

Process Analyzers

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Process Analyzers

Section A—Process Analyzer Considerations

A.1 Scope

Process monitors that measure and transmit information about chemical composition, physical properties, or chemical properties are known as *process analyzer systems*. Many of these systems were first developed for laboratory analysis. Today they are primarily used as continuous on-line analyzers.

A process monitoring system usually requires a sample conditioning system, a process analyzer, and one or more data output devices. Properly designed systems also require overall considerations as to calibration, utilities, sample disposal, safety, and systems packaging.

Process analyzers measure chemical concentrations or physical or chemical properties that can be used as control variables instead of relying on indirect physical parameters, such as pressure, temperature, and inferred data from computer models. Process analyzer systems can provide a significant economic return when incorporated into process optimization and advanced control loops or when used for product quality control.

This section will address the generic design factors that must be taken into consideration in the design and implementation of all analyzer applications.

Chapter 1 provides general information to be considered in the design of analyzer systems.

Chapter 2 describes the requirement for analyzer system data management.

Chapter 3 provides information on analyzer calibration and validation.

Chapter 4 provides an overview of analyzer sample system design considerations.

Chapter 5 describes the benefits of pre-packaging analyzer systems versus field construction methods.

Chapter 6 provides information on the installation and maintenance of analyzer systems.

Chapter 7 provides information on safety in the design of analyzer systems.

1 Analyzer Selection Design Requirements

1.1 Economic Considerations

Analyzer systems can improve product quality, increase the yields of products with higher economic value, increase product throughput and output, and reduce energy costs.

Process analyzer systems should be considered for product quality control when frequent and rapid measurements are required because of fast and substantial variations in process stream quality.

If an analyzer system is to be installed to improve operational efficiency of a process unit, the installation should be justifiable from an economic standpoint. Increased profit from improved efficiency combined with decrease in off-spec material produced must be weighed against the cost of installing, operating, and maintaining the system.

1.2 Environmental and Safety Considerations

Today, environmental standards are becoming more stringent. The use of analyzers for safety or environmental monitoring should be considered in compliance with the regulations of the agencies specifying such monitoring and documentation requirements.

Process analyzers are used to detect hazardous plant conditions and for monitoring government-mandated requirements concerning pollutants in ambient air, stack emissions, risk mitigation, equipment, personnel protection, and effluent streams.

1.3 Technical Considerations

Several technical criteria should be considered when specifying a process analyzer. These are often summarized in a data sheet, and most often would include the following information.

- a) *Measured variable*: The variable of interest could be a pure element (such as O₂, H₂, or N₂), an inorganic compound (such as CO, NO₂ or H₂SO₄), an organic compound or group (such as CH₄, C₆+ or TOC), a chemical property (such as pH, ORP, or electrolytic conductivity), or a physical property (such as specific gravity, opacity or vapor pressure).
- b) *Measurement range*: The range of measurement includes a lower limit (not always zero), and upper limit and the unit of measurement. When the unit of measurement is percent, ppm or ppb, the measurement basis should be included (i.e. mole %, weight ppm, etc.)
- c) *Measurement purpose*: It is important to establish the analyzer purpose, such as process monitoring, process control, quality control, safety, regulatory compliance, etc. in order to make a proper analyzer selection.
- d) *Complete Stream Composition*: Provide expected sample stream composition of all components in the stream. This should include the minimum and maximum concentrations, toxic and corrosive properties. This information will be used to maximize the analyzer's capability to function properly during startup, upset process conditions, and to properly design sample conditioning systems. Provide all operational parameters at the sample point (pressure, temperature, and flow) including the minimum, maximum, and design values. This information will be used to determine the sample extraction probe design or in situ interface, when required.
- e) *Application method*: First a determination must be made regarding whether a physical or chemical property or a composition analyzer is required. Then a determination must be made on the specific measurement method (such as infrared spectrophotometry, gas chromatograph, chemiluminescence, etc.). Such method is typically selected for a particular measurement or analysis according to process experience.
- f) *Repeatability and accuracy*: The design of all analyzer applications should consider accuracy and high/low limits of detection. Emphasis is usually placed on analyzer stability and repeatability of the measurement. The capability of the analyzer must match the requirements of the analysis required.
- g) *Analyzer Availability*: A goal of 95 % or greater on-stream factor of on-line availability is generally desired. Analyzers exhibiting less than 95 % are generally not considered reliable by operations. Analyzers should operate at 98 % or greater availability for use in closed loop control applications. Analyzer availability is defined as the percentage of time the analyzer is operating reliably, relative to process operations. Reliability of the analyzer system, commitment of maintenance personnel, and ease of maintenance contribute to Analyzer Availability.
- h) *Overall system response time*: This is the total time required to take a representative sample, transport, condition, analyze the sample, and transmit the measurement results.
- i) *Sample conditioning*: The location of the sample tap in the process is important to obtain a representative sample. Ensure that the process conditions are a single phase (100 % liquid or gaseous) at the sample tap. A sample

conditioning system must extract, transport and deliver a representative, contaminant-free, single phase sample to the analyzer, conditioned for pressure, temperature and flow. One method of sample conditioning is to provide a sample probe.

- j) *Sample Probe*: The sample probe provides primary particulate rejection through kinetic energy. This is accomplished by the process fluid velocity and prevents pipeline “wall creep” debris from entering the sample transport tubing. Thus the sample probe is an essential component of the sample system. See 4.3.3 for additional information on sample probes.
- k) *Installation*: Consideration must be given to area electrical classification, protection from the environment, ambient temperature variation effects, ease of availability for maintenance, cylinder storage and replacement accessibility, and sample disposal requirements. The location of sample taps and fast loop requirements should be evaluated when determining analyzer shelter placement.
- l) *Maintenance*: Maintenance requirements including frequency, and resources should be considered early in the design phase.
- m) *Operating costs*: These should include the cost of utilities, consumables, spare parts, labor, and maintenance.
- n) *Safety*: Personnel shall be protected from hazardous conditions associated with analyzer systems. These include toxic, explosive, chemical, electrical, and mechanical hazards.
- o) *Training*: Training of operations and maintenance personnel is necessary to ensure the analyzer functions as designed throughout its life cycle.
- p) *Environmental requirements*: If an analyzer is required for regulatory monitoring the analyzer must comply with all applicable regulations.

2 System Data Management Requirements

2.1 General

Data transmission is an important consideration in the analyzer system design. Three types of transmissions are common: analog transmission, digital transmission, and discrete.

2.2 Analog Transmission

The electronic output signal from the analyzer is a voltage or current proportional to the measured parameters in the stream. The most common analog signal is 4-20 mA DC. Analog signal loops may be powered from the analyzer (4-wire transmitter) or from the receiving device (2-wire transmitter). A few analyzer manufacturers use the 0-4 mA range of a 4-20 mA signal to transmit special alarms for diagnostic information.

2.3 Digital Transmission

Analyzer communication via a direct serial link is a means of transmitting measurement and status information. Analyzers equipped with one or more serial ports can be interfaced to networks and/or devices such as a printer, central processor unit, personal computer, host computer, or basic process control system (BPCS). Serial ports are also capable of two-way communications. The data messages communicated are not limited to concentration values and may include such things as alarms, system status, data validation or calibration commands, program commands, and diagnostic maintenance routines such as reconstructed chromatograms for process gas chromatographs.

Analyzer status information available through a serial port can include data validation status and hardware status information that can be used by the BPCS for implementing process control strategies.

Typical alarms for data validation are as follows:

- a) tolerance against calibration check (validation) drift;
- b) excessive change of data output;
- c) excessive baseline noise and drift;
- d) peak drift for gas chromatographs;
- e) communication failure;
- f) EPROM error;
- g) optical integrity for photometers/spectrometers.

Typical alarms for analyzer system status information include the following:

- a) loss of sample flow;
- b) loss of utilities;
- c) hardware failure;
- d) loss of pressurization;
- e) loss of power;
- f) temperature inside shelter;
- g) toxic/LEL inside shelter;
- h) oxygen deficiency in shelter.

For multi-analyzer distributed systems, each analyzer produces output data completely independent of any central programmer or central computer system, data highways are used for transmitting analytical data and analyzer status information. Data highways allow many analyzers to communicate through one network to a central location. A distributed system typically may also contain a central operator station for analyzer management and maintenance. Such communication requires simple installation of only two to four wires for linking all the analyzers in the system. Precautions must be made to protect this highway path from the risk of damage or failure so all communications and control will not be lost. For example, if a redundant highway is available, each path should be routed in different physical paths.

Figure 2-1 represents a general multi-analyzer distributed system with typical highway links. Most highway systems then link to a BPCS through a common gateway with a standard communication protocol. The analyzer communication interface connecting to a host device must be coordinated between equipment suppliers to assure compatibility. The communication may require writing a driver program to collect and format the data so as to be compatible with the host device.

Remote links incorporated into analyzer highway systems can include a modem link for remote factory maintenance support.

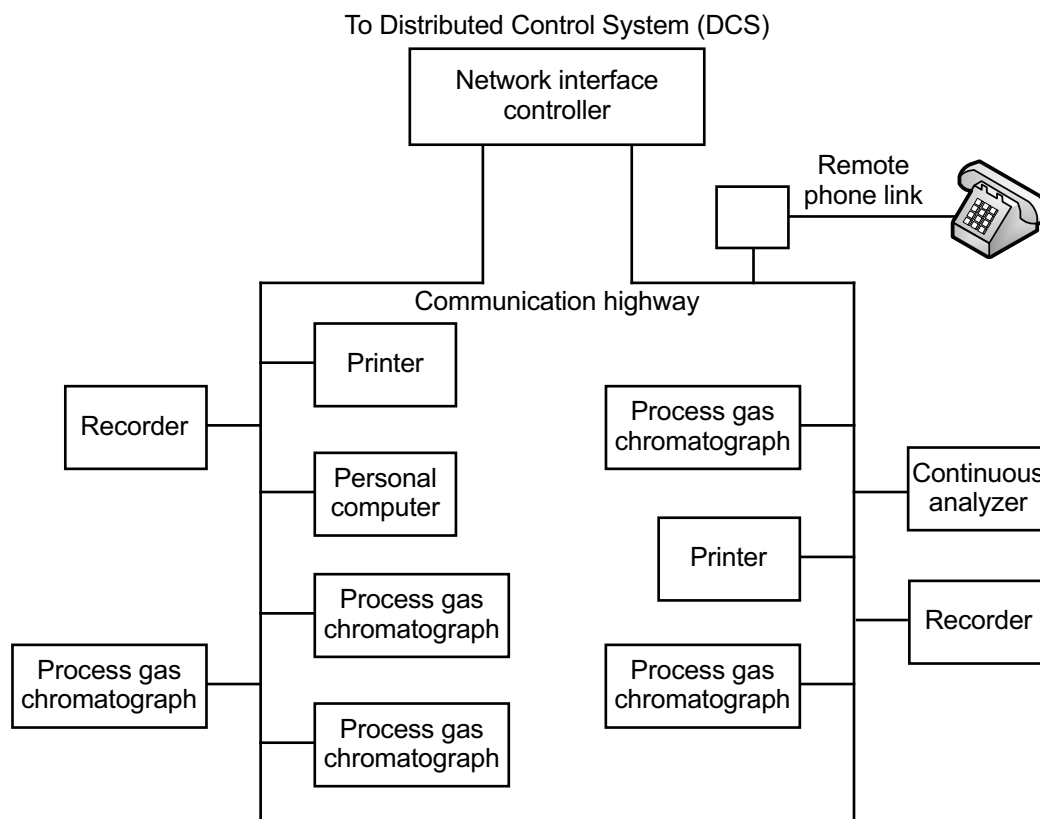


Figure 2-1—Multi-analyzer Distributed System

2.4 Discrete Transmission

Discrete contacts may be available to transmit status information such as validity, analyzer integrity and alarms. Such contacts carry a design rating that must be compatible with the voltage and current to be applied in the loop (i.e. 24V DC, 1 amp). Most often voltage for a discrete signal loop is provided from the receiving device rather than from the analyzer (dry contacts). Both the contact rating and the source of loop power should be determined in advance to ensure loop functionality.

2.5 Other Types of Protocols

Other types of protocols provide diagnostics and additional alarm signals not usually available through analog or discrete outputs. Refer to the different suppliers for their specific capabilities.

3 Analyzer System Calibration and Validation

3.1 General

To determine whether an analyzer is performing properly, it should be checked against calibration/validation samples.

3.2 Calibration

3.2.1 General

Calibration is an important part of the startup, as well as the continuing operation of a process stream analyzer. Depending upon the type of analyzer, its history, and how critical its analysis may be, calibration can be an occasional or routine check to see if the analyzer is operating within acceptable limits.

This section discusses only general methods of calibration because the types of analyzers are too numerous and varied to give specific details for each. The manufacturer's instruction manuals are usually detailed enough to determine the preferred method for calibrating a particular analyzer.

3.2.1.1 Purpose of Calibration

Before an analyzer is shipped from the manufacturing facility, it is operationally tested by the manufacturer to demonstrate performance to design specifications. This calibration data can then be used as a reference for future operational and performance analyzer checks.

