



FUGITIVE EMISSIONS FROM EQUIPMENT LEAKS I: MONITORING MANUAL

Health and Environmental Affairs Department Publication Number 342 May 1998





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Fugitive Emissions From Equipment Leaks I: Monitoring Manual

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iv

ABSTRACT

The American Petroleum Institute (API) commissioned two manuals to be prepared, providing options and recommendations on procedures for obtaining inspection and maintenance (I/M) data from certain process equipment with the potential to leak "fugitive emissions." These manuals are designed to provide assistance to those who collect fugitive data, ensure regulatory compliance, and calculate emissions associated with these fugitive emissions. The manuals are focused on the recommended fugitive emission practices in the petroleum industry, specifically for refineries, petroleum marketing terminals, and the oil and gas production industries.

The first volume is entitled Fugitive Emissions from Equipment Leaks I: Monitoring Manual. This manual is designed primarily for those who manage or apply fugitive emission I/M programs at a facility. This manual discusses the compilation of a component inventory, describes monitoring equipment that meet specifications identified in the United States Environmental Protection Agency's (U.S. EPA) Method 21, describes quality control practices, explains the screening procedures, and addresses alternative measurement methods.

The second volume, entitled Fugitive Emissions from Equipment Leaks II: Calculation Procedures for Petroleum Industry Facilities (API Publ. 343), is designed primarily for those who perform the emission calculations associated with fugitive emissions. This manual also discusses equipment categories, provides an overview of available emission estimation approaches, presents sample calculations for different calculation methods, discusses issues that affect the determination of fugitive emissions, and addresses data management.

TABLE OF CONTENTS

•

Page

1.0	INTRODUCTION 1-1
2.0	EQUIPMENT INVENTORIES 2-1
	2.1 EQUIPMENT TYPES 2-1 2.1.1 Agitators 2-1 2.1.2 Compressors 2-2 2.1.3 Connectors 2-2 2.1.4 Open-ended Lines 2-2 2.1.5 Pressure Relief Devices 2-3 2.1.6 Pumps 2-3 2.1.7 Sampling Connections 2-3 2.1.8 Valves 2-4 2.19 Others 2-4 2.21 Agitators 2-4 2.22 Countring Compensions 2-3 2.23 Connectors 2-4 2.24 Open-ended Lines 2-4 2.25 2.22 Compressors 2-5 2.24 Open-ended Lines 2-6 2.25 Pressure Relief Devices 2-7 2.26 Pumps 2-7 2.27 Sampling Connections 2-7 2.28 Valves 2-7 2.3 COMPONENT TRACKING 2-8 2.31 Component Identification 2-8 2.31.1 Recommended Information 2-8 2.3.2 Data Collection 2-11 2.33 Data Management 2-13
3.0	MONITORING EQUIPMENT FOR APPLYING METHOD 21
	3.1 SELECTION CRITERIA FOR A PORTABLE ANALYZER 3-1 3.2 ANALYZER TYPES 3-3 3.2.1 Flame Ionization Detectors 3-3 3.2.2 Photoionization Detectors 3-3 3.2.3 Nondispersive Infrared Instruments 3-6 3.2.4 Solid State, Electrochemical, Combustion Analyzers 3-6

TABLE OF CONTENTS (CONTINUED)

		Page
4.0	QUALITY CONTROL	. 4-1
4.1	TESTING PROGRAM SET-UP QUALITY CONTROL 4.1.1 Calibration Precision Test 4.1.2 Response Time Test 4.1.3 Response Factor Test 4.1.4 START OF DAY QUALITY CONTROL 4.2.1 Instrument Cleaning 4.2.2 Probe Leak Tests 4.2.3 Pump Flow Rate Tests 4.2.4 Instrument Calibration 4.2.5 Dilution Probe Adjustments	. 4-1 . 4-3 . 4-3 . 4-4 . 4-5 . 4-5 . 4-5 . 4-5 . 4-6 . 4-6 . 4-7
	4.3 DURING THE DAY QUALITY CONTROL	. 4-7
5.0	SCREENING PROCEDURES	5-1
	 5.1 GENERAL SCREENING GUIDANCE 5.1.1 Screening Distance 5.1.2 Fouling Prevention 5.1.3 Length of Time to Screen 5.1.4 Responding to Ambient Conditions 5.1.5 Background Measurements 5.2 SPECIFIC GUIDANCE BY COMPONENT TYPE FOR SCREENING 5.2.1 Valves 5.2.2 Connectors 5.2.3 Pumps, Compressors and Agitators 5.2.4 Pressure Relief Devices 5.2.5 Open-ended Lines and Vents 5.3 FIRST REPAIR ATTEMPTS 5.4 SAFETY 	. 5-1 . 5-1 . 5-1 . 5-3 . 5-3 . 5-3 . 5-4 . 5-5 . 5-5 . 5-5 . 5-10 . 5-10 . 5-10 . 5-10 . 5-10
6.0	ALTERNATIVE MEASUREMENT METHODS	6-1
-	6.1 SOAP TESTING 6.2 NON-METHOD 21 TESTING	6-1 6-2
7.0	KEFERENCES	K-I
Арр	endix A: METHOD 21 - DETERMINATION OF VOLATILE ORGANIC COMPOUND LEAKS	A-1

LIST OF FIGURES

	Page
2-1	Threaded Connector Elbow 2-6
2-2	Ball Valve with Side Flanges
2-3	Sample Screening Data Sheet 2-12
4-1	Calibration Precision for Portable VOC Analyzer ID 4-2
4-2	Sample Drift Test Data Sheet Analyzer ID 4-9
5-1	Valves
5-2	Connectors
5-3	Pumps
5-4	Pressure-Relief Valve 5-12
5-5	Open Ended Lines

;

LIST OF TABLES

	Page
2-1	Data Loggers
3-1	Summary of EPA Method 21 Monitoring Equipment Requirements 3-2
3-2	Flame Ionization Analyzers Method 21 Capabilities 3-4
3-3	Flame Ionization Analyzers Characteristics 3-5
3-4	Photoionization Analyzers Method 21 Capabilities
3-5	Photoionization Analyzers Characteristics
3-6	Infrared, Electrochemical, and Solid State Analyzers Method 21 Capabilities 3-10
3-7	Infrared, Electrochemical, and Solid State Analyzers Characteristics
5-1	Summary of Screening Procedures 5-2

LIST OF ACRONYMS

AC	-	actual concentration
API	-	American Petroleum Institute
ASTM	-	American Society for Testing and Materials
CFC	-	chlorofluorocarbons
COS	-	carbonyl sulfide
CS_2	-	carbon disulfide
FID	-	flame ionization detector
HAP	-	hazardous air pollutant
I/M	-	inspection and maintenance
ID	-	identification
LDAR	-	leak detection and repair
MTBE	-	methyl tert-butyl ether
NDIR	-	nondispersive infrared
NSPS	-	New Source Performance Standards
OEL	-	open-ended line
OVA	-	organic vapor analyzer
PID	-	photo ionization detector
ppmv	-	parts per million by volume
PRV	-	pressure relief valve
RF	-	response factor
SOCMI	-	Synthetic Organic Chemical Manufacturing Industry
SV	-	screening valve
TLV	-	threshold limit valve
TOC	-	total organic compounds
TVA	-	total vapor analyzer
U.S. EPA	-	United States Environmental Protection Agency
VOC	-	volatile organic compound

SECTION 1.0 INTRODUCTION

This manual has been prepared for the American Petroleum Institute (API) to provide a reference for screening and data management techniques for certain process equipment that have the potential to leak "fugitive emissions." These fugitive emissions are regulated by a number of federal, state, and local regulations that are designed to control the emissions of Volatile Organic Compounds (VOCs) and organic Hazardous Air Pollutants (HAPs). Screening is the procedure of using a handheld analyzer to gather VOC and HAP readings from process equipment such as valves, pumps, compressors, and connectors.

The primary objective of this document is to present methods that will assist in obtaining quality inspection and maintenance (I/M) data. An I/M program is the Leak Detection and Repair (LDAR) activity associated with components that screen above a regulatory-specifiedthreshold level. A variety of regulatory interpretations and applications of I/M methods have resulted in confusion regarding recommended or required methodology. This document was designed to reduce this confusion by clearly explaining monitoring options and in some cases providing recommendations. This guidance will assist with compliance with several different regulations affecting fugitive emissions. This guidance should also assist facilities to collect and manage data more efficiently.

This document is Volume I of a two volume set. The companion volume, Volume II, is designed to present the latest recommendations for calculating fugitive emissions for petroleum industry facilities.

Note:

Some requirements identified in this document may not be applicable in all locations. Care should be taken when applying the recommendations in this document to ensure that these recommendations meet all local regulatory requirements and internal facility procedures to run an effective I/M program.

The remainder of this document is organized as follows:

- Section 2.0 discusses the compilation of a component inventory including a discussion of regulated equipment and component tracking recommendations;
- Section 3.0 identifies monitoring equipment that meet U.S. EPA Method 21 specifications;
- Section 4.0 discusses quality control;
- Section 5.0 explains the screening procedure;
- Section 6.0 addresses alternative measurement methods; and
- Section 7.0 includes the references.

SECTION 2.0 EQUIPMENT INVENTORIES

An accurate equipment inventory is essential for most inspection and maintenance (I/M) programs, as defined in this volume, and for determining the amount of emissions from equipment leaks, as provided in Volume II. This section identifies the process equipment that may be subject to equipment leak regulations and explains how to count and keep track of these components.

2.1 EQUIPMENT TYPES

The primary equipment types (or component types) that could be sources of fugitive emissions are:

- Agitators;
- Compressors;
- Connectors;
- Open-ended lines;
- Pressure relief devices;
- Pumps;
- Sampling connections;
- Valves; and
- Others.

Graphical depictions of these types of components are shown in Section 5.0 of this volume.

The seals on agitators, compressors and pumps are the source of equipment leaks associated with these equipment types; thus, the emissions from these equipment types are often described as from agitator seals, compressor seals and pump seals. In this volume and the companion volume (Volume II), this terminology (with or without seals) is often used interchangeably. For example, a leak could be described as coming from a "pump" or from a "pump seal." Due to the evolving nature of nomenclature, other terminology is also often used interchangeably to describe equipment For example, connectors can also be types. referred to as "fittings."

Subsequent sections of this report provide a description of these component types and information related to how these components leak.

2.1.1 Agitators

Agitators are used to stir or blend chemicals. Four seal arrangements are commonly used with agitators: packed seals, mechanical seals, hydraulic seals, and lip seals.

A packed seal consists of a cavity, called a *stuffing box*, in the agitator casing filled with a packing gland to form a seal around the shaft. There are several types of single mechanical seals, with many variations to their basic design and arrangement, but all have a lapped seal face between a stationary element and a rotating seal ring. There are also many variations of dual and tandem mechanical seals. Dual mechanical seals with the following characteristics are

considered to be leak free (and therefore typically do not require monitoring):

- Barrier fluids pressurized higher than the agitator cavity;
- A barrier fluid reservoir vented to a control device; and
- A pressure tight barrier fluid with a pressure alarm indicator.

In a hydraulic seal, an annular cup attached to the process vessel contains a liquid that contacts an inverted cup attached to the rotating agitator shaft. Although it is the simplest agitator shaft seal, the hydraulic seal is limited to low temperature/low pressure applications and can handle only very small pressure changes. A lip seal consists of a spring-loaded, nonlubricated elastomer element, and is limited in application to low-pressure, top-entering agitators.

Agitator seals can leak because of poor installation, aging, and deterioration of the seals themselves, thermal stress, and vibration.

2.1.2 <u>Compressors</u>

Compressors provide the force to transport gases through a process unit in much the same way that pumps transport liquids. There are centrifugal, reciprocating, and rotary compressors in use by industries affected by equipment leak regulations. The sealing mechanisms for compressors are similar to the packed and mechanical seals for agitators.

2.1.3 Connectors

Connectors are used to join sections of piping and equipment. Connectors can be flanges, screwed or threaded connectors, union connectors, tubing connectors, caps, plugs, etc.

Flanges are bolted, gasket-sealed connectors. Flanges are normally used for pipes with diameters of 2.0 inches or greater. The primary causes of flange leakage are poor installation, aging and deterioration of the gasket, thermal stress and vibration. Flanges can also leak if improper gasket material is chosen.

The non-flange connectors (screwed, union, tubing, caps, plugs, etc.) typically are used to connect piping and equipment having diameters of 2.0 inches or less. Emissions from these connectors can occur as the sealant ages and eventually cracks. Leakage can also occur as the result of poor assembly or sealant application, or from thermal stress or vibration on the piping and fittings.

2.1.4 Open-ended Lines

Some valves are installed in a system so that they function with the downstream line open to the atmosphere. A faulty valve seat or incompletely closed valve on such an open-ended line would result in a leakage through the open end. In some locations open-ended lines are prohibited. A cap, plug, or blind flange used to control leaks from open-ended lines can also leak from improper installation and aging and deterioration of the gasket or threads. Because these leaks are similar to those found in connectors, a potentially open-ended line that is

capped, plugged, or blind flanged is counted as a connector.

2.1.5 Pressure Relief Devices

Pressure relief devices are safety devices commonly used in petroleum and chemical facilities to prevent operating pressures from exceeding the maximum allowable working pressures of the process equipment. Note that when a pressure relief device functions as designed during an over-pressure incident and allows pressure to be reduced it is not considered an equipment leak. Equipment leaks from pressure relief devices occur when material escapes from the pressure relief device when it is in the closed position. These leaks can occur from the aging and deterioration of packing or sealing materials.

The most common pressure relief device is a spring-loaded pressure relief valve (PRV). The PRV is designed to open when the operating pressure exceeds a set pressure and to reseat after the operating pressure has decreased to below the set pressure.

Another pressure relief device is a rupture disk. Rupture disks are sometimes used upstream of PRVs to control emissions during normal operations. These disks rupture when a set pressure is exceeded, thereby allowing the system to depressurize. Rupture disks do not permit emissions during normal operations. During normal operations it should be assumed that rupture disks do not have any fugitive emissions. However, as a caution, rupture disks are generally not advisable for small diameters due to restriction of flow.

2.1.6 Pumps

Pumps are used extensively in the petroleum industries for the movement of liquids. The centrifugal pump is the most widely used pump type in the petroleum industry; however, other types, such as the positive displacement (reciprocating) pump, are also used. Liquids transferred by pump can leak at the point of contact between the moving shaft and the Consequently, all pumps stationary casing. except the sealless types, such as canned-motor, magnetic drive, and diaphragm pumps, require a seal at the point where the shaft penetrates the housing in order to isolate the pumped fluid from the environment. Sealless pumps do not have fugitive emissions.

Packed and mechanical seals for pumps are similar in design and application to packed and mechanical seals for agitators. Packed seals can be used on both reciprocating and centrifugal pumps. Mechanical seals are limited in application to pumps with rotating shafts. The cause of pump seal leaks are similar to those described for agitators.

2.1.7 Sampling Connections

Sampling connections are fittings where samples are routinely taken for process and quality control purposes. A sampling connection has a specific function (to aid in sample taking) with specific types of emissions that are distinct from those described previously. A sampling connection can leak from a faulty valve seat or incompletely closed valve that is upstream of the sampling connection. A sampling connection

2-3

can also have emissions from the flushing of the line during the sampling process.

2.1.8 Valves

Except for connectors, valves are the most common process equipment type found in the petroleum industries. Valves are available in many designs, and most contain a valve stem that operates to restrict or allow fluid flow. Typically, the stem is sealed by a packing gland or O-ring to prevent leakage of process fluid to the atmosphere. Emissions from valves occur at the stem or gland area of the valve body when the packing or O-ring in the valve deteriorates. Some emissions could also occur from the valve housing, generally at the bonnet flange.

Bellows valves and rubber diaphragm valves have negligible emissions as long as there is not a break in the bellows or the diaphragm.

2.1.9 Others

Other component types can also be a source of fugitive emissions. These other types are usually small in number at a facility, and they might be unique to one sector of the petroleum industry. Other equipment types that are not listed above that may be considered as sources of fugitive emissions are: instruments, loading arms, stuffing boxes, site glasses, vents, dump lever arms, diaphragms, drains, hatches, meters, and polished rods. These component types can leak for a variety of reasons including improper installation, aging, deterioration, thermal stress, and vibration.

2.2 COUNTING COMPONENTS

An accurate inventory of components is essential for a precise determination of fugitive emissions as well as to ensure that all appropriate components are monitored. The first step in developing this inventory is to define the process unit boundaries. A process unit is the smallest set of process equipment that can operate independently and includes all operations necessary to achieve its process objective. All of the components, by component type, need to be specified within that process unit.

Components can, in some cases, be identified from process flow diagrams. However, process flow diagrams may not include all of the components that emit fugitive emissions, because all changes in the numbers of valves or connectors may not have been included on the flow diagrams. Therefore, it is usually necessary to systematically follow process streams while counting, categorizing, and labeling components as you go. Even after this systematic approach, it is recommended to divide the process unit into a grid to search for components (usually connectors) that were missed on the initial survey.

Some components will not be easily accessible. Many flanges are covered with insulation, and some components may be beyond the reach of a person on the ground. The exact definition of what is considered inaccessible differs among the various regulations controlling fugitive emissions from equipment leaks. Difficult to monitor (defined in the regulations) or covered components are often considered inaccessible. Although monitoring requirements may differ for inaccessible components, an inventory of these components would be needed for emission calculation purposes if it is required to calculate all potential sources of fugitive emissions.

Some components will be unsafe to monitor. Unsafe-to-monitor equipment could be associated with high temperature or pressure operations or with process specific safety concerns. These unsafe-to-monitor components should be included as part of the inventory for fugitive emission calculations.

Note that more components may need to be counted for emission calculation purposes than need to be monitored as part of a leak detection and repair program (i.e., "unsafe-to-monitor," "heavy liquid service," etc.). Even though no monitoring may be required, it has been found that some of these components may leak, even if the emission rate is low. Average emission factors for these components can be applied when emission calculations are needed. In order to apply these average emission factors, component counts are needed. It may be advisable to utilize some unique codes in the component inventory to keep track of these special categories.

Other components may not need to be monitored or included in emission estimates. For example, leakless components (such as welded connectors), components not in VOC or HAP service, or components under a vacuum should be excluded from inventories and not used for either monitoring or emission calculation purposes.

The components need to be counted according to the governing regulation. If emission calculations are being performed for submittal to a regulatory agency, it should be noted that each agency may differently define what constitutes a component. Therefore, it is critical to understand the regulations that govern the inspection and maintenance activities for each facility.

2.2.1 Agitators

Each agitator seal is associated with a single agitator housing penetration. Therefore, an agitator may have a single housing penetration equipped with either a single or double mechanical seal that is counted as one agitator seal. Some agitators, however, have a shaft that penetrates both sides of the agitator housing with a separate seal on both the inboard and outboard sides. This type of arrangement is counted as two agitator seals.

2.2.2 <u>Compressors</u>

Compressors can have housing penetrations and seals that are similar to agitators and are counted in the same fashion. A compressor may have a single housing penetration equipped with either a single or double mechanical seal that is counted as one compressor seal. However, if the compressor has a shaft that penetrates both sides of the compressor housing with a separate seal on both the inboard and outboard sides, it should be counted as two compressor seals. Large compressors often include several other component types that are needed for the compressor to function. For instance, a compressor could also include valves on cylinders and multiple connectors on the compressor housing or piping. These other component types, although attached to the compressor, should be counted separately as components themselves and not included as a part of the compressor.

2.2.3 Connectors

A connector is typically defined for equipment leak purposes as any fitting used to join two pieces of pipe and/or components together, with the exception of welded connectors which are assumed to be leak free. This definition includes flanges, threaded connectors, unions, tubing fittings, caps, plugs, etc.

The definition of a connector may, however, vary by regulation. In some cases, connectors have been identified as only including flanges. In other cases, all types of connectors (threaded, union, tubing, etc.) are included. These other types of connectors have occasionally been found to leak. Therefore, if it is desired to develop the most accurate estimate of fugitive emissions, these other types of connectors should be included in component inventories.

There has been some confusion over how to count the many varieties of connectors. Much of this confusion arises from the use of aggregate component names that include multiple connectors. For instance, an elbow fitting is a common fitting in petroleum facilities that would have a connector on each end of a 90 degree bend of pipe. (See Figure 2-1). Although many people think of an elbow as one fitting, there are actually two connectors, either of which can leak independently of the other. Similarly, a "Tee" fitting would be counted as three connectors. A spool piece or swage piece would be counted as two connectors. The most difficult fitting to explain is the union connector, which has two potential leak sites (one at the threads and one at the back of the collar nut) but is counted as a single connector.



Figure 2-1. Threaded Connector Elbow

Heat exchanges have flanged ends and often have several screwed connectors. Some facilities and regulators count these components in inventories and others do not. Again, regulatory direction and facility operating practice for maintaining these components

should be followed. However, note that these flanged ends and screwed connectors have also been found to leak on occasion.

2.2.4 Open-ended Lines

Open-ended lines are generally easy to count. Some confusion does occur when a potentially open-ended line is controlled with a cap, plug, or blind flange. Such a controlled potentially open-ended line is counted as a connector, because that is the effective leak sealing mechanism.

2.2.5 Pressure Relief Devices

The most common pressure relief device is a spring-loaded pressure relief valve (PRV). Another pressure relief device is a rupture disk. Both pressure relief valves and rupture disks should be counted in the same fashion as valves. It is recommended that the flange on the upstream side of pressure relief devices be counted as a separate component from the pressure relief device. The downstream flange should also be counted as a separate component if the downstream line is not exposed to the atmosphere (such as a line connected to a different process vessel).

2.2.6 <u>Pumps</u>

Like agitators, each pump seal is associated with a single pump housing penetration. Therefore, a pump may have a single housing penetration equipped with either a single or double mechanical seal that is counted as one pump seal. Some pumps, however, have a shaft that penetrates both sides of the pump housing with a separate seal on both the inboard and outboard sides. This type of arrangement is counted as two pump seals.

2.2.7 Sampling Connections

Each uncontrolled sampling connection should be counted uniquely. Sampling connections can have emissions reduced by using a closed-loop system or collecting purged process fluid and transferring it to a control device or back to the process.

distinction The between sampling connections and other open-ended lines is dependent on both the configuration and use. An open-ended line that is used for routine sampling would be counted as both an openended line and a sampling connection. If equipped with a cap or plug, the same system would be counted as a connector (threads of the cap or plug) and a sampling connection. On the other hand, an open-ended line that is used as a drain or a high point vent would not be counted as a sampling connection.

2.2.8 <u>Valves</u>

Valves are most commonly defined for counting purposes as including the stem seal, the packing gland, and the connection between the parts of a multi-part valve body (like the bonnet flange). This definition should provide the most accuracy in calculating emissions, because it is the same definition that was used in the bagging studies from which the average factors and the emission correlation equations were developed (Ricks, 1993; Ricks, 1994; Webb, 1993). Most regulatory agencies also use this definition for valves.

Although not supported by methods used to develop emission factors and emission correlation equations, some regulatory agencies may define a value for inspection and maintenance purposes as including the flanges on either side of the valve. Figure 2-2 shows the locations of these flanges on some valves. Regulations may provide conflicting definitions of a valve, or may not provide a definition at all. The result is that facilities across the nation may differ in their counting practices. Some include the flanges on either side as part of the valve, and some facilities count these flanges as separate components. Therefore, one needs to refer to regulations for the appropriate action.



2.2.9 Others

Other component types such as instruments, loading arms, stuffing boxes, site glasses, vents diaphragms, drains, hatches, motors, and polished rods may also need to be counted to develop a complete inventory of potential fugitive emission sources. Again, one needs to refer to regulations for appropriate counting of these other types of components.

2.3 COMPONENT TRACKING

Keeping track of components, their periodic inspection results, and the repairs performed, requires a component identification system, as well as a consistent system for data collection, management, and reporting. In designing its component tracking system, each facility should consider such factors as facility complexity, internal management practices, and procedures and regulatory requirements.

2.3.1 Component Identification

Certain information is recommended for component identification. A method to identify the components is also needed. These recommendations are explained in this section.

2.3.1.1 <u>Recommended Information</u>. It is recommended that each component to be monitored be uniquely identified. The identification is more than just a numbering or tagging scheme. The following items can be used to uniquely identify components:

- Process unit descriptions;
- Equipment ID;

2-8

- Type of equipment (i.e., pumps, valves, etc.);
- Type of service (i.e., gas/vapor, light liquid, or heavy liquid);
- Primary material being transported in the line; and
- Unique location descriptions (to allow for repeat monitoring of targeted components).

The service type of a component identifies the general type of material carried in the process lines under normal conditions (as opposed to conditions of leakage as fugitive emissions). Gas/vapor service indicates that the piece of equipment contains process fluid that is in the gaseous state at operating conditions. An example of the distinction between normal and leakage conditions is liquefied butane in a process line that escapes as a fugitive emission. The service type for a component leaking this material is light liquid service. The distinction between light liquid service and heavy liquid service is defined differently in different regulations. In addition to the service type, the percent of VOCs and HAPs in the lines will directly impact if certain regulations apply. Please refer to the specific applicable regulation for details.

2.3.1.2 <u>Tagging</u>. Some method is required to uniquely identify components. One of the most common methods to identify components is called "tagging," which involves placing some identifier directly on the component. Facilities use a variety of tagging strategies. Some elect to physically tag each component. Others tag only some major pieces of equipment and identify the others by associations. Yet, others might only tag leaking components, following inspection, to identify components for repair. These various tagging schemes might entail unique identifiers on diagrams similar to process flow diagrams. Inspectors locate, monitor, and repair components based on any combination of tags and diagrams used in their facility.

If tagging is used, several methods are in use to maintain the identity of each individual component. Currently, most facilities are using some type of metal or plastic tags. The tag will have a unique identifying code for each component. The code can be either alphabetically-based, numerically-based, or a combination of alpha-numeric characters. The code may have identifiers for the:

- Process unit;
- Area of the process unit;
- Type of equipment being tested;
- Chronological placement of the tags; and
- Process fluids in the process streams.

Metal and plastic tags have the advantage of being a low cost method of identifying components uniquely. All types of tags have the disadvantage of being influenced by the occasionally harsh petroleum industry environment of corrosion, erosion, grease, paint, or dirt. Embossed metal or plastic tags probably currently have the best resistance to this harsh environment. Physical tags might also get lost or misplaced following some maintenance activity.

Other methods for identifying components uniquely are also in use today. Some facilities use bar codes. The bar codes are similar to those used in grocery stores to automate pricing and checkouts. A wand can be passed over these bar codes that accepts the coded information (name of component, location, etc.) and records it in a database. Then the inspection and repair results are recorded separately. Use of bar codes, and some other new tag types, does ensure that a component was indeed visited by inspection teams. However, bar codes are also subject to the degrading influence of the potentially harsh petroleum industry environment including being difficult to read if covered by grime, rain, snow, and even morning dew.

Another version of bar codes is also on the market. These bar codes are called "2D" tags. These tags can include much more information than is stored with the standard bar codes similar to those used in grocery stores. For example, historical information, or specific hazard information can be stored on these same tags.

A method that appears to be less subject to the damages of a petroleum industry environment is the use of "hotel keys." These hotel keys have encoded information holepunched into a metal tag. The hotel keys are read by a hotel key reader to identify the name of the component, etc.

Other identification methods are under development. Potential exists for data to be stored on electronic chips (or "buttons") that can be downloaded to data retrieval equipment in the field. The buttons could contain the identifying information. Radio frequency identification systems also have potential to transmit component information to data readers. Future identifiers may give exact location descriptions based on global mapping formats.

Regardless of the tagging strategy used, it must be decided at the start of the tagging process how and which components will be Most regulations require unique tagged. identifying information for each component subject to inspection and repair in the form of a "logbook," but do not necessarily require physical tagging of components. The exact method for identifying components should be selected by facilities in line with their size, complexity, and compliance documentation system in place. For example, if regulations do not require routine inspection of connectors, then some sort of identifying tag for all of the non-connector components would be а manageable alternative. If it is required to inspect and repair connectors, then the tagging of components becomes much more difficult.

If facilities choose to tag every single component, including individual every connector, field accessible information could be However, it can be extremely maximized. costly to place that many tags and manage them over time. Furthermore, replacing these tags after repairs affecting process lines can sometimes be very difficult. After some repairs, buckets of tags might become available that have to be put back in exactly the right locations. This would require accurate process flow diagrams that indicate where each component (by tag ID) is located with reference to specific equipment.

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Facilities that choose not to put tags on each connector could identify them in their databases based on the distance from a tagged valve or pump. For example, the valve could have the code PUB4482. The first connector beyond the valve could have the code PUB4482-A. The second connector could have the code of PUB4482-B, and so forth. The location of these connectors is maintained either in a database or process flow diagram.

The selection of a tagging method and which components to tag must be made individually by each facility. Decisions should be based on regulatory requirements, ease of implementation, ease of inspection and repair, initial cost, and replacement cost.

2.3.2 Data Collection

Once an identification method has been established, the method to collect inspection and repair information must be resolved. The options for screening instruments are discussed in the next section. Data collected are gathered either on hard-copy sheets, or by a data logger, or sometimes by a combination of both.

An example data sheet for the collection of screening data is shown in Figure 2-3. These sheets require the name of the process unit, the date of the inspection, the inspector's name, the component ID, the background screening value, the measured screening value, and comments. There are many variations of these data sheets. Information on repair attempts and post-repair values, failure code, and repair code are often recorded on the same sheet or a supplemental sheet. Hard-copy data sheets have the advantage of being less costly initially than the purchase of data loggers. However, typically these data sheets require more time to complete in the field and to load into a data management system than using data loggers. The costs for the additional time required to record information on the hardcopy sheets should be evaluated against the additional costs for the data loggers.

Data loggers are hand-held or wearable computers that are carried into the field. Rather than writing data in a log, inspectors can directly enter readings into the device's memory, which can later be transferred directly to a database. Some data loggers are being built into the analyzer itself or can be linked with the analyzer. These data loggers do not require that the screening values be keyed into the system. The screening values are automatically recorded with the press of a button. Care needs to be taken to ensure that the recorded screening values represent a maximum screening reading taken over a time period of at least two times the response time rather than an instantaneous reading. Comments still can be typed into the device. Other data loggers require a reading to be made by the inspector from the analyzer and then keyed in by the inspector into the machine.

Data loggers have many advantages over hard copy sheets. In the past, two inspectors were frequently used for inspections; one to operate the instrument, the second to record the information on the hard-copy sheets. With data loggers it is possible to perform this work with a single inspector. Frequently, the use of data loggers is much quicker than using hard-copy sheets because much of the required information

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is already in the system and the data loggers can prompt the inspector for specific information. Hard-copy sheets are subject to damage from rain, grease, and wear in the field. The data logger data are more durable and frequently more legible. The data from the data logger can be uploaded directly into a data management system, reducing data entry time and improving the accuracy of the information transferred.

Several new types of data loggers have recently entered the market. The decision on the selection of the best data logger for a facility could change as the new products enter the market. The selection of the best data logger could depend on the:

- Intrinsically safe nature of the instrument when not connected to an analyzer;
- Intrinsically safe nature of the instrument when connected to an analyzer;
- Number of components to be tested;
- Number of components that can be stored on the data logger at any one time;
- Number and size of data fields that can be stored on a data logger;
- Speed of the data logger to prompt for information;
- Durability of the data loggers under normal conditions;
- Durability of the data loggers under unique conditions (for example, cold weather impacts);
- Speed and ease of data entry;

- Ease of interface with data management software;
- Weight and bulk of the data logger;
- Cost; and
- Technical support.

Some parameters for certain data loggers in use today are shown in Table 2-1. Data for Table 2-1 were supplied by data logger vendors.

One of the parameters shown on Table 2-1 is whether the data logger is "wearable." Some data loggers and bar code scanners are now capable of being worn rather than carried by hand. Usually the wearable instruments are mounted on the back of a hand, leaving the fingers and front of the hand available for other work. Other recent innovations for data entry that are being developed include speech recognition instruments to record data directly from commands issued by an inspector and Head-Up-Displays (HUD) that allows the data display to be worn on the head of the inspector for easier, quicker viewing.

2.3.3 Data Management

Tens of thousands of measurements are often required at facilities every year. Managing these data can be a tremendous undertaking. Data may need to be analyzed for:

- Repair requirements;
- Follow-up monitoring requirements;

Loggers
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ti si	AppConi -	AppConi.	Corvallis MicroTech.	DAP Microflex	DAP Microflex	Husky	LXB	MicroPalm
SPECTIVES	INOISTA	IT-NOISIA	* PCS	PC9500	PC9000	FS/2	2285	PC3000
Type	Wearable	Wearable	Handheld	Handheld	Handheld	Handheld	Handheld	Handheld
Processor	7/14MHZ 8680 MS-DOS 6.2	7/14MHZ 8680 MS-DOS 6.2	7/14MHZ 8680 MS-DOS 5.0	7/14MHZ 8680 MS-DOS 5.0	80C88, 8MHz MS-DOS 3.31	NEC V30, 8086 MS-DOS 3.31		NEC V30, 8086 MS-DOS 3.31
Display	320x200 CGA	320x200 CGA	128x200 CGA	200x200 CGA	128x128 CGA	240x64	160x80	320x200 CGA
Memory - RAM	2M - 16M	2M - 16M	2M	1M - 2M	128k - 640k	512k - 4M	128k - 1M	512k - 8M
Operating Temperature (C)	0 to 70	(-)20 to 85	(-)40 to 50	(-)20 to 50	(-)20 to 50	(-)20 to 50	(-)10 to 50	(-)20 to 75
Class	Ruggedized	Ruggedized	Ruggedized	Ruggedized	Ruggedized	Military	Ruggedized	Military
FCC Class*	a.	a .	b.	a.	a.	b.	b.	а.
Durability**	A, B, C, E	A, B, C, E	B, C, E	B, C	B, C	B, C, D, E, F	B, C	A, B, C, D, F
Weight***	1.25 lbs	1.0 Ibs	1.75 Ibs	1.75 lbs	2.25 lbs	1.75 lbs	1.75 lbs	2.4 Ibs
Power	12 - 16 hours	12 - 16 hours	2 - 3 days	12 - 16 hours	8 - 10 hours	30 hours	4 - 6 hours	12 - 16 hours
Company Phone	(713) 686-3773	(713) 686-3773	(503) 752-5456			44 203 668181 (England)	(404) 447-4224	(813) 289-6116

STD.API/PETRO PUBL 342-ENGL 1998

*FCC Class pertains to Electrostatic Emission Rating; "a" being the most stringent class.

****Durability Classes:**

- A. UL-913 intrinsically safe ä
- Chemical and dust resistant Water resistant υ

- Withstand 4 feet drop to concrete Waterproof to 3 feet Ошн
- Withstand 6 feet drop to concrete

***With batteries.

*****Please note that all information appearing on the table was provided by the manufactures. Neither API nor its contractor verified such information.

(Continued)
Data Loggers
^{*****} Table 2-1. I

MicroPalm		Norand	Omnidata****	Omnidata	NOISA	NOISA	Radix	Symbol
PC/4000 R1/D11700	KI/D/LI700		Pro2000	286LX	HC120	HCDOS	FW200	PDT-3100
Handheld Handheld Ha	Handheld Ha	Ha	ndheld	Handheld	Handheld	Handheld	Handheld	Handheld
80C88, 8MHz 16-bit / 286 16-bit MS-DOS 2.25 MS-D	16-bit / 286 16-bit MS-D	16-bi MS-D	: / 286 OS 6.0	16-bit / 286 MS-DOS 5.0	80C86, 4MHz MS-DOS 5.0	80c86 MS-DOS 5.0	16-bit / 286	80C88 DOS, BIOS
120x64 128x200 CGA 128x1	128x200 CGA 128x1	128x1	92 CGA	128x192 CGA	160x80	160x80 CGA	128x192 CGA	Alinex 20, Back-lit, Reverse Video
256k - 640k 512k 1M	512k 1M	IM	I - 8M	1M - 8M	128k - 512k	IM		640k - 2M
(-)20 to 75 0 to 50 (-)30	0 to 50 (-)30	(-)30	to 55	(-)30 to 55	0 to 50	(-)10 to 50	(-)40 to 50	0 to 40
Military Ruggedized Rugge	Ruggedized Rugge	Rugge	dized	Ruggedized	Ruggedized (IP64)	Ruggedized (IP54)	Industrial	Industrial
a. b. b	þ. þ	q		þ.	þ.	þ.	þ.	
A, B, C, F, G A, B, C, E A, B, C	A, B, C, E A, B, C	A, B, C	C, D, E	A, B, C, D, E	C, E	C, E	B, C, D, F, G	
2.9 lbs 1.75 lbs 2.4 - 2	1.75 lbs 2.4 - 2	2.4 - 2	sdl 6.	2.4 - 2.9 Ibs	1.75 lbs	1.3 lbs	1.75 lbs	15.5 oz
24 hours 12 - 16 hours 2 - 3	12 - 16 hours 2 - 3	2 - 3	days	2 - 3 days	20 - 50 hours	15 - 20 hours	8 - 10 hours	9V Alkaline/ NiCad Recm.
								4 - 6 days/9V 8 - 12 hours/N.
(813) 289-6116 (319) 369-3100 (713) 5	(319) 369-3100 (713) 5	(713) 5	78-6733		(508) 371-0310		(801) 537-1717	(214) 402-8270

*FCC Class pertains to Electrostatic Emission Rating; "a" being the most stringent class.

- **Durability Classes: A. UL-913 intrinsically safe
- Chemical and dust resistant Water resistant ю U
- Withstand 4 feet drop to concrete с пі пі

Waterproof to 3 feet

Withstand 6 feet drop to concrete

***With batteries.

****The manufacturer/distributor of this data logger is AIW. This data logger is also referred to as the AIW polycorder.

*****Please note that all information appearing on the table was provided by the manufactures. Neither API nor its contractor verified such information.

2-15

(Continued)
Data Loggers
2-1.
*****Table

A. Company	Symbol****	Symbol****	Teklogix	Telxon	Teixon	Telxon
SPEC TYPE	10T 3805	PDT 33001s	7025	PTC-860RF	PTC-960	PTC-912
Type	Handheld	Handheld	Handheld	Handheld	Handheld	Handheld
Processor	NEC V25+, 808 MS-DOS 3.31	NEC V25+, 808 MS-DOS 3.31	32-bit / 386	80C88, 8MHz MS-DOS 3.31	80C88, 8MHz MS-DOS 3.31	NEC V20, 8 MH MS-DOS 3.31
Display	128x128 CGA	120x64	256x128 MDA	128x128 CGA	128x128 CGA	128x64
Memory - RAM	256k - 4M	256k - 4M	256k	128k - 4M	128k - 1M	128k - 1M
Operating Temperature (C)	(-)20 to 40	0 to 50	(-)40 to 80	(-)20 to 50	0 to 40	0 to 50
Class	Ruggedized	Ruggedized	Industrial	Ruggedized	Ruggedized	Ruggedized
FCC Class*	ci	Ą.	b.	þ.	b.	તં
Durability**	A, B, C, E	A, B, C, E	н	A, B, C	B, C	B, C, D
Weight***	1.75 lbs	1.75 Ibs	1.75 lbs	2.0 lbs		
Power	8 - 10 hours	12 - 16 hours	8 - 10 hours			
Company Phone	(214) 402-8270		(800) 633-3040	(216) 867-3700		

*FCC Class pertains to Electrostatic Emission Rating; "a" being the most stringent class.

**Durability Classes:

UL-913 intrinsically safe Ŕ

Chemical and dust resistant Water resistant ы. v

Withstand 4 feet drop to concrete Ощщ

Waterproof to 3 feet

Withstand 6 feet drop to concrete

***With batteries.

*****Used with FEC leaktracker system.

*****Please note that all information appearing on the table was provided by the manufactures. Neither API nor its contractor verified such information.

Not for Resale

2-16

- Regulatory compliance determinations;
- Emission calculations;
- Statistical determinations;
- Report generation; and
- Specific information related to program effectiveness (for example, whether one type of valve or packing is more effective than another).

To obtain the above information, all of the component identification information mentioned in Section 2.2 (type of component, component ID, service type, etc.) will need to be analyzed. The results of inspections and repairs will need to be evaluated. In addition to information on components, calibration data must be maintained.

Nearly all facilities use some form of electronic data management to manage these data. This electronic data management can be spreadsheets, word processing files, or a simple database. Several facilities are using sophisticated relational databases to assist in management tasks. These these data sophisticated systems can assist in all aspects of the required data management, including all regulatory compliance adherence, emission calculations, and report generation.

As with data loggers, several data management systems have recently come into the market. Because of the wide variety of functions that these systems can perform (from spreadsheets to sophisticated relational databases), these data management systems are not examined here. Decisions on which system to use depend on:

- Number of components monitored;
- Storage and manipulation capability of the data management system;
- Number of regulations that apply to the facility;
- Complexity of the regulations;
- Number of functions that the data management system can perform;
- Adaptability of the data management system to revisions in regulations, reporting, and calculation procedures;
- Speed of the system;
- Ease of implementation in a facility;
- Ease of ongoing use and training of new personnel;
- Cost; and
- Technical support.

SECTION 3.0 MONITORING EQUIPMENT FOR APPLYING METHOD 21

The regulations associated with controlling fugitive emissions specify which component types must be measured, the frequency of monitoring, and the time to effect repairs. The United States Environmental Protection Agency (U.S. EPA) has developed a method to measure total fugitive hydrocarbons that leak from these components. It should be noted that most regulations requiring leak detection and repair require facilities to monitor, control and report volatile organic compounds (VOCs) or volatile hazardous air pollutants (HAPs) which are a subset of total organic compounds (TOC). See Volume II, Section 3, for guidance on calculation procedures to convert measured TOC to either VOC or volatile HAP.

U.S. EPA Method 21 (40 CFR, Part 60, Appendix A, 1996) has been used for years as the basis for VOC leak monitoring. The requirements of Method 21 are summarized in Table 3-1. The full text of Method 21 is provided in Appendix A. The monitoring equipment requirements of Method 21 with supporting information and discussion are explained in this section.

3.1 SELECTION CRITERIA FOR A PORTABLE ANALYZER

To select a portable analyzer for use in an inspection and maintenance (I/M) program at a

petroleum facility, the following criteria should be considered:

- Ability to meet Method 21 specifications;
- Ease of use of acquired data in emission calculations;
- Ability to measure the particular compounds and chemicals in the process streams being inspected;
- Range of readings (0 to 1,000,000 ppmv) and reliability over the range;
- Durability under normal conditions;
- Durability under unique or harsh conditions (such as cold or wet weather conditions);
- Response time (some analyzers are at the limit of Method 21 specifications to register hydrocarbons which can significantly slow routine inspections or cause leaks to be missed);
- Length of operation time before needing to be repowered (battery charged, additional fuel, etc.) under various conditions (wet, cold, hot, etc.);
- Readability of the response;
- Weight and bulk;
- Cost of purchase; and
- Cost of maintenance.

Table 3-1.Summary of EPA Method 21Monitoring Equipment Requirements

Determination of Volatile Organic Compound Leaks

1. Analyzer response factor <10.

2. Analyzer response time ≤ 30 seconds.

3. Calibration precision $\leq 10\%$ of calibration gas.

4. Internal pump capable of pulling 0.1 to 3.0 L/min.

5. Intrinsically safe.

6. Single hole probe with maximum ¹/₄-inch OD.

7. Linear and measuring ranges must include leak definition value (may include dilution probe).

8. Instrument readable to $\pm 2.5\%$ of leak definition.

9. No detectable emissions (NDE) value defined as ±2.5% of leak definition (i.e., 500 ppm spread if leak definition is 10,000 ppm).

3.2 ANALYZER TYPES

Any analyzer can be used to monitor fugitive emissions, provided it can meet the requirements of Method 21. The four most common types of analyzers are:

- Flame ionization detectors (FIDs);
- Photoionization detectors (PIDs);
- Infrared detectors; and
- Solid state, chemical instruments, combustion analyzers.

Each type of analyzer operates on unique principles. A discussion of each analyzer type follows. Data for all of the instruments in this section were supplied by instrument vendors and from *Survey of Portable Analyzers for the Measurement of Gaseous Fugitive Emissions* (Skelding, 1992). Instruments not included in these subsections could also be used for I/M purposes, based on the Method 21 criteria.

3.2.1 Flame Ionization Detectors

Ionization detectors operate by ionizing the sample and then measuring the charge (number of ions) produced. In a standard flame ionization detector (FID) organic vapor is ionized in a hydrogen flame and drawn toward a negatively charged collector. The current generated is proportional to the concentration of hydrocarbons present. An FID ideally measures total carbon in a sample. However, certain organic compounds containing nitrogen, halogen, or oxygen atoms do not fully ionize when sampled with an FID and give a reduced

response. High water vapor content may affect response characteristics in an FID.

FIDs are highly desirable for use in portable instruments because of their inherently stable baseline qualities. FIDs have become the standard for conducting studies of fugitive emissions in the petroleum business. The recent API studies for refineries, marketing terminals and the oil and gas production industry have all used the FIDs (Ricks, 1993; Ricks, 1994; Webb, 1993).

Tables 3-2 and 3-3 show certain characteristics of several FIDs. The ability to meet Method 21 specifications is shown on Table 3-2. Table 3-3 describes characteristics of these FIDs that could impact analyzer selection.

3.2.2 Photoionization Detectors

Photoionization detectors (PIDs) operate similarly to FIDs, except ultraviolet light rather than a flame ionizes the sample. Similar to the FID, the current generated is proportional to the concentration of hydrocarbons present. PIDs measure halogenated hydrocarbons, aldehydes, ketones, and any other compound that can be ionized by UV light, including several that cannot be measured by an FID. The higher the energy of the lamp, the larger the number of compounds that can be ionized.

Because of the ability to measure certain compounds that do not fully ionize when sampled with an FID, PIDs have been used in industries that process these compounds. This is especially true for certain chemical industries. Table 3-2. Flame Ionization Analyzers Method 21 Capabilities

					Method 2	I Cruena		
A State And Charles of the			Maximum	Intrinsically	Response	0.25" o.d.	Sample	
T. Manufacturer	Phone Number	Model	Range (ppm)	Safe	Time (sec)	Probe	Flow (Ipm)	Comments
The Foxboro Company	(508) 378-5477	OVA 88	0-100,000	ON	2	YES	2.0	
		OVA 108	0-10,000	YES	7	YES	2.0	
		OVA 128	0-1,000	YES	2	YES	2.0	5
		TVA 1000	0.2-50,000	YES	3	YES	1.0	
Heath Consultants, Inc.	(800) 432-8487	III-4Q	0-10,000	NO	3	YES	2.0	1
		DP-II	0-1,000	NO	ę	YES	2.5	7
		PF-II	0-5,000	NO	5	YES	0.7	3, 5
MSA/Baseline	(800) 672-4678	GasCorder	0-10,000	YES	3	YES	0.5	4,7
Industries, Inc.		FID						
P.E. Photovac	(516) 254-4199	Micro FID	0.1-50,000	YES	۵	YES	0.6	
Sensidyne, Inc.	(800) 451-9444	Intrinsicall y Safe FID	0-10,000	SEX	<10	YES	1	9
Thermo Environmental Instruments, Inc.	(508) 520-0430	680 H&M	0-20,000	YES	4	YES	1.0	6

Comments

Plans are underway to make DP III intrinsically safe.

Plans are underway to make DP II intrinsically safe. . . 4 сi

Currently being modified to be intrinsically safe.

Was expected to meet Class I, Division 1 & 2 standards by approximately 12/92. We have been unable to verify this with the manufacturer.

Five percent definition at 500 ppm leak level. ś

FM Class I, Division 1, Groups A, B, C, and D. 5

Instruments may be capable of measuring above 10,000 ppm with the use of a dilution probe.

Source: Vendor information and Skelding, 1992. (Table includes information on all devices of which the authors were aware at the time this document was written.)

Note: Intrinsically safe, as defined for Method 21, is to be safe for operation in explosive atmospheres as defined by the applicable U.S.A. standards (e.g., National Electrical Code by the National Fire Prevention Association).

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Table 3-3. Flame Ionization Analyzers Characteristics

		1. 1.	Maximum	Battery/Fuel			
		Calibration	Range	Life	Dimensions (in),	Temperature	
🔒 📄 Manufacturer	Model	Gas	(udd)	(Jurs)	Weight (lbs)	(°C)	Comments
The Foxboro Company	0VA 88	Methane	0-100,000	×	9x12x4, 11	10 to 40	1
	OVA 108	Methane	0-10,000	8	9x12x4, 12	10 to 40	7
	OVA 128	Methane	0-1,000	×	9x12x4, 12	10 to 40	e
	TVA 1000	Methane and	0.2-50,000	×	13x10x3, 12	10 to 50	4
		Isobutane					
Heath Consultants, Inc.	DP-III	Methane	0-10,000	∞	3.5x7x10, 7	-20 to 48	5
	DP-II	Methane	0-1,000	8	11x7x9, 9	-20 to 48	9
	PF-II	Methane	0-5,000	10	3x10x9, 6.3	-20 to 48	7
MSA/Baseline	GasCorder	Methane	0-10,000	8	17x11.2x8, 18.5	5 to 35	∞
Industries, Inc.	FID						
P.E. Photovac	Micro FID	Methane	0.1-50,000	15/<12	17x4x7.5, 8	5 to 45	6
Sensidyne, Inc.	Intrinsically Safe FID	Methane	0-10,000	16	14.5x4.6x9.3, 8.6	0 to 40	
Thermo Environmental Instruments, Inc.	680 H&M	Methane	0-20,000	×	12.5x11.5x2.6, 11.75	0 to 40	

Comments

The OVA 88 is primarily for natural gas leak detection. Logarithmic analog scale.

Generally accepted as the industry standard. Logarithmic analog scale. ë e,

GC option (\$1,200) for qualitative analysis. Three scales 0-10, -100, -1000. Linear analog scale.

FID and PID capabilities. Has data logger. 4 5

Five scales, maxima of 10, 50, 100, 1000, and 10,000. Five scales, maxima of 10, 50, 100, 500, and 1000.

ý.

Three scales 0-50, 0-500, 0-5000. Analog scale. ۲.

Dedicated air and hydrogen cylinders. Datalogging capabilities. ൽ ത്

Optional bar code reader and Method 21 software. Includes data logger. Scales of 0-20, 0.5-2000 and 10 to 50,000 ppm.

Source: Vendor information and Skelding, 1992. (Table includes information on all devices of which the authors were aware at the time this document was written.)

365.000

3-5

However, an API petroleum industry study was not able to correlate screening values taken at refineries from two PIDs to screening values from FIDs (Ricks, 1995). This is because PIDs respond poorly to straight chained hydrocarbons. For instance, PIDs will not respond to methane. Because the FID was used to develop the emission correlation equations for the petroleum industries, great care is advised when applying these equations to PID screening measurements. PIDs should only be used in areas where process chemistry indicates good response characteristics. This limitation restricts the use of PIDs for routine I/M activities in the petroleum business.

Note that one analyzer has been introduced to the market, the Foxboro Total Vapor Analyzer (TVA) 1000, that has both an FID and a PID that can operate simultaneously. The TVA 1000 FID readings have been found (Ricks, 1995) to correlate well with the organic vapor analyzer (OVA) 108 readings used in the recent petroleum studies.

Tables 3-4 and 3-5 show certain characteristics of several PIDs. The ability to meet Method 21 specifications is shown on Table 3-4. Table 3-5 describes characteristics of these PIDs that could impact analyzer selection. Instruments not on these tables could also be analyzed for I/M purposes, based on these criteria.

3.2.3 Nondispersive Infrared Instruments

Nondispersive infrared (NDIR) instruments measure the amount of light of specific wavelengths absorbed by the sample. NDIR instruments are usually subject to interference because common gases, such as water vapor and carbon dioxide, may also absorb light of the same wavelength as the compound of interest. Because of this frequent interference, NDIR instruments are generally used to measure and detect only a single compound. The wavelengths at which a certain compound absorbs are predetermined and the device is preset at that wavelength using optical filters and different lamps. Other instruments can be field tuned to detect a wide variety of chemicals (one at a time). Because of this, NDIR instruments are excellent for HAP monitoring, but less useful for total VOC monitoring. Once the emission rate of one compound of interest is known, stream speciation data can be used to determine the emission rate of the entire stream.

3.2.4 <u>Solid State, Electrochemical,</u> <u>Combustion Analyzers</u>

A large number of the portable analyzers currently on the market use solid state sensing devices, the most common being a tin oxide device that converts changes in current to concentration as a sample gas flows over the sensor. A gold film senses changes in resistance as mercury or hydrogen sulfide molecules are deposited on it. Electrochemical cells are also being employed as gas sensors in many compound-specific instruments.

Combustion analyzers typically use solid state technology. Most portable combustion analyzers measure the heat of combustion and are referred to as hot wires or catalytic oxidizers. Combustion analyzers, like ionization detectors, measure the total hydrocarbon

			Maximum		Method 21	Criteria		
Manutacturer	Phone Number	Model	Range (ppm)	Intrinsically Safe	Response Time (sec)	0.25" o.d. Prohe	Sample	
HNu Systems, Inc.	(617) 964-6690	101-SI	0-2,000	YES	3	YES	0.17	Comments
		DL-101-2	0-2,000	ON	ŝ	YES	0.25	
		DL-101-4	0-2,000	ON	ŝ	YES	0.25	1, 4
MSA/Baseline Industries. Inc.	(800) 672-4678	GasCorder	0-2,000	YES	3	YES	0.5	3, 4, 10
		ЧИ						
MSA	(800) 672-4678	Passport PID	0-2,000	ON	3	YES	0.2	1, 4, 5
P.E. Photovac	(516) 254-4199	Microtip MP-1000	0.1-2,000	YES	۵	YES	0.5	000
		HL-2000	0.1-2,000	YES	♡	YES	0.5	6, 8, 9
		IS-3000	0.1-2,000	YES	Ŷ	YES	0.5	7, 8, 9
		2020	0.1-2,000	ON	۵	YES	<0.3	∞
		2020-IS	0.1-2,000	YES	۵	YES	<0.3	7, 8, 9
RAE Systems Inc.	(408) 481-4990	PGM-76	0 - 2,000	ON	Ş	YES	0.5	6, 8, 9
		PGM-76IS	0 - 2,000	YES	ŵ	YES	0.5	7, 8, 9
Sentex Sensing Technology, Inc.	(201) 945-3694	Scentogun	0-2,000	ON	2	YES	0.1	2, 4
Thermo Environmental	(508) 520-0430	580-S	0-2,000	YES	2	YES	0.4	4
Instruments, Inc.		580-B	0-2,000	NO	2	YES	0.4	

Comments

Class I, Division 2 certified. <u>...</u>

Meets Method 21 probe size criteria only when used with optional extension.

Was expected to meet Class I, Division 1 & 2 requirements by 9/91. We have been unable to verify with the manufacturer.

Five percent definition at 500 ppm leak level.

Class I, Division 2; Groups A, B, C, and D; Class II, Division 2, Groups E, F, and G; and Class III, Division 1 and 2, hazardous locations. Class I, Div II, Parts A, B, C, and D intrinsically safe.

Class I, Div I, intrinsically safe.

8.4, 9.5, 10.0, 10.6 and 11.7 lamps. Datalogging capabilities.

Dilution system available.

Instrument may be capable of measuring above 10,000 ppm with the use of a dilution probe.

Source: Vendor information and Skelding, 1992. (Table includes information on all devices of which the authors were aware at the time this document was written.)

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Sec. of Concession
Analyzers	
Photoionization	Characteristics
Table 3-5.	

1987		menga									<u> </u>			<u></u>							<u> </u>
		Comments	1		7		3	L		5	6	6	8, 9	6	8,9	8, 9	8, 9	9		4	4
	Temperature	Celsius	-15 to 40		40 Max		40 Max	5 to 35		0 to 40	0 to 40	0-40	0-40	0-40	0-40	-10 to 40	-10 to 40	None	Supplied	5 to 40	5 to 40
	Dimensions (in),	Weight (Ibs)	8x5x9, 10		8x3x6, readout 4	8x3, probe 3	8x3x6, readout 4	17x8x8, 10		8x4x4, 3	14x5x9, 5.5	14x5x9, 5.5	14x5x9, 5.5	10x3x2, 1.75	10x3x2, 1.75	7.1x2.7x1.8, 1.1	7.1x2.7x1.8, 1.1	9x6x4, 4		6.75x5.75x10, 7	6.8x5.8x10, 6
Battery/Fuel	Life	(hrs)	8		œ		8	80		×	8	∞	8	8	×	10	10	9		8	8
Maximum	Range	(mqq)	0-2,000		0-2,000		0-2,000	0-2,000		0-2,000	0.1-2,000	0.1-2,000	0.1-2,000	0.1-2,000	0.1-2,000	0 - 2,000	0 - 2,000	0-2,000		0-2,000	0-2,000
	Calibration	Gas	Benzene,	Isobutylene	Benzene		Benzene	Benzene		Isobutylene	Isobutylene	Isobutylene	Isobutylene	Isobutylene	Isobutylene	Isobutylene	Isobutylene	Benzene		Benzene	Benzene
		🐺 Model 📑	IS-101		DL-101-2		DL-101-04	GasCorder	PID	Passport PID	Microtip MP-1000	HL-2000	IS-3000	2020	2020-IS	PGM-76	PGM-76IS	Scentogun		580-S	580-B
	Phone -	Number	(617) 964-6690					(800) 672-4678		(800) 672-4678	(516) 254-4199					(408) 481-4990		(201) 945-3694		(508) 520-0430	
		Manufacturer	HNu Systems,	Inc.				MSA/Baseline	Industries, Inc.	MSA	P.E. Photovac					RAE Systems Inc.		Sentex Sensing	Technology, Inc.	Thermo	Environmental Instruments, Inc.

Comments

Basic instrument is PI-101. The HW-101 (Hazardous Waste) is Class I, Division 2 certified. Analog readout, 3 scales, 9.5, 10.2, 11.7 eV lamps. _____

DL-101-2 has two modes of operation, datalogging capabilities, digital readout, 9.5, 10.2, 11.7 eV lamps. DL-101-4 has four modes of operation, datalogging capabilities, digital readout, 9.5, 10.2, 11.7 eV lamps.

Digital display, datalogging capabilities, optional bar code reader interface.

Digital display, datalogging capabilities, 10.6 eV lamp.

Digital display, 10.6, 11.5 eV lamps.

Dilution system available. 8.4, 9.6, 10.2, 10.6, 11.8 eV lamps. Datalogging capabilities.

Dilution system available.

8.4, 9.5, 10.0, 10.6 and 11.7 lamps. Datalogging capabilities.

Source: Vendor information and Skelding, 1992. (Table includes information on all devices of which the authors were aware at the time this document was written.)

3-8

concentration of a gas. Gases that are not readily combustible, such as formaldehyde and carbon tetrachloride, exhibit reduced responses or no response at all.

The recent API study of hydrocarbon analyzers (Ricks, 1995) developed a correlation between a combustion analyzer, the Bacharach TLV (Threshold Limit Value) Sniffer[®], and the FID used to develop the emission correlation equations.

Tables 3-6 and 3-7 show characteristics of several infrared, electrochemical, and solid state analyzers. The ability to meet Method 21 specifications is shown on Table 3-6. Table 3-7 describes characteristics of these instruments that could impact analyzer selection. Instruments not on these tables could also be analyzed for I/M purposes, based on these criteria.

Table 3-6. Infrared, Electrochemical, and Solid State Analyzers Method 21 Capabilities

			Maximum		Method 2	l Criteria		
Manufacturee	Phone Number	Model	Range (nom)	Intrinsically Safe	Response Time (sec)	0.25" o.d. Probe	Sample Flow	Comments
AIM USA	(713) 240-5020	1350	0-50.000	YES	<2	YES	1.5	5
		3501	0-50,000	YES	Ś	YES	1.5	ŝ
Arizona	(602) 966-9681	Jerome 431X	6660	ON	13	YES	0.750	Э
Instrument			(mg/m3)					
		Jerome 631X	0-50	NO	9	YES	0.150	4
Bacharach, Inc.	(412) 782-3500	TLV Sniffer	0-10,000	YES	<30	YES	1.75	
		MV-2	0-1.0	NO	S	YES	N/A	2, 9
			(mg/m3)					
CEA	(312) 991-3300	Gaseeker GS4	0-10,000	YES	<10	YES	0.3	6
Instruments,								
Inc.								
The Foxboro	(508) 378-5477	MIRAN 1Bx	1	YES	Compound	ON	30	-
Company					Dependent			
Gas Tech, Inc.	(510) 794-6200	1238ME	0-10,000	YES	20	YES	1.0 - 1.5	2
		GT105	0-10,000	YES	20	YES	0.7 - 1.0	œ
McNeil		Gasurveyor 4	0-1,000	YES	5	YES	0.5	
International								

Comments

Internal library of approximately 115 compounds.

No sample flow given. ci,

- Scale reads in milligrams per cubic meter. e.
- Four scales 1-1000 ppb, 0.1-1.0 ppm, 1-10 ppm, and 10-50 ppm. Response time varies by scale and mode setting (survey mode times given). 4
 - Meets Method 21 criteria only when used with optional sample pump attachment. Ś
 - **BASEEFA** certification is pending. ن
 - 1
- Meets leak definition at 10,000 ppm with optional meter scale. Intrinsically safe Class I, Division 1, Groups C and D.
 - Intrinsically safe Class I, Division 1, Groups A through D. ∞່ ດ່
- Instruments may be capable of measuring above 10,000 ppm with the use of a dilution probe.

Source: Vendor information and Skelding, 1992. (Table includes information on all devices of which the authors were aware at the time this document was written.)

Sec. 1

3-10

Analyzers	
State	
Solid	
and	S
Electrochemical,	Characteristi
Infrared,	
Table 3-7.	

		an Septembri Septembri	Calibration	Maximum Range	Battery/Fuel Life	Dimensions (in).	Temperature	
Manufacturer	Phone Number	Model	Gas	(mqq)	(brs)	Weight (lbs)	Celsius	Comments
AIM USA	(713) 240-5020	1350	Methane	0-50,000	7.5	18x2 dia, 1.5	0 to 50	1
		3501	Methane	0-50,000	7.5	7.5x4x2.5, 3.5	0 to 50	2
Arizona	(602) 966-9681	Jerome 431X	N/A	.0999 0	9	6x13x4, 7	0 to 40	e
Instrument				(mg/m3)				
		Jerome 631X	N/A	0-50	6	6x13x4, 7	0 to 40	æ
Bacharach, Inc.	(412) 782-3500	TLV Sniffer	Hexane	0-10,000	8	9x3.75x6.6, 5	10 to 49	4
		MV-2	N/A	0-1.0	4	11.4x4.8x4.4, 6	N/A	5
				(mg/m3)				
CEA Instruments, Inc.	(312) 991-3300	Gaseeker GS4	Methane	0-10,000	10	3x6x6, .3	-10 to 50	6
The Foxboro	(508) 378-5477	MIRAN 1Bx	1		4	27x9x11, 28	5 to 40	7
Company								
Gas Tech, Inc.	(510) 794-6200	1238ME	Hexane	0-10,000	10	12x3.7x5.5, 8	-20 to 0	8
		GT105	Hexane	0-10,000	10	10x5x6, 5	-20 to 45	
McNeil		Gasurveyor 4		0-1,000	15	7x3.8x4.1, 3.5	-20 to 50	6
TINVIIIau Ollai								

Comments

4

Solid state sensor, data logging capability, detachable pump. Solid state analyzer.

- Catalytic bead sensor (HS, CO & 02-included), data logging capability.
 - Digital readout, datalogging capabilities, software optional.
- Range can be expanded to 0-100,000 ppm with 10:1 dilution probe option. Combustion analyzer.
- Mercury vapor detector only. Digital readout. Combustion analyzer. Logarithmic LED scale, not defined enough at 95% for Method 21.
- Infrared. Internal library of approximately 115 compounds. Calibration ranges from 0-10 ppm to 0-2000 ppm. Digital readout. Infrared analyzer.
 - Analog meter, also reads 0-100% LEL combustibles.
 - Electronically calibrated.

Source: Vendor information and Skelding, 1992. (Table includes information on all devices of which the authors were aware at the time this document was written.)

3-11

SECTION 4.0 QUALITY CONTROL

To ensure that data collected are of an acceptable quality several quality control steps are suggested. These quality control steps include those required prior to beginning any screening, those recommended with the daily monitoring, and those recommended during the day's testing.

4.1 TESTING PROGRAM SET-UP QUALITY CONTROL

Method 21 requires three quality control procedures prior to initiating any testing program, including:

- Calibration precision test;
- Response time test; and
- Response factor determination.

4.1.1 <u>Calibration Precision Test</u>

Method 21 requires a demonstration of calibration precision prior to using the analyzer and then again at three month intervals. If an analyzer is unused for more than three months, it can be checked for calibration precision at its next use. Figure 4-1 is an example of how to document calibration precision. The instrument ID number should be entered in the heading of the table. The date, the operator, the reference compound, the calibration gas concentration, the zero air reading, the measured concentration after 30 seconds, and the statistical results of the calibration should be shown on the table.

Prior to calibrating the instrument it is necessary to choose a calibration gas mixture appropriate for the instrument and compounds being measured (refer to the instrument's operating manual). Methane is often used as the calibration gas for FIDs. Because PIDs cannot measure methane, benzene or isobutylene is often used as a calibration gas. Other instruments, including the TLV Sniffer®, use hexane as the calibration gas. The concentration of the gas mixture used for calibration must be certified. If the shelf life of the gas has expired, either replace the gas or analytically verify the concentration of the gas before each use. Method 21 requires the use of certified $\pm 2\%$ accuracy calibration gases that have been analyzed and certified by the manufacturer.

Calibration gas standards temporarily stored in a bag must be replaced each day of use unless it can be demonstrated that degradation does not occur during storage. If Tedlar® bags or aluminized bags are used to store the calibration gas for testing, these bags should be emptied and refilled with exactly the same calibration gas as was used in these bags the previous day of testing. Typically, the purging of these bags should be done two or three times prior to conducting any calibration check to ensure that all of the previous testing gases have been replaced with fresh gas.

The concentration of the calibration gas mixture to be used would depend on the leak definition of the regulation requiring the monitoring. A calibration gas approximately equal to the leak definition specified in the regulation should be selected, but on the readable

VOC Analyzer	
Calibration Precision for Portable	Analyzer ID
Figure 4-1.	

Calibration Precision [#] (9)			1.4%		-					
Average Difference (8)			133							
Absolute Difference Measured Known	100	100	200							
Measured Concentration (after 30 sec) (6)	9,700	9,500	9,800							
Zero Air (5)	0	0	0							
Calibration Gas Concentration (4)	9,600 ppm	· · · · ·								
Reference Compound (3)	Methane									
Inspector (2)	RR						:			
Date (1)	10/31/95									

 $x \ 100 = 1.4\%$ 9,600 133 x 100 = calibration gas concentration average difference ^a Calibration precision =



scale of the analyzer. For instance, a 9,000 ppmv methane in air standard would be a good calibration gas for an FID with the range of 0-10,000 ppmv.

An example procedure to determine calibration precision is:

- i) Assemble and warm up the instrument according to manufacturer's instructions;
- ii) Adjust the instrument reading to zero based on the reading with the zero gas (less than 10 ppmv VOC);
- iii) Introduce the calibration gas (for approximately 30 seconds) and adjust the instrument until the readout matches the calibration gas value;
- iv) Again introduce the zero gas and record the reading in column 5;
- Again introduce the calibration gas for approximately 30 seconds and record the reading in column 6;
- vi) Repeat the zero gas and calibration gas readings two more times, recording each zero gas reading in column 5 and each calibration gas reading in column 6;
- vii) Determine the absolute value of the difference between the known concentration and the measured concentration and record it in column 7;
- viii) Take the sum of column 7 and divide by the number of calibration checks (3) and record it in column 8; and

ix) Divide the value in column 8 (the average difference) by the known calibration gas value (column 4) and multiply by 100 to calculate the calibration precision:

Calibration precision =
$$\frac{avg \ diff}{calib \ gas \ conc} \times 100$$

(Eq. 4-1)

An example of this calibration precision method is shown in Figure 4-1. The calibration precision cannot vary by more than 10 percent or internal instrument maintenance will be required, as specified in Method 21.

4.1.2 <u>Response Time Test</u>

The response time of the instrument must also be checked when first used or after any major servicing. An example procedure to check response time is:

- i) Introduce hydrocarbon-free gas (zero gas) into the probe of the instrument.
- ii) When the meter reading has stabilized, switch quickly to the calibration gas.
- Measure and record the time from switching to the time when 90 percent of the final stable reading is attained. For example, if the detector stabilizes at 8,000 ppm, record the time when the analyzer indicates 7,200 ppm. (This may actually require an earlier pass through to know the stabilized reading value.)
- iv) Repeat this response time check two more times.

v) Average the three response times for each concentration.

The response time must be less than 30 seconds or internal instrument maintenance will be required as specified in Method 21.

4.1.3 Response Factor Test

Not every compound screened will respond fully to all detectors. Some compounds will not respond at all or must be heavily concentrated to evoke a response, and others will take several seconds to respond. Therefore, it is necessary to ensure that the chosen instrument will actually measure the compounds of interest at the expected concentrations. Response factors, which correct for the sensitivity of an analyzer to certain compounds, must be determined for each compound to be measured. The response factor is defined as:

Response Factor= Actual concentration of compound Observed concentration detected (Eq. 4-2)

A response factor of 1.0 means that the instrument readout is identical to the actual concentration of the chemical in the gas sample. Response factors can either be greater than 1.0 or less than 1.0, depending on the instrument and the compound measured. Method 21 specifies that only those instruments with response factors of less than 10 may be used to monitor organic compounds for equipment leak monitoring. Method 21 does not mention any lower limits.

Response factors have been developed and published by the U.S. EPA and some of the

companies with analyzers in use today. A response factor determination is not required by Method 21 if existing results can be referenced. Ideally, a facility should check if response factors exist for an analyzer prior to purchasing an analyzer. If analyzers have already been purchased, then the manufacturer's literature or technical staff should be able to explain if response factors have been prepared for that instrument.

If no response factors have been published, and the manufacturer cannot assure you that the compounds you are measuring have a response factor less than 10, Method 21 specifies the following:

Calibrate the instrument with the reference compound as specified in the applicable regulation. For each organic species that is to be measured during individual source surveys, obtain or prepare a known standard in air at a concentration of approximately 80 percent of the applicable leak definition unless limited volatility by or explosivity. In these cases, prepare a standard at 90 percent of the saturation concentration, or 70 percent of the lower explosive limit, respectively. Introduce this mixture to the analyzer and record the observed meter reading. Introduce zero air until a stable reading Make a total of three is obtained. measurements by alternating between the known mixture and zero air. Calculate the response factor for each repetition and the average response factor.

In practice, very few petroleum company process streams have response factors greater than 10 for most of the commonly used analyzers. The exceptions are in specialized

4-4

areas such as MTBE, reduced sulfur species such as COS and CS_2 , ethylene glycol, carbon tetrachloride, and CFC refrigerants. Response factors should be considered prior to beginning testing, especially if a facility is planning on using an analyzer that is new to the market or beginning a sampling program in an area where petroleum hydrocarbons are not the dominant species.

4.2 START OF DAY QUALITY CONTROL

Method 21 requires that the instrument be calibrated daily. Good practices for daily quality control procedures also would include:

- Cleaning the instrument's filters and probe assembly;
- Checking for probe or instrument leaks;
- Checking and recording the pump flow rate (optional); and
- Adjusting the dilution probe to a 10:1 ratio (or record what ratio is being used).

4.2.1 Instrument Cleaning

The first recommended daily quality control task is to ensure that the instrument's filters and probe assembly are cleaned. Contaminated filters and probe assemblies can influence calibration results and readings in the field. The exact cleaning procedures depend on the instrument type. Typically there are filters in the probe tip. Usually dirt can simply be knocked out on a table top. Deposits that are wet and caked on can be washed away with a solution of soap and alcohol. The filter should be dried before reuse. Additional clean-up procedures may be required from time to time based on the instrument design.

4.2.2 Probe Leak Tests

Some analyzers could develop leaks in the probe assembly, the pump sample line, or in the assembly of the analyzer itself. Leaks can particularly be a problem with analyzers that have been used extensively. The analyzer should be checked for leaks every day. The exact checking method for leaks depends on the analyzer type. For an OVA, a check would include the following:

- i) Cover (with your thumb or another plugging device) the inlet of the probe tip on the fully assembled analyzer;
- ii) Listen to the internal pump mechanism (it should shut off, or nearly shut off because of the lack of flow);
- iii) If a leak is found (pump doesn't shut off or nearly shut off), remove the probe tip to the readout and sample line and cover the inlet;
- iv) Again listen for the pump to shut off or nearly shut off;
- v) If a leak is still found, remove the sample line to the analyzer and cover the inlet to the instrument housing; and
- vi) Again listen for the pump to shut off or nearly shut off.

It may be necessary to apply plumber's tape to the instrument or probe assembly to ensure that there are no leaks.

4.2.3 <u>Pump Flow Rate Tests</u>

Another optional daily (or at least frequent) task is to record the pump flow rate of the analyzer. Method 21 specifies that the instrument must have a pump capable of drawing sample at a rate of 0.10 to 3.0 liters per minute. Once the Method 21 specifications have been met, Method 21 does not require daily checking of this flow rate. However, changes in pump flow rate can potentially affect results. Changes in pump flow rates with time could potentially explain changes in some readings over time. Significant changes in pump flow rate (approximately $\pm 20\%$) could indicate problems with the analyzer. Therefore, frequent testing of the pump flow rate is recommended. Pump flow rates can be measured by bubble flow meters attached to the sample line. Care should be used to avoid sucking fluids into the analyzer when conducting this test.

4.2.4 Instrument Calibration

Method 21 requires instrument calibration for every day of testing. The daily calibration steps are comparable to those used in the original set-up of the testing program. The same calibration gas specifications are required. This time only one check of the zero gas and calibration gas is required. However, at least one additional check is recommended if adjustments to the instrument's calibration controls are necessary. The recommended procedures for the daily calibrations are as follows:

- i) Assemble and warm up the instrument according to manufacturer's instructions;
- ii) Adjust the instrument reading to zero, based on the reading with the zero gas;
- iii) Introduce the calibration gas (for approximately 30 seconds) and adjust the instrument to correspond with the calibration gas value;
- iv) Again introduce the zero gas and record this reading;
- v) Again introduce the calibration gas for approximately 30 seconds and record this reading;
- vi) Continue until the readings at the zero gas and calibration gas are reproducible;
- vii) If not repeatable, conduct another calibration precision check; and
- viii) If the calibration precision check is not within 10 percent, then internal instrument maintenance is required, as specified by Method 21.

Method 21 specifies using only two calibration gases, at zero air and at a hydrocarbon concentration at approximately the leak definition. In some cases it may be desired to check the calibration of the instrument at other hydrocarbon concentrations as well. The selected calibration gases could be based on the range of the analyzer. A low concentration calibration gas (5-25% of the range of the analyzer), a mid-concentration calibration gas (40-60% of the range of the analyzer), and a high concentration calibration gas (80-90% of the range of the analyzer) could be used. The linearity of the analyzer over the entire range of potential screening values could then be determined.

4.2.5 <u>Dilution Probe Adjustments</u>

A dilution probe extends the range of an analyzer, and thus can provide significantly more information to the I/M team. For some regulations, a dilution probe is necessary for several analyzer types to read up to a specific leak concentration. For example, without a dilution probe, the OVA 108 has a range of only 10,000 ppmv. A dilution probe can typically extend the range of the OVA to 100,000 ppmv.

Most dilution probes restrict the flow of the incoming sample stream into the analyzer and make up the remainder of the flow with ambient air. The air is pulled from a location away from the source of the leak and it is often pulled through a carbon filter to reduce the chance that hydrocarbons in the air are affecting the reading of the analyzer. For example, frequently a dilution probe is set at a 10:1 ratio. The dilution air, pulled from away from the leak, dilutes the leak by a factor of 10. A 1,000 ppmv leak would now read 100 ppmv on the analyzer, while a 10,000 ppmv leak would now read 1,000 ppmy, and a 100,000 ppmy leak would read 10,000 ppmv. Because the dilution probe reduces the sensitivity of the readings, they are recommended for use only if the measured leak exceeds the normal range of the analyzer.

Dilution probes can usually be adjusted to change the dilution ratio. Often the valves used to make these adjustments are sensitive to slight movements. The dilution ratio can often easily be changed from 3:1 to 10:1 or even 20:1. Therefore, it is important to adjust the dilution ratio at the beginning of each testing day. Typically, the dilution ratio should be set at 10:1. Locking the valve at the adjusted dilution ratio is recommended (i.e., specialized valves, or even with tape). Usually, a high concentration calibration gas should be used to calibrate the dilution probe. Preferably a calibration gas at, or above, the highest range of the analyzer (without a dilution probe) should be selected. For example, the OVA 108 has an upper limit of 10,000 ppmv without a dilution probe, thus, a 10,000 ppmv or higher (up to safety limits) calibration gas is desired for the calibration of the dilution probe.

Another style of dilution probe does not restrict the sample stream and pull in the remainder of the flow from ambient air. These dilution probes are powered to bring in additional air without any restriction of sample stream flow. The primary advantage of this powered dilution probe is that it allows the analyzer to work with very large dilution ratios, which could allow measurements of any concentration.

4.3 DURING THE DAY QUALITY CONTROL

The analyzers that have been calibrated at the start of the test day do not always remain calibrated throughout the day. Some analyzers

4-7

have a tendency to "drift" as the day progresses. This drift can cause readings to either be higher or lower than those found on the original calibration. Drift may be due to decreased power (i.e., reduced battery strength) or to some internal changes in the analyzer with time. To maintain quality control during the day, drift checks are useful (but not required by Method 21).

A drift check consists of introducing one of the standard gases (non-zero) used in the calibration of the analyzer. The instrument response is recorded and compared to the response obtained during the latest calibration. It would be appropriate for the instrument to be recalibrated if the measurement is off by more than 20 percent.

Where % error =
$$\frac{cert. conc. - meas. conc.}{cert. conc.} \times 100$$

Drift checks are recommended after breaks, once between breaks, and at the end of the day. A sample drift check data sheet is shown in Figure 4-2.

If an instrument is shut off for any reason, such as to change the battery or replenish hydrogen, it should be drift checked and, if necessary, recalibrated after startup.

Data Sheet	
Test	
Drift	
Sample	alyzer II
4-2.	An
Figure	

	Comments							
	% error ^a							
	Measured Concentration							
Date:	Calibration Gas Concentration							
	Inspector							
	Time							
Plant ID:	Date							



4-9

SECTION 5.0 SCREENING PROCEDURES

This section explains the procedures used to perform screening of components that can leak fugitive emissions. General guidance applicable to all component types is explained first. Then, specific guidance for each component type is given. First attempts at repairs are discussed briefly. Finally, safety recommendations are given.

5.1 GENERAL SCREENING GUIDANCE

Method 21 specifies a screening procedure for monitoring components that have the potential to emit fugitive emissions. Table 5-1 is a general screening procedure that is consistent with Method 21, with some clarifications and a few additional steps.

As a clarification to, or in addition to, the Method 21 specified screening procedures, the following issues are addressed here:

- Screening distance;
- Fouling prevention;
- Length of time to screen;
- Responding to ambient conditions; and
- Background measurements.

5.1.1 Screening Distance

Method 21 says to, "Place the probe inlet at the surface of the component interface where leakage could occur." For components without rotating shafts (everything except pumps, compressors, and agitators), this is generally as close as possible to the component without fouling the tip or restricting flow into the analyzer probe. For components with rotating shafts (pumps, compressors, and agitators), the probe inlet should be within 1 cm of the shaftseal interface. Great care should be taken when working around rotating shaft equipment to avoid placing oneself in an unsafe position.

5.1.2 Fouling Prevention

Fouling of the probe with grease, dust, or liquids should be avoided. It is recommended that great care should be taken to prevent contamination, and the probe should be cleaned should contamination occur.

One method that has been used successfully to avoid contamination is to use a short piece of tubing (such as Teflon®, Tygon® or polyethylene) placed on the probe tip. The diameter of the tubing should be approximately the same as the diameter of the probe tip. Furthermore, it is recommended to use the same tubing during calibration and drift checks. Even with the tubing on the end of the probe tip, it is best to avoid fouling of the probe whenever possible. Hold the end of the probe/tubing as close as possible to the surface, but above areas that appear to have a probability of causing fouling. Even with these precautions, some fouling is inevitable. As the tubing tip becomes

Table 5-1. Summary of Screening Procedures

	General Screening Procedures
1.	Prepare analyzer for sampling.
2.	Check analyzer for leaks.
3.	Calibrate analyzer.
4.	Record a background reading approximately one meter away from the component being measured.
5.	Without fouling the tip, and without restricting flow into the analyzer probe, place probe as close as possible and approximately perpendicular to the component surface or seam where leakage could occur.
6.	Move the probe slowly along the line(s) of potential leakage to locate the maximum reading.
7.	Leave the probe tip at the maximum reading location for approximately two times the instrument response time.
8.	If the reading exceeds full scale, use the dilution probe if available.
9.	Record the maximum screening value.

fouled, it can be snipped off. In addition, in areas of high dust fouling potential, a fiberglass or glass wool filter can be placed in the tubing as a filter. Again, if this type of filter is used it should also be in place for calibration and drift checks. Cleaning of the probe and analyzer filters will also be required on occasion.

5.1.3 Length of Time to Screen

Method 21 states,

Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where leakage is indicated until the maximum meter reading is obtained. Leave the probe inlet at this maximum reading location for approximately two times the instrument response time. (emphasis added) (40 CFR, Part 60, Appendix A, 1996)

The great majority of components that are monitored for fugitive emissions do not have detectable emissions. The emissions are below the background reading. A fairly quick pass can be made at all of the leak interfaces to see if there are any increased meter readings. Only if an increased meter reading is indicated does the measurement need to be slowed down to determine where the maximum reading is obtained. Method 21 specifies that only at this maximum reading location does the instrument need to be held for approximately two times the instrument response time. However, if the initial pass is performed too quickly, leaks can be missed, especially if the instrument used has a long response time. A balance needs to be achieved between moving too slowly and unnecessarily losing time, or too quickly and potentially missing the maximum leak location. This balance needs to be determined through experience and possibly through observations of regulatory inspections or discussions with regulatory agencies.

Although not required by Method 21, for components with a highly variable screening value, two times the response time may not be enough time to get an accurate reading of the maximum leak. Some of the instruments have a very quick response. These sensitive instruments may also have significant fluctuations in the response. Some components have leaks that move up and down rapidly. Sometimes very sharp peaks in readings can be noticed that could simply be the meter needle momentum. As a practical consideration, even though not specified in Method 21, peaks reached by analog instruments that are clearly caused by needle momentum may not be the "maximum" leaks. Rather, for these analog readout instruments, the maximum leak could be considered as the leak rate that stabilizes for approximately one to two times the instrument response time ("sustained maximum"), or could be the highest reading that is repeated multiple times over a longer period. This definition of the maximum may need to be discussed with and approved by individual regulatory agencies.

5.1.4 <u>Responding to Ambient Conditions</u>

Screening measurements are affected by wind and perhaps by other ambient conditions such as humidity, temperature, rain, etc. However, during the refining and marketing terminal bagging studies (Ricks, 1993; Ricks,

1994), no actions were taken to compensate for these ambient factors. No attempt was made to block the wind. No adjustments to the emission factors or emission correlation equations were made for ambient conditions. Because the screening measurements are intended to match the mass emissions determined from these bagging studies, no changes in screening procedures are recommended based on ambient conditions. Therefore, for <u>refineries</u> and <u>marketing terminals</u>, <u>do not</u> try to block the wind when obtaining a reading.

Wind is more likely to impact screening values in more exposed areas, such as those found in the oil and gas production areas. Because of this, some actions (generally using the hand as a shield) were taken to block the wind for the oil and gas production bagging studies (Webb, 1993). Therefore, blocking the wind in the <u>oil and gas production area</u>, by using ones body or hand as an upwind shield, may be appropriate.

Many of the monitoring instruments may be damaged by adverse conditions such as rain. The instrument limitations clearly need to be understood and followed. Some of the instruments come with special attachments for use in adverse conditions, such as in wet, dirty or greasy conditions. However, even with special attachments, adverse ambient conditions may prohibit testing for a period. The ability of each analyzer to function in adverse conditions is one of the criteria that should be considered when purchasing an analyzer.

5.1.5 Background Measurements

facilities have All petroleum some background hydrocarbon readings. Typically, these background readings, when measured several meters away from any leaking components, will be less than 10 ppmv. In some facilities, these background measurements could be nearly 100 ppmv. Background measurements need to be representative of the background near the components being tested, but not too close to pick up the reading from the component itself. Typically, a distance of approximately one meter is sufficient to measure the hydrocarbons from ambient conditions without picking up significant hydrocarbons from the component to be measured or other nearby components. Sometimes it is impossible to get one meter away from any component and still obtain a background reading that is relevant to the component being measured, so for these components, a minimum standoff distance of about one foot can be used.

To be most accurate, a separate background reading at each component could be measured. However, typically the background does not vary appreciably at a facility. Also, unless the background readings are unusually high, background readings are unlikely to significantly affect the calculation of emissions from a facility. Evidence of this can be demonstrated at refineries (Ricks, 1992) and is believed to be the case at other types of petroleum facilities. Because the background readings are not likely to significantly affect total emission calculations, the improved accuracy of taking a background reading for each component is unlikely to justify the additional time it takes to record them.

Several alternatives to taking individual background readings for each component can be considered. One alternative would be to take a background reading each day for each process unit or area of the facility that is being Another alternative is to take a inspected. background reading on a regularly scheduled (such as every 10th component). basis Α remaining alternative would be to take a "typical" background reading by taking several measurements throughout the facility and developing an average value. This average value could then be used for all component readings taken.

5.2 SPECIFIC GUIDANCE BY COMPONENT TYPE FOR SCREENING

Stated simply, components should be screened wherever they could leak. This section is designed to explain and illustrate where these leaks could occur for the regulated component types.

5.2.1 Valves

The most common leaks from valves occur at the seal between the stem and the housing. To screen this source, place the probe as close as possible (without fouling or blocking the probe tip) to where the stem exits the packing gland and move the probe around the circumference. The maximum reading is the screening value. Also, move the probe around the periphery of the packing gland take-up flange seat. In addition, the valve housings of multi-part assemblies should be screened at all points where leaks could occur. Note that very few maximum leaks are found in the valve housing of multi-part assemblies, such as at the valve bonnet. Therefore, minimal time should be spent inspecting away from the valve stem and the packing gland. Figure 5-1 illustrates screening points for several types of valves. Where valves are installed with flanges, the end flanges are generally considered separate components, rather than part of the valve.

There are several types of valves which do not readily fit the above directions because they have no stem penetration of the valve housing. Check valves are the most common example of this. Check valves have only a static seal for the multi-part body assembly (or bonnet connection). Check valves should therefore be categorized as connectors and should be screened as such.

5.2.2 <u>Connectors</u>

For flanges, place the probe at the outer edge of the flange-gasket interface and sample the circumference of the flange. It may be impossible to get to the flange-gasket leak interface because the probe cannot get between the two flange edges. In these cases, the only alternative is to get as close as physically possible to the interface. For threaded connectors, the threaded connector interface must be screened. Any other type of connector should be screened at the point of connection. Screening points for connectors are illustrated in Figure 5-2.









5.2.3 Pumps, Compressors and Agitators

Pumps, compressors, and agitators are screened where the shaft exits the housing. Sample along the circumference of the shaft-seal interface by holding the probe within 1 cm from the shaft. If the housing of the pump, compressor, or agitator prevents sampling all the way around the seal, sample all accessible portions. All other joints on the pump, compressor or agitator housing that could leak should also be sampled. Figure 5-3 illustrates screening points for pumps. Similar screening points should be measured for compressors and agitators. Note that connectors on these units should be considered as separate components for monitoring purposes.

5.2.4 Pressure Relief Devices

Most pressure relief devices cannot be sampled at the sealing seat. Because of their design and function, pressure relief devices must be approached with extreme caution. These devices should not be tested in times of process upset or any other time when activation seems likely, and the seal disk, spring and other working parts of the valve should not be For devices with an enclosed disturbed. extension, or horn, place the probe inlet at approximately the center of the exhaust area. Only the probe tip should be placed in the horn; keep hands, arms, head and other body parts out. Occasionally a weep hole is part of the horn. If the end of the horn is not accessible, the weep hole in the horn should be screened, but be careful of probe tip contamination.

Screening of pressure relief valves is illustrated in Figure 5-4.

Pressure relief valves that vent to the flare header or are equipped with upstream rupture disks need not be screened.

5.2.5 Open-ended Lines and Vents

Emissions from most other components leak through regularly shaped openings. If the opening is less than 1 inch in diameter, a single reading in the center is sufficient. For larger openings (up to 6 inches in diameter), screen in the center of the hole and around the hole. Do not insert the probe into the open-ended line. Instead hold the probe at the mouth of the openended line. Components more than 6 inches in diameter should also be screened across the opening. Sample approximately every 3 inches. Record the maximum reading as the screening value. Figure 5-5 shows sampling of openended lines and vents.

5.3 FIRST REPAIR ATTEMPTS

I/M teams often do more than simply screen components; I/M teams also may make a first attempt at a repair for leaks found in the field. First repair attempts usually boil down to tightening operations, either valve packing bolts, flange bolts, threaded connectors, etc. First repair attempts are often successful at reducing a leak to below the leak definition. For example, a valve may leak at 20,000 ppmv when first screened. The I/M team may then try tightening the valve packing bolts. A rescreening of the valve could indicate that this



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leak has been reduced to 3,000 ppmv (lower than the leak definition for the applicable rule in this example). The first attempt at repair, if successful, may be all that is required for repairs.

There are some procedures for tightening that can enhance the effectiveness of the repair. Research involving the area of sealing highpressure components (over 2000 psia) has been conducted (Payne, 1992). The specifics of that research are outside the scope of this document, but some of the principles discovered can be applied to fugitive component repairs. Overtightening can damage a gasket or packing and actually increase leakage. Unequal tightening of bolts that are spaced around a flange can result in higher leakage. Tightening the bolts in the wrong order can create stresses in the gasket that result in higher leakage. Based on these principles, the following protocol can be suggested for flanges:

- i) Tighten the first bolt (selected at random) by one half turn;
- ii) Tighten the bolt 180 degrees from the first bolt by one half turn;
- iii) Tighten the bolt at 90 degrees from the first bolt by one half turn;
- iv) Tighten the bolt at 270 degrees from the first bolt by one half turn;
- v) If there are more than four bolts, continue to tighten them by a similar procedure that crosses the flange to promote even stresses around the gasket;

- vi) Once all of the bolts are tightened by one half turn, check the emission with a portable instrument;
- vii) If acceptably low, the repair is finished; if not, repeat by tightening another one half turn in the same sequence on all bolts;
- viii) Check the emissions and repeat as necessary or until the bolts will not move, at which point the component would need to be put on the nonreparable list until shutdown. Caution should be followed to avoid stripping the bolts.

The above discussion focused on flanges, because they usually have the most complex bolt pattern. The same principles apply to valves, but there are typically only two packing bolts. The appropriate procedure would be to put one half turn of tightening on each bolt and then check the emission level, repeating until the repair is successful or the component is declared non-reparable.

Other repair attempts are also occasionally made, such as lubricating a plug valve, or replacing the cap or plug on an open-ended line that had been left off by mistake.

If the first attempt is not successful, more extensive follow-up attempts may be required to reduce the leak. Later attempts could be as simple as replacement of valve packing to the more involved effort of complete component replacement. These later repair attempt methods are beyond the scope of this document.

For greatest efficiency, the analyzer probe can be placed at the location of the maximum leak during the tightening effort. This will aid the repair personnel in determining exactly how much tightening is necessary. If this is not practical, then tighten a little, check the reading, and repeat as many times as necessary to get the leak under the leak definition without overtightening. This approach is called directed maintenance. Some regulations may require the use of directed maintenance to minimize the screening value rather than to just get under the leak definition. As mentioned, over-tightening can cause a distortion of the packing and actually increase emissions.

5.4 SAFETY

Screening team members should be familiar with safety requirements specific to petroleum facilities. Personnel must comply with all standard plant safety requirements such as ear protection, hard hats, steel-toed shoes, safety glasses with sideshields, and fire resistant clothes. Although not intended as a comprehensive safety checklist, screening crews should also take care in the following areas:

- Calibrate instruments in a well ventilated space.
- Be aware that hydrocarbon vapors can explode and/or catch fire.
- Stand upwind, when possible, of sources being monitored.
- Wear long-sleeved, close-fitting clothing.

- Be careful of extremely hot or cold surfaces.
- Move slowly and deliberately, watching for head bumping and tripping hazards.
- Do not hang off of or over ladders to reach sources.
- Inform the head operator that you are testing in the unit and identify the location within the unit. Ask if there are any hazardous or unusual activities of which you should be aware.
- Have an instrumentation specialist and the unit operator conduct the repair. Do not move the hand wheels on any valves or tamper with other process units or fittings.
- Use caution when tightening the packing bolts on a pneumatically operated control valve. If tightened too far, the valve may stick and not respond to the signals from the control board, which could cause a unit upset or accident.
- The I/M team should not use extremely large wrenches or "cheater" pipes to give greater leverage to move corroded or stuck bolts because of the potential to break a fitting. If a reasonable attempt to tighten fails, then a more involved repair attempt should be made by facility maintenance teams.

SECTION 6.0 ALTERNATIVE MEASUREMENT METHODS

There are alternatives to the types of measurement methods identified earlier. The use of these alternatives is currently limited for I/M purposes; however, in certain applications, or for future applications, these alternatives should be considered.

6.1 SOAP TESTING

Method 21 (Section 4.3.3) does identify one alternative measurement method for measuring leaks. This method is the use of soap solution that is sprayed on a potential leak source. This relatively simple and inexpensive method may be used only on potential leak sources that:

- Have no continuously moving parts;
- Have a surface temperature less than the boiling point and greater than the freezing point of the soap solution;
- Do not have open areas to the atmosphere that the soap cannot bridge (the solution must cover all holes); and
- Are not leaking liquid.

Unless all of these conditions are met, the source must be surveyed with a VOC analyzer.

To use soap testing, these steps may be followed:

i) Obtain a commercial soap solution or prepare one using 100 ml of rug shampoo in a gallon of either distilled water or a mixture of distilled water and ethylene glycol.

- ii) Spray a soap solution over all potential leak sources. The solution may be applied with either a squeeze bottle or pressure sprayer.
- iii) Observe the source and record whether or not bubbles are formed.
- iv) If no bubbles are formed, the source is assumed to have no detectable emissions or leaks.
- v) If any bubbles are formed, the local concentration of VOCs from the leak must be determined by VOC analyzers.

While soap testing is inexpensive, it does have several limitations. A source observed to be bubbling may be leaking non-hydrocarbons. Similarly, a zero or low soap score may not mean zero or low emissions. If a process stream is not a gas at ambient pressure and temperature, the leakage will be liquid, which evaporates and does not produce bubbles with the soap test. Horizontal valve stems may also produce false soap scores. The valve stem packing face, where the solution is applied and leaks usually occur, is vertical. The soap solution can flow to the bottom of the packing area, and leaks in the upper area can easily be missed.

Soap testing may not be accepted by regulatory agencies for I/M testing. In many cases, soap bubbles may not even form at the leak rates that currently require repairs (leak definitions). Therefore, soap testing has a limited role in current I/M practices for most petroleum facilities.

6.2 NON-METHOD 21 TESTING

New methods to measure fugitive emissions are being developed that do not meet the current guidelines of Method 21. However, these methods have the potential to identify leaking components. These methods include such things as remote sensing or continuous monitoring devices that can be attached to components. The measurement capabilities of these methods will need to be documented and receive some form of regulatory acceptance before they can be considered as replacements for the portable analyzers when conducting regulatory monitoring.

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METHOD 21 DETERMINATION OF VOLATILE ORGANIC COMPOUND LEAKS (40 CFR Part 60, Appendix A)

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EMISSION MEASUREMENT TECHNICAL INFORMATION CENTER NSPS TEST METHOD

(EMTIC M-21, 2/9/93)

Method 21 - Determination of Volatile Organic Compound Leaks

1. APPLICABILITY AND PRINCIPLE

1.1 Applicability. This method applies to the determination of volatile organic compound (VOC) leaks from process equipment. These sources include, but are not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals.

1.2 Principle. A portable instrument is used to detect VOC leaks from individual sources. The instrument detector type is not specified, but it must meet the specifications and performance criteria contained in Section 3. A leak definition concentration based on a reference compound is specified in each applicable regulation. This procedure is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rate from individual sources.

2. **DEFINITIONS**

2.1 Leak Definition Concentration. The local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present, The leak definition is an instrument meter reading based on a reference compound.

2.2 Reference Compound. The VOC species selected as an instrument calibration basis for specification of the leak definition concentration. (For example, if a leak definition concentration is 10,000 ppm as methane, then any source emission that results in a local concentration that yields a meter reading of 10,000 on an instrument meter calibrated with methane would be classified as a leak. In this example, the leak definition is 10,000 ppm, and the reference compound is methane.)

2.3 Calibration Gas. The VOC compound used to adjust the instrument meter reading to a known value. The calibration gas is usually the reference compound at a known concentration approximately equal to the leak definition concentration.

2.4 No Detectable Emission. The total VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is not present. Since background VOC concentrations may exist, and to account for instrument drift and imperfect reproducibility, a

difference between the source surface concentration and the local ambient concentration is determined. A difference based on the meter readings of less than a concentration corresponding to the minimum readability specification indicates that a VOC emission (leak) is not present. (For example, if the leak definition in a regulation is 10,000 ppm, then the allowable increase is surface concentration versus local ambient concentration would be 500 ppm based on the instrument meter readings.)

2.5 Response Factor. The ratio of the known concentration of a VOC compound to the observed meter reading when measured using an instrument calibrated with the reference compound specified in the applicable regulation.

2.6 Calibration Precision. The degree of agreement between measurements of the same known value, expressed as the relative percentage of the average difference between the meter readings and the known concentration to the known concentration.

2.7 **Response Time.** The time interval from a step change in VOC concentration at the input of the sampling system to the time at which 90 percent of the corresponding final value is reached as displayed on the instrument readout meter.

3. APPARATUS

3.1 Monitoring Instrument.

3.1.1 Specifications

a. The VOC instrument detector shall respond to the compounds being processed. Detector types which may meet this requirement include, but are not limited to, catalytic oxidation, flame ionization, infrared absorption, and photoionization.

b. The instrument shall be capable of measuring the leak definition concentration specified in the regulation.

c. The scale of the instrument meter shall be readable to + or - 5 percent of the specified leak definition concentration.

d. The instrument shall be equipped with a pump so that a continuous sample is provided to the detector. The nominal sample flow rate shall be 0.1 to 3.0 liters per minute.

e. The instrument shall be intrinsically safe for operation in explosive atmospheres as defined by the applicable U.S.A. standards (e.g., National Electrical Code by the National Fire Prevention Association).

f. The instrument shall be equipped with a probe or probe extension for sampling not to exceed 1/4 in. in outside diameter, with a single end opening for admission of sample.

3.1.2 Performance Criteria.

a. The instrument response factors for the individual compounds to be measured must be less than 10.

b. The instrument response time must be equal to or less than 30 seconds. The response time must be determined for the instrument configuration to be used during testing.

c. The calibration precision must be equal to or less than 10 percent of the calibration gas value.

d. The evaluation procedure for each parameter is given in Section 4.4.

3.1.3 Performance Evaluation Requirements.

a. A response factor must be determined for each compound that is to be measured, either by testing or from reference sources. The response factor tests are required before placing the analyzer into service, but do not have to be repeated at subsequent intervals.

b. The calibration precision test must be completed prior to placing the analyzer into service, and at subsequent 3-month intervals or at the next use whichever is later.

c. The response time test is required before placing the instrument into service. If a modification to the sample pumping system or flow configuration is made that would change the response time, a new test is required before further use.

3.2 Calibration Gases.

The monitoring instrument is calibrated in terms of parts per million by volume (ppm) of the reference compound specified in the applicable regulation. The calibration gases required for monitoring and instrument performance evaluation are a zero gas (air, less than 10 ppm VOC) and a calibration gas in air mixture approximately equal to the leak definition specified in the regulation. If cylinder calibration gas mixtures are used, they must be analyzed and certified by the manufacturer to be within + or - 2 percent accuracy, and a shelf life must be specified. Cylinder standards must be either reanalyzed or replaced at the end of the specified shelf life. Alternatively, calibration gases may be prepared by the user according to any accepted gaseous preparation procedure that will yield a mixture accurate to within + or - 2 percent. Prepared standards must be replaced each day of use unless it can be demonstrated that degradation does not occur during storage.

Calibrations may be performed using a compound other than the reference compound if a conversion factor is determined for that alternative compound so that the resulting meter readings during source surveys can be converted to reference compound results.

4. PROCEDURES

4.1 Pretest Preparations. Perform the instrument evaluation procedure given in Section 4.4 if the evaluation requirement of Section 3.1.3 have not been met.

4.2 Calibration Procedures. Assemble and start up the VOC analyzer according to the manufacturer's instructions. After the appropriate warmup period and zero internal calibration procedure, introduce the calibration gas into the instrument sample probe. Adjust the instrument meter readout to correspond to the calibration gas value. (Note: If the meter readout cannot be adjusted to the proper value, a malfunction of the analyzer is indicated and corrective actions are necessary before use.)

4.3 Individual Source Surveys.

4.3.1 Type I - Leak Definition Based on Concentration. Place the probe inlet at the surface of the component interface where leakage could occur. Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where leakage is indicated until the maximum meter reading is obtained. Leave the probe inlet at this maximum reading location for approximately two times the instrument response time. If the maximum observed meter reading is greater than the leak definition in the applicable regulation, record and report the results as specified in the regulation reporting requirements. Examples of the application of this general technique to specific equipment types are:

a. Valves - Leaks usually occur at the seal between the stem and the housing. Place the probe at the interface where the stem exits the packing and sample the stem circumference and the flange periphery. Survey valves of multipart assemblies where a leak could occur.

b. Flanges and Other Connections - Place the probe at the outer edge of the flange-gasket interface and sample the circumference of the flange.

c. Pump or Compressor Seals - If applicable, determine the type of shaft seal. Perform a survey of the local area ambient VOC concentration and determine if detectable emissions exist as described above.

d. Pressure Relief Devices - For those devices equipped with an enclosed extension, or horn, place the probe inlet at approximately the center of the exhaust area to the atmosphere.

e. Process Drains - For open drains, place the probe inlet as near as possible to the center of the area open to the atmosphere. For covered drains, locate probe at the surface of the cover and traverse the periphery.
f. Open-ended Lines or Valves - Place the probe inlet at approximately the center of the opening of the atmosphere.

g. Seal System Degassing Vents, Accumulator Vessel Vents, Pressure Relief Devices - If applicable, observe whether the applicable ducting or piping exists. Also, determine if any sources exist in the ducting or piping where emissions could occur before the control device. If the required ducting or piping exists and there are no sources where the emissions could be vented to the atmosphere before the control device, then it is presumed that no detectable emissions are present. If there are sources in the ducting or piping where emissions could be vented or sources where leaks could occur, the sampling surveys described in this section shall be used to determine if detectable emissions exist.

h. Access door seals - Place the probe inlet at the surface of the door seal interface and traverse the periphery.

Type II - "No Detectable Emission". Determine the ambient 4.3.2 concentration around the source by moving the probe randomly upwind and downwind around one to two meters from the source. In case of interferences, this determination may be made closer to the source down to no closer than 25 centimeters. Then move the probe to the surface of the source and measure as in 4.3.1. The difference in these concentrations determines whether there are no detectable When the regulation also requires that no detectable emissions. emissions exist, visual observations and sampling surveys are required. Examples of this technique are: (a) Pump or Compressor Seals - Survey the local area ambient VOC concentration and determine if detectable emissions exist. (b) Seal System Degassing Vents, Accumulator Vessel Vents, Pressure Relief Devices Determine if any VOC sources exist upstream of the device. If such ducting exists and emissions cannot be vented to the atmosphere upstream of the control device, then it is presumed that no detectable emissions are present. If venting is possible sample to determine if detectable emissions are present.

4.3.3 Alternative Screening Procedure.

4.3.3.1 A screening procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts, that do not have surface temperatures greater than the boiling point or less than the freezing point of the soap solution, that do not have open areas to the atmosphere that the soap solution cannot bridge, or that do not exhibit evidence of liquid leakage. Sources that have these conditions present must be surveyed using the instrument technique of Section 4.3.1 or 4.3.2.

4.3.3.2 Spray a soap solution over all potential leak sources. The soap Solution may be a commercially available leak detection solution or may be prepared using concentrated detergent and water.

A pressure sprayer or squeeze bottle may be used to dispense the solution. Observe the potential leak sites to determine if any bubbles are formed. If no bubbles are observed, the source is presumed to have no detectable emissions or leaks as applicable. If any bubbles are observed, the instrument techniques of Section 4.3.1 or 4.3.2 shall be used to determine if a leak exists, or if the source has detectable emissions, as applicable.

4.4 Instrument Evaluation Procedures. At the beginning of the instrument performance evaluation test, assemble and start up the instrument according to the manufacturer's instructions for recommended warmup period and preliminary adjustments.

4.4.1 Response Factor.

4.4.1.1 Calibrate the instrument with the reference compound as specified in the applicable regulation. For each organic species that is to be measured during individual source surveys, obtain or prepare a known standard in air at a concentration of approximately 80 percent of the applicable leak definition unless limited by volatility or explosivity. In these cases, prepare a standard at 90 percent of the standard saturation concentration, or 70 percent of the lower explosive limit, respectively. Introduce this mixture to the analyzer and record the observed meter reading. Introduce zero air until a stable reading is obtained. Make a total of three measurements by alternating between the known mixture and zero air. Calculate the response factor for each repetition and the average response factor.

4.4.1.2 Alternatively, if response factors have been published for the compounds of interest for the instrument or detector type, the response factor determination is not required, and existing results may be referenced. Examples of published response factors for flame ionization and catalytic oxidation detectors are included in the Bibliography.

4.4.2 Calibration Precision. Make a total of three measurements by alternately using zero gas and the specified calibration gas. Record the meter readings. Calculate the average algebraic difference between the meter readings and the known value. Divide this average difference by the known calibration value and multiply by 100 to express the resulting calibration precision as a percentage.

4.4.3 Response Time. Introduce zero gas into the instrument sample probe. When the meter reading has stabilized, switch quickly to the specified calibration gas. Measure the time from switching to when 90 percent of the final stable reading is attained. Perform this test sequence three times and record the results. Calculate the average response time.

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