

Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms

API RECOMMENDED PRACTICE 14C
SEVENTH EDITION, MARCH 2001

REAFFIRMED: MARCH 2007



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Upstream Segment

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FOREWORD

This standard was developed as an API recommended practice under the jurisdiction of the API Upstream Segment Executive Committee on Drilling and Production Operations.

This recommended practice presents a standardized method to design, install, and test surface safety systems on offshore production platforms and is intended for use by design engineers and operating personnel. Recognized systems analysis methods are used to develop requirements for a safety system and procedures are included to document the safety system and verify conformance with the recommended practice.

Other API recommended practices for safety and antipollution systems used in offshore oil and gas production include the following:

- RP 14E *Design and Installation of Offshore Production Platform Piping Systems*
- RP 14F *Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class 1, Division 1 and Division 2 Locations*
- RP 14G *Fire Prevention and Control on Open Type Offshore Production Platforms*
- RP 14J *Design and Hazards Analysis for Offshore Production Facilities*
- RP 75 *Development of a Safety and Environmental Management Program for Outer Continental Shelf (OCS) Operations and Facilities*

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Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms

1. GENERAL

1.1 INTRODUCTION

For many years the petroleum industry has prepared documents representing the combined knowledge and experience of industry on various phases of oil and gas producing operations. In continuation of this effort, this recommended practice presents a systematization of proven practices for providing a basic surface safety system for offshore production platforms. Proper application of these practices, along with good design, maintenance, and operation of the entire production facility, should provide an operationally safe platform.

1.2 SCOPE

This document presents recommendations for designing, installing, and testing a basic surface safety system on an offshore production platform. The basic concepts of a platform safety system are discussed and protection methods and requirements of the system are outlined.

This recommended practice illustrates how system analysis methods can be used to determine safety requirements to protect any process component. Actual analyses of the principal components are developed in such a manner that the requirements determined will be applicable whenever the component is used in the process. The safety requirements of the individual process components may then be integrated into a complete platform safety system. The analysis procedures include a method to document and verify system integrity. A uniform method of identifying and symbolizing safety devices is presented and the analysis method is exemplified by a sample process system.

In addition to the basic surface safety system, this recommended practice covers ancillary systems such as pneumatic supply and liquid containment. Procedures for testing common safety devices are presented with recommendations for test data and acceptable test tolerances.

This recommended practice emphasizes pneumatic systems since they are the most commonly used; however, the same principles and procedures are applicable to hydraulic and electrical systems and to systems incorporating two or more control media. Instrumentation logic circuits are not discussed since these should be left to the discretion of the designer as long as the recommended safety functions are accomplished. Rotating machinery is considered in this recommended practice as a unitized process component as it interfaces with the platform safety system. When rotating machinery (such as a pump or compressor) installed as a unit

consists of several process components, each component can be analyzed as prescribed in this recommended practice.

1.3 ORGANIZATION OF TECHNICAL CONTENT

The technical content of this recommended practice is arranged as follows:

- a. Section 2: Recommended standard symbols and abbreviations for safety device and process component identification.
- b. Section 3: The general purpose, functional requirements, and basic premises of platform safety system analysis and design.
- c. Section 4: A detailed discussion of recommended safety analysis techniques, the concepts of protection from which they were developed, and a step-by-step procedure for analyzing and establishing design criteria for a basic platform safety system.
- d. Appendix A: A safety analysis for each process component commonly used in a production process, including a checklist of additional criteria that should be considered when the component is used in a specific process configuration.
- e. Appendix B: A sample Safety Analysis Table (SAT), a composite Safety Analysis Checklist (SAC), and a sample Safety Analysis Function Evaluation (SAFE) Chart.
- f. Appendix C: A discussion of supporting systems that perform specific safety functions common to the entire platform.
- g. Appendix D: Testing procedures and reporting methods for the accumulation of safety system test data that can be used for operational analysis, and reports that may be required by regulatory agencies.
- h. Appendix E: An example Safety Analysis Function Evaluation (SAFE) Chart prepared using procedures presented in this recommended practice.
- i. Appendix F: A discussion of procedures and location of detectors for platforms that process toxic hydrocarbons.

1.4 GOVERNMENT CODES, RULES, AND REGULATIONS

Regulatory agencies have established certain requirements for the design, installation, and operation of facilities on offshore production platforms. In addition to federal regulations, certain state and local regulations may be applicable. The following federal documents pertain to offshore oil and gas producing operations and should be used when applicable.

30 *Code of Federal Regulations* Part 250 (Oil and Gas Sulphur Operations in the Outer Continental Shelf)

33 *Code of Federal Regulations* Chapter I, Subchapter N (Artificial Islands and Fixed Structures on the Outer Continental Shelf)

40 *Code of Federal Regulations* Part 112, Chapter I, Subchapter D (Oil Pollution Prevention)

49 *Code of Federal Regulations* Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards)

49 *Code of Federal Regulations* Part 195 (Transportation of Liquids by Pipeline)

Minerals Management Service, Notice to Lessees and Operators of all Federal Oil, Gas, and Sulphur Leases on the Outer Continental Shelf (NTL) and Letters to Lessees and Operators (LTL)

1.5 INDUSTRY CODES, STANDARDS, AND RECOMMENDED PRACTICES

Various organizations have developed numerous standards, codes, specifications, and recommended practices that are useful references for designing and installing surface safety systems on offshore production facilities. Some of the more commonly used documents are listed below. These documents are not considered to be a part of this recommended practice, except for those specific sections of documents referenced elsewhere in this recommended practice.

API

- API 510 *Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration*
- RP 14B *Design, Installation and Operation of Subsurface Safety Valve Systems*
- RP 14E *Design and Installation of Offshore Production Platform Piping Systems*
- RP 14F *Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class 1, Division 1 and Division 2 Locations*
- RP 14G *Fire Prevention and Control on Open Type Offshore Production Platforms*
- RP 14H *Use of Surface Safety Valves and Underwater Safety Valves Offshore*
- RP 14J *Design and Hazards Analysis for Offshore Production Facilities*
- RP 500 *Classification of Locations for Electrical Installations at Petroleum Facilities*

RP 505 *Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1 and Zone 2*

RP 520 *Design and Installation of Pressure-Relieving Systems in Refineries, Parts I and II*

RP 521 *Guide for Pressure-Relieving and Depressuring Systems*

RP 550 *Manual on Installation of Refinery Instruments and Control Systems*

Spec 6A *Wellhead Equipment*

Spec 6D *Pipeline Valves, End Closures, Connectors, and Swivels*

Spec 14A *Subsurface Safety Valve Equipment*

Std 2000 *Venting Atmospheric and Low Pressure Storage Tanks*

Std 2564 *Conversion of Operational and Process Measurement Unit to the Metric System*

Spec Q1 *Specification for Quality Programs*

Guide for Inspection of Refinery Equipment, Chapter XV, "Instruments and Control Equipment"

Guide for Inspection of Refinery Equipment, Chapter XVI, "Pressure-Relieving Devices"

ANSI¹

B31.3 *Petroleum Refinery Piping*

B31.4 *Liquid Petroleum Transportation Piping Systems*

B31.8 *Gas Transmission and Distribution Piping Systems*

Y32.11 *Graphical Symbols for Process Flow Diagrams*

ASME²

Boiler and Pressure Vessel Code, Section VIII, "Pressure Vessels," Divisions 1 and 2

ISA³

RP 7.1 *Pneumatic Control Circuit Pressure Test*

RP 42.1 *Nomenclature for Instrument Tubing Fittings*

55.1 *Instrumentation Symbols and Identification*

RP 60.9 *Piping Guide for Control Centers*

S20 *Specification Forms for Process Measurement and Control Instruments, Primary Elements and Control Valves*

102-198X *Standard for Gas Detector Tube Units – Short Term Type for Toxic Gases and Vapors in Working Environments*

¹American National Standards Institute, 1430 Broadway, New York, New York 10018

²American Society of Mechanical Engineers, 345 East 47th Street, New York, New York 10017

³Instrument Society of America, 67 Alexander Drive, P.O. Box 12277, Research Triangle Park, North Carolina 27709

- S12.15 Part I, *Performance Requirements, Hydrogen Sulfide Gas Detectors*
- S12.15 Part II, *Installation, Operation, and Maintenance of Hydrogen Sulfide Gas Detection Instruments*
- S12.13 Part I, *Performance Requirements, Combustible Gas Detectors*
- S12.13 Part II, *Installation, Operation, and Maintenance of Combustible Gas Detection Instruments*

NACE⁴

- Std MR0175 *Standard Material Requirements Sulfide Stress Cracking Resistant Metallic Materials For Oilfield Equipment*

⁴National Association of Corrosion Engineers, P.O. Box 218340, Houston, Texas 77218-8340

1.6 METRIC CONVERSIONS

U.S. customary units are in all cases preferential and shall be the standard in this recommended practice. These factors were taken from API Standard 2564.

- Length: 1 inch (in.) = 25.4 millimeters (mm) exactly.
- Pressure: 1 pound per square inch (psi) = 0.06894757 bar (Note: 1 bar = 100 kilopascals (kPa)).
- Strength or stress: 1 pound per square inch (psi) = 0.006894757 megapascals (MPa).
- Impact energy: 1 foot-pound (ft-lb) = 1.355818 Joules (J).
- Torque: 1 foot-pound (ft-lb) = 1.355818 newton-meters (N • m).
- Temperature: The following formula was used to convert degrees Fahrenheit (°F) to degrees Celsius (°C):

$$C = 5/9 (F-32)$$

- Mass: 1 pound (lb) = 0.4535924 kilograms (kg).

2. SAFETY DEVICE SYMBOLS AND IDENTIFICATION

2.1 INTRODUCTION

A standard method for identifying, abbreviating, and symbolizing individual safety devices is needed to promote uniformity when describing or referring to safety systems. This method can be used to illustrate safety devices on flow diagrams and other drawings, and to identify an individual safety device for any purpose.

Abbreviations and symbols recommended are derived, insofar as possible, from Instrument Society of America (ISA) Standard ISA-S5.1. Additional applications that adhere to this standard may be derived as required. However, certain abbreviations have such wide oil field acceptance that their continued use is justified even though they do not strictly conform to the ISA standard. The abbreviations SSV for surface safety valve, SDV for shutdown valve, and ESD for emergency shutdown are examples.

2.2 FUNCTIONAL DEVICE IDENTIFICATION

Each safety device should be identified by a system of letters used to classify it functionally. The functional identification includes one first letter covering the measured or initiating variable and one or more succeeding letters covering the function of the device. The term “safety” (S) shall apply to emergency protective elements, and is used as the second letter of sensing and self-acting devices.

If two or more devices of the same type are installed on a single component, each device should be numbered consecutively and the number shown following the functional identification. If only one device is installed, the device number may be omitted.

2.3 SYMBOLS

The circular balloon is used to tag distinctive symbols, such as a pressure relief valve. In such instances, the line connecting the balloon to the instrument symbol is drawn close to, but not touching, the symbol. In other instances, the balloon serves to represent the device proper. Table 2-1 illustrates recommended example symbols.

2.4 COMPONENT IDENTIFICATION

The complete identification of a safety device includes reference to the component that it protects. This is accomplished by following the device functional identification or device number, if applicable, with a component identification. Table 2-2 presents the recommended component identification method.

The first letter is the component type and must be one of the letters in the code column under component type. The letter “Z” is used to cover a component not listed.

The second and third letters may be used to further define or otherwise modify the first character. If a modifier is not used, the character “ϕ” should be shown in lieu of the modifier.

The last four characters identify the specific component. These characters are user assigned and must be unique to the component at the particular location.

2.5 EXAMPLE IDENTIFICATION

Example applications of the recommended identification method are illustrated in Figure 2-1 .

Table 2.1—Safety Device Symbols












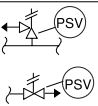










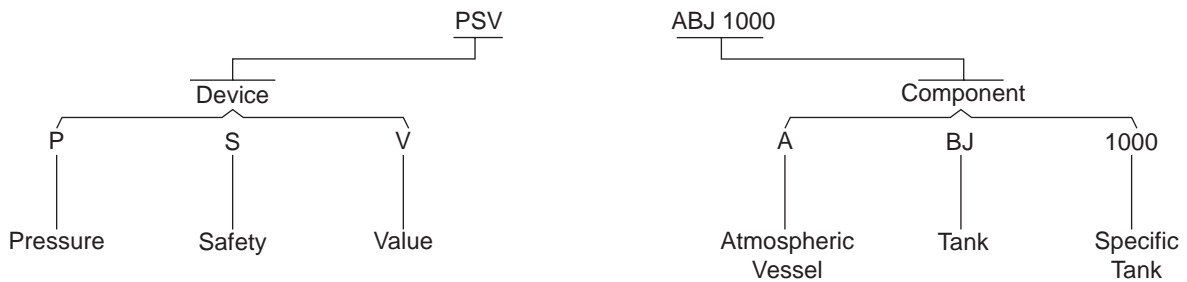
SENSING AND SELF-ACTING DEVICE				
VARIABLE	SAFETY DEVICE DESIGNATION		SYMBOL	
	COMMON	INSTRUMENT SOCIETY OF AMERICA (ISA)	SINGLE DEVICE	COMBINATION DEVICE
Backflow	Check valve	Flow Safety Valve		
Burner flame	Burner flame detector	Burner Safety Low		
Flow	High flow sensor	Flow Safety High		
	Low flow sensor	Flow Safety Low		
Level	High level sensor	Level Safety High		
	Low level sensor	Level Safety Low		
Pressure	High pressure sensor	Pressure Safety High		
	Low pressure sensor	Pressure Safety Low		
	Pressure relief or safety valve	Pressure Safety Valve		
	Rupture disc or safety head	Pressure Safety Element		
Pressure or vacuum	Pressure-vacuum relief valve	Pressure Safety Valve		
	Pressure-vacuum relief manhole cover	Pressure Safety Valve		
	Vent	None		
Vacuum	Vacuum relief valve	Pressure Safety Valve		
	Rupture disc or safety head	Pressure Safety Element		
Temperature	High temperature sensor	Temperature Safety High		
	Low temperature sensor	Temperature Safety Low		
Flame	Flame or stack arrestor	None		

Table 2.1—Safety Device Symbols (continued)

SENSING AND SELF-ACTING DEVICE				
VARIABLE	SAFETY DEVICE DESIGNATION		SYMBOL	
	COMMON	INSTRUMENT SOCIETY OF AMERICA (ISA)	SINGLE DEVICE	COMBINATION DEVICE
Fire	Flame detector (Ultraviolet/Infrared)		(USH)	
	Heat detector (Thermal)	Temperature Safety High	(TSH)	
	Smoke detector (Ionization)		(YSH)	
	Fusible material	Temperature Safety Element	(TSE)	
Combustible gas concentration	Combustible gas detector	Analyzer Safety High	(ASH)	
Toxic gas concentration	Toxic gas detector		(OSH)	

ACTUATED VALVES				
SERVICE	COMMON SYMBOLS			
Wellhead surface safety valve or underwater safety valve			Note: Show "USV" for Underwater Safety Valves	
Blow down valve				
All other shut down valves				

EXAMPLE A



EXAMPLE B

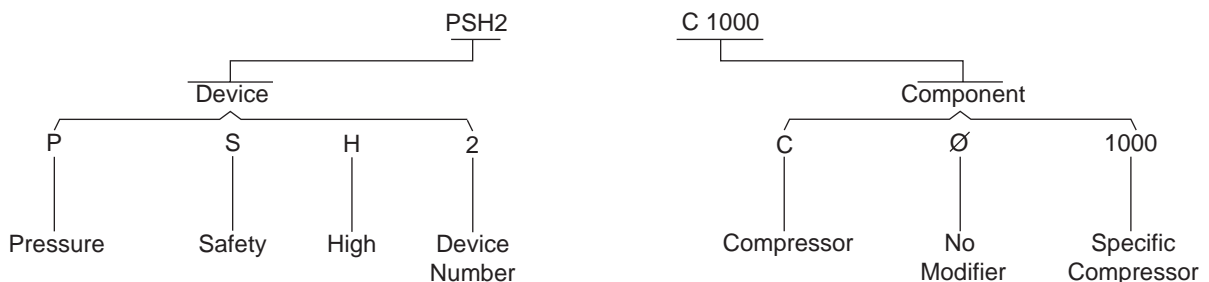


Figure 2-1—Examples of Safety Device Identification

Table 2-2—Component Identification

FIRST LETTER			SECOND LETTER		SUCCEEDING CHARACTERS	
X			XX		XXX	
Component Type			Component Modifier		Component Identifier	
CODE	COMPONENT	COMMON MODIFIERS	CODE	COMPONENT		
A	ATMOSPHERIC VESSEL (AMBIENT TEMPERATURE)	BH,BJ,BM	AA	BI-DIRECTIONAL	User Assigned Identification Unique to Equipment at Location	
B	ATMOSPHERIC VESSEL (HEATED)	AP,BC,BK,BM	AB	BLOWCASE		
C	COMPRESSOR	NONE	AC	BOILER		
D	ENCLOSURE	AE,AN,AU,BB	AD	COALESCER		
E	FIRED OR EXHAUST HEATED COMPONENT	AL,AW,BN	AE	COMPRESSOR		
F	FLOWLINE	A1-A9	AF	CONTACTOR		
G	HEADER	AR,AS,AT,AY,AZ	AG	CONTROL UNIT		
H	HEAT EXCHANGER	BG	AH	DEPARTING		
J	INJECTION LINE	AR,AS,AT	AJ	FILTER		
K	PIPELINE	AA,AH,AQ	AK	FILTER-SEPARATOR		
L	PLATFORM	AG	AL	FORCED DRAFT		
M	PRESSURE VESSEL (AMBIENT TEMPERATURE)	AB,AD,AF,AJ,AK,AM,AV,BD,BF,BH,BJ,BL,BM	AM	FREEWATER KNOCKOUT		
N	PRESSURE VESSEL (HEATED)	AC,AF,AM,AP,BC,BD,BG,BJ,BK	AN	GENERATOR		
P	PUMP	AX,BA,BE	AP	HEATER		
Q	WELLHEAD	AR,AT,AY,AZ	AQ	INCOMING		
Z	OTHER		AR	INJECTION, GAS		
			AS	INJECTION, GAS LIFT		
			AT	INJECTION, WATER		
			AU	METER		
			AV	METERING VESSEL		
			AW	NATURAL DRAFT		
			AX	PIPELINE		
			AY	PRODUCTION, HYDROCARBON		
			AZ	PRODUCTION, WATER		
			A1-A9	FLOWLINE SEGMENT		
			BA	PROCESS, OTHER		
			BB	PUMP		
			BC	REBOILER		
			BD	SEPARATOR		
			BE	SERVICE		
			BF	SCRUBBER		
			BG	SHELL AND TUBE		
			BH	SUMP		
			BJ	TANK		
			BK	TREATER		
			BL	VOLUME BOTTLE		
			BM	WATER TREATING		
			BN	EXHAUST HEATED		
			ZZ	OTHER		

3. INTRODUCTION TO SAFETY ANALYSIS AND SYSTEM DESIGN

3.1 PURPOSE AND OBJECTIVES

The purpose of a production platform surface safety system is to protect personnel, the environment, and the facility from threats to safety caused by the production process. The purpose of a safety analysis is to identify undesirable events that might pose a threat to safety, and define reliable protective measures that will prevent such events or minimize their effects if they occur. Potential threats to safety are identified through proven systems analysis techniques that have been adapted to the production process. Recommended protective measures are common industry practices proven through long experience. The systems analysis and protective measures have been combined into a “safety analysis” for offshore production platforms.

The technical content of this recommended practice establishes a firm basis for designing and documenting a production platform safety system for a process composed of components and systems normally used offshore. Moreover, it establishes guidelines for analyzing components or systems that are new or significantly different from those covered in this document.

After a production platform surface safety system is placed in operation, procedures should be established to assure continued system integrity. Appendix D, Testing and Reporting Procedures, may be used for this purpose.

3.2 SAFETY FLOW CHART

Figure 3-1 is a safety flow chart depicting the manner in which undesirable events could result in personnel injury, pollution, or facility damage. It also shows where safety devices or procedures should be used to prevent the propagation of undesirable events. As shown on the chart, the release of hydrocarbons is a factor in virtually all threats to safety. Thus, the major objective of the safety system should be to prevent the release of hydrocarbons from the process and to minimize the adverse effects of such releases if they occur.

a. Referring to Figure 3-1, the overall objectives may be enumerated as follows:

1. Prevent undesirable events that could lead to a release of hydrocarbons.
2. Shut in the process or affected part of the process to stop the flow of hydrocarbons to a leak or overflow if it occurs.
3. Accumulate and recover hydrocarbon liquids and disperse gases that escape from the process.
4. Prevent ignition of released hydrocarbons.
5. Shut in the process in the event of a fire.
6. Prevent undesirable events that could cause the release of hydrocarbons from equipment other than that in which the event occurs.

b. Accidents that occur external to the process on a production platform are not self-propagating unless they affect the process or start a fire. If they affect the process, the safety system should shut down the process or affected part of the process. If they result in fire, the safety system should shut down all platform activity except that necessary for fire fighting. Such accidents may be caused by natural phenomenon, ship or helicopter collision, failure