It is recommended that an owner or owner's representative witness calibration during inspection at the manufacturer's facility and also during commissioning. Calibration will also be required after a maintenance shutdown or after replacement of parts in the sensing mechanism (such as light or power sources, detector elements, or columns, in the case of a chromatograph). Process plant operators may also request a check as part of plant operations.

Quite often calibration is only verification rather than an update or change in the analyzer's calibration factor(s). Apparent disagreements between analyzer and laboratory results are sometimes due to differences between sampling or measurement techniques between the off-line and on-line data. When comparing lab analysis to process analyzer data wrong time stamping and failure to consider test method reproducibility and analyzer repeatability are common mistakes. Historical records may be used to understand the differences and to indicate whether disagreement is an actual error or not (see 3.2.3.5). Statistical Quality Control techniques may be employed to determine if the analyzer should be re-calibrated or merely validated (i.e. calibration components are measured, but the factors are not updated).

3.2.1.2 Personnel

In most plants, an analyzer maintenance specialist is responsible for the validity and accuracy of the measurement. Refer to Chapter 6 for the qualifications of calibration and commissioning personnel.

An understanding of the sample's chemistry and the analyzer's measuring method will help in procuring suitable standards and in calibrating the device. Laboratory personnel involved in preparing or analyzing calibration standards should understand the principle or technique used in the process analyzer.

Familiarity with measurement units with each type of analyzer [such as mole percent, liquid volume percent or PPM (v/v)] is important for performing a successful calibration.

The analyzer maintenance specialist should understand the process analyzer's theory of operation. This can be useful in deciding whether a change in results is due to component failure or aging.

The specialist should also understand the operation of the sample system associated with the analyzer, since problems with calibration can be caused by problems of the sample system itself.

3.2.2 Standards for Calibration

3.2.2.1 Sources for Standards

Sources for calibration should be certified and traceable to standards provided by the National Institute of Standards and Technology (NIST), or other governmental laboratories that provide traceable certified standards.

A source for calibration information is a laboratory analysis of samples taken from the identified process stream. To avoid possible errors, the container utilized for lab analysis should be used for the process calibration check, thereby maintaining the uniformity of the media. The lab analysis should be made on more than one analyzer where possible. Lab results should then be averaged and the variation in results should be within the test method reproducibility.

Multiple samples and laboratory analyses, plus knowledge of the laboratory's confidence factor are needed to translate the analysis to a standard value. Differences between the laboratory analytical method and the process analyzer's analytical method may result in different measurement data. The confidence factor will indicate if the results are reasonable. The traceable standard should be used as a baseline.

A process line sample calibration uses laboratory analyses of plant samples drawn during steady-state operation. Analyzer readings are noted and then used to make new settings if significant differences are detected. Daily (or routine) laboratory results are used to plot trends for comparison with those of the process analyzer; however, the analyzer may have inherent drift tendencies that must be corrected for on a more frequent basis to achieve the highest accuracy.

A reference sample can be either a retained process stream taken during normal or desirable operation, as described above, or a synthetic blend prepared, analyzed, and certified by a commercial supplier. The synthetic standard may be necessary for materials that react with other ingredients when left standing, or when cooled, or to allow calibration of a material that polymerizes or decomposes with time. "Pure" compounds (gas or liquid) can be used to set the "span" or full-scale reading for some analyzers just as pure air or nitrogen can be used to obtain a zero setting. The retained process stream can serve as an inexpensive "secondary standard" to verify analyzer operation, using the expensive and complex synthetic blend only when required to resolve response issues or full calibration. On occasion process samples can be hazardous and alternative safer calibration fluids can be found. For example, safer fluids are with similar physical properties or chemical composition without the hazardous fluid.

3.2.2.2 Equipment for Calibration

Cylinders containing the calibration standard are often stored at the analyzer location. Some provision should be made for protecting the cylinders from the elements and from tampering. Records of the standard's analysis should be filed for future use since tags or stencil markings on the cylinders can fade or become illegible. Temperature-sensitive samples vapor or liquid, must be stored and used under their design conditions.

Maintain proper records of Certificate of Analysis for all standards used for calibration/validation of process analyzers. These standards must be replaced or recertified upon the expiration of the Certificate of Analysis. Proper storage and connection of calibration standards should be considered in design.

Regulators should be reserved for "standard" service to minimize contamination errors. Tools required to connect and disconnect standard sources should be a part of the operating supplies. Thermometers, pressure gages, flow-measuring devices, and other tools are often needed to verify calibration.

A facility may prepare "check" standards on-site. Additional equipment required includes absolute pressure gages, vacuum pumps, cylinders of "pure" gases to make gas blends, and containers of "pure" liquids to make liquid mixtures.

A supply of small cylinders to transport pressurized samples to a laboratory for checking can be useful for off-line verification.

3.2.3 Calibration Procedures

If service work that can change the output signal of an analyzer is to be performed, the operations personnel should be notified. If the analyzer is used for process control then steps must be taken to switch the controller to manual mode or hold mode.

All calibration procedures should be well documented in a written step-by-step form to ensure repeatability between technicians.

3.2.3.1 “Automatic” Calibration Systems

If the analyzer system is automated to the extent that it periodically (daily or weekly) checks its output reading against a standard, personnel servicing the analyzer may be required only to check the flow rate or pressure gage readings or to verify the operation of solenoid valves. Programmed limit values can be used to alert the user to abnormal readings.

A semiautomatic system allows the service person or process operator to check or update analyzer readings. Again, sample pressure or flow should be checked visually or by the programmed limits.

A preliminary check of the standard(s) should include details such as the age, pressure, or volume remaining and the ambient temperature.

3.2.3.2 Zero/Span Calibration Systems

Some analyzers are calibrated by adjusting the output readings of a fluid containing none of the components of interest (zero) and then adjusting the output readings to match another fluid containing a high-scale amount of the component (span). The high scale value is typically about 80 % of full scale. For such analyzers, the following calibration procedures are recommended.

- a) Turn off the process sample to the analyzer.
- b) Turn on and adjust the flow of the zero standard.
- c) When readings stabilize, make adjustments if necessary.
- d) Turn off the zero standard.
- e) Turn on and adjust the flow of the span standard.
- f) When readings stabilize, make adjustments if necessary.
- g) Turn off the span standard, and turn on the process stream flow.

Several iterations will be required if the zero and span adjustments are interactive. Double Block and Bleed valves can be used to improve isolation of process fluids when introducing calibration fluids to prevent cross contamination.

3.2.3.3 Complex Analyzer Systems

In more complex analyzer systems, standards containing one or more components of interest are introduced to set or verify factors. For such analyzers, the following calibration procedures are recommended.

- a) Set the analyzer controls to calibration or manual mode, and suspend process values normally at existing values.
- b) Turn off the process sample to the analyzer.
- c) Turn on and adjust the flow of the standard. (If the calibration mode computes new factors, compare the new factor with the old factor.)
- d) Run multiple analyses if output values differ from the standard value to confirm signal values are within the acceptable repeatability range.
- e) Verify error values and if percent of the maximum error is exceeded, then adjust factor settings or enter new data to the control device.

- f) Turn off the standard and turn on the process stream flow.
- g) Restore the suspended values with the new process value readings.

Caution—Before updating the value of the latest factor or changing the analyzer calibration, consider the quality of the standard and the calibration history of the analyzer. Some standards can change with age. A laboratory calibration, especially for blended standards, is recommended at least every 3 months.

3.2.3.4 Alternative Forms of Calibration Check

In analyzer systems where the standard comes from a known process sample, the standard is introduced when the system is in a normal mode (except that the output is off-line). Readings are compared with the known values of the components or quality of interest. For such analyzers, the following calibration procedures are recommended.

- a) Shut off plant sample flow.
- b) Turn on the standard and adjust the flow.
- c) When the analyzer readings stabilize, compare readings with the known values.
- d) Make adjustments.
- e) Rerun the standard to verify the new settings.
- f) Turn off the standard and turn on the plant sample.
- g) Put the analyzer system back in operation.

3.2.3.5 Calibration History

A schedule of routine calibration checking should be set up as a part of the analyzer's maintenance procedures. Records of monthly, weekly, or even daily checks serve to increase the user's confidence in the analyzer, as well as to alert the technician to signs of impending analyzer failures. A well designed analyzer system may show no change between periodic calibration checks. The checks then serve as a verification of the equipment's stability. In the case of an analyzer malfunction, the calibration procedure becomes a part of troubleshooting, either by showing an analyzer fault or directing attention to other components, such as the sample system or recorder. The frequency of these checks may vary depending upon the criticality of the measurement. Small process analysis errors can result in large economic losses. The calibration frequency depends on the process criticality and frequency of analyzer failures.

A maintenance history can be brief or extensive but as a minimum should include a log of repair, component replacement, calibration, and consumables replacement, complete with dates and technicians' names for each entry.

Many users set up individual folders for each analyzer as a means of storing these documents. Some have established computer programs for accumulating maintenance history and costs and for scheduling preventive maintenance.

3.2.4 Calibration Criteria

3.2.4.1 Accuracy

The main reason for calibrating an analyzer is to ensure that the analyzer provides an accurate result. In most cases, accuracy is limited by the standard analysis or laboratory results. If an analyzer is calibrated to an erroneous standard, the output is in error even though it may be useful for following changes in the process. The cost of

achieving a certain degree of accuracy may be a limiting factor. If high accuracy is required, repeated analyses of standards, verification through parallel lab analyses, and cross-checks with the process operation are important parts of the analyzer maintenance program. The user must establish acceptable calibration accuracy criteria.

3.2.4.2 Repeatability and Reproducibility

The repeatability of a process analyzer is its ability to give the same reading, using the same method on identical test material under the same conditions. Repeatability can be stated as the difference between successive results.

Reproducibility is the closeness of agreement between independent results with the same method on identical test material but under different conditions (different operators, different apparatus, different laboratories, and/or after different intervals of time).

3.2.4.3 Linearity

A sample standard is necessary for each calibration point. Analyzers that inherently have poor linearity will require multiple calibration points. In addition to zero and span standards, intermediate concentrations may be required to establish a “curve-fit” of detector response to concentration.

Although not a typical specification, linearity has an impact on accuracy which is typically quoted as $\pm$ % of reading. Linearity error problems usually are minimized if the analyzer can be calibrated at a value close to the normal process concentration.

3.3 Validation

Validation is confirming the analyzer readings using known samples without adjusting factors.

Fully automated systems using Statistical Quality Control (SQC) methods to flag performance issues provides validation.

Where the repeatability of the analyzer is closer than the reproducibility of the reference laboratory test, calibration/validation samples should be multi-tested to reduce the standard error of the mean.

Detailed information on the validation of analyzers can be found in ASTM D-3764, *Standard Practice for Validation of Process Analyzers*.

Process analyzers can be installed with remote validation capability. A substantial amount of maintenance time is spent validating analyzers because of a request by operations, often with no analyzer problem. Designing the sample system with remote validation capability (e.g. from BPCS) can save in valuable maintenance personnel hours. Validation “Pass”, “Fail”, and “validation request denied” (e.g. low validation fluid flow) flags can be activated to inform the operator of the analyzer condition.

Validation results should be evaluated to determine the frequency of future validations. Too many validations are a waste of maintenance time, and too few validations can lead to excessive analyzer errors. Manufacturer recommendations should be considered.

4 Sample Conditioning

4.1 General

Sample conditioning systems are comprised of all the components necessary to extract a representative sample and to transport and condition it for measurement by the analyzer. The design of the total sample conditioning system must be engineered for each specific application.

The sample conditioning system assemblies are sometimes complex (actually small chemical processes with control systems) and if poorly designed may be often the least reliable segment of an analyzer system.

It is important that all factors that influence an overall system and the operation of an analyzer be given thorough consideration. Such factors as unknown process conditions, process upsets, and contaminants can lead to poor designs.

4.2 Functions of a Sample System

The functions performed by the sample conditioning system as the interface between the process and the process analyzer include the following:

- a) Taking and delivering a representative sample from the process.
- b) Transporting the sample from the sample tap to the analyzer and from the analyzer to the spent sample recovery system or process return point to reduce the sample transport time.
- c) Conditioning the sample by controlling the pressure, temperature and flow rate. Filtering and phase maintenance of the sample are also addressed in order to make the sample compatible with the process analyzer.
- d) Sample-stream switching and calibration/validation switching into the analyzer.
- e) Control of dew/bubble point.
- f) Design incorporates capability for ease of maintenance, cleaning, or (when needed) flushing the entire system.

4.3 Design Factors

4.3.1 Sample Stream Composition

The complete stream composition of all the components and contaminants must be considered. Some contaminants, such as solids or entrained liquids in a gaseous stream, may have to be removed in order to deliver a single phase sample to the analyzer. The process conditions and range of all components during normal and especially abnormal conditions (such as startup, shutdown, rate change, and so forth) must be considered for the analyzer application and sample system design.

4.3.2 Sample Point Location

The following factors should be considered in determining the optimum sample point location.

- a) Locate the sample tap in the process stream where a representative sample can be withdrawn.
- b) It is important to locate the sample tap such that corrective action may best be achieved in the process. Locations downstream of large vessels or accumulators should be avoided due to an increase in lag time that is introduced by the significant volume increase.
- c) Locate the analyzer as near as practical to the sample point to minimize sample transport time while allowing easy access for maintenance.
- d) Location should be considered to offer significant differential pressure if the sample is returned to the process. If possible, avoid sample fast loops around process control valves due to the possibility of the valve being fully open and loss of differential pressure across the valve. If this must be used ensure that the CV of the valve is such that when fully open there is sufficient differential pressure to give required minimum fast loop flow. Sample and return points around control valves present two problems: the sample bypasses the valve when it should be closed and there is little or no sample bypass flow when the control valve is wide open.

- e) Locate the sample tap for ease of access for cleaning and maintenance. Sample taps should be located such that cherry pickers or ladders are not required to reach them.
- f) Locate the sample point where the process reaction or mixing is stable, and avoid sample point location where mixed phases may exist.
- g) Locate the sample tap on the top or side of horizontal process lines, and horizontally in vertical process lines to minimize poor sampling. See Figure 4-1.
- h) Consideration should be given to the use of single or double process isolation valves in the sample line for high pressure or toxic service.

4.3.3 Sample Probes

4.3.3.1 General

Sample probes should be used because they provide a more representative sample due to the higher flow rates away from process pipe walls.

NOTE For small diameter lines, the line may be swaged up to 3 in. with a spool piece to allow a probe to be inserted.

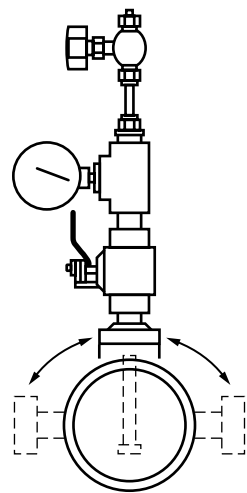
A benefit of the use of sample probes (with extraction near center of pipe) significantly reduces contamination from the inner pipe wall and act as a first stage of filtration and conditioning. Process stream stresses can be significant due to high velocity flow; therefore, stress calculations should be performed on probes and incorporated into design considerations. Corrosive service or high temperatures may require special alloys or materials. Flanged thermowells are often used as sample probes by merely cutting the end off at a 45 degree angle. The probe inlet should face downstream to minimize particulate matter in the extracted sample. Flow direction should be stamped or engraved on any directional probe to minimize errors in installation and reinsertion.

4.3.3.2 Extractive probe: (See Figure 4-2.) Extractive probes are typically made of short lengths of stainless steel or tube, $\frac{3}{8}$ in. or $\frac{1}{2}$ in. outside diameter and used at temperatures up to approximately 1000 °F (540 °C). Removable insertion probes should have a mechanical restraining device to prevent the probe from blowing out when the packing gland is loosened. To prevent probe damage, all sampling probes should have a means of indicating when the probe is pulled out past the process isolation valve. Extractive probes are not recommended in toxic service. Vibration calculations should be made to ensure the probe design is sufficient to prevent the probe from breaking off inside the pipe, where loss of the mechanical restraining device can cause injury to analyzer technician.

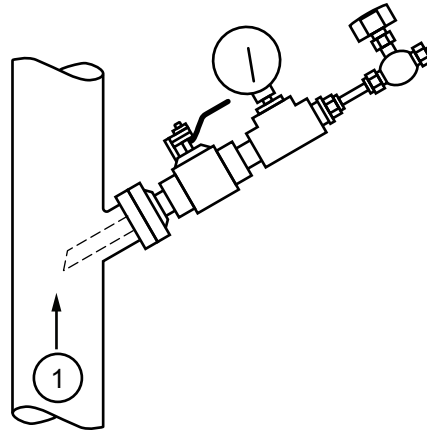
4.3.3.3 Fixed probe: (See Figure 4-3.) Fixed probes cannot be removed from service without interrupting the process. They have the advantage of being less prone to environmental leaks than extractive probes. The minimum bore diameter of a single fixed probe internal diameter is $\frac{3}{8}$ inch. For clean service only $\frac{1}{4}$ in. ID may be used, $\frac{3}{8}$ in. ID or greater for all else.

4.3.3.4 Multiport sample averaging probes: (See Figure 4-4.) Multiport sample averaging probes are used to obtain a sample whose composition is an average of that existing across the entire duct. Averaging is not normally attempted in ducts under 2 ft in diameter. Multiple probe sample averaging is frequently used in flues and stacks of large boilers and heaters in which stratification may be a problem or where required by compliance regulations. The preferred insertion length L and the maximum number of entry holes may be obtained from Figure 4-4.

4.3.3.5 Filter probes: Filter probes are generally used in gas streams such as combustion applications when the stream contains significant quantities of particulate material. The filter materials used are primarily sintered or woven stainless steel and various ceramics. These probes must always be located in the process duct in a manner that minimizes their exposure to particulate matter, or else frequent cleaning will be required. Locating the probe inside and just downstream of a bend, or adding baffles just upstream of the probe minimizes the probe exposure (see Figure 4-5).



Acceptable sampling
point locations from
a horizontal line

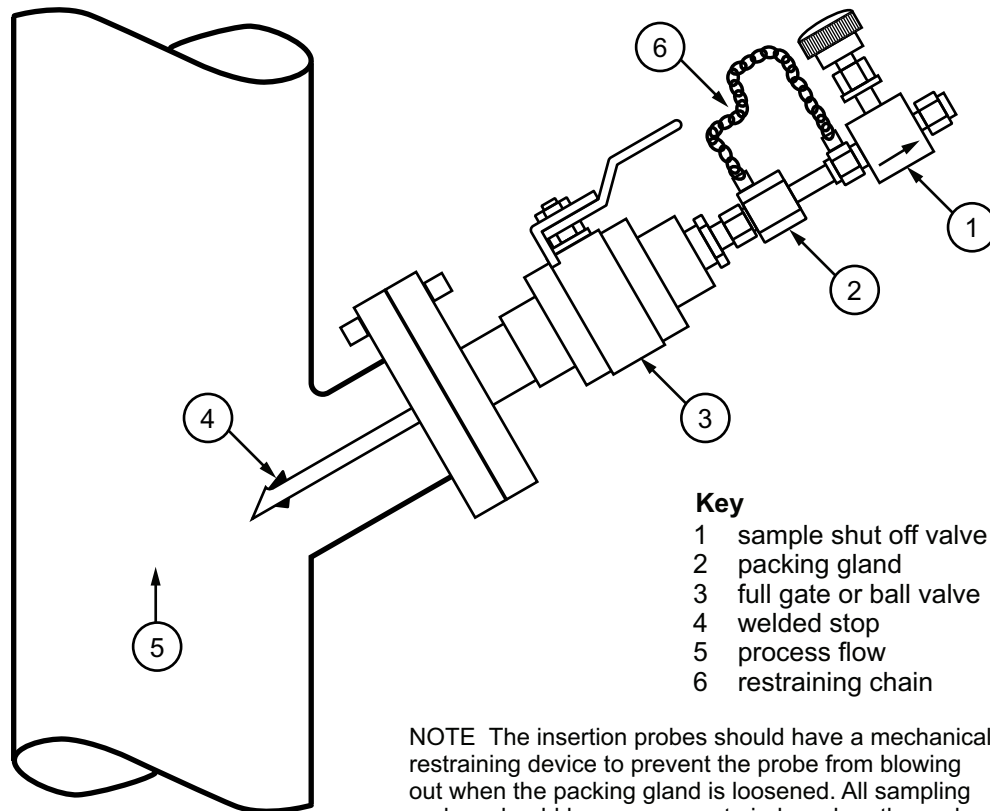


Preferred sampling
on a vertical line

Key

1 flow

Figure 4-1—Acceptable Sampling Areas



Key

- 1 sample shut off valve
- 2 packing gland
- 3 full gate or ball valve
- 4 welded stop
- 5 process flow
- 6 restraining chain

NOTE The insertion probes should have a mechanical restraining device to prevent the probe from blowing out when the packing gland is loosened. All sampling probes should have a means to judge when the probe is pulled out past the valve to prevent probe damage.

Figure 4-2—Insertion Sample Open Probe

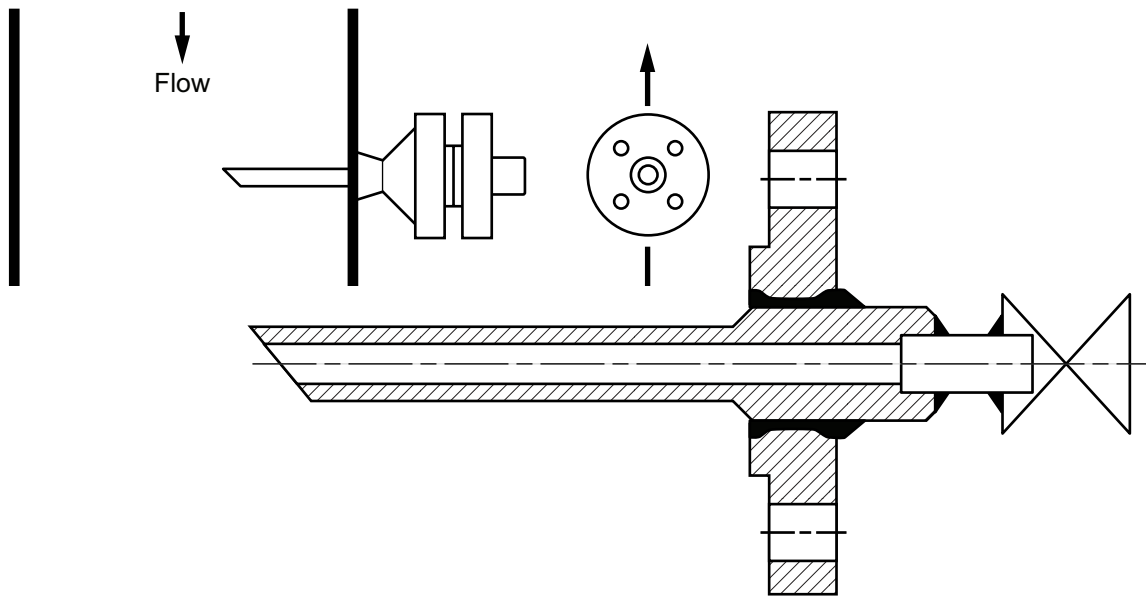
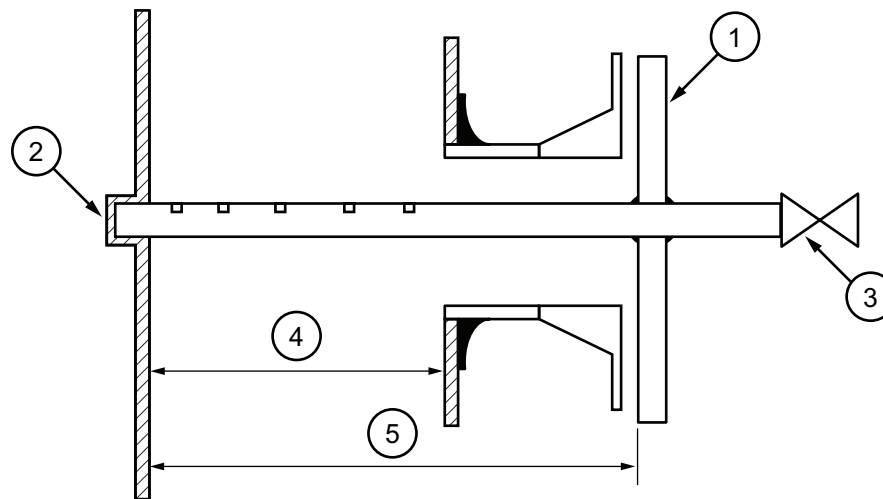


Figure 4-3—Fixed Sample Probe Open Flow Design



Duct area (ft ²)	No. of points	Location of entry holes as fraction of diameter measured from inner wall at sample point
<2	2	0.146, 0.854
2-8	4	0.062, 0.250, 0.750, 0.938
8-12	6	0.044, 0.147, 0.294, 0.706, 0.853, 0.956
12-16	8	0.033, 0.105, 0.195, 0.321, 0.679, 0.805, 0.895, 0.967
16-24	10	0.019, 0.076, 0.153, 0.217, 0.361, 0.639, 0.783, 0.847, 0.924, 0.981

Key

- 1 1 ½ in. to 2 in. NB flange
- 2 for longer probes, support as required
- 3 ball or gate valve (straight-through valve)
- 4 stack diameter
- 5 probe length

Figure 4-4—Multiport Sampling Probe for Flue Gas Analysis



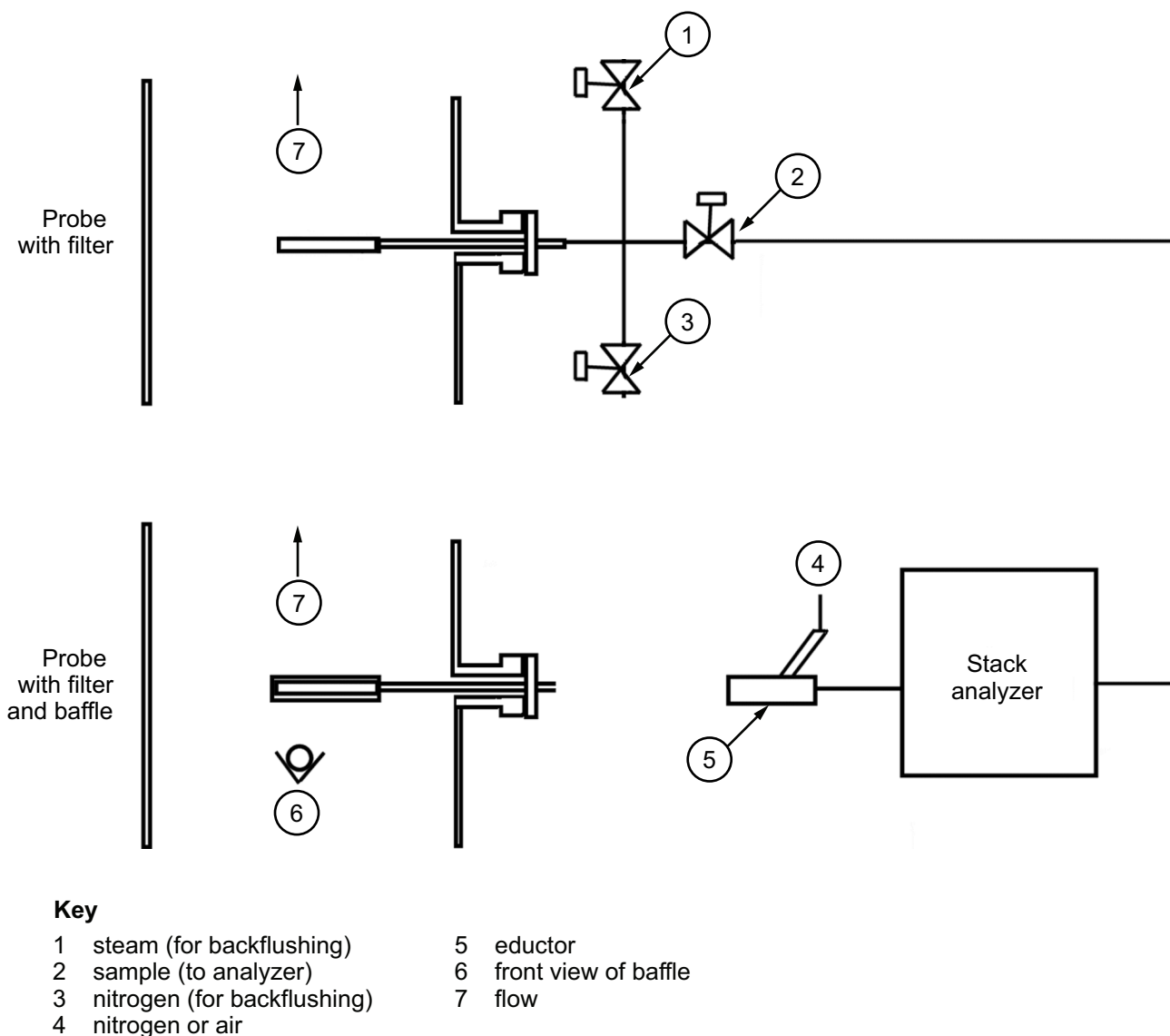


Figure 4-5—Filter Probes

A filter probe must always be operated at a temperature well above the dew point temperature of the stream in which the probe is inserted. Filter probes can be cleaned by removal of the probe from service; however, a more common method is a *blow-back* system, which introduces air, nitrogen, or steam into the sample line to blow back through the filter in the reverse direction. This may be done manually when the sample flow begins to drop to unacceptable levels or automatically at preset intervals. To improve effectiveness filter blowback design should incorporate accumulative blow back gas tanks close to the probe to maximize mechanical shock to the filter. The blowback should be pulsed (e.g. a 1 second pulse with a 5 second air pressure recovery) with up to 5 pulses. This again maximizes shock and reduces the cooling effect on the probe from continual air flow. The sample transport line should be isolated on blowback. If the blow back gas is pulsed and does not drop the sample gas below the dew point temperature, then the blowback gas does not need to be heated.

NOTE Blow-back gas must be compatible with the process stream.

4.3.4 Sample Tap Primary Conditioning

Installation of primary conditioning systems at the sample tap typically allows for more reliable operation of extremely difficult samples that cannot be transported easily to a remote sample conditioning system.

Pyrolysis furnace effluents, regenerator gas from FCCU and reformers or other hot gases with condensable material, particulate matter, and catalyst fines are examples requiring primary sample conditioning in order to maintain a reliable continuous sample draw-off without plugging. A filter reflux column is mounted directly on the process line shut-off valve. The sample is cooled, and the condensable material reflux washes down the solids back into the process line, with a clean saturated sample coming out of the top of the column to the analyzer. Depending on the amount of condensable material available in the sample, steam can be added to the bottom of the column to provide additional condensable material to the reflux and to dilute the acids formed in the process (see Figure 4-6).

Remote pressure let-down and vaporizer regulator stations are another type of primary conditioning system. These stations must be mounted near the sample tap to flash liquid samples and reduce lag times by controlling the sample pressure before transport to the analyzer location. Insulation of a heated enclosure may be required on these installations if the sample dewpoint temperature cannot be maintained.

4.3.5 Sampling Time Dynamics and Transportation Lag Times

In installations where the analyzer and sample system must be located at some distance from the sample point, the sample transport time must be considered. The sample transport time is defined as the time required to transport the sample from the tip of the sample probe to the analyzer inlet.

The total measurement response time is defined as the sample transport time plus the analyzer response time. The analyzer response time for continuous analyzers is often expressed as a T80 or T90 value, designating the time required for an analyzer output signal to achieve 80 % or 90 % of the final measured value from a process step change. For discontinuous analyzers, the cycle time would substitute for the analyzer response time.

A convenient means for reducing the sample transport time is the use of a fast loop connecting process line, sample conditioning system, (commonly located outside the analyzer shelter), and a low pressure return point.

In some applications a lower return pressure may not be found. In this instance either a sample pump can be installed or a sweep stream system can be used (a fast flow by passing the analyzer). A sweep stream sample can be returned into a collection tank (liquids) for pumping back to the process or to flare (gases) for disposal. (see Figure 4-7).

The sample transport time, or lag time, is a function of the sample line length inside line diameter, line pressure (for vapor samples), and sample flow rate. The sample transport time can be calculated by dividing the total volume in the sample line by the average flow rate as described in the following equations.

$$t_{lag} (\text{liquid}) = \frac{(V)(L)}{\text{Flow rate}} \quad (1)$$

$$t_{lag} (\text{vapor}) = \frac{(V)(L)}{F_s} \frac{(P1 + 14.7)}{P2} \frac{(520)}{460 + T} \quad (2)$$

where

t_{lag} is the sample transport time in minutes;

$P1$ is the pressure in sample volume whose lag time is to be calculated, in psig;

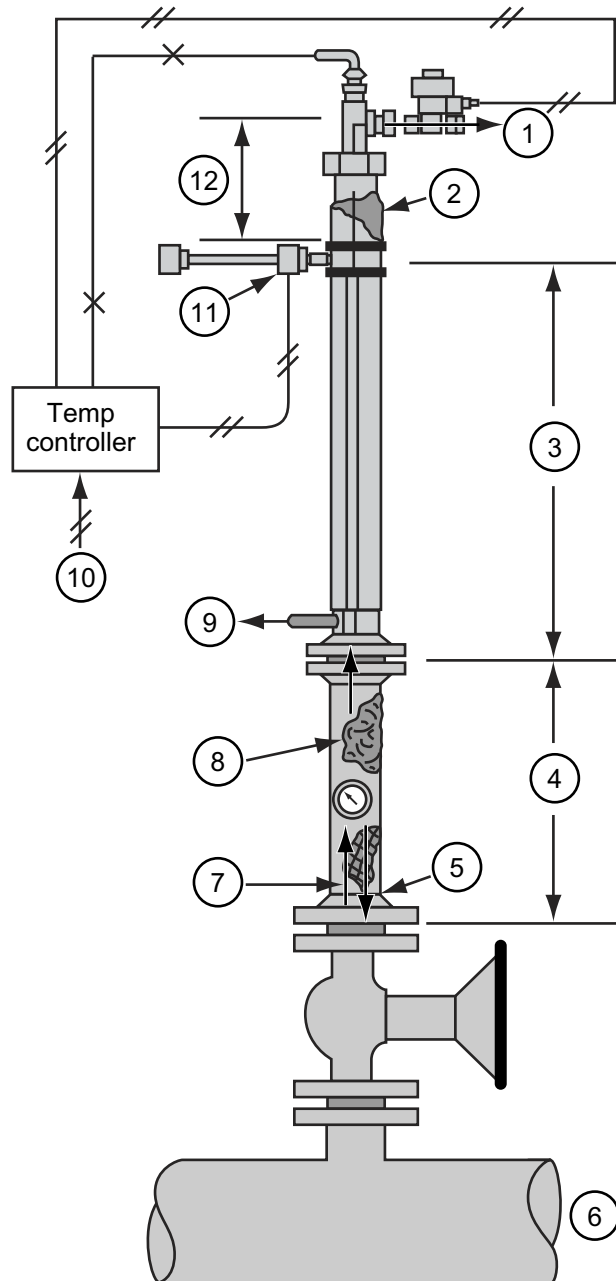
$P2$ is the pressure at point of flow measurement in psig;

V is the tubing volume in cc/ft;

L is the total line length in ft;

F_s is the flow rate in cc/min at standard conditions, (14.7 psia, 60 °F);

T is the temperature in °F.



Key

- | | |
|-------------------------|--------------------------|
| 1 sample to analyzer | 7 sample |
| 2 coalescer | 8 reflux action |
| 3 cooling section | 9 warm coolant exhaust |
| 4 filter reflex section | 10 instrument air supply |
| 5 condensibles | 11 vortex cooling tube |
| 6 process line | 12 conditioning |

Figure 4-6—Pyrolysis Gas Sample Conditioner

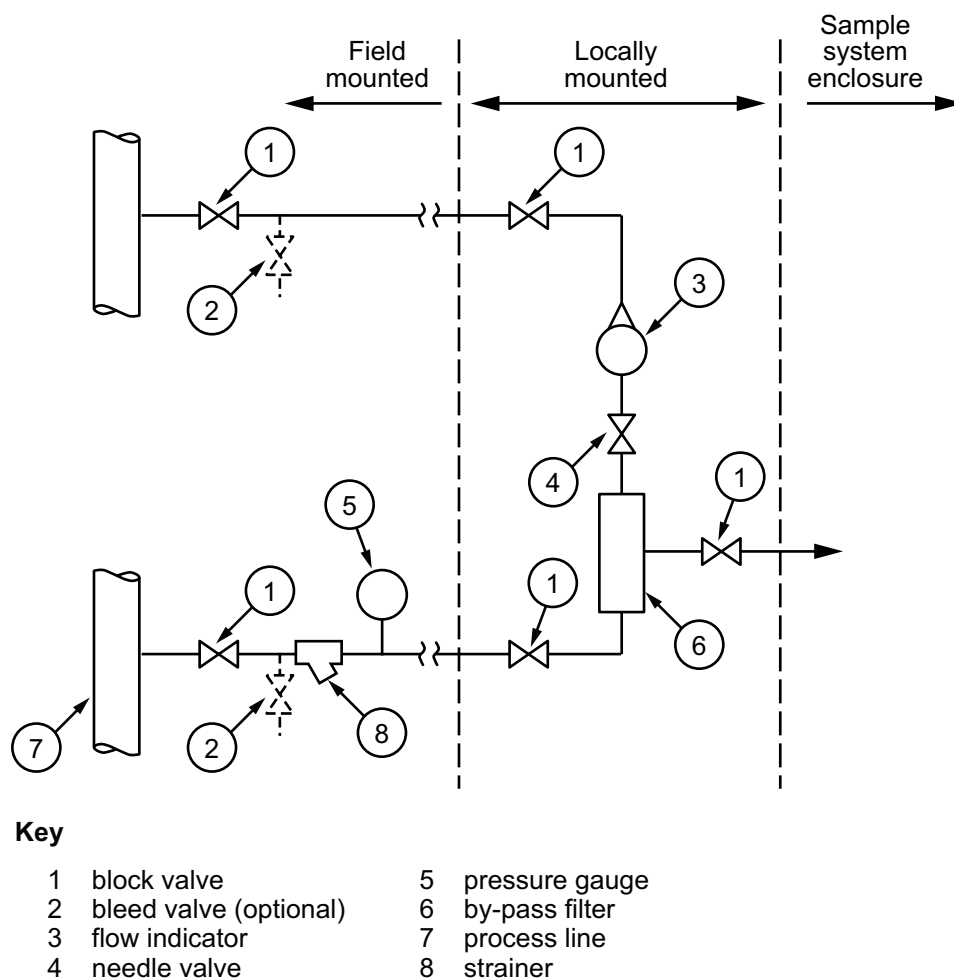


Figure 4-7—Fast Loop Sampling System

Following the ideal gas law, volume varies directly with absolute temperature and inversely with absolute pressure for a fixed quantity of gas. Since gas analyzers are normally vented to atmospheric pressure for stability, the simplest method for determining sample transport lag time is to relate the total gas volume in the system to standard conditions of temperature and pressure (STP). Thus, for any part of a vapor system, the volume at STP can be determined according to Equation 2.

4.3.6 Vaporizing Liquid Samples—Lag Time Considerations

Vaporizing a liquid sample can contribute to a severe lag time because of the expansion effect of a hydrocarbon liquid changing into a vapor. Typically light hydrocarbons can have a vapor expansion of 600 to 1, which results in 1 cubic centimeter (cc) of liquid forming approximately 600 cc of vapor. Since vapor speed loops may flow as little as 2000 cc/min., a representative sample of liquid would not be adequately purged, and partial vaporization might occur if the liquid volume flow is not sized properly for the vapor flow rate.

In high pressure applications, it may be advisable to use a sample probe with an internal diameter of approximately $\frac{1}{8}$ in. to avoid the large dead volume of modified thermowells. It is also advisable to minimize the dead volume between the sample probe and the vaporizing regulator (see Figure 4-8). Figure 4-9 illustrates a design of a low pressure sample probe and vaporizer that reduces the liquid dead volume.

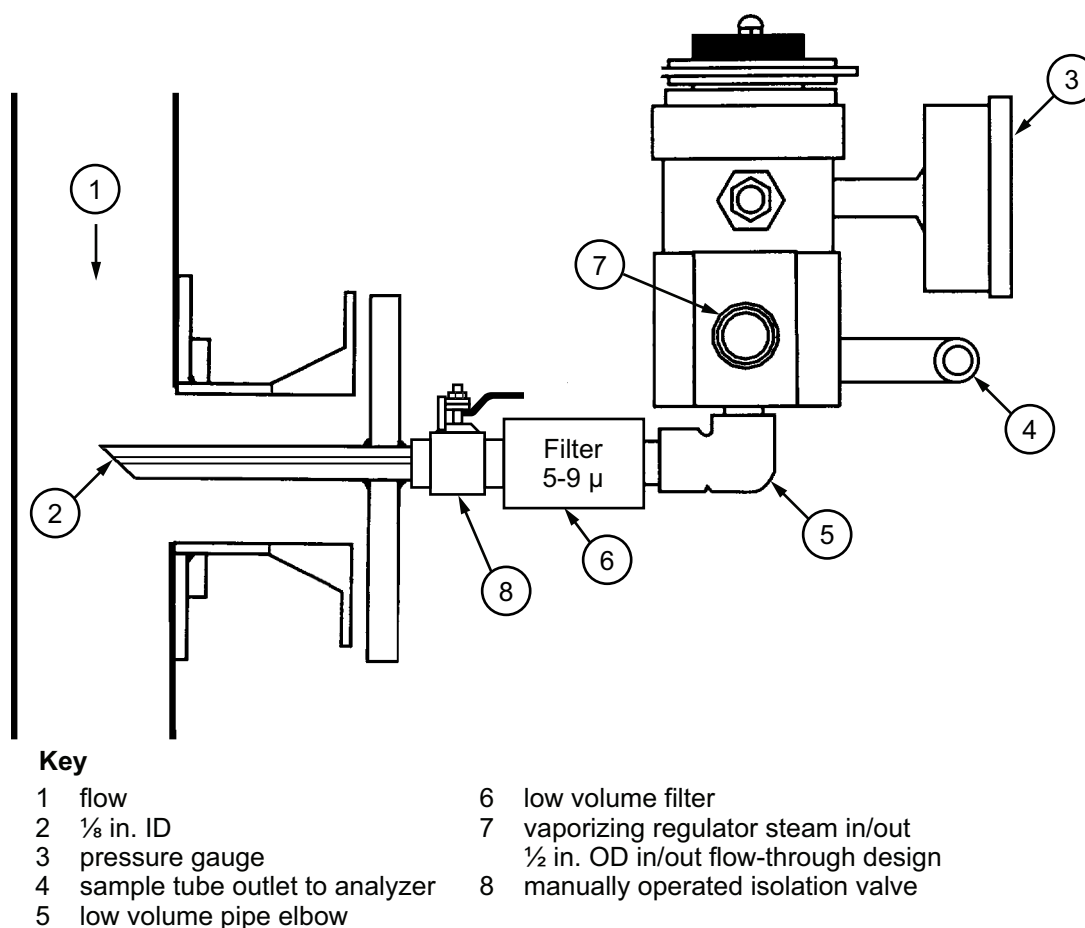


**Figure 4-8—Liquid Vaporization Sample Probe and Regulator Section
(High-temperature/Pressure Applications)**

4.3.7 Sample Transport Line—General Considerations

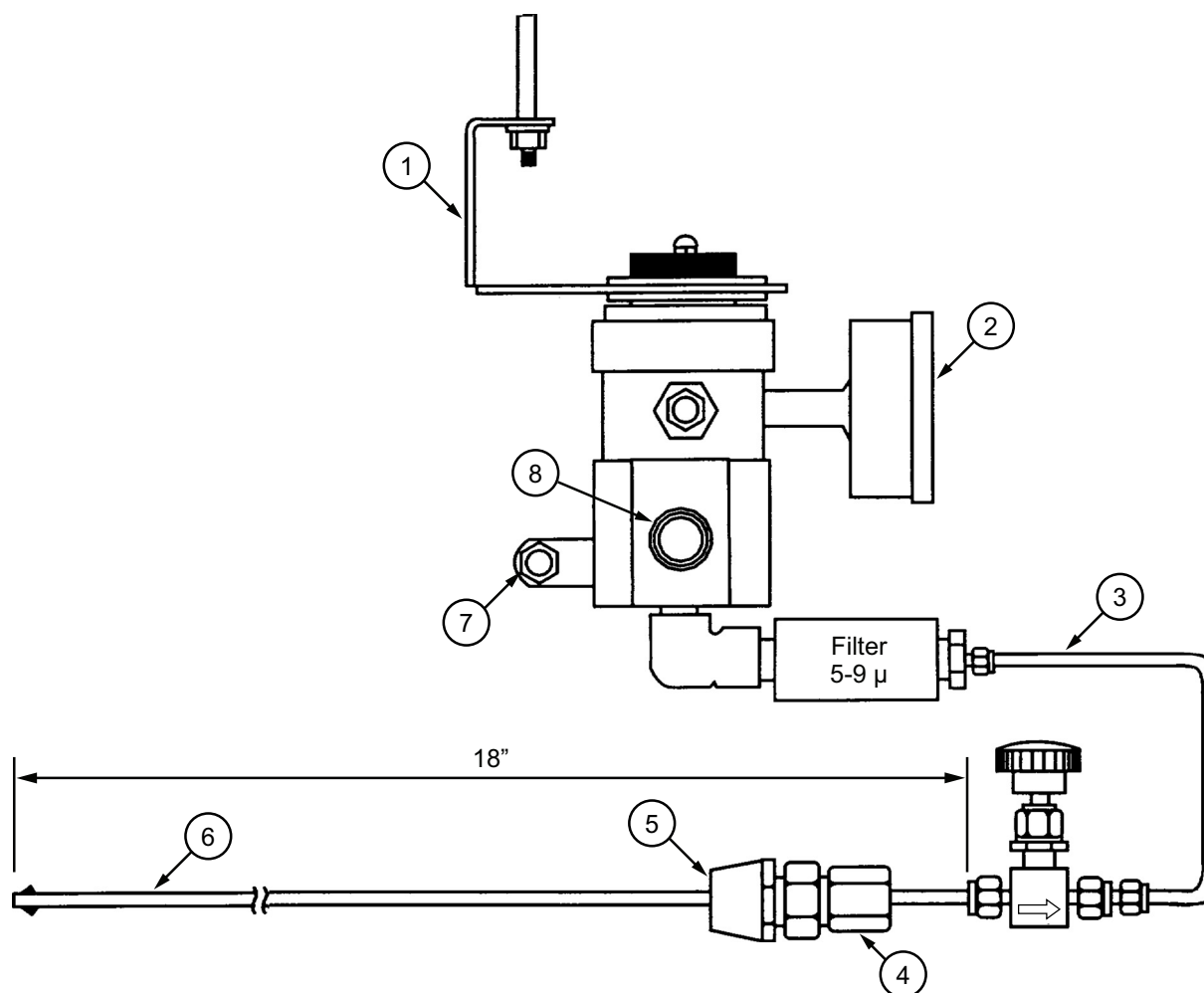
4.3.7.1 Tubing runs are recommended because of metallurgy, smaller internal volume, less entrainment due to abrupt bends, and ease of installation. Piping runs are sometimes required for long speed loops (e.g., >300 ft) to minimize lag times.

Specification of tubing should consider corrosion allowances. The materials used to manufacture the tubing can be very important, especially in high or low temperature installation and where certain chemicals can cause stress cracking. Seamless tubing is often selected to eliminate stress cracking in the tubing longitudinal welds. Continuous drawn tubing bundles reduce the likelihood of sample line leaks as the use of compression fittings is minimized. Tubing bundles can be purchased insulated or traced and insulated which reduces installation costs. Continuous tubing runs must be used for sub-atmospheric pressure applications.

4.3.7.2 Keep samples lines as short as possible to minimize transport lag time.

4.3.7.3 Use the smallest diameter line available to ensure a representative single phase sample that is consistent with the required flow rate and the available pressure drop. Sample supply and return lines of 1/4-in. O.D., with a 0.035-in. wall are common for many vapor phase transport lines. Liquid sample lines are often 3/8-in. or 1/2-in. O.D. due to higher pressure drops.

4.3.7.4 Provide sufficient pressure to maintain adequate velocities. Typical linear flow velocities are 5 ft/sec to 10 ft/sec (~2 m/sec to 4 m/sec) for liquids and 20 ft/sec to 40 ft/sec (~7 m/sec to 15 m/sec) for gases.



Key

- | | |
|---|---|
| 1 mounting bracket | 5 stainless steel bushing 1 in. x ¼ in. NPT |
| 2 pressure gauge | 6 ¼ in. stainless steel tube 0.065 in. (1.7 mm) wall |
| 3 ⅛ in. stainless steel tubing | 7 sample ¼ in. tube outlet |
| 4 packing gland mount into process gate valve | 8 vaporizing regulator steam in/out ½ in. OD tube (front and rear, flow-through design) |

Figure 4-9—Liquid Vaporization Sample Probe and Regulator Section (Low-pressure Applications)

4.3.7.5 Use indicators (flow, pressure, temperature) and check-valves as necessary to ensure that sample flow is adequate and in the proper direction.

4.3.7.6 The sizing of sample transport lines will be influenced by a number of factors as follows.

- a) The process sample phase (whether liquid or vapor), dew point, bubble point, density, and viscosity may all influence the calculations of lag time and pressure drop. For relatively low flow and short line lengths, the pressure drop should not be significant; however, at a high flow or long line length, the pressure drop may become an important factor in the system design, especially for liquids. Although the specific gravity of a gas or liquid does not affect the lag time calculation, specific gravity must be considered when specifying flow control and indicating devices. Tables are available relating flow rate to pressure drop for different sample line diameters. Table 4-1 provides examples of pressure drops at various flow rates for gases and Table 4-2 provides examples for liquids. Table 4-3 illustrates the relationship between sample line velocity and pressure drop. Table 4-4 provides a comparison of pressure drops at various flow rates for various liquids, and Table 4-5 provides a similar comparison for common gases.

Table 4-1—Darcy Pressure Drops vs. Line Size per 100 ft Sample Line—Gas Samples

Sample Line Size/Type	Friction Factor (unitless)	Wall Thickness (in.)	Sample Line ID (in.)	Darcy Head Loss (ft)	Methane Density (lb/ft ³)	Methane d/p (psi)	CO ₂ Density (lb/ft ³)	CO ₂ d/p (psi)	Butane Density (lb/ft ³)	Butane d/p (psi)
1/8 in. Tube	0.035	0.028	0.069	9.417	0.042	0.0027	0.116	0.0076	0.153	0.0100
	0.035	0.035	0.055	11.815		0.0034		0.0095		0.0126
1/4 in. Tube	0.028	0.028	0.194	2.680		0.0008		0.0022		0.0028
	0.028	0.035	0.180	2.888		0.0008		0.0023		0.0031
	0.028	0.049	0.152	3.420		0.0010		0.0028		0.0036
	0.028	0.065	0.120	4.332		0.0013		0.0035		0.0046
3/8 in. Tube	0.025	0.035	0.305	1.522		0.0004		0.0012		0.0016
	0.025	0.049	0.277	1.676		0.0005		0.0013		0.0018
	0.025	0.065	0.245	1.894		0.0006		0.0015		0.0020
1/2 in. Tube	0.022	0.035	0.430	0.950		0.0003		0.0008		0.0010
	0.022	0.049	0.402	1.016		0.0003		0.0008		0.0011
	0.022	0.065	0.370	1.104		0.0003		0.0009		0.0012
	0.022	0.083	0.334	1.223		0.0004		0.0010		0.0013
1/8 in. P (40)	0.027	0.088	0.364	1.377		0.0004		0.0011		0.0015
Sch 80	0.027	0.119	0.302	1.660		0.0005		0.0013		0.0018
3/4 in. P (40)	0.025	0.113	0.824	0.563		0.0002		0.0005		0.0006
Sch 80	0.025	0.154	0.742	0.626		0.0002		0.0005		0.0007
1 in. P (40)	0.023	0.133	1.049	0.407		0.0001		0.0003		0.0004
Sch 80	0.025	0.179	0.957	0.485	▼	0.0001	▼	0.0004	▼	0.0005

$$\text{Darcy Friction Head Loss} = \frac{(\text{Frict. Fact})(\text{Line Length})(\text{Square of Line Velocity})}{(2)(\text{Gravity Constant})(\text{Line ID})}$$

$$\text{Units} = \frac{(\text{ft})(\text{ft}^2/\text{sec}^2)}{(\text{ft}/\text{sec}^2)(\text{ft})} = \text{ft}$$

$$\text{Pressure Drop} = (\text{Friction Head Loss})(\text{Density})$$

$$\text{Units} = (\text{lb}/\text{ft}^2)(\text{ft}^2/144 \text{ in.}^2) = \text{psi}$$

$$\text{Gravity Constant} = 32.1725 \text{ ft}/\text{sec}^2$$

$$\text{Flow Velocity} = 1 \text{ ft}/\text{sec}$$

Table 4-2—Darcy Pressure Drops vs. Line Size per 100 ft Sample Line—Liquid Samples

Sample Line Size/Type	Friction Factor (unitless)	Wall Thickness (in.)	Sample Line ID (in.)	Darcy Head Loss (ft)	Pentane Density (lb/ft ³)	Pentane d/p (psi)	Benzene Density (lb/ft ³)	Benzene d/p (psi)	Octane Density (lb/ft ³)	Octane d/p (psi)
1/8 in. Tube	0.035	0.028	0.069	9.460	39.357	2.586	55.168	3.624	44.079	2.896
	0.035	0.035	0.055	11.868		3.244		4.547		3.633
1/4 in. Tube	0.028	0.028	0.194	2.692		0.736		1.031		0.824
	0.028	0.035	0.180	2.901		0.793		1.111		0.888
	0.028	0.049	0.152	3.435		0.939		1.316		1.052
	0.028	0.065	0.120	4.352		1.189		1.667		1.332
3/8 in. Tube	0.025	0.035	0.035	13.321		3.641		5.103		4.078
	0.025	0.049	0.377	1.237		0.338		0.474		0.379
	0.025	0.065	0.245	1.903		0.520		0.729		0.583
1/2 in. Tube	0.022	0.035	0.430	0.954		0.261		0.366		0.292
	0.022	0.049	0.402	1.021		0.279		0.391		0.312
	0.022	0.065	0.370	1.109		0.303		0.425		0.339
	0.022	0.083	0.334	1.228		0.336		0.471		0.376
1/8 in. P (40)	0.027	0.088	0.364	1.383		0.378		0.530		0.423
Sch 80	0.027	0.119	0.302	1.667		0.456		0.639		0.510
3/4 in. P (40)	0.025	0.113	0.824	0.566		0.155		0.217		0.173
Sch 80	0.025	0.154	0.742	0.628		0.172		0.241		0.192
1 in. P (40)	0.023	0.133	1.049	0.409		0.112		0.157		0.125
Sch 80	0.025	0.179	0.957	0.487	▼	0.133	▼	0.187	▼	0.149

$$\text{Darcy Friction Head Loss} = \frac{(\text{Frict.Fact})(\text{Line Length})(\text{Square of Line Velocity})}{(2)(\text{Gravity Constant})(\text{Line ID})}$$

$$\text{Units} = \frac{(\text{ft})(\text{ft}^2/\text{sec}^2)}{(\text{ft}/\text{sec}^2)(\text{ft})} = \text{ft}$$

$$\text{Pressure Drop} = (\text{Friction Head Loss})(\text{Density})$$

$$\text{Units} = (\text{lb}/\text{ft}^2)(\text{ft}^2/144 \text{ in.}^2) = \text{psi}$$

$$\text{Gravity Constant} = 32.1725 \text{ ft}/\text{sec}^2$$

$$\text{Flow Velocity} = 1 \text{ ft}/\text{sec}$$

Table 4-3—Liquid Pressure Drops vs. Different Flow Velocities for a 100 ft Sample Line

Sample Line Size/Type	Friction Factor (unitless)	Wall Thickness (in.)	Sample Line ID (in.)	Flow Velocity (ft/sec)	Darcy Head Loss (ft)	Propane Density (lb/ft ³)	Propane d/p (psi)	Butane Density (lb/ft ³)	Butane d/p (psi)	Hexane Density (lb/ft ³)	Hexane d/p (psi)
1/8 in. Tube	0.035	0.028	0.069	1	9.460	31.616	2.077	36.422	2.393	41.412	2.721
				2	37.839		8.308		9.571		10.882
				3	85.139		18.693		21.534		24.485
				4	151.358		33.231		38.283		43.528
				5	236.497		51.924		59.817		68.013
1/4 in. Tube	0.028	0.035	0.180	1	2.901		0.637		0.734		0.834
				2	11.604		2.548		2.935		3.337
				3	26.109		5.732		6.604		7.509
				4	46.416		10.191		11.740		13.349
				5	72.526		15.923		18.344		20.857
3/8 in. Tube	0.025	0.035	0.305	1	1.529		0.336		0.387		0.440
				2	6.115		1.342		1.547		1.758
				3	13.758		3.021		3.480		3.957
				4	2.038		0.447		0.516		0.586
				5	38.216		8.391		9.666		10.990
1/2 in. Tube	0.022	0.035	0.430	1	0.954		0.209		0.241		0.274
				2	3.817		0.838		0.965		1.098
				3	8.587		1.885		2.172		2.470
				4	15.267		3.352		3.861		4.390
				5	23.854	▼	5.237	▼	6.033	▼	6.860

$$\text{Darcy Friction Head Loss} = \frac{(\text{Frict. Fact})(\text{Line Length})(\text{Square of Line Velocity})}{(2)(\text{Gravity Constant})(\text{Line ID})}$$

$$\text{Units} = \frac{(\text{ft})(\text{ft}^2/\text{sec}^2)}{(\text{ft}/\text{sec}^2)(\text{ft})} = \text{ft}$$

$$\text{Pressure Drop} = (\text{Friction Head Loss})(\text{Density})$$

$$\text{Units} = (\text{lb}/\text{ft}^2)(\text{ft}^2/144 \text{ in.}^2) = \text{psi}$$

$$\text{Gravity Constant} = 32.1725 \text{ ft}/\text{sec}^2$$

$$\text{Flow Velocity} = 1 \text{ ft}/\text{sec.}$$

Table 4-4—Comparison of Pressure Drops in PSI for Various Liquids vs. Common Line Sizes

Liquid Sample	Density (lb/ft ³)	¹ / ₈ in. Tube ID = 0.055 in. FF = 0.035	¹ / ₄ in. Tube ID = 0.180 in. FF = 0.028	³ / ₈ in. Tube ID = 0.305 in. FF = 0.025	¹ / ₂ in. Tube ID = 0.430 in. FF = 0.022	Gravity Constant = 32.1725 ft/sec. ²
Acetonitrile	48.832	4.025	0.984	0.518	0.324	Flow Velocity = 1 ft/sec 100 ft Sample Lines
Acetic Acid	65.495	5.398	1.319	0.695	0.434	
Benzaldehyde	65.021	5.359	1.310	0.690	0.431	
Benzene	55.096	4.541	1.110	0.585	0.365	
Bunker Fuel	63.304	5.217	1.275	0.672	0.419	
1,3 Butadiene	42.202	3.478	0.850	0.448	0.280	
Butane	37.532	3.093	0.756	0.398	0.249	
Chloroform	92.971	7.662	1.873	0.987	0.616	
Carbonyl Sulfide	78.835	6.497	1.588	0.837	0.522	
Carbon Tetrachloride	80.722	6.653	1.626	0.857	0.535	
Cyclohexane	48.602	4.006	0.979	0.516	0.322	
DMF	59.227	4.881	1.193	0.629	0.392	
Ethanol	49.382	4.070	0.995	0.524	0.327	
Ethyl Ether	44.513	3.669	0.897	0.473	0.295	
Fuel #3	56.062	4.620	1.129	0.595	0.371	
Fuel #6	61.992	5.109	1.249	0.658	0.411	
Gasoline	42.140	3.473	0.849	0.447	0.279	
Heptane	42.683	3.518	0.860	0.453	0.283	
Hexane	41.663	3.434	0.839	0.442	0.276	
HCL (40 %)	74.916	6.174	1.509	0.795	0.496	
H ₂ SO ₄ (87 %)	112.374	9.261	2.264	1.193	0.745	
Isohexanes	41.203	3.396	0.830	0.437	0.273	
Isopentane	39.000	3.214	0.786	0.414	0.258	
Isopropyl Ether	45.205	3.726	0.911	0.480	0.300	
Kerosine	51.192	4.219	1.031	0.543	0.339	
Methanol	49.400	4.071	0.995	0.524	0.327	
MTBE	46.261	3.813	0.932	0.491	0.307	
Naphtha	41.516	3.422	0.836	0.441	0.275	
Nonane	44.799	3.692	0.903	0.476	0.297	
Oil (–10 API)	72.731	5.994	1.465	0.772	0.482	
Oil (10 API)	62.430	5.145	1.258	0.663	0.414	
Oil (30 API)	54.688	4.507	1.102	0.581	0.362	
Oil (50 API)	49.195	4.054	0.991	0.522	0.326	
Pentane	39.093	3.222	0.788	0.415	0.259	
Petroleum Ether	39.955	3.293	0.805	0.424	0.265	
Phenol	66.937	5.517	1.349	0.711	0.444	
Propanol-1	50.175	4.135	1.011	0.533	0.332	
SAE 30 Lube	56.062	4.620	1.129	0.595	0.371	
Sea Water	63.991	5.274	1.289	0.679	0.424	
Toluene	54.121	4.460	1.090	0.575	0.359	
Turpentine	54.314	4.476	1.094	0.577	0.360	
Water	62.430	5.145	1.258	0.663	0.414	
Xylene-O	54.951	4.529	1.107	0.583	0.364	



Table 4-5—Comparison of Pressure Drops in PSI for Various Gases vs. Common Line Sizes

Liquid Sample	Density (lb/ft ³)	1/8 in. Tube ID = 0.055 in. FF = 0.035	1/4 in. Tube ID = 0.180 in. FF = 0.028	3/8 in. Tube ID = 0.305 in. FF = 0.025	1/2 in. Tube ID = 0.430 in. FF = 0.022	Gravity Constant = 32.1725 ft/sec. ² Flow Velocity = 1 ft/sec 100 ft Sample Lines
Acetylene	0.0686	0.0057	0.0014	0.0007	0.0005	
Air (70°F)	0.0752	0.8925	0.2182	0.1150	0.0718	
Ammonia	0.0449	0.5329	0.1303	0.0686	0.0428	
Butane (120 °F)	0.1557	1.8478	0.4517	0.2380	0.1486	
Butylene (120 °F)	0.1502	1.7826	0.4357	0.2296	0.1433	
Carbon Dioxide	0.1236	1.4669	0.3586	0.1889	0.1179	
Carbon Monoxide	0.0780	0.9257	0.2263	0.1192	0.0744	
Chlorine	0.1873	2.2228	0.5434	0.2863	0.1787	
Ethane	0.0793	0.9411	0.2301	0.1212	0.0757	
Ethylene	0.0734	0.8711	0.2129	0.1122	0.0700	
Freon	0.3406	4.0422	0.9881	0.5207	0.3250	
Helium	0.0104	0.1234	0.0302	0.0159	0.0099	
Hydrogen	0.0052	0.0617	0.0151	0.0079	0.0050	
Natural Gas	0.0503	0.5970	0.1459	0.0769	0.0480	
Neon	0.0524	0.6219	0.1520	0.0801	0.0500	
Nitrogen	0.0732	0.8687	0.2124	0.1119	0.0698	
NO	0.0779	0.9245	0.2260	0.1191	0.0743	
NO ₂	0.1143	1.3565	0.3316	0.1747	0.1091	
Oxygen	0.0832	0.9874	0.2414	0.1272	0.0794	
Pentane (120 °C)	0.1874	2.2240	0.5437	0.2865	0.1788	
Propylene	0.1093	1.2972	0.3171	0.1671	0.1043	
Propane	0.1176	1.3957	0.3412	0.1798	0.1122	
SO ₂	0.1705	2.0235	0.4946	0.2606	0.1627	

- b) The flow rate, pressure, and sample temperature requirements of the analyzer as configured for the analysis must be considered. In the case of multi-stream analyzers, dead volume of the system and adequate flushing of the previous streams must be considered to minimize cross contamination and to deliver a representative sample.
- c) Sample conditioning elements contribute to pressure drop and lag time, and must be considered in calculating the overall sample line pressure drop. A common way to do this is to consider each element as contributing a pressure drop equal to some equivalent length of tube and adding all these equivalent lengths to the above calculated straight run length from the sample tap to the analyzer. Even pipe and tubing elbows and bends contribute to the sample line pressure drop. Table 4-6 illustrates the equivalent ft of straight run tubing equal to a bend or elbow that should be added to the sample line length for pressure drop calculations.

The purge time of each element is dependent on the individual volumes and is calculated as the time necessary for a minimum of three volumes of the sample stream to flow through the element.

Table 4-6—Equivalent Feet of Straight Run Tubing

Tubing OD (in.)	90° Elbow (ft)	90° Bend (ft)	180° Bend (ft)	45° Bend (ft)	Tee Branch (ft)
0.25 in.	1	0.5	1	0.5	1
3/8 in.	1.5	0.5	1	0.5	1.5
0.5 in.	2	5.5	1	0.5	2
5/8 in.	2.5	1	2	0.5	2.5
0.75 in.	3	1	2	0.5	3
1 in.	4.5	1	2	0.5	4.5

- d) Consideration of operating pressure at the sample tap and of how much pressure can be used to supply driving power for the sample line is important. For example, even with a high sample point pressure, there may be some minimum pressure, above which the sample must be maintained at the analyzer in order to avoid problems such as bubble formation or premature flashing of the sample. Pressure at the process point is very important since this consideration partly determines the pressure drop that is available to drive the sample to the analyzer. Also very important is the pressure at the process return point. Calculation of the available differential pressure determines whether a continuous return line is feasible (with or without a sample pump) or if the sample must be returned to an approved disposal system.

The flow velocity in a sample line is related to the pressure drop in the line by the Darcy equation below.

$$h_L = (fLV^2)/(2Dg) = 0.1863 (fLV^2)/(d)$$

where

h_L is the friction head loss;

f is the friction factor of the line material;

L is the length of the line;

V is the linear flow velocity;

g is the acceleration due to gravity;

d is the internal diameter of the line in inches;

D is the internal diameter of the line in feet.

And, since $\Delta P = \rho h_L$, then the sample line pressure drop may be calculated by the following equation.

$$DP = 0.001294 fLpV^2/d$$

Friction factors are a function of the material of the sample line. Friction factors for several common sizes of sample lines are given in Table 4-7.

- e) Flow in a sample line must be turbulent to ensure that it is well-mixed and representative of the process. Mixing generally isn't an issue with gaseous samples, but laminar or poorly mixed liquid sample flows can result in data that is not representative of the process dynamics. An estimation of sample mixing may be obtained by calculating the Reynolds Number of the sample flow. The Reynolds Number is a dimensionless number that is based on the

Table 4-7—Friction Factors for Sample Lines

Line Type	Line Size	Friction Factor
Tubing	3/4 in.	0.018
Tubing	1/2 in.	0.022
Tubing	1/4 in.	0.028
Tubing	1/8 in.	0.035
Schedule 80 Pipe	1 in.	0.0225
Schedule 80 Pipe	3/4 in.	0.0245
Schedule 80 Pipe	1/2 in.	0.026
Schedule 80 Pipe	1/4 in.	0.032

internal diameter of the line, the linear flow velocity, the density and dynamic viscosity of the gas or liquid by the following equation:

$$Re = 123.9 (dVp)/(\mu)$$

where

Re is the Reynolds Number, a dimensionless number;

d is the internal diameter of the line, in inches;

V is the linear flow velocity, in ft/sec.;

p is the density, in lb/ft³;

μ is the dynamic viscosity, in centipoise.

Sample flows with Reynolds Numbers greater than 4000 are considered to be turbulent. Flows with values less than 2000 are considered to be laminar (poorly mixed, or “plug flow”). Sample flow with values between 2000 and 4000 are considered to be transitional or partially mixed.

Since the viscosity and density of a process stream are known, it is a common practice to calculate the Reynolds Numbers of the common sample line sizes at various linear velocities. A calculation of the Reynolds Number allows a determination to be made of the minimum linear velocity required for turbulent flow (for example, the typical 1/4 in. tubing with a standard wall thickness of 0.035 in. has an internal diameter of 0.18 in.).

As an example, water has a viscosity of 0.692 cP at 100 °F, and a density of 62.43 lb/ft³. If the sample line length were 300 ft and the minimum lag time allowed were two minutes (120 seconds), what would the Reynolds Number be for a 1/4 in. stainless steel line with a wall thickness of 0.035 in.?

$$Re = 123.9 (0.18 \text{ in.} \times 2.5 \times 62.43) / (0.692) = 5030$$

(turbulent flow)

- f) In addition to ensuring turbulent flow in the sample line, provisions must often be made to maintain the temperature above a dew point so that a single phase sample is provided to the analyzer. In such cases, the sample lines must be heat-traced. Sample composition can be affected if the lines are heated or cooled excessively. Improper heating of the lines (especially when analyzing for trace amounts) can result in the tendency of some components adsorbing into the walls of the tube and changing the sample composition during its transport from the sample tap to the analyzer. Manufactured pre-insulated, pre-traced tubing bundles are recommended.

4.3.7.7 Sample line routing, is an important factor for proper operation. Sample line accessibility should be considered for maintenance. Sharp bends or kinks in the lines should be avoided. To minimize potential for leakage, avoid using an excessive number of fittings. Welded tubing joints may be used to avoid leakage. The sample lines should be sloped continuously downwards or upwards (depending on the application) to the analyzer to avoid pocketing. Pre-insulated tubing bundles should be run in a cable tray to eliminate low spots in the lines. The minimum bend radius for pre-insulated bundles can be obtained from the manufacturer. When installing insulated heated sample lines, it is important to make sure that the insulation covers the entire length of the transport tubing as even short segments of exposed transport tubing can result in cooling of the sample to ambient temperatures.

4.3.7.8 When low concentrations of “sticky molecule” measurements are required (e.g., sulphur compounds, moisture etc) the measurand can attach to roughness sites in the sample tubing causing slow reaction to change in the measurement both from increasing and decreasing values. In addition memory effect is dependent on temperature therefore increase in temperature can cause the attached measurand to be released. This is known as diurnal effect. Dependant on the measurand, its concentration and the sample transport line length, tubing with reduced roughness factors (e.g. electro polished/silica glass lined) can be selected to reduce memory effect. The diurnal effect is also seen in pressure reducing regulators due to the Joule-Thompson effect. This can be mitigated by using heated or vaporizing regulators to maintain temperature. Sample lines can be heat traced to reduce diurnal effects. This consideration is only significant in low ppm measurements.

4.3.8 Multi-stream Switching

Single stream/single analyzer configurations are recommended. Multi-stream versions are more complex and have a greater chance of failure, which means a loss of analysis on all streams.

There are several factors that should be considered when designing multi-stream switching systems:

- a) Separate conditioning equipment for each stream.
- b) Provisions for venting between switching valves to prevent contamination.
- c) Cross contamination due to mechanical failure (leakage) or failure to properly purge the stream previously analyzed. Sample streams of high concentration may not be sufficiently flushed causing contamination of very low concentration streams.
- d) The relative concentrations of the components in each stream.

A typical Double Block-and-Bleed (DBB), multi-stream sample system designed to minimize cross contamination and reduce dead volumes is illustrated in Figure 4-10. During operation the internal volumes between the valves of the unselected streams are vented to a low pressure destination that allows for a leakage path out of the system and not into the other sample streams. The vent from a DBB valve should be fitted with a sight flow indicator in order to determine if the primary valve has failed.

4.3.9 Sample Disposal

The circulating sample should be returned to the process at lower pressure using a speed loop system.

When a sample return point does not exist in the process it is necessary to choose whether to discard the sample to the flare system/closed sewer system or provide a means of pumping the sample back into the process. Discarding of hydrocarbon samples to the atmosphere or an open sewer system must be minimized and is often prohibited for environmental reasons. Sample disposal systems are used when the sample is too valuable or too hazardous to discard. Figure 4-11 illustrates a type of liquid sample recovery system.

4.3.10 Laboratory Sample Taps

Manual sample taps should be installed in a manner that allows lab samples to be taken easily to verify the on-line analyzer readings. Locate laboratory sample points so that they do not interfere with analyzer performance. Lab sample capture may be needed in sample cylinders. When this is necessary adequate cylinder flushing is required and the cylinder should have self sealing connection fittings, isolating valves and anti hydraulic devices (liquid samples). Operating procedures should include “top off” (ensuing vapor space in liquid sample cylinder). Cylinder design should include provision for vapor space.

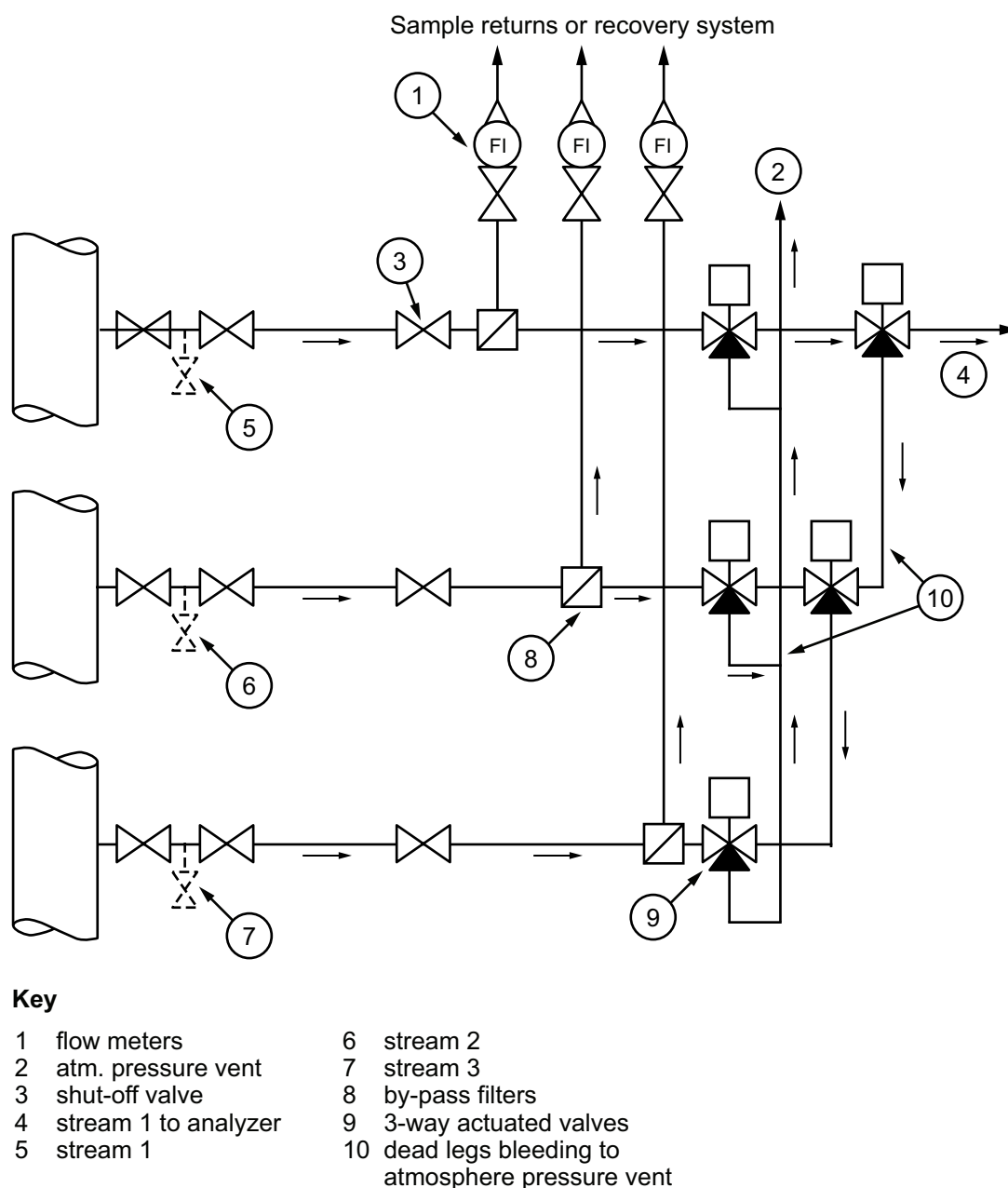


Figure 4-10—Stream Select System with Double Block-and-Bleed

5 Prepackaged Systems

5.1 General

A systems approach is generally considered whenever a packaged system can be a single analyzer with a sample system, or multiple analyzers consolidated into a common enclosure. A complete system is typically supplied by a single packaged systems supplier (PSS). The PSS has general responsibility for:

- analyzers and materials including 3rd party suppliers;
- suitability of the analyzer for the application;

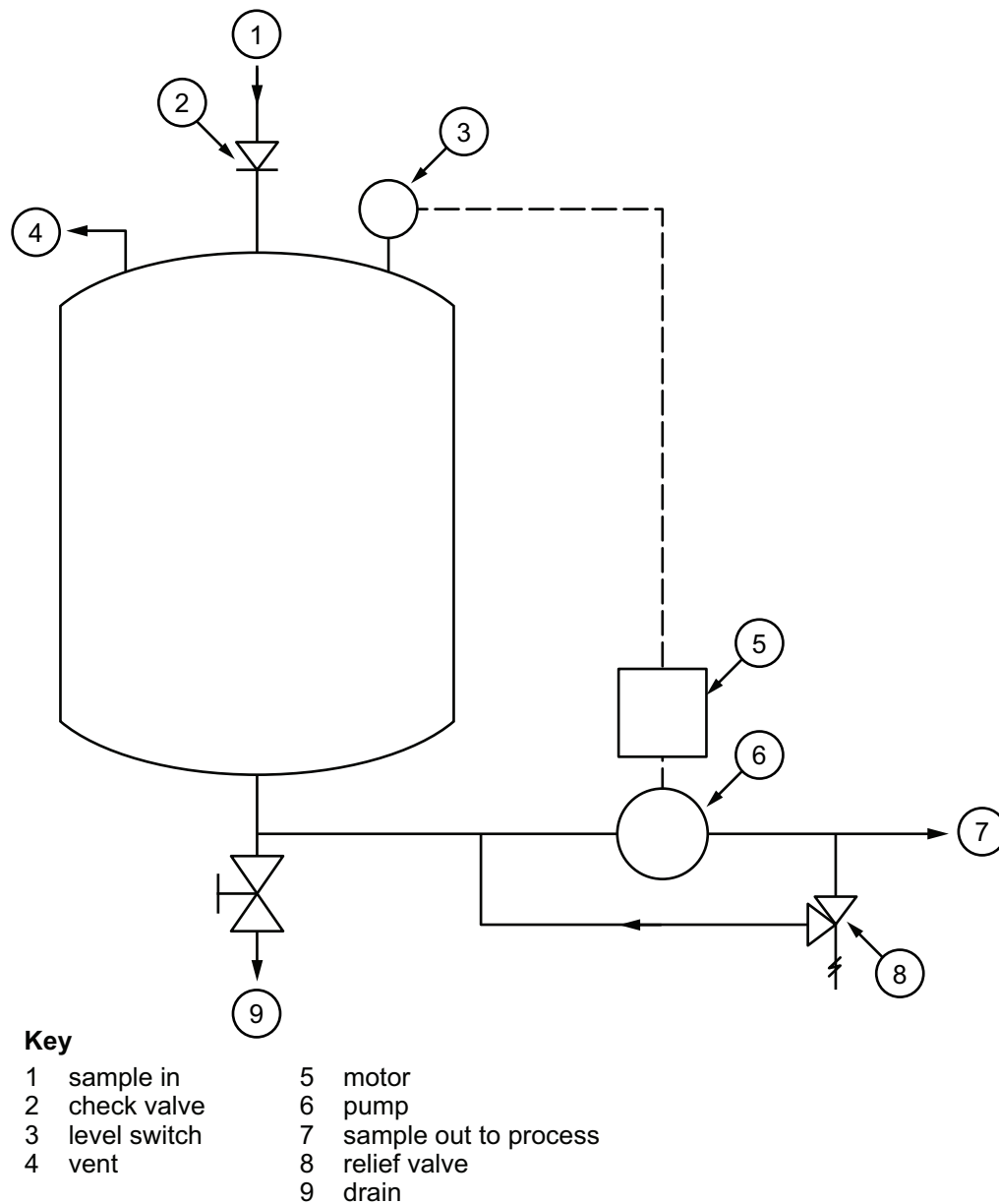


Figure 4-11—Liquid Sample Recovery System

- c) design of the total packaged system;
- d) assembly of multiple analyzers into common enclosures;
- e) installation design requirements of the analyzer, shelter/enclosures, sample systems, and sample transport system;
- f) complete system calibration, and factory acceptance testing;
- g) requirements for routine testing and maintenance;
- h) site acceptance testing, startup, and commissioning;
- i) analyzer system training.

5.2 Advantages of Pre-Packaged Systems

It is recommended that the analyzer system be an engineered prefabricated package complete with analyzers, sample conditioning and calibration system(s) piped and wired in a self-contained unit.

Advantages include the following.

- a) Construction is independent of weather and labor conditions at the site.
- b) The system is designed and built by specialists familiar with the requirements.
- c) The system can be fully tested under simulated operating conditions before shipment.
- d) The complete system components and analyzers are warranted by the PSS.
- e) The complete analyzer system training is available from the PSS.
- f) Cost effective.

5.3 Total Systems Approach

To ensure successful analyzer performance and installation, a total system engineering approach should be followed.

- a) Basic requirements should be completely specified with a thorough review of measurement types, analysis requirements, stream composition and stream conditions. The process requirements, site location, maintenance requirements, code compliance, and regulations should be specified completely.
- b) Analyzer specification and performance testing requirements should be completely described.
- c) Installation and enclosure specifications should also include additional support equipment, calibration requirements and facilities, and suitable spares capability.
- d) Documentation requirements that include operation manuals, detailed drawing packages, tagging requirements, bill-of-materials lists, and spare part lists are mandatory.
- e) A “Kick off” meeting should be held to agree with the work scope and design details.
- f) Identify schedules and milestone payments.
- g) It is important to identify the purpose of the analyzer (control, monitoring, safety, environmental compliance, etc.) for proper analyzer selection system design.

6 Maintenance, Training, Installation, Inspection, Testing, and Startup Requirements

6.1 Maintenance

6.1.1 Organization

An analyzer maintenance organization may range from one mechanic working part time on analyzers in a general maintenance group to a fairly large group of engineers, technicians, and mechanics with full-time analyzer maintenance responsibility. The size of the group is largely dependent on the number and complexity of analyzers installed in the plant, as well as the attitude of that plant's management toward analyzer maintenance. Most refineries and plants contain a sufficient number of analyzers to justify at least one full-time person assigned to this task.

An analyzer maintenance group can be structured and function successfully in the refinery organization as part of maintenance, engineering, or operations departments, or the laboratory; however, the analyzer maintenance group must maintain liaison and communication with the other departments if maximum benefits are to be realized from using analyzers.

Some of the specific communication needs of the analyzer maintenance group are:

- a) With the maintenance department to schedule other craft work required in analyzer systems and to schedule and plan work and provide for training.
- b) With the instrument engineering department to learn of new applications planned, to feed back advantages or disadvantages of particular analyzer system installations and to jointly develop maintenance strategies.
- c) With the operations department to learn problems, to schedule and plan maintenance work, to assist operating personnel in the use and understanding of the analyzers, and to receive feedback regarding the advantages and disadvantages of particular analyzer installations.
- d) With the laboratory to develop calibration techniques and obtain standards and to develop and maintain laboratory testing as necessary to back-up plant analyzers.

Often the most effective analyzer maintenance groups are those in which there is direct involvement of professionally trained people: instrument engineers, process engineers, and laboratory chemists. They can be very helpful in training, reviewing the efficacy of existing analyzers, and assisting in developing an overall maintenance strategy.

Some plants hire outside specialists for analyzer maintenance. This method may not be as effective as using plant personnel if the specialists are called in only for emergency work; however, it can be satisfactory if preventive maintenance is scheduled where needed or if the specialists report to the plant each day. In this case, they function as regular plant personnel.

6.1.2 Personnel

Special skills are required of analyzer maintenance personnel because most analyzers are complex and difficult to maintain. Therefore, the tendency is to assign more talented people to analyzers. It is desirable that these persons have a good background in the maintenance of conventional instruments, a basic knowledge of chemistry and piping, and a comprehensive understanding of electronics, including digital circuitry and microprocessors. They also require knowledge of refinery processes and laboratory methods.

The classification of analyzer maintenance personnel often is different at various locations. Some use hourly employees, some use staff personnel called technicians or inspectors, some use engineers, and some use various combinations of these groups. Any of these classes of maintenance personnel can be effective if they possess the proper skills. Training is the key. Training of maintenance personnel is discussed in 6.2.

Manpower requirements for maintenance of specific instruments, control valves, and analyzers have been determined by International Society of Automation (ISA) Maintenance Management Division through a survey of its members. Published results for maintaining analyzers are listed in Table 6-1.

NOTE For comparison purposes, differential pressure type flow transmitters required a mean of 6 and a range of 4 to 8 work hours per year.

6.1.3 Facilities

6.1.3.1 General

Maintenance facilities required for analyzers include a shop, adequate facilities for storing appropriate records (including maintenance instructions), necessary test and training equipment, and hand and power tools.

Table 6-1—Analyzer Maintenance in Manhours per Year

Analyzer	Mean	Range	Standard Deviation
Boiling point	80	85 to 74	4.82
Carbon dioxide	21	25 to 18	2.10
chromatograph, gas	145	170 to 130	2.50
Combustibles	50	61 to 44	3.74
Density (displacement)	34	40 to 29	3.16
Density (radiation)	40	49 to 33	4.00
Infrared	76	94 to 62	5.69
Oxygen	38	42 to 35	2.30
pH	29	40 to 20	6.21
Refractive index	40	49 to 33	6.32
Ultraviolet	59	78 to 42	6.00

Ideal shop facilities for analyzers are somewhat different than those required for conventional instruments. Many analyzers constitute a system that includes sampling components, sensors, a transmitter, a control unit, and receiver devices for display and/or alarm and control. Calibration facilities may be included in the total analyzer system. The shop should be designed to handle such complete systems for actual operation of most types of analyzers with representative samples. This requires that the shop be designed for the safe introduction, circulation, and disposal of sample fluids and equipped with the required utilities.

An electronics test and repair area is needed because most analyzers are electronic in nature. This area should be housed in a clean, temperature-controlled room separate from valve or other major equipment repair areas and isolated from the calibration facility. Frequently used parts and components should be readily available. An area is often provided for continuous operation of “Hot Spares” (full or parts of analyzers supplied with electrical power) in order to insure serviceability. Hot spares are also used as diagnostic or fault finding tools.

6.1.3.2 Maintenance Documentation

Appropriate records and documentation are an important part of the facilities required for effective analyzer maintenance. A dedicated information package, often referred to as a “loop folder” is recommended for each analyzer to facilitate repairs and troubleshooting by personnel that may not be familiar with the application.

A typical “loop folder” should contain the following information:

- a) sample system diagram (including the fast loop sample and return points);
- b) loop diagram (signal(s));
- c) a simplified P&ID diagram;
- d) all associated prints (electrical, piping, plot plan sample and return points, etc.);
- e) original analyzer specification sheets;
- f) original vendor literature concerning normal operation and maintenance;
- g) calibration standard certification sheets;

- h) diagnostic chromatograms indicating the failure of a column or a switching valve (for gas chromatographs);
- i) chromatograms (calibration standard and startup runs on each stream [for gas chromatographs]);
- j) analyzer startup procedures (such as setting flows, pressures, etc.);
- k) procedures for calibration of output devices to recorders or the control system;
- l) spare parts lists (especially those that are not stocked in the warehouse);
- m) maintenance history log (unless a separate maintenance logbook is kept).

6.1.4 Techniques

6.1.4.1 General

Analyzer maintenance techniques can be preventive maintenance or emergency/breakdown maintenance in nature. Preventive maintenance is designed to prevent breakdowns, whereas emergency maintenance is performed following some problem that appears in the analyzer system. An effective preventative maintenance program substantially decreases analyzer downtime and reduces work orders for equipment failure.

6.1.4.2 Preventive Maintenance

Preventive maintenance is designed to:

- a. ensure the integrity of measurement;
- b. minimize breakdowns;
- c. reduce overall costs.

Often the preventive technique is little more than a series of frequent inspections with minor adjustments performed as necessary. This “mothering” of the analyzer system may be necessitated by the replacement schedule of consumables such as reagents, carrier gases, and calibration standards. More often the inspection is performed to assure that the sampling system is functioning properly and other components in the analyzer loop are operational. The inspection may or may not include a calibration of the analyzer (see Chapter 3).

Preventive maintenance of analyzer systems in many respects is similar to the overview provided by operators of their process units. Indeed the overview of the analyzer system, which often resembles a miniature process, may be the responsibility of the operator.

Other duties performed during preventive maintenance include cleaning, back-flushing, blowing down, and component replacement. The frequency of this work should be based on the manufacturer’s recommendations and the actual maintenance history of the analyzer.

Frequency of performing preventive maintenance may also be governed by the importance of the analyzer in the process. Assuring integrity of analyzer performance may be more valuable on those analyzers in closed loop control than those used just to provide operator information.

6.1.4.3 Emergency Maintenance

Emergency maintenance may be the most cost-effective technique for some analyzers. Under this system the analyzer is operated without preventive work until a failure occurs. This technique could be best for analyzers: