and scope of the audit,
- the purpose of the audit report,
- a list of the audit team and their affiliations, and
- a description of the facility being audited.

The Findings (and recommendations) cover

- a summary of the plant's actions following the previous audit,
- a list of good practices at the plant, and
- a list of non-conformances (followed by recommendations).

The audit report must be factual and avoid opinions and speculations. The report should avoid extreme language (e.g., incompetent and terrible), use familiar terminology (i.e., minimize buzz words), and avoid drawing legal opinions or judgments.

A typical audit report has been produced as an example and is shown in Appendix I.

History, Frequency, and Record of Audits

The frequency of control system audits varies, depending on many factors, but in general, it is between three to five years. The concept of control system auditing is relatively new; therefore, the history of such audits is in most cases limited at best to one or two.

The audit program, if it exists at a plant, is typically a scheduled activity that indicates the frequency and scope of control system auditing. Generally, it covers the auditing of many engineering disciplines, such as safety, mechanical, and civil, with the control systems being a part of the total picture. Without such a program, the need for audits tends to be forgotten or postponed until a costly hazardous event occurs, at which time somebody in management asks, "When was the last time we had an audit? Who is responsible for audits? Why were no audits performed?"

The frequency of audits is a matter generally determined by plant management and depends on such factors as the importance of the control system in question, the results of previous audits, the overall condition of the plant engineering and maintenance functions, and regulatory requirements. Once the frequency of auditing is defined, the auditor needs to verify the time span between the last audit and the present one to confirm compliance (or non-compliance).

The records of the last audit and the verification that the recommendations were carried out should form part of any audit. In most audit interviews, the last audit report is reviewed and discussed, because it gives the auditor a good view of the strong and weak points at the plant and provides a reasonable starting point for further discussions. In most cases, the two key documents that will break the ice at interview time are the job descriptions and the last audit report.

Auditing of Management

The first step in auditing the control system support functions is to audit the management side of control systems. In most cases, the auditor will find this step to be one of the easiest and fastest to accomplish.

The auditor will typically cover in this activity

1. The plant organization, which includes

    - the structure of the organization,
    - the definitions of authority and responsibility, and
    - the job descriptions.

    With this information, the auditor will first learn about the official lines of communication and responsibility and then about the different members of the control team at the plant—their roles and their relationships to plant management.

2. The history and record of previous audits

3. The management of drawings and documents

4. Personnel training

Auditing of Engineering Records

The auditor will now begin the audit of the plant technical information, also known as the engineering records. This is where his or her experience as a process control engineer comes into play. The auditor will discover a great deal of available data. But is it complete and correct? He or she may find that the records have not been updated to reflect plant changes. The auditor's function is to find that out.

Engineering records contain essential technical data and are regularly used by plant personnel; therefore, they require auditing. The engineering records that can be audited are described in chapter 14 of this book. Additional documents may be encountered, and it is up to the auditor to decide if they should be audited.

To conform to the ISO 9000 International Standard, the plant being audited must have in place a system for identification, collection, indexing, filing, storage, maintenance, retrieval, and disposition of pertinent engineering records.

Two points to consider:

> First, the auditor must realize that it is impossible to sift through all the data. The audit will be a random check that relies heavily on the auditor's experience and gut feelings about where to search.
>
> Second, the auditor must be ready for surprises. Data that should be accessible and up to date is often missing or unusable.

Auditing of Maintenance

The last part of auditing activities for control system support functions is not as straightforward as auditing management and engineering records because it comprises a large portion of human interrelations. But the auditor should not be discouraged; it can be accomplished successfully through a combination of technical know-how, persistence, patience, tact, and experience.

The auditor must verify that not only is the maintenance done correctly but also that any alterations comply with the electrical code in effect at the site. The auditor should keep in mind that modifications to approved equipment may void the approval of such equipment.

As the audit is conducted, considering the vastness of maintenance auditing, the auditor should periodically pick one item of his or her choice, concentrate on it, and follow it through. For example, when equipment is withdrawn from service, what do they do with the exposed wires? Are they correctly terminated in an appropriate enclosure? Are they insulated? Are they left hanging loose? The auditor may find it useful to check on-site some of the data acquired during the interviews (e.g., take the loop drawings and check some minor items, such as does the cable number on the drawing match the one on the actual cable). Another item that must be checked is how closely the vendor's instructions are followed when maintenance is performed.

A primary activity in maintenance is the calibration of equipment (see chapter 17). Quite often, this is performed in a calibration shop, where most of the calibrating equipment is located. The auditor must evaluate the quality of the calibration shop, including the quality of the instruments used for calibration, their accuracy (obviously it must be better than the instruments being calibrated), and the calibration records for all the instruments. Verify that control equipment is calibrated prior to first use to confirm all settings (an ISO 9000 recommendation).

Where repair has been done on personnel safety-related equipment, the auditor should check to see if the plant policy is to have a second person inspect the work. If this is not the case, he or she must verify how safety and quality of the work are ensured. After all, anyone can make a mistake, but no one can afford deadly ones.

The auditor should observe carefully to note any conflicts that may exist between maintenance and their three main links—engineering, purchasing, and production. For example, Is purchasing responsive to maintenance needs? Is production satisfied with maintenance? Do they release equipment for preventive maintenance?

During the auditing of the activities related to maintenance and testing in hazardous locations, the auditor will not be able, in most cases, to witness those activities. The information that must be collected will be based on interviews and on visually checking the equipment used in testing.

As the auditor conducts the audit interviews, he or she should ascertain the procedures used in maintaining equipment in hazardous environments. It is a good idea to pick one item of his or her choice and discuss it in detail. For example, how is the opening of an explosion-proof box performed? How is the absence of power ensured? Do they wait for stored electrical energy to dissipate before opening? Do they allow the equipment's surface temperature to come down first? What is done if maintenance is required but power cannot be cut off?

Refer to chapter 16 for further information on the topic of Maintenance.

Auditing of Process Control Systems

Part of the auditor's function is to look at the existing control system—how it's installed, operated, and maintained and how new devices are implemented. This is done to ensure compliance with good engineering practice, corporate requirements, and local bylaws in effect at the plant. Many chapters in this book provide a good source of information to the different items to be checked by the auditor.

Evaluation of Plant Needs

The purpose of evaluating plant needs is similar to an audit (i.e., to ensure optimum plant operation and to maintain a path of continuous improvement).

This evaluation goes typically through three steps. They are

- to conduct a brainstorming session to bring out the ideas and plant needs,
- to evaluate the ideas developed in the brainstorming session and decide which are acceptable and which are not, and
- to issue a report confirming those needs and the cost to the plant.

The Brainstorming Session

The purpose of this session is to have a team of key personnel bring out the ideas, the problems, and the needs of the plant without hindrance or preconceived notions. The session team should have a coordinator.

In most cases, the team consists of representatives from different plant groups, such as management, engineering, production, marketing, maintenance, and operations. In general, a total of five to seven attendees is a good size. If the number reaches 10, communication problems start developing and a few attendees tend to take over the session while the rest of the group remain silent. Less than four may mean that some plant groups are not represented and their views are not being heard. The team at all times is guided by the coordinator, who, once the evaluation is completed, will probably be performing the justification analysis as well. The team as a whole should have an excellent understanding of the overall facility and its business needs.

It is recommended that the team include the manager (or his or her representative), who will eventually approve the funding. The manager's commitment is essential. Without it, the entire process could eventually fail due to lack of support and understanding.

In general, the coordinator may come from one of three sources:

1. From within the plant. This approach is the least recommended because it is difficult for such an individual to maintain impartiality.

2. From another plant (or office) belonging to the same organization. This is a better approach because it satisfies the impartiality requirement and if the team already knows the coordinator, the personal introductory part can be skipped.
3. From an outside firm specializing in control system evaluation. This approach allows the coordinator function to be performed with a minimum of interference to plant personnel and at the same time ensures impartiality and experienced performance. In addition, in many cases, an outsider can keep the brainstorming session under better control without having to worry about internal politics and egos.

The coordinator needs to be self-disciplined and must keep the brainstorming under control at all times. Yet, he or she must be tactful, keep the enthusiasm going, keep everybody involved, keep the session on track, and prevent any single individual or small group from taking over the meeting.

The coordinator has a key role in the success of the brainstorming session and must have the confidence of the team. He or she should get to know each of the team members, preferably on a one-to-one basis, and should listen to their individual needs before the meeting starts. In addition, the coordinator should never take sides and must remain impartial at all times.

The coordinator must always remember that he or she is only a facilitator and that the responsibility for the ideas and the needs rests with the team involved in the session. The responsibility of the coordinator is to help the plant solve its problems. The coordinator may table ideas and plant seeds for discussion, but the team has the final say.

The brainstorming session begins with the coordinator's explanation of the purpose and benefits of the meeting. From the meeting, a list of needs will emerge, and they will form the basis for system selection and justification.

Once the overview of the different steps is explained to and understood by the team, the coordinator must clearly define the concept and rules for the upcoming brainstorming session. The rules are generally

1. During a brainstorming session, criticism and the evaluation of ideas are not allowed and all ideas are recorded.
2. Following the brainstorming session, all ideas are looked at individually, and evaluated. During the evaluation, each idea will be given GO or NO-GO status (some may require further investigation; however, they should be kept to a minimum).

In some cases, depending on the experience and knowledge of the team involved, the brainstorming session can be broken into two parts: a preliminary segment to start everyone thinking, and a second segment in which the attendees come prepared with ideas and financial values for their problems (e.g., solving the emission problem we now have will save us $x).

As a starting point and to get the juices flowing, the coordinator may table some of the concerns, problems, and needs he or she heard about from previous discussions with key personnel. The coordinator must use a flip chart so that everybody can see the ideas that are being tabled. The group must learn, through the efforts of the coordinator, to quickly operate as a team.

In the brainstorming session, the team should avoid finding a solution (e.g., we need to buy equipment ABC); this will come later. The team should identify the problems and the cost of the problems at present. The coordinator must always watch for this finding-solution trap; it is a temptation that must be resisted.

If talks about the high cost of implementing this or that idea come up, the coordinator should restate the purpose of the meeting and remind the team “Ideas and needs only, please.” The justification is the next stage.

A few hints for the coordinator:

- avoid Monday a.m. and Friday p.m. meetings,
- do not impose views— resist the temptation,
- keep the meeting rolling; keep the ideas flowing; watch for and steer away from inter-departmental finger-pointing and blaming,
- avoid team fatigue; take breaks when needed; do not extend the session beyond its limit (when it's finished, it's finished),
- avoid the following in the brainstorming session (the coordinator can actually write these rules on the first flip chart paper and then pin it on the wall):

  1 Do not ignore ideas.
  2 Do not criticize ideas.
  3 Do not change an idea into a totally different one.
  4 Do not evaluate ideas.

At the end of the brainstorming session, the coordinator will thank the team for their efforts. By now, the walls of the meeting room are probably covered with sheets from the flip chart, with all the ideas listed as they were being generated by the team and recorded by the coordinator.

The Evaluation of Ideas

Now is the time to evaluate the ideas and decide as a team which of the ideas should be considered GO and which are NO-GO. The coordinator must remain diplomatic and tactful. He or she should give no personal ideas and opinions. The coordinator can ask clarifying questions that help the team look at ideas from a different perspective.

The evaluation of ideas starts with the team reviewing each one and rejecting the ones that are not feasible for technical or financial reasons. Those are the NO-GOs. The marking of GO or NO-GO is done right on the charts (by now all over the walls).

If action needs to be taken after the meeting, the coordinator must follow up and make sure that target dates are met (otherwise they may die of neglect). Such actions could be, for example, to obtain the present values for a malfunction (and confirm the values obtained from the brainstorming session), or to obtain the total of environmental fines the plant has received. Such actions, in most cases, must be completed before the issuance of the report, hence the need for immediate action.

It is a good idea to have the allocation of dollars done by all the members of the team at the meeting. This is really a continuation of the evaluation of ideas. The allocated values must be factual; guessing should be kept to a minimum (and preferably should be avoided). In some cases, the coordinator may need to list the source next to each value. This action by the coordinator depends on the seniority of the team and the reliability of the data being presented.

Issuance of the Report

Once the evaluation of ideas is completed, a report should be issued to confirm the work done so far and list the findings of the team.

The report goes through three stages (see figure 19-3). The first is the preliminary report, which is circulated to the members of the team for their comments. In most cases, comments received tend to clarify the needs that have been listed in the brainstorming session. The last stage is the final report, which should be prepared within a month of the preliminary report. The final report is distributed to the members of the team and to the plant manager. It is recommended that the distribution list be agreed upon at the beginning of this exercise.

Figure 19-3
Issuing the report.

A typical report consists of two main sections: (1) the purpose and scope of the evaluation, and (2) the findings. The first part describes the reasons for the evaluation and the different parts of the plant that were reviewed. This first part should include a note of recognition from the coordinator to the team for their efforts. The second part describes the findings of the team and the value of these findings. There are different opinions regarding the inclusion of the NO-GO points, but in some cases, these are needed to avoid discussing them in the future. Some companies require only the GO results to act on. The choice depends on the requirements of the plant as described to the coordinator at the start of these activities. An example of a report is shown as figure 19-4 with only the GOs present.

With the completion of the report, the person responsible now has a list of key features that will be required of the potential new control system. In figure 19-4, they are the effluent problem, the data collection needs, and the limited capabilities of the existing control system.

Justification

Justification and payback problems arise because of the difficulties in measuring and quantifying the real economic benefits—and, therefore, in calculating payback. Management wonders: Is it worth it? What is the payback on the investment? Is the risk worth taking? They know that without risk nothing is achieved and that a calculated risk is better than a leap of faith.

Many managers are willing to lead their organizations into market and technology leadership but are reluctant to pay the required price. They need justification. A leap of faith could be suicidal, and, therefore, it is easy to understand their hesitation. A systematic, methodical technique of justification is needed.

Without sound justification, real progress is difficult to measure. Accountants are poor engineers (what cannot be justified has a value of 0), and engineers are poor accountants (they find it almost impossible to generate those badly needed numbers for justification). Justification attempts to bring management, accountants, and engineers' points of view closer to each other.

Quiet often, when it comes to control systems, decision makers are split into two groups: believers and non-believers (see figure 19-5). On the believers' side, justifying is generally not needed. Modern control systems are a way of existence (the only way). Some are convinced of unrealistic savings that generally cannot be achieved, which adds fuel to the fire of the non-believers. See chapter 9 for more information on computer-based control systems.

Figure 19-4
Simplified sample report.

EVALUATION of PLANT NEEDS
ABC Inc.

Meeting held on: September 10, 2006, in the plant's main conference room.
Attendees: J. Smith, J. Doe, S. Green, P. White, and A. Black

1) Purpose and Scope of Evaluation
The purpose of this evaluation was to identify the needs of the plant and the areas of improvement and to evaluate the present cost of these weaknesses. The evaluation was conducted by N. Battikha, an independent process control system evaluator. The following plant areas were reviewed: A4, A13, and A27. The values shown in this report are annual costs based on last year's data.

The coordinator wishes to acknowledge the efforts of the attendees at this meeting; their contributions were key to its results.

2) Findings
1. Present effluent problems of the plant (see attached memo 3257.2 by J. Doe)
1.1 Yearly fines (these values will probably increase over the next year due to new upcoming legislation) $30K
1.2 A bad public image in the nearby community (it is estimated that at a minimum this represents an annual loss in sales and increased PR expenses)...............$10K
Total = $40K

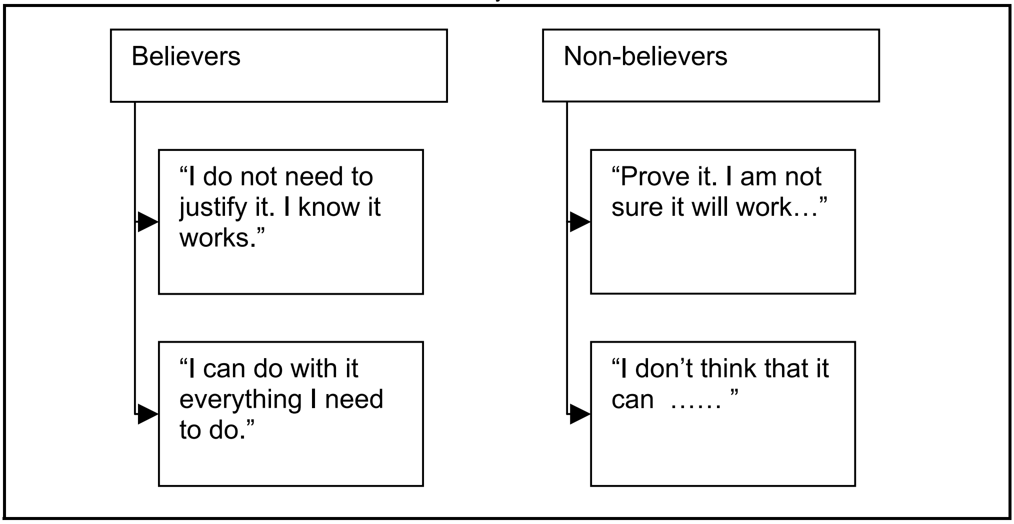
2. Present data logging and data collection functions
2.1 Two man-months per year are spent manually collecting data from different monitoring devices. The data must then be massaged to obtain useful info (e.g., plant efficiency, material balance, energy balance, etc.).................................$10K
2.2 Errors in copying (from searching through old data from online recorders and reconstituting the data as it should have been recorded), conservatively evaluated at one man-month per year.........................$5K
Total = $15K

3. The present control system is limited in capabilities. When problems occur, the operator takes control of the process, but this is after the fact.
3.1 Problems of this nature result in scrap material and disposal costs. (We expect this cost to increase next year, when our neighbor Scrap, Inc., shuts down, which means finding new outlets for our scrap; there are none in this region of the country.)...............$50K
3.2 We are now using the lab to try to ascertain potential problems in advance (i.e., increase in lab workload)..$30K
3.3 These problems tend to be frustrating to the operators. (They spend a lot of time talking about it, with no results because the present control system is really pushed to its limits.)..........................$20K
Total = $100K

Prepared by: N.E. Battikha
Sep. 23, 2006

On the non-believers' side, engineering judgments are only guesses. Non-believers usually have little experience with modern control systems (or perhaps they've had a bad experience) and need proof. They know that many vendors avoid guarantees of performance (obviously a difficult task, if not impossible, because vendors don't really know the conditions of the plant). What the non-believers' side needs is a justification in black and white and a bottom line that shows if the investment is worth it. The purpose of this chapter is to change the concepts of belief and faith into facts and justification, thus bringing the two sides together with the help of the logical and factual decision-making process.

Figure 19-5
The believers and non-believers of modern control systems.



Hurdles in the Justification Process

When the need for a justification emerges and is recognized, there will be, in many cases, hurdles to be surmounted. Some of them can be handled easily, but others will be difficult but not impossible to overcome (with much tact and dedication).

Such problems can be roughly divided into two classifications

1. Management hurdles, such as no commitment, unwillingness to make decisions, no (or an unclear) strategy in existence, or bad communication between departments

2. Personnel hurdles, such as no champion, a shortage of expertise (and lack of knowledge), poorly understood problems and benefits, and strong resistance to change

There are no quick solutions to these problems. However, an essential starting point is commitment from management. Without it, the whole justification process could be a waste of time. Another aid in overcoming these hurdles is keeping a vision of the future and the benefits of modern control systems in mind, and involving as many individuals as possible. In other words, it should become a common cause and a common vision.

Cost Justification

There are two steps in the cost justification process.

1. Totalize all the costs. Costs are not limited to the cost of the control system only. They include engineering, installation, training, and so on. A breakdown is shown below to provide a starting point. Each case will obviously have to be looked at individually to develop its own list of items.

2. Justify the costs. Following totalization of costs, calculations using either the payback method or the return-on-investment (ROI) method will be used. These two methods are the most current and the easiest to understand. Some plants may have different methods of calculating justification, but all require the value of the benefits and the total cost.

Costs - The Bottom Line

The overall cost includes two parts: (1) the initial cost of equipment, engineering, installation, and operation, and (2) maintenance costs (see figure 19-6). The initial cost is a one-shot expense, but the second is an ongoing expense. The amount of the maintenance cost can vary from year to year, depending on additional plant needs, changes in maintenance manpower, system and component age, and reliability of the control system equipment.

Figure 19-6
Overall costs for modern control systems.

1. INITIAL COSTS (a one-time expense)
   - control system (hardware and software), control room,
   - engineering,
   - installation,
   - training, and
   - miscellaneous (travel costs, start-up).
2. MAINTENANCE COSTS (ongoing)
   - repairs
   - system upgrades,
   - training, and
   - personnel.

1) Initial Costs

The first major cost is the control system itself, which could be considered a lot price (e.g., a DCS) or the total of the prices of different components (e.g., PLCs, PCs, PLC programming software, PC application software, and communication highways). For the purpose of this chapter, the control system will be broken down into two parts: hardware and software.

The hardware cost includes the CPU, memory, disk drives, input/output (I/O) modules, power supplies, I/O racks, communication modules, CRTs, printers, desks, consoles, and uninterrupted power supplies —if required.

The software cost includes operating system software, programming and documentation software, operator interface software, software for communications between the different devices, troubleshooting and diagnostic software (if not built into the control system), and any custom software to meet specific plant requirements.

In the case of software costs, estimating the time required to develop custom software, if it is required, is a tricky exercise. Extreme care is required in estimating, even for the development of PLC programs and operator interface applications, which are relatively easy. Beyond such simple applications, software development time tends to be longer than expected, first in development and then in debugging. The author uses the "custom software factor of 2". This means "take the final estimate received, multiply it by 2, and you have an idea of how much time it will really take."

Another not-always-necessary cost item is control rooms (depending on the facility). For further details on this item, refer to chapter 11.

Engineering costs vary depending on the scope of the work and the type of control system. This cost, which is a major portion of the total cost, includes project engineering, engineering contractors, programming, system checks, preparation of manuals, and commissioning and start-up assistance. The cost of checking the system before installation, and preferably at the vendor's facility, is of prime importance and includes simulating all I/Os. No one wants to discover defective I/Os or incorrect programming at commissioning time.

Installation is a major cost that generally involves the plant, vendor(s), engineering contractor (if one is used on the project), and the installing contractor. Installation costs (see chapter 15) cover moving the control equipment to the plant and into the control room, the wiring of all I/Os, power supply, and grounding, and the testing of the complete installation to ensure its working condition.

Training cost must be allowed for. This cost will not be repeated when similar systems are added in the future, but it is an initial cost. Initial training is generally supplied by the vendor (note that sometimes training costs are included in the cost of the system by the vendor). In many cases, training also includes some basic troubleshooting skills.

If the control system must be installed on an operating process line, with the minimum downtime, additional costs should be allowed for this "hot cutover." First, additional care must be taken in pre-testing; then items such as additional manpower and standby test equipment must be allocated. Even the best of hot cutovers have some form of lost time during the transition.

Travel costs for training, consultants, checkouts at the vendor facility, and so on will vary depending on locations and the complexity of the control system. These must be included. The better the quality of work done upfront, the lower the start-up costs will be and the lower the final cost will be.

2) Maintenance Costs

Control systems, like any other piece of equipment, will fail sooner or later, regardless of how reliable the equipment is—hence, the need for maintenance and its related costs (see chapter 16). Items purchased as components to create a control system come with their own individual warranties. If the control system was purchased as a complete system from one vendor, maintenance is generally more straightforward and easier for the user to understand. In addition, the supplier of a control system should have the resources to service the whole system at the plant if the need arises.

Once the warranty period is over (three months to one year, depending on the equipment), maintenance agreements are available from system vendors (or third-party service companies). A decision to purchase maintenance or have an in-house maintenance person(s) depends on the size and complexity of the system, as well as on the capabilities of plant personnel.

Updates should also be included in costs. Once the operators become familiar and comfortable with the control system, they start asking for more functionality. Management and plant engineering may start asking for system improvements. In many cases, all of these activities fall under maintenance, and they all cost money.

As maintenance and engineering personnel change, and as the control system gets updated, additional training may be required. Generally, this cost is minor compared with the other maintenance costs.

Maintenance personnel, including supervisors, and overhead must also be included in maintenance costs. In most cases, the cost of maintenance personnel for control systems is less than for conventional systems because of the reliability of the equipment and its self-diagnostic features.

Cost Justification

Two sources of information are needed to complete the cost-justification process:

- the calculated benefits from the evaluation of plant needs, and
- the calculated total costs.

Since payback and ROI are used by most firms and they are relatively easy to understand, they are used in this chapter. In either method, the time value of money has been ignored to simplify the calculations.

For example, say the calculated benefits of an alternative solution gave a value of $97K per year (see table 19-1). This alternative is a new control system, with an initial cost of $180K, which includes hardware, software, engineering, and so on, as listed in the previous section. The average annual operating and maintenance cost of $5K includes the maintenance contract, updates to the system, training, etc., as listed in the previous section.

At the first stages of implementation, when the system is acquired and installed, the cost of $180K has not yet reaped any benefits, and therefore, there is a negative cash flow of $180K. In the following year (year 1), the annual benefits of $97K required an annual maintenance cost of $5K, giving an annual cash flow of $92K. The annual net cash flow is the difference between the annual benefit and the annual cost. In this example, we'll assume that the annual benefits of $97K will repeat every following year.

The resulting average annual estimated benefits, costs, and resulting cash flows are shown in figure 19-7.

Figure 19-7
Benefits, costs, and cash flow.

Year	Benefits ($)	Cost ($)	Net Cash Flow ($)
0	0	180K	(180K)
1	97K	5K	92K
2	97K	5K	92K
3	97K	5K	92K
-	-	-	-
-	-	-	-
-	-	-	-
10	97K	5K	92K

Calculation Using the Payback Method

The payback method works as follows: The annual net cash flow is added year after year until the value of the original investment is reached; the number of years required to achieve this balance is known as the payback time. The lower the number, the faster the payback on the investment. Obviously, the higher the benefits and the lower the cost, the shorter the payback period will be.

We use the ongoing example and add the net cash flow until we reach $180K (i.e., 180K / 92K = 1.95). So the payback time equals around two years. In other words, it takes about two years to recoup the original investment.

Calculation Using the ROI Method

The ROI method works as follows: an estimated usable life is set (in the example, it will be set at 10 years). From the original cost, an annual depreciation is calculated (by dividing the original cost by the number of years—the usable life. The average annual benefit of the investment is calculated by adding the net cash flows of the 10 years and averaging them. And the ROI is calculated by dividing the average net cash flow by the original cost.

Using the ongoing example, and based on 10 years of usable life, the annual depreciation = 180K/10 = 18K.

The average annual benefit of the investment = 92K
Using depreciation, the ROI = (92K - 18K) / 180K = 41%.
If this calculation is performed without depreciation, the ROI = 92K / 180K = 51%

Calculation Results

Obviously, as the annual benefit increases, the payback will take less time and the ROI increases. With this information in hand, plant personnel now know

- the benefits to be obtained from the potential control system,
- the required features of the potential system,
- the total implementation cost; and
- the return on investment.

The original question, "Is it worth it?," can now be answered.

Justification Follow-up

Now that the justification is complete, the system has been purchased and installed, and it is operating, the question arises: "Does the installed system actually provide the benefits that were listed (and valued) in the justification?"

A justification follow-up is often required, particularly in cases where a system upgrade is done on a small scale (i.e., one section at a time) and management needs to know if they should proceed with the upgrade of the whole plant. This is a feedback activity to the investment and is not easy. The main difficulty lies in the assembly of data (i.e., the collection of information from before and after implementation).

The collection of information is guided mainly by the list of benefits in the justification analysis. It is quite common to discover benefits that were not on the original list and drawbacks that were never thought of.

On control systems that are replacing old ones, justification follow-up requires two sources of information: first, information to be collected before the implementation (generally taken from the justification analysis); and second, information to be collected after the implementation (confirming or changing the estimated benefits listed in the justification analysis).

In most cases, there will be a difference between the values reached before implementation and those obtained after implementation as a result of the follow-up because the forecasted benefits cannot predict exactly the final benefits. If the original evaluation of plant needs was on the conservative side, the final benefits generally tend to be on the positive side. However, the closer the evaluation and estimated costs are to reality, the smaller the gap between the two values.

With control systems that are being incorporated in a new plant, the benefits attained need to be compared with the original requirements generally outlined in a control philosophy document and justification analysis.

The justification follow-up not only examines the items listed in the justification analysis and the control philosophy document, but it must also investigate operator and maintenance training, quality of support documentation, handling/security of software, and so forth. In other words, the follow-up becomes a control system audit, focusing only on the system in question. Control system auditing was covered in detail in the first part of this chapter.

System Evaluation

The exercise of systematically assessing different alternatives (or choices) is known as decision making. In the field of process instrumentation and controls, this is commonly used when evaluating different potential control systems and comparing them to a plant requirement or to an existing system. It should be noted at this point that this tool can also be used for any decision making process requiring a quantified and systematic approach (e.g., buying a car when faced with so many available models).

The approach used in this book is a quantified method that gives the decision maker a tool for selecting the best option. This approach also acts as a record as to why a decision was taken and why a certain result was obtained.

Quantified decision making consists of a table where the requirements are shown in rows and the available options in groups of columns. The following simple step-by-step example describes how this method of decision analysis works (see Table 19-1).

First, the requirements of the plants are classified into two types (i.e., two sets of rows):

A The Primary Requirements (i.e., the essential requirements of the plant). These generally include safety, environmental concerns, codes and regulations, and disaster prevention needs. They are typically identified in the plant control philosophy and are essential for any system in the plant. A control system that does not provide for these requirements should be immediately rejected. In the case of Primary Requirements, if the control system meets the plant needs, it rates a GO; otherwise, it's a NO-GO and the system is rejected.

B The Secondary Requirements (i.e., the wish list requirements). These have a value to the plant. They cover most of the production requirements and include quality, information reporting, process protection, etc. They define which control system alternatives (that have successfully passed the Primary Requirements) will be evaluated based on their relative benefits. A control system that does not provide these features 100% is not rejected; instead, its features are weighed. All Secondary Requirements are given a relative weight of 0 to 100%. The 0 to 100% weight reflects the relative compliance of the alternatives with respect to the plant needs. A 0% means a full non-compliance; a 100% indicates that the alternative offered meets plant needs fully.

In the simple cases where a bidder has specifically complied or has not, the decision is easy to make. However, in most cases, the offered computer-based control system may be close but not 100% compliant. For example, one system (as offered by a vendor at a very attractive price) may have the ability to display only 100 points per graphic page, whereas the plant requirements specified 140 points per page. Now it must be determined how close the offered system is to the original requirements and what its value is to the plant. In other words, if, as a result of the evaluation of the plant needs, the above example of 140 points has a value of

$10K and the control system offered only has 100 points, the plant may decide that this non-compliance reduces the value of this benefit by 50%, making the $10K benefit a $5K benefit.

For the purpose of this example, the Secondary Requirements to be used are the benefits identified earlier in this chapter (see figure 19-4). In real-life situations, the list of benefits is generally much longer than the one generated for the purpose of this example.

At this stage of the evaluation process, the decision analysis can also be used to compare the functionality of different types of control systems. For example, if a DCS vendor and a PLC/PC vendor are bidding on the job, the decision analysis that follows can help direct the decision to be taken based on the benefits achieved from each system.

The table (see table 19-1) is then divided vertically into a series of columns that are grouped into:

1. Plant Needs. This is what the plant requires based on the previous audits and the evaluation of plant needs (see figure 19-4), as reflected in the system specification that was sent to the vendors for bidding.

2. A number of groups of columns representing the existing control system, followed by all the available alternatives (i.e., the available choices from all the bids and systems offered by vendors). In this example, two alternatives are shown, but often, three and even four alternatives would be shown.

The data available in this table will allow a comparison between the Plant Requirements and each of the existing analog system and the two control system alternatives (1 and 2).

The first step is to complete the left-hand column for the Primary Requirements. In our example, the three Primary Requirements shown were part of the functional specification to the bidders and are essential to the plant. The existing system and the three alternatives are entered, and the GO/NO-GO column is completed to immediately rule out noncompliant systems. In our example, all alternatives are compliant. If, however, one of the alternatives is not compliant, it would be rejected from the evaluation.

Following this, the first column of the Secondary Requirements is completed. This is done by entering the information and annual values [V] that were obtained from the evaluation of plant needs (see figure 19-4). It is obvious that the Decision Analysis Table cannot include all the requirements from the functional specification that was submitted to the vendors. It should include only the key items with which the alternatives are not in complete compliance. In some cases, instead of one value [V], two or three may emerge, as when the team during the plant needs evaluation cannot agree on a number. Therefore, two numbers may emerge as high and low, or sometimes three numbers may emerge: a minimum (pessimistic), a mid-point (most likely), and a maximum (optimistic). In such cases, two- or three-value analyses could be done, one for each set of values, or the averages of two (or three) could be combined into one average value.

The information section in each of the second, third, and fourth columns is a reference and a reminder. It records key points and summarizes discussions and facts.

Following the Information column, weights (0 to 100%) are applied to the individual Secondary Requirements of the existing system and each alternative (W0, W1, and W2). This shows the relative closeness or compliance of the individual Secondary Requirements to the plant needs.

Multiplying the value [V] by each weight (for each alternative) results in a weighted $ value (A0, A1, and A2), the purpose of which is to provide a comparative evaluation between the alternatives with respect to the plant requirements and needs.

For example, on the first Secondary Requirement, the existing system has a real value to the plant of only

$40K x 0 = $0K.

Alternative 1, because it complies with 80% of the requirements, has a value of

$40K x 0.8 = $32K.

Each alternative is now totalled

A0 = $40K,
A1 = $72K,
A2 = $137K.

This represents the “real” value of a particular control system to the plant.

Finally the annual benefit of each of the alternatives in relation to the existing system must be evaluated. This is done by subtracting the weighted value of the existing system from the weighted value of each alternative:

A1 – A0 = $32K, and
A2 – A0 = $97K.

The result of the decision analysis shows that Alternative 2 has the highest annual benefit, which makes it the logical choice.

Table 19-1
Decision analysis.

Plant Needs		Existing System (Old analog)			Alternative 1				Alternative 2			
Primary Requirements		**Information**		**Go/NoGo**	**Information**			**Go/NoGo**	**Information**			**Go/NoGo**
1) Sequential and analog controls are required		Yes		GO	Available, refer to vendor manual and bid			GO	Available, refer to vendor manual and bid			GO
2) Vendor support is available: a. Engineering support available 24/7 through a phone line b. Maintenance is available through distributor (max. ½ day drive from plant)		YES a. in town b. in town		GO	Yes, a- and b- available—see bid and supporting brochures			GO	Yes, a- and b- available – see bid and supporting brochures			GO
3) UL approval is required on all components		Yes		GO	Yes			GO	Yes			GO
Secondary Requirements	**V**	**Information**	**W0**	**A0**	**Information**	**W1**	**A1**	**A1 - A0**	**Information**	**W2**	**A2**	**A2 - A0**
1) Reduce Effluent Reductions: a. Average yearly fines= $30K b. Bad PR image (requiring special advertisement) = $10K	$40K	Existing system cannot predict effluent release in the environment (see report # xxxx).	0%	$0	A similar system was installed by ACME Inc. (see trip report #xxxx). We expect to reach 80% compliance with this new system.	80%	0.8 x 40k = $32K	$32K	Vendor guarantees the performance of their system and will meet our environmental requirements (see bid – item 12.9).	100%	$40K	$40K
2) Implement Automatic Data Logging: a. Two man-months are now spent for data collection & calculations = $10K b. Manual operation creates errors = $5K	$15K	Present analog system has no capabilities for data logging and cannot be modified to perform such a function.	0%	$0	A similar system was installed by ACME Inc. (see trip report #xxxx). The system can fully meet our requirements.	100%	$15K	$15K	The system will meet most of our requirements. Historical data over a month old cannot be retrieved.	80%	0.8 x 15 = $12K	$12K
3- Forecast Production Problems: a. To reduce scrap and its disposal = $50K b. To reduce QC lab workload (new tech. required) = $30K c. To improve worker morale, reduce absenteeism = $20K	$100K	Partial improvement can be made by retuning the PID settings on all controllers and by additional training.	40%	0.4 x100 = $40K	A similar system was installed by ACME Inc. (see trip report #xxxx). The "Forecast Production" system is still not fully functional. They expect that another month of troubleshooting is required.	25%	.25 x 100 = $25K	25 - 40 = - $15K (Note 1)	The vendor is confident that their system will meet our requirements. A similar system at XYZ Inc. took two years to finally operate correctly.	85%	.85 x 100 = $85K	85 – 40 = $45
Totals				$40K			$72K	$32K (Note 2)			$137K	$97K (Note 2)

Notes: 1) In this case, the existing system fills this function better (hence the negative sign).
2) Alternative 2 is better than Alternative 1.

CHAPTER 20

ROAD TO CONSULTING

Overview

What is consulting?

Consultancy, by definition, is the work of a person that provides advice. In the world of engineering, and more specifically in process control, that person not only provides engineering services but also may provide other technical services, such as auditing, justification, system evaluation, participation in installation, commissioning, and startup activities.

A consultant is a person with sound knowledge and extensive experience. The person has skills and talent to provide a certain expertise to people and organizations lacking this expertise and in need of it. A professional consultant makes that expertise available to clients for a fee. The scope of a consultant is typically shaped by the client's needs.

Is there a need for consultants?

The need for a consultant generally occurs when an organization's internal staff lacks the special skills or expertise to resolve an issue or problem. The organization is then typically faced with three options; training its staff for the task, hiring full-time employees with the expertise for the task, or retaining a consultant.

The advantages of an outside consultant are such that

- the objective can be reached in a short period of time,
- the client obtains highly skilled and experienced personnel relatively cheaply and used for a specific project/application,
- the consultant is available on demand and gone when the job is done,
- the consultant provides an impartial opinion because he or she is independent of the organization's political system and brings a new and different perspective, and
- the consultant can often also design, develop, and conduct various training programs.

Hiring a consultant is generally beneficial to both the consultant and the client.

The need for skilled and experienced temporary assistance (i.e., good quality consultancy) is on the increase. This is due to the need created by the absence of trained and skilled professional in the field of process control (following personnel layoffs due to budget cuts or the retirement of experienced employees)—and the continuous demand for process automation to maintain a competitive edge (i.e., survival). In addition, the speed of technological change may be a handicap to small organizations whose staff does not have the time to stay abreast of the complexity of modern automation, its ever changing and growing technology, and increasing regulations.

The demand for consultancy also exists, and is at present growing very rapidly, in third-world nations. Their economic growth is often at a much higher rate than their ability to produce skilled personnel—and therefore their need for outside sources to supplement and train their own skilled task force.

Where do consultants come from?

Consultants are found from different sources. The most common are referrals. The client typically would first consider consultants with whom they worked successfully in the past. If this is not possible, the client may contact acquaintances and ask for referrals.

Other sources include consultants' directories (e.g., yellow pages); placing an ad in the local paper; looking for a consultant's ad; looking for leading authorities, such as book or article authors; contacting trade and professional associations or local universities; or searching on the Internet with a few key words.

One word of advice here: the client should always first define its needs and objectives, determine what it wants from the consultant, and then start the search for the appropriate consultant. Not having a clear understanding of the consultant's scope before the search starts inevitably leads to mismatching, misunderstandings, delaying projects, and increasing costs.

What are the qualities of a consultant?

The life of a consultant is not as rosy as it looks from the other side of the fence. To become a consultant certain qualities are required.

1. The consultant should first of all have the necessary knowledge, expertise, skills, and talent to provide the required services to the clients.
2. The consultant must be self-reliant, resourceful, and have a good personality.
3. The successful consultant is typically a self-starter with excellent self-discipline.
4. A consultant is not a typical employee. No guidance is provided by a manager and decisions are not reviewed by anyone else.

A successful consultant must carefully listen to the client needs and often read between the lines. He or she must be tactful, yet strong enough to maintain control of discussions with the client to be able to understand its needs and desires and respond to those needs. The consultant is expected to provide an effective solution to a client's issue in a timely manner and within budget. This leads to a successful consultation and a satisfied client.

What is the lifecycle of a consultancy?

The lifecycle of a typical consulting company goes through four stages: startup, expansion, maturity, decline (see figure 20-1).

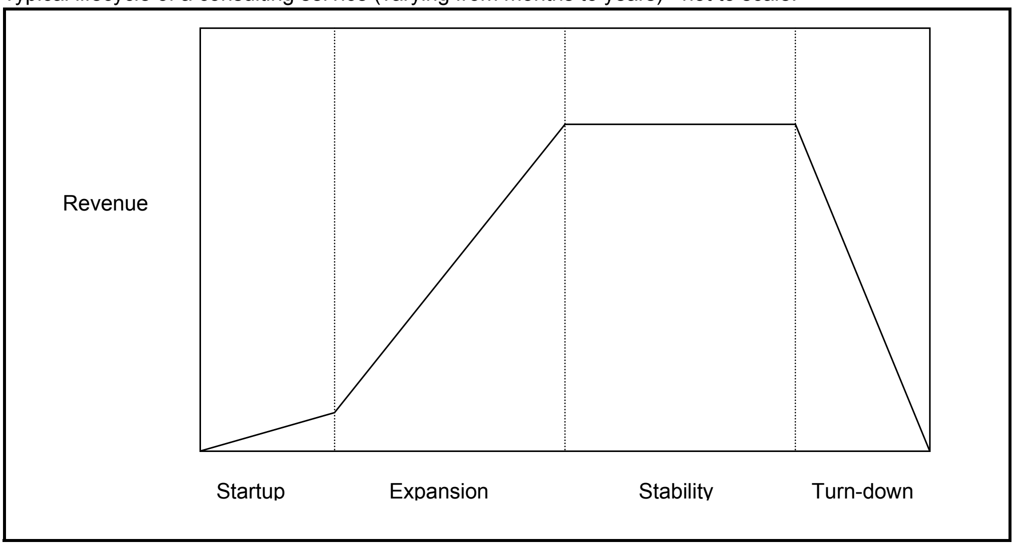
During startup, services are offered to potential clients generally through intensive marketing (see following section on marketing). Typically, throughout this period, workload and income go up and down. The consultant may wonder if the decision to become "independent" was the right one. However, on good days (i.e., when the workload is good and income is generated) frustrating days are forgotten, and the future seems bright. The major activities that occur during this time are business setup and marketing.

Expansion is a stage that follows startup. Now the business is growing, work is coming in, and survival looks certain. At this stage of business development, the main problem is to find enough hours in a day to satisfy all the clients. At this point, a major decision has to be made: Do I expand, or do I start refusing work? This is a difficult situation to face, and the consultant should examine his or her life priorities before making a decision—hopefully not regretting it in the future.

Stability occurs as income and workload balance each other for an extended period of time. Ideally, new work is poised to start as soon as ongoing work is completed and manpower loading is in sync with the workload.

As time goes by, a downturn starts. At this stage, revenues and workload begin falling over time. This may occur intentionally, if the consultant decides to reduce the workload for personal or other reasons, or unintentionally, if the demand for consulting services is dropping.

Figure 20-1
Typical lifecycle of a consulting service (varying from months to years) - not to scale.



Following this overview, the chapter is organized into the following sections:

- a description of the types of consulting services,
- the basic tools required to set up a consulting company,
- the marketing of consulting services,
- the steps required to move from proposal to purchase order,
- the content of a contract, types of contracts, and basis for consulting fees, and
- how to maintain client relationships.

Types of Consulting Services

Consulting services can be classified as one of three common types: sole practitioner, small group, and large group.

As a sole practitioner, the consultant creates the business and operates on his or her own. Quite often, the consultant is pushed into consultancy by events beyond his or her control, such as when the professional retires or loses employment.

The consultant typically works from a home office but can also lease space in an office suite. Leasing space provides additional services not typically available from a home office, such as a receptionist, waiting and conference areas, and clerical services commonly available on a fee-for-services basis. The downside of leasing office space is the additional cost, and that can be an excessive load on a small starting business. However, it can be worth the added expenses.

Most consulting firms consist of a sole practitioner—some are incorporated and some are not. The decision to incorporate depends on many issues, such as liability and size of income. This is a decision that should be discussed with an accountant.

A sole practitioner must have extensive knowledge and work experience because he or she operates without the support of colleagues in the same organization. A one-person consultancy generally provides, at a relatively low cost, the personal attention a client seeks.

A sole practitioner is faced with an erratic workload and income and a continuous need for marketing. In addition, he or she must perform a balancing act between personal income and business revenues. When the consultant stops working, the business ends. Income depends on the number of hours worked because the daily/hourly rate is limited to the ongoing market rates. The only way to work less hours and make more money is to expand the business and allow others to work for the consultant.

When a small group creates a consultancy, typically with a small clerical and drafting staff, they operate out of a small office. The office is generally located in a professional building that houses other business professionals, such as lawyers and accountants. The business is typically incorporated (and sometimes a partnership is formed).

A small group of consultants can help each other through their pool of knowledge and experience, benefiting the client. The group may also provide more personal attention at a lower cost than a large firm. However, small groups must balance the needs and personalities of the different member partners and be able to reach decisions quickly through a consensus process—sometimes a difficult activity.

A large group typically consists of dozens, hundreds, or even thousands of professionals and support staff. They are large corporations, with a wide variety of specialists that can efficiently implement large projects. These groups are commonly involved in different industries and can offer a greater number of products and services, providing independency and strength.

Types of services

For each of the three types, consultants provide their services with different outcomes, depending on their expertise and approach to problem solving. The following is a generalized description of different consultancies that should be matched to the client's needs.

Generalists are consultants experienced in a broad range of industries and disciplines. They can easily transfer the information learned in one area to another area. They have broad experience and knowledge. Generalists can refer to specialists when looking for specialized expertise. Specialists are knowledgeable in unique and specific areas of expertise, which in many cases is all a client may need.

Industrial consultants have hands-on experience and should be familiar with industry's problems. They tend to shy away from theoretical knowledge because they probably have not referred to their college books since graduation—which was years ago. On the other hand, if a person knowledgeable with theory and academia is the requisite, then an academic consultant is required. This person will probably be available on a part-time basis and be part of a teaching staff at a university.

Advisory consultants provide advice and recommendations to a client. However, the implementation of such recommendations is left to the client. Whereas, industrial consultants not only provide advice and recommendations but also become involved in implementing the recommendations and ensuring functionality and operation on behalf of the client.

Consultant availability is sometimes a difficult issue for small consultancies because they can be tied to other projects that have to be completed first. A client must decide if it requires a full-time or part-time consultant. A full-time consultant provides undivided time and attention to a client for a particular project. However, this comes with a high price because the consultant is charging all his or her time to one client until the project is completed. A part-time consultant will cost less because he or she has other obligations (i.e., other projects to charge his or her time to). However, this division of availability may not always match the client's needs and timeframe.

Basic Tools

A consultant's office requires certain tools. The following is a list of minimum requirements. Obviously, this will be adjusted to meet the needs of the consultant's business.

A telephone is one of the first tools required. If the office is home-based, it should have a separate phone number. The consultant must ensure that it is a quiet place. It is unprofessional to be on a business call while the kids are screaming and the TV is blaring in the background.

In addition to a telephone, an answering machine or answering service is a must because the consultant will not always be available to answer incoming calls. In addition, he or she must retrieve messages on a regular basis. Clients get annoyed if their messages are not returned in a timely manner. With a rented office space, calls will be answered by a receptionist. With today's technology, there is no reason to leave a business phone unanswered. Some sole practitioners use their cell phone as their business phone. Eventually, a fax machine and scanner will also be required.

The next item of major importance is a personal computer with Internet access, e-mail, and an e-mail address. The software should include word processing capabilities, with preformatted correspondence for standard letters, invoices, contracts, fee schedules, and fax forms. Standard letters thank clients for the opportunity to call, confirm meeting dates and times, transmit documents, and accompany marketing brochures. In addition, spreadsheet (and some times database) capabilities are useful when reading information sent by clients and vendors.

The consultant can create a Web site to describe his or her capabilities and experience. However, the Web site must be kept up to date with relevant information. The design of such a Web site must be carefully thought out, starting with its purpose and target audience.

The consultancy should have a ready-on-demand resume and a list of satisfied clients, with references and telephone numbers. In addition to a resume, the consultant can have a brochure describing his or her capabilities. A one-page resume showing experience and education is usually sufficient.

Then business cards must be prepared. They should look professional (i.e., they should be kept simple, without fancy colors or extravagant shapes). A logo is ok. Printers have a variety of styles to choose from. The consultant may check what other consultants have done with their business cards to get more ideas.

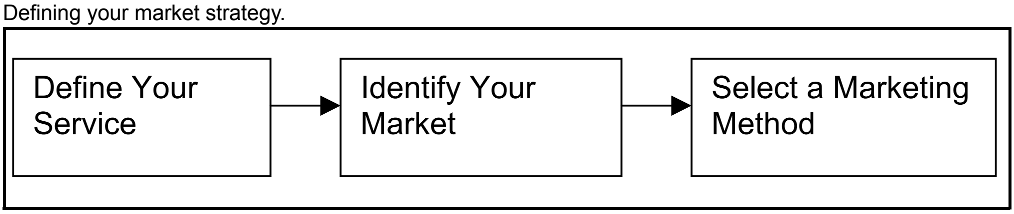
Marketing

Consultancy may fail just because of poor marketing, even if the service offered is good. Marketing is the most important factor in the startup of a consultancy, and yet it is quite often overlooked by technical personnel eager to start their business.

Marketing is a vital and time-consuming activity for any consultant. A marketing strategy must be identified and implemented to generate business. Such a strategy is based on the type of business offered, the products and skills available and their uniqueness, the available market, and the organization of the consultancy. The organization factor is practically non-applicable for a sole practitioner, but it is a major issue for large organizations.

The strategy should define how the consultancy's goals will be reached. This will be modified and adjusted over time as the business starts growing and more is learned about the results of previous marketing efforts. Typically a strategy should have a planning horizon of three to five years. In addition, the strategy should have a detailed one-year plan to cover budgets and personnel commitments. This strategy can be a simple one- or two-page document. The development of the marketing strategy goes through three basic steps (see figure 20-2).

Figure 20-2
Defining your market strategy.



As the consultancy prepares its marketing strategy some soul searching will emerge. Questions arise such as: Will any job be accepted, or will some be turned down? Should out-of-town jobs be accepted? How about overseas assignments? Accordingly, the consultancy is setting an operating philosophy that determines how to respond to certain proposals and how to price certain projects. Occasionally, answers to such questions are not simple yes or no answers. In such cases, the consultancy should decide based on the relationship with the client and the expected profit to be made from such an assignment and future projects.

Defining your service

To define the service to be offered to clients, the consultant must first define the expertise that he or she can offer clients. The consultant must look back at the accomplishments of his or her career, knowledge learned, and experience acquired.

Following this exercise, the consultant now must honestly assess if this expertise is real and if it is worth offering to clients for a fee. It is important to match the expertise with the needs of the market. The consultant then must assess the competition. Is there a niche that makes this particular consultancy any different?

Indentifying your market

A client is any person or organization that decides to give work to a consultancy. It is important that a consultant identifies the market segments he or she will be dealing with. They can be government, businesses, or other professionals. Within these segments, the decision makers may be engineers, foremen, purchasing agents, and/or management.

In identifying the market, a consultant must first identify the skills required, the demand cycle, and the market size, location, and stability. Then the consultant must assess the competition and the uniqueness and benefits of his or her services, including the possibilities of market niches. Another item of great importance is pricing—typically the hourly rate. Many consultants prefer an hourly rate over a daily rate because it is not clear how long a day is, in particular for clients that have the habit of working late into the night.

Selecting a marketing method

There are several marketing methods. All are based on communication with potential clients. Each method has its advantages and disadvantages, and the consultant should adapt the method to the situation at hand. Most important of all, and common to all methods, the consultant should remember that the most powerful marketing tool is "genuinely caring about the client." The key word here is "genuinely." People see through artificial interest. When a consultant really cares for a client, the correct questions are asked to understand the client's real problem. Then an appropriate solution can be reached to everybody's satisfaction.

The most common marketing methods are:

A. Face-to-Face
Face-to-face is the preferred method of communication. It helps develop a good relationship. Through discussions, the consultant can best understand the client's true problems and needs. The consultant should ask questions, refrain from talking too much, and listen carefully—often reading between the lines.

B. Direct Mail
Direct mail does not mean junk mail. Direct mail in the form of personal letters, announcements on new technology, course offerings, and periodic newsletters is acceptable and often welcomed by clients. Newsletters require preparation time—and time is a commodity sometimes not available. Some consultants get a great response to newsletters while others think it is a waste of time. It probably varies with the market and the consultant's specialty. Newsletters are typically published every three to six months.

C. Telemarketing
Telemarketing uses the telephone as a tool to eventually lead to a face-to-face meeting. Cold calls are a form of telemarketing where the person calling is unknown to the person receiving the call. Not too many consultants are good at cold-call telemarketing. They often hire a telemarketer (or telemarketing company) to do this work. Some clients do not appreciate cold calls, and the consultant needs to decide if he or she should take such a route. The following points should help a consultant when phoning someone:

1. Before starting a call, be sure you have the correct name of the person you will be talking to and make sure you have the information you'll be talking about.
2. When the client answers, relax, smile, introduce yourself clearly, and explain the purpose of your call. The client will sense your smile. Then check the availability of your client to talk.
3. Give your total attention to the conversation at hand, be friendly, don't talk too fast or too slowly, and listen carefully.
4. If you have to put your customer on hold, make sure it's no more than 20 to 30 seconds.

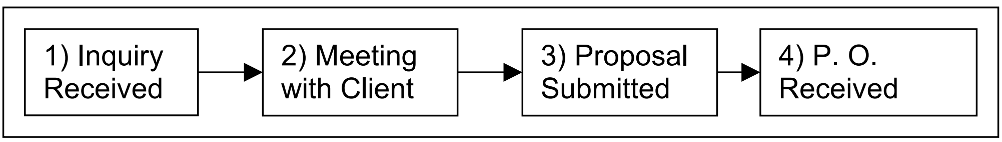
D. Events
Courses and seminars are sometimes the starting point of a relationship between the consultant doing the teaching and the attending potential customers. Some consultants obtain good results while others have tried it and did not receive any work from the sessions, in spite of the fact that the training course or seminar was well received.

E. Referrals
Referrals are the most important source of a consultant's business. It varies with the business in question, but for an established consultancy, typically 75% to 90% of annual sales comes from referrals and repeat business.

From Proposal to Purchase Order

Following successful marketing efforts, a consultant can now receive an inquiry from a potential client for a job to be done. At this point, the consultant will review the inquiry, call the potential customer, and set a meeting to discuss in detail the needs of the client. When the consultant returns to his or her office, a proposal is prepared and then submitted to the client. If successful, the consultant receives a purchase order giving the go ahead to start with the work (see figure 20-3).

Figure 20-3
From proposal to purchase order.



Inquiry Received

This is the first move by the client that hopefully leads to a purchase order and the start of work by the consultant. The consultant should review the client's inquiry and prepare a list of questions and clarifications. A misunderstanding of the client's needs and consultant's expectations always leads to problems, including extra costs and project delays. In the end, both the client and consultant are dissatisfied. A dissatisfied client will not give future work to a consultant who did not meet its needs. As discussed earlier, repeat business is the major source of income, so reputation and satisfied customers are key to a successful consultancy.

A careful review of the inquiry ensures that the consultant has a good understanding of the client's needs. If the consultant determines that the inquiry is not within his or her field of expertise, he or she should immediately contact the client and decline to bid on the job,

Sometimes the consultant, for whatever reason, does not want to take on a job, even though the work is within his or her scope of work. However, the consultant should keep the door open for future business. In this case, a typical response from the consultant would be that the consultancy has too many projects at hand, and in the interest of the client, it cannot take on the project at this time.

Once the consultant determines to take the job described in the inquiry, he or she should contact the client and set up an appointment to discuss the inquiry and get a clear understanding of the client's needs.

Meeting with the client

This is the first meeting for the upcoming project. It is generally held at the client's place of business. At the meeting, the consultant communicates with all the people that will be involved in the project. The consultant must understand the needs of the client— a vital step for the success of the project—and confirm that the work to be done is within his or her scope of work and expertise. Sometimes, especially on large projects, a single meeting is not sufficient, and additional meetings are held to clarify the client's requirements.

In addition to clarifying the client's needs, the consultant can discuss other topics, such as financial arrangements and contractual terms and conditions, subcontracting possibilities, liability insurance, confidentiality agreements, and any possible conflicts of interest.

At the meeting, the consultant and client get to know each other. It is important that the consultant makes a good impression right from the start. The consultant should begin with a smile and a solid handshake—and always maintain eye contact. The consultant should be open to new ideas, be genuinely interested in the client's problems, listen carefully, see where he or she can help, be courteous, and say thank you. Building a good rapport with the client is vital to the success of a project. Once the consultant obtains a solid understanding of the client's needs and all points are agreed upon, the meeting ends.

Sometimes a client will question the fees that the consultant is charging—trying to pressure the consultant to reduce the charge-out rate. The consultant should resist this attempt. If the consultant does reduce the rate, the haggling will occur every time the client approaches the consultant with work. The consultant should explain to the client that it is in the client's best interest to pay a little more and receive good-quality work. Minor savings do not even compare with poor quality workmanship—resulting at the end in delays and extra costs to correct errors. In addition to quality work being completed on time, clients also look for a consultant that is easy to work with and accessible, and responds quickly.

Proposal submitted

Once the consultant is confident that the client's needs are well defined, a proposal is prepared and submitted to the client. The content of the proposal should be clear and simple to read. The proposal should basically describe the summary of all discussions and state the understanding reached by the consultant. If a purchase order based on the proposal is issued, the client accepts the content and understanding of the consultant (i.e., the onus is on the client to ensure and verify that the consultant's understanding meets the client's needs).

In addition to describing the scope of work, the proposal should also set a time frame for the work to be done and set the fees to be charged, with estimated expenses, along with the payment terms and conditions. Quite often, the fee is broken down into regular time and overtime, as well as weekend rates.

The content of a proposal can vary from simple to extensive detail, depending on the size of the project and the client's way of doing business. Typically, a proposal is divided into three parts: the front section, the body of the proposal, and the end section.

The front section includes a title page, table of contents, and summary of the work to be done. The body of the proposal clearly describes the work to be done, and includes any necessary supporting technical documents. The end section contains fees, overtime rates, estimated expenses, terms of payment (including phased payment—to invoice as the project is proceeding) schedules and project completion time frame, resume of the consultant(s), references (if required by client), and a brochure describing the consultant's capabilities. In summary, the proposal should give the client the confidence required to award a purchase order to the consultant.

It is recommended that rates be quoted by the hour, not by the day. Because it is not clear what a day is. Is it 7 hours, 8 hours, 10 hours, or 24 hours?

Purchase order received

With the receipt of a purchase order, the consultant has the go-ahead to start working. In the proposal, all the details were identified; however, it is a good practice for the consultant to meet again with key personnel to finalize any requirements that may have been omitted during the bidding cycle and confirm the project time frame and delivery date. Often, the client can decide to modify the scope of the project, and the consultant should handle the modification with care because it may delay the project completion date.

In some cases, instead of the proposal and purchase order format, a contract is signed between the consultant and the client. The contract may be a formal contract or just simply be in the form of a letter. Whatever the form, a contract should include a description of the job, its estimated time frame, the consultant's responsibilities and deliverables, the client's responsibilities, payment fees and terms of payment, any special conditions, and a cancellation clause. Written agreements avoid misunderstandings between the consultant and the client.

Fees

A consultant should remember that not every day is a billable day. There will be days spent on marketing, and there are also holidays and sick days. So when setting fees, the consultant should compare his rate with the cost of a full-time senior member of the client's organization—that includes benefits, insurance, sick pay, training time, and costs.

Consultancy fees should include the overhead costs incurred by the consultant. These are in addition to the straight consultancy fees. They include office rent, equipment and supplies, business licenses, insurance, accounting, legal services, professional dues and subscriptions, professional development, telephone, marketing, and other miscellaneous expenses.

Typically, a consultant bills services to clients on an hourly basis plus expenses. Sometimes, instead of billing on an hourly basis, consultants bill on a daily basis. The second most common billing rate is a fixed price, and the third is on a performance basis. The third option is the least common because it involves a high risk to the consultant.

Daily/hourly rate contract + expenses

Daily or hourly billing is the most common approach taken by consultants. With this approach, the consultant does not have to worry about either overcharging the customer or losing revenues. The client is billed the hours used and the client takes the risk. Between hourly and daily, hourly is the most common. Quite often, the daily rate is lower than an hourly rate multiplied by the number of hours in a day.

Consultants add incurred expenses to the daily/hourly rate. Sometimes the expenses are billed at cost (i.e., the client is charged exactly what the consultant has paid), and sometimes the consultant adds a 5% charge to cover the cost of administration and the cost of money between the time the expenses are paid by the consultant and the time the client pays back the expenses. Expenses can also be handled as a per diem rate. Here the consultant charges a flat fee for expenses. A combination of incurred expenses and per diem rate can also be used.

A profit of 15% to 20% is sometimes added to the total as a percentage of the fee. The decision to add profit as a separate item or build it into the fees should be decided by the owner(s) of the consultancy.

A variation of the daily/hourly contract is the retainer contract. In a retainer contract, the consultant is available to the client on an open-ended basis for an agreed-upon hourly (or daily) rate. The contract can be terminated at any time by either the consultant or the client. This type of agreement is common when a client needs to hire a consultant for the duration of a project, but the project does not have a clear end date—or it may start and stop throughout the design and construction phases.

Fixed-Price Contracts

In a fixed-price approach, the consultant offers the client a fixed amount to do the job. Typically expenses are excluded, but they are estimated by the consultant and submitted to the client for budget purposes (see figure 20-4). The consultant basically agrees to do the job at a set price regardless of the consultant's cost. Partial payments are generally done at predetermined milestones.

Figure 20-4
Example of a job estimate for a small consultancy.

Direct Fees:		
Senior Engineer	= 17 days x $650.00/day =	$11,050.00
Junior Engineer	= 12 days x $350.00/day =	$ 4,200.00
Clerical	= 4 days x $200.00/day =	$800.00

	Total Direct Fees =	$16,050.00
Overhead:		
100% of $16050.00		$16,050.00
	Subtotal (Direct Fees + Overhead) =	$32,100.00
Profit: 20% of subtotal =		$ 6,420.00

	Fees Total =	$38,520.00
Expenses:		
Air travel		$1,500.00
Car Rental		$850.00
Per diem allowance (hotel, meals, etc.) =	17 days x 200.00/day =	$3400.00
Postage, Printing		$250.00

	Total Expenses =	$6000.00

	Grand Total (Fees + Expenses) =	**$44,520.00**

In this type of contract, the consultancy takes the risk and does not profit from every job. The consultant must have a clear and specific definition of the work to be done and be capable of accurately estimating the time required to do the job. This is possible on routine assignments where similar previous jobs have been done. However, the consultant should always remember that not all clients are the same and some may need more reports, more meetings, and more coaching. In such cases, the fixed-price contract gets inflated a bit to accommodate for such unknowns.

Most consultants avoid fixed-price contracts due to the unknown factors. They prefer to use the daily/hourly rate contracts.

Performance Contracts

In a performance contract, the consultant is paid on the basis of a previously set agreement in which the consultant is expected to supply a service that will provide a measurable return to the client. With performance contracts, the consultant takes all the risk, and if the return is not achieved, he or she makes no money out of the effort. However, if he or she does meet the agreed upon return, the economic gains are generally large.

Consultants often use this type of agreement when they are confident that the work to be done is beneficial to their client and yet the client is hesitant. Performance contracts eliminate the client's risk. However, the consultant must have measurable parameters to gauge the accomplished benefits.

Some performance contracts minimize the risk to the consultant by guaranteeing a minimum revenue to the consultant, with a sizeable bonus if the expected return is achieved.

Maintaining client relationships

It is important for a consultant to stay in touch with his or her clients. The statement "out-of-sight, out-of mind" is very much applicable in the consultancy business. The consultant must maintain an ongoing relationship with his or her clients to obtain new business, referrals, and testimonials when needed. Maintaining a good relationship reminds the client of the consultant's availability and capabilities.

There are many ways to maintain relationships. The consultant may send copies of magazine articles to clients on topics of interest or e-mail a regular newsletter (say once a quarter). The consultant also may provide some free advice for simple and quick questions.

The consultant can use regular mail (or e-mail). This method leaves an actual paper (or an electronic) message on the client's desk—to be looked at as soon as the client has time available. Another option is the telephone. However, quite often a message is left, and telephone tag may develop to everyone's frustration. The most powerful approach is the face-to-face meeting. This approach renews the relationship, and the consultant can learn about upcoming projects and who's who in the client's organization. The face-to-face meeting can easily evolve into an invitation of the client to lunch, dinner, or game of golf—all further steps toward cementing the relationship.

APPENDIX A

UNITS CONVERSION TABLES

Overview

Attributes of measurement and control devices require the use of units of measurement to define the physical properties. Units commonly used in such applications are of the English system (such as pound, foot, gallon), the SI system (such as kilogram, meter, liter), or some other unique system peculiar to a particular industry.

The International System of Units (SI, from its French name Système International d'Unités) is a simplified system of measurement developed from the metric units of measurement. It has been adopted almost worldwide. In the United States many large industrial leaders have started using the SI system.

The SI Units

SI units use symbols to abbreviate numbers (Table A-1). Using the preferred form may present a large magnitude; therefore, a more suitable term may be used. For example 1,000,000 pascals is expressed as 1 MPa or one megapascals.

The SI system includes three types of units: base units, supplementary units, and derived units. It derives almost all its units from only seven base units (Table A-2) and two supplementary units (Table A-3).

Base Units

These units are listed in Table A-2. In these units, the kilogram is the only base unit that contains a prefix.

Supplementary Units

These units are listed in Table A-3 and consist of two purely geometric units. However, it should be noted here that the 360° circle, created by the Babylonians, is still in use in engineering, in latitude and longitude measurements, as well in time zones due to its practical importance and widespread use.

Derived Units with or without Special Names

These units (shown in Tables A-4 and A-5) are expressed algebraically in terms of base or supplementary units. Some have special names, such as the degree Celsius and the Pascal.

Other Units

In addition to the above three types of units, other units (shown in Table A-6) are in use. They are outside the SI and yet are recognized and retained.

Metric Units

Metric units represent the origin of the SI system and contain units that should not be used with the SI system. These are shown in Table A-7.

Guidelines for the Application of Units of Measurement

Flow

Flow can be expressed in units of mass or volume per second.

Volume

Volume is generally expressed in cubic meters. For small volumes of solids, cubic millimeters can be used. For liquids and gases, quantities less than 1 m^3 can use the liter (L) and smaller quantities the milliliter (mL). The unit of liter is sometimes expressed as a lowercase "l" and in some cases may be confused with the number 1. Therefore, some countries such as Canada, have adopted the uppercase "L" to express liters.

Temperature

Kelvin is the absolute temperature scale in the metric system whereas degree Rankine is the absolute temperature scale in the English (Fahrenheit) system. However, the degree Celsius is the most commonly used unit. Note that 1°C is equivalent to 1 K. (The term "degree Kelvin" should not be used, just the term "Kelvin.")

Pressure

The proper unit is the pascal (Pa); however, the kPa is recognized as the most commonly used except for vacuum applications, where the Pa is more convenient to use. The kPa is used for measurement of both gage and absolute pressure, but to avoid misunderstanding it is recommended that the unit kPa be followed by the word "gage" or "absolute" in parentheses—for example, 120 kPa (gage). Some companies abbreviate these two words to "g" and "a" respectively, while others have specific instructions not to do so. Where differential pressure is measured, the units are Pa (or kPa) only. It should be noted that the use of the "bar" unit is discouraged, even though it is a multiple of the Pa unit (1 bar = 100 kPa).

Table A-1:
Multiples and Submultiples of SI units

Prefix	Symbol	Multiplying Factor	
exa	E	10^{18}	1 000 000 000 000 000 000
peta	P	10^{15}	1 000 000 000 000 000
tera	T	10^{12}	1 000 000 000 000
giga	G	10^{9}	1 000 000 000
mega	M	10^{6}	1 000 000
kilo	k	10^{3}	1 000
hecto*	h	10^{2}	100
deca*	da	10	10
deci*	d	10^{-1}	0.1
centi	c	10^{-2}	0.01
milli	m	10^{-3}	0.001
micro	u	10^{-6}	0.000 001
nano	n	10^{-9}	0.000 000 001
pico	p	10^{-12}	0.000 000 000 001
femto	f	10^{-15}	0.000 000 000 000 001
atto	a	10^{-18}	0.000 000 000 000 000 001

* these prefixes are not normally used

Table A-2
SI Base Units

Quantity	Name	Symbol
Length	meter	m
Mass	kilogram	kg
Time	second	s
Electric current	ampere	A
Thermodynamic temperature	kelvin	K
Amount of substance	mole	mol
Luminous intensity	candela	cd

Table A-3
SI Supplementary Units

Quantity	Name	Symbol
Plane angle	radian	rad
Solid angle	steradian	sr

Table A-4
SI Derived Units with Special Names

Quantity	SI Unit		Expressed in Terms of Other SI Units	Expressed in Terms of Base and Supplementary Units
	Name	Symbol		
Frequency	hertz	Hz	s^{-1}	s^{-1}
Force	newton	N	$m \cdot kg/s^2$	$m \cdot kg \cdot s^{-2}$
Pressure, stress	pascal	Pa	N/m^2	$m^{-1} \cdot kg \cdot s^{-2}$
Energy, work, quantity of heat	joule	J	$N \cdot m$	$m^2 \cdot kg \cdot s^{-2}$
Power, radiant flux	watt	W	J/s	$m^2 \cdot kg \cdot s^{-3}$
Quantity of electricity, electric charge	coulomb	C	$s \cdot A$	$s \cdot A$
Electric potential, potential difference, electromotive force	volt	V	W/A	$m^2 \cdot kg \cdot s^{-3} \cdot A^{-1}$
Electric capacitance	farad	F	C/V	$m^{-2} \cdot kg^{-1} \cdot s^4 \cdot A^2$
Electric resistance	ohm	Ω	V/A	$m^2 \cdot kg \cdot s^{-3} \cdot A^{-2}$
Electric conductance	siemens	S	A/V	$m^{-2} \cdot kg^{-1} \cdot s^3 \cdot A^2$
Magnetic flux	weber	Wb	$V \cdot s$	$m^2 \cdot kg \cdot s^{-2} \cdot A^{-1}$
Magnetic flux density	tesla	T	Wb/m^2	$kg \cdot s^{-2} \cdot A^{-1}$
Inductance	henry	H	Wb/A	$m^2 \cdot kg \cdot s^{-2} \cdot A^{-2}$
Luminous flux	lumen	lm	$cd \cdot sr$	$cd \cdot sr$
Illuminance	lux	lx	lm/m^2	$m^{-2} \cdot cd \cdot sr$
Activity of radionuclides	becquerel	Bq	s^{-1}	s^{-1}
Absorbed dose of ionizing radiation	gray	Gy	J/kg	$m^2 \cdot s^{-2}$

Table A-5
Examples of SI Derived Units Without Special Names

Quantity	Description	Expressed in Terms of Other SI Units	Expressed in Terms of Base and Supplementary Units
Area	square meter	m^2	m^2
Volume	cubic meter	m^3	m^3
Speed – linear – angular	meter per second radian per second	m/s rad/s	$m \cdot s^{-1}$ $rad \cdot s^{-1}$
Acceleration – linear – angular	meter per second squared radian per second squared	m/s^2 rad/s^2	$m \cdot s^{-2}$ $rad \cdot s^{-2}$
Wave number	1 per meter	m^{-1}	m^{-1}
Density, mass density	kilogram per cubic meter	kg/m^3	$kg \cdot m^{-3}$
Concentration (of amount of substance)	mole per cubic meter	mol/m^3	$mol \cdot m^{-3}$
Specific volume	cubic meter per kilogram	m^3/kg	$m^3 \cdot kg^{-1}$
Luminance	candela per square meter	cd/m^2	$cd \cdot m^{-2}$
Dynamic viscosity	pascal second	$Pa \cdot s$	$m^{-1} \cdot kg \cdot s^{-1}$
Moment of force	newton meter	$N \cdot m$	$m^2 \cdot kg \cdot s^{-2}$
Surface tension	newton per meter	N/m	$kg \cdot s^{-2}$
Heat flux density, irradiance	watt per square meter	W/m^2	$kg \cdot s^{-3}$
Heat capacity, entropy	joule per kelvin	J/K	$m^2 \cdot kg \cdot s^{-2} \cdot K^{-1}$
Specific heat capacity, specific entropy	joule per kilogram kelvin	$J/(kg \cdot K)$	$m^2 \cdot s^{-2} \cdot K^{-1}$
Specific energy	joule per kilogram	J/kg	$m^2 \cdot s^{-2}$
Thermal conductivity	watt per meter kelvin	$W/(m \cdot K)$	$m \cdot kg \cdot s^{-3} \cdot K^{-1}$
Energy density	joule per cubic meter	J/m^3	$m^{-1} \cdot kg \cdot s^{-2}$
Electric field strength	volt per meter	V/m	$m \cdot kg \cdot s^{-3} \cdot A^{-1}$
Electric charge density	coulomb per cubic meter	C/m^3	$m^{-3} \cdot s \cdot A$
Surface density of charge, flux density	coulomb per square meter	C/m^2	$m^{-2} \cdot s \cdot A$
Permittivity	farad per meter	F/m	$m^{-3} \cdot kg^{-1} \cdot s^4 \cdot A^2$
Current density	ampere per square meter	A/m^2	$A \cdot m^{-2}$
Magnetic field strength	ampere per meter	A/m	$A \cdot m^{-1}$
Permeability	henry per meter	H/m	$m \cdot kg \cdot s^{-2} \cdot A^{-2}$
Molar energy	joule per mole	J/mol	$m^2 \cdot kg \cdot s^{-2} \cdot mol^{-1}$
Molar entropy, molar heat capacity	joule per mole kelvin	$J/(mol \cdot K)$	$m^2 \cdot kg \cdot s^{-2} \cdot K^{-1} \cdot mol^{-1}$
Radiant intensity	watt per steradian	W/sr	$m^2 \cdot kg \cdot s^3 \cdot sr^{-1}$

Table A-6
Other recognized Units

Name	Symbol	Value in SI Units
Minute	min	1 min = 60 s
Hour	h	1 h = 60 min = 3600 s
Day	d	1 d = 24 h = 86400 s
Year	a	
Degree (of arc)	°	1° = (π/180) rad
Minute (of arc)	'	1' = (1/60)° = (π/ 10 800) rad
Second (of arc)	"	1" = (1/60)' = (π/648 000) rad
Liter	L or l	1 liter = 1 dm^3
Celsius temperature	°C	temperature difference 1°C = 1K
Hectare	ha	1 ha = 10 000 m^2
Electronvolt	eV	1 eV = 0.160 210 aJ (approx)
Unified atomic mass unit	u	1u = 1.660 44 x 10^{-27} kg (approx)
Revolution per minute	r/min	
Revolution per second	r/s	

Table A-7
Metric Units that should not be used with the SI System

Quantity	Name	Symbol	Definition
Length	ångstrom	Å	1Å = 0.1 nm
	micron	μ	1μ = 1μm
	fermi	fm	1 fermi = 1 femtometer = 1 fm
	X unit		1 X unit = 100.2 fm
Area	are	a	1 a = 100 m^2
	barn	b	1 b = 100 fm^2
Volume	stere	st	1 st = 1 m^3
	lambda	λ	1 λ = 1 μl = 1 mm^3
Mass	metric carat	–	1 metric carat = 200 mg
	gamma	γ	1 γ = 1 μg
Force	kilogram-force	kgf	1 kgf = 9.806 65 N
	kilopond	kp	1 kp = 9.806 65 N
	dyne	dyn	1 dyn = 10 μN
Pressure	torr	Torr	1 torr = (101 325/760)Pa
Energy	calorie	cal	1 cal = 4.1868 J
	erg	erg	1 erg = 0.1 μj
Viscosity dynamic kinematic	 poise stokes	 P St	 1 P = 1 dyn·s/cm^2 = 0.1 Pa·s 1 St = 1 cm^2/s
Conductance	mho	mho	1 mho = 1 S
Magnetic field strength	oersted	Oe	1 Oe ≅ (1000/4π)A/m
Magnetic flux	maxwell	Mx	1 Mx ≅ 0.01 μWb
Magnetic flux density	gauss	Gs, G	1 Gs ≅ 0.1 mT
Magnetic induction	gamma	γ	1 g ≅ 1 nT
Iilluminance	phot	ph	1 ph = 10 klx
Luminance	stilb	sb	1 sb = 1 cd/cm^2
Activity (radioactive)	curie	Ci	1 Ci = 37 GBq
Absorbed dose of ioniz-ing radiation	rad	rad	1 rad = 10 mGy

Unit Conversion Table

Table A-8
Length Units

Millimeters	Centimeters	Meters	Kilometers	Inches	Feet	Yards	Miles
mm	cm	m	km	in	ft	yd	mi
1	0.1	0.001	0.000001	0.03937	0.003281	0.001094	6.21e-07
10	1	0.01	0.00001	0.393701	0.032808	0.010936	0.000006
1000	100	1	0.001	39.37008	3.28084	1.093613	0.000621
1000000	100000	1000	1	39370.08	3280.84	1093.613	0.621371
25.4	2.54	0.0254	0.000025	1	0.083333	0.027778	0.000016
304.8	30.48	0.3048	0.000305	12	1	0.333333	0.000189
914.4	91.44	0.9144	0.000914	36	3	1	0.000568
1609344	160934.4	1609.344	1.609344	63360	5280	1760	1

Table A-9
Area Units

Millimeter square	Centimeter square	Meter square	Inch square	Foot square	Yard square
mm^2	cm^2	m^2	in^2	ft^2	yd^2
1	0.01	0.000001	0.00155	0.000011	0.000001
100	1	0.0001	0.155	0.001076	0.00012
1000000	10000	1	1550.003	10.76391	1.19599
645.16	6.4516	0.000645	1	0.006944	0.000772
92903	929.0304	0.092903	144	1	0.111111
836127	8361.274	0.836127	1296	9	1

Table A-10
Volume Units

Centimeter cube	Meter cube	Liter	Inch cube	Foot cube	US gallons	Imperial gallons	US barrel (oil)
cm^3	m^3	ltr	in^3	ft^3	US gal	Imp. gal	US brl
1	0.000001	0.001	0.061024	0.000035	0.000264	0.00022	0.000006
1000000	1	1000	61024	35	264	220	6.29
1000	0.001	1	61	0.035	0.264201	0.22	0.00629
16.4	0.000016	0.016387	1	0.000579	0.004329	0.003605	0.000103
28317	0.028317	28.31685	1728	1	7.481333	6.229712	0.178127
3785	0.003785	3.79	231	0.13	1	0.832701	0.02381
4545	0.004545	4.55	277	0.16	1.20	1	0.028593
158970	0.15897	159	9701	6	42	35	1

Table A-11
Mass Units

Grams	Kilograms	Metric tonnes	Short ton	Long ton	Pounds	Ounces
g	kg	tonne	shton	Lton	lb	oz
1	0.001	0.000001	0.000001	9.84e-07	0.002205	0.035273
1000	1	0.001	0.001102	0.000984	2.204586	35.27337
1000000	1000	1	1.102293	0.984252	2204.586	35273.37
907200	907.2	0.9072	1	0.892913	2000	32000
1016000	1016	1.016	1.119929	1	2239.859	35837.74
453.6	0.4536	0.000454	0.0005	0.000446	1	16
28	0.02835	0.000028	0.000031	0.000028	0.0625	1

Table A-12
Density Units

Gram/milliliter	Kilogram/meter cube	Pound/foot cube	Pound/inch cube
g/ml	kg/m^3	lb/ft^3	lb/in^3
1	1000	62.42197	0.036127
0.001	1	0.062422	0.000036
0.01602	16.02	1	0.000579
27.68	27680	1727.84	1

Table A-13
Volumetric Liquid Flow Units

Liter/second	Liter/minute	Meter cube/hour	Foot cube/minute	Foot cube/hour	US gallons/minute	US barrels (oil)/day
L/sec	L/min	m^3/hr	ft^3/min	ft^3/hr	gal/min	US brl/d
1	60	3.6	2.119093	127.1197	15.85037	543.4783
0.016666	1	0.06	0.035317	2.118577	0.264162	9.057609
0.277778	16.6667	1	0.588637	35.31102	4.40288	150.9661
0.4719	28.31513	1.69884	1	60	7.479791	256.4674
0.007867	0.472015	0.02832	0.01667	1	0.124689	4.275326
0.06309	3.785551	0.227124	0.133694	8.019983	1	34.28804
0.00184	0.110404	0.006624	0.003899	0.2339	0.029165	1

Table A-14
Volumetric gas flow units

Normal meter cube/hour	Standard cubic feet/hour	Standard cubic feet/minute
Nm^3/hr	scfh	scfm
1	35.31073	0.588582
0.02832	1	0.016669
1.699	59.99294	1

Table A-15
Mass flow units

Kilogram/hour	Pound/hour	Kilogram/second	Ton/hour
kg/h	lb/hour	kg/s	t/h
1	2.204586	0.000278	0.001
0.4536	1	0.000126	0.000454
3600	7936.508	1	3.6
1000	2204.586	0.277778	1

Table A-16
High Pressure Units

Bar	Pound/square inch	Kilopascal	Megapascal	Kilogram force/ centimeter square	Millimeter of mercury	Atmospheres
bar	psi	kPa	MPa	kgf/cm^2	mm Hg	atm
1	14.50326	100	0.1	1.01968	750.0188	0.987167
0.06895	1	6.895	0.006895	0.070307	51.71379	0.068065
0.01	0.1450	1	0.001	0.01020	7.5002	0.00987
10	145.03	1000	1	10.197	7500.2	9.8717
0.9807	14.22335	98.07	0.09807	1	735.5434	0.968115
0.001333	0.019337	0.13333	0.000133	0.00136	1	0.001316
1.013	14.69181	101.3	0.1013	1.032936	759.769	1

Table A-17
Low Pressure Units

Meter of water	Foot of water	Centimeter of mercury	Inches of mercury	Inches of water	Pascal
mH_2O	ftH_2O	cmHg	inHg	inH_2O	Pa
1	3.280696	7.356339	2.896043	39.36572	9806
0.304813	1	2.242311	0.882753	11.9992	2989
0.135937	0.445969	1	0.39368	5.351265	1333
0.345299	1.13282	2.540135	1	13.59293	3386
0.025403	0.083339	0.186872	0.073568	1	249.1
0.000102	0.000335	0.00075	0.000295	0.004014	1

Table A-18
Speed Units

Meter/second	Meter/minute	Kilometer/hour	Foot/second	Foot/minute	Miles/hour
m/s	m/min	km/h	ft/s	ft/min	mi/h
1	59.988	3.599712	3.28084	196.8504	2.237136
0.01667	1	0.060007	0.054692	3.281496	0.037293
0.2778	16.66467	1	0.911417	54.68504	0.621477
0.3048	18.28434	1.097192	1	60	0.681879
0.00508	0.304739	0.018287	0.016667	1	0.011365
0.447	26.81464	1.609071	1.466535	87.99213	1

Table A-19
Torque Units

Newton meter	Kilogram force meter	Foot pound	Inch pound
Nm	kgfm	ftlb	inlb
1	0.101972	0.737561	8.850732
9.80665	1	7.233003	86.79603
1.35582	0.138255	1	12
0.112985	0.011521	0.083333	1

Table A-20
Dynamic Viscosity Units

Centipoise*	Poise	Pound/foot·second
cp	poise	lb/(ft·s)
1	0.01	0.000672
100	1	0.067197
1488.16	14.8816	1

Table A-21
Kinematic Viscosity Units

Centistoke*	Stoke	Foot square/second	meter square/second
cs	St	ft^2/s	m^2/s
1	0.01	0.000011	0.000001
100	1	0.001076	0.0001
92903	929.03	1	0.092903
1000000	10000	10.76392	1

*note: centistokes x specific gravity = centipoise

Table A-22
Temperature Conversion Formulas

Degree Celsius (°C)	(°F - 32) x 5/9
	(K - 273.15)
Degree Fahrenheit (°F)	(°C x 9/5) + 32
	(1.8 x K) - 459.67
Kelvin (K)	(°C + 273.15)
	(°F + 459.67) ÷ 1.8

Table A-23
Temperature Conversions

In the center column, locate the temperature to be converted. In the left and right columns are the converted (and rounded off) Celsius and Fahrenheit temperatures, respectively.

C		F	C		F	C		F	C		F	C		F
-273.15	-459.67		-118	-180	-292	-11.7	11	51.8	4.4	40	104.0	36.7	98	208.4
-268	-450		-112	-170	-274	-11.1	12	53.6	5.0	41	105.8	37.2	99	210.2
-262	-440		-107	-160	-256	-10.6	13	55.4	5.6	42	107.6	37.8	100	212.0
-257	-430		-101	-150	-238	-10.0	14	57.2	6.1	43	109.4	43	110	230
-251	-420		-95.6	-140	-220	-9.4	15	59.0	6.7	44	111.2	49	120	248
-246	-410		-90.0	-130	-202	-8.9	16	60.8	7.2	45	113.0	54	130	266
-240	-400		-84.4	-120	-184	-8.3	17	62.6	7.8	46	114.8	60	140	284
-234	-390		-78.9	-110	-166	-7.8	18	64.4	8.3	47	116.6	66	150	302
-229	-380		-73.3	-100	-148	-7.2	19	66.2	8.9	48	118.4	71	160	320
-223	-370		-67.8	-90	-130	-6.7	20	68.0	9.4	49	120.2	77	170	338
-218	-360		-62.2	-80	-112	-6.1	21	69.8	10.0	50	122.0	82	180	356
-212	-350		-56.7	-70	-94	-5.6	22	71.6	26.7	80	176.0	88	190	374
-207	-340		-51.1	-60	-76	-5.0	23	73.4	27.2	81	177.8	93	200	392
-201	-330		-45.6	-50	-58	-4.4	24	75.2	27.8	82	179.6	99	210	410
-196	-320		-40.0	-40	-40	-3.9	25	77.0	28.3	83	181.4	100	212	414
-190	-310		-34.4	-30	-22	-3.3	26	78.8	28.9	84	183.2	104	220	428
-184	-300		-28.9	-20	-4	-2.8	27	80.6	29.4	85	185.0	110	230	446
-179	-290		-23.3	-10	14	-2.2	28	82.4	30.0	86	186.8	116	240	464
-173	-280		-17.8	0	32	-1.7	29	84.2	30.6	87	188.6	121	250	482
-169	-273	-459.4	-17.2	1	33.8	-1.1	30	86.0	31.1	88	190.4	127	260	500
-168	-270	-454	-16.7	2	35.6	-0.6	31	87.8	31.7	89	192.2	132	270	518
-162	-260	-436	-16.1	3	37.4	0.0	32	89.6	32.2	90	194.0	138	280	536
-157	-250	-418	-15.6	4	39.2	0.6	33	91.4	32.8	91	195.8	143	290	554
-151	-240	-400	-15.0	5	41.0	1.1	34	93.2	33.3	92	197.6	149	300	572
-146	-230	-382	-14.4	6	42.8	1.7	35	95.0	33.9	93	199.4	154	310	590
-140	-220	-364	-13.9	7	44.6	2.2	36	96.8	34.4	94	201.2	160	320	608
-134	-210	-346	-13.3	8	46.4	2.8	37	98.6	35.0	95	203.0	166	330	626
-129	-200	-328	-12.8	9	48.2	3.3	38	100.4	35.6	96	204.8	171	340	644
-123	-190	-310	-12.2	10	50.0	3.9	39	102.2	36.1	97	206.6	177	350	662
182	360	680	349	660	1220	516	960	1760	682	1260	2300	849	1560	2840
188	370	698	354	670	1238	521	970	1778	688	1270	2318	854	1570	2858
193	380	716	360	680	1256	527	980	1796	693	1280	2336	860	1580	2876
199	390	734	366	690	1274	532	990	1814	699	1290	2354	866	1590	2894
204	400	752	371	700	1292	538	1000	1832	704	1300	2372	871	1600	2912
210	410	770	377	710	1310	543	1010	1850	710	1310	2390	877	1610	2930
216	420	788	382	720	1328	549	1020	1868	716	1320	2408	882	1620	2948
221	430	806	388	730	1346	554	1030	1886	721	1330	2426	888	1630	2966
227	440	824	393	740	1364	560	1040	1904	727	1340	2444	893	1640	2984
232	450	842	399	750	1382	566	1050	1922	732	1350	2462	899	1650	3002
238	460	860	404	760	1400	571	1060	1940	738	1360	2480	904	1660	3020
243	470	878	410	770	1418	577	1070	1958	743	1370	2498	910	1670	3038
249	480	896	416	780	1436	582	1080	1976	749	1380	2516	916	1680	3056
254	490	914	421	790	1454	588	1090	1994	754	1390	2534	921	1690	3074
260	500	932	427	800	1472	593	1100	2012	760	1400	2552	927	1700	3092
266	510	950	432	810	1490	599	1110	2030	766	1410	2570	932	1710	3110
271	520	968	438	820	1508	604	1120	2048	771	1420	2588	938	1720	3128
277	530	986	443	830	1526	610	1130	2066	777	1430	2606	943	1730	3146
282	540	1004	449	840	1544	616	1140	2084	782	1440	2624	949	1740	3164
288	550	1022	454	850	1562	621	1150	2102	788	1450	2642	954	1750	3182
293	560	1040	460	860	1580	627	1160	2120	793	1460	2660	960	1760	3200
599	570	1058	466	870	1598	632	1170	2138	799	1470	2678	966	1770	3218
304	580	1076	471	880	1616	638	1180	2156	804	1480	2696	971	1780	3236
310	590	1094	477	890	1634	643	1190	2174	810	1490	2714	977	1790	3254
316	600	1112	482	900	1652	649	1200	2192	816	1500	2732	982	1800	3272
321	610	1130	488	910	1670	654	1210	2210	821	1510	2750	988	1810	3290
327	620	1148	493	920	1688	660	1220	2228	827	1520	2768	993	1820	3308
332	630	1166	499	930	1706	666	1230	2246	832	1530	2786	999	1830	3326
338	640	1184	504	940	1724	671	1240	2264	838	1540	2804	1004	1840	3344
343	650	1202	510	950	1742	677	1250	2282	843	1550	2822	1010	1850	3362
1016	1860	3380	1143	2090	3794	1271	2320	4208	1399	2550	4622	1527	2780	5036
1021	1870	3398	1149	2100	3812	1277	2330	4226	1404	2560	4640	1532	2790	5054
1027	1880	3416	1154	2110	3830	1282	2340	4244	1410	2570	4658	1538	2800	5072
1032	1890	3434	1160	2120	3848	1288	2350	4262	1416	2580	4676	1543	2810	5090
1038	1900	3452	1166	2130	3866	1293	2360	4280	1421	2590	4694	1549	2820	5108

Table A-23 continued
Temperature Conversions

In the center column, locate the temperature to be converted. In the left and right columns are the converted (and rounded off) Celsius and Fahrenheit temperatures, respectively.

C		F	C		F	C		F	C		F	C		F
1043	1910	3470	1171	2140	3884	1299	2370	4298	1427	2600	4712	1554	2830	5126
1049	1920	3488	1177	2150	3902	1304	2380	4316	1432	2610	4730	1560	2840	5144
1054	1930	3506	1182	2160	3920	1310	2390	4334	1438	2620	4748	1566	2850	5162
1060	1940	3524	1188	2170	3938	1316	2400	4352	1443	2630	4766	1571	2860	5180
1066	1950	3542	1193	2180	3956	1321	2410	4370	1449	2640	4784	1577	2870	5198
1071	1960	3560	1199	2190	3974	1327	2420	4388	1454	2650	4802	1582	2880	5216
1077	1970	3578	1204	2200	3992	1332	2430	4406	1460	2660	4820	1588	2890	5234
1082	1980	3596	1210	2210	4010	1338	2440	4424	1466	2670	4838	1593	2900	5252
1088	1990	3614	1216	2220	4028	1343	2450	4442	1471	2680	4856	1599	2910	5270
1093	2000	3632	1221	2230	4046	1349	2460	4460	1477	2690	4874	1604	2920	5288
1099	2010	3650	1227	2240	4064	1354	2470	4478	1482	2700	4892	1610	2930	5306
1104	2020	3668	1232	2250	4082	1360	2480	4496	1488	2710	4910	1616	2940	5324
1110	2030	3686	1238	2260	4100	1366	2490	4514	1493	2720	4928	1621	2950	5342
1116	2040	3704	1243	2270	4118	1371	2500	4532	1499	2730	4946	1627	2960	5360
1121	2050	3722	1249	2280	4136	1377	2510	4550	1504	2740	4964	1632	2970	5378
1127	2060	3740	1254	2290	4154	1382	2520	4568	1510	2750	4982	1638	2980	5396
1132	2070	3758	1260	2300	4172	1388	2530	4586	1516	2760	5000	1643	2990	5414
1138	2080	3776	1266	2310	4190	1393	2540	4604	1521	2770	5018	1649	3000	5432

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Appendix F Development of Corporate Standards and Guidelines

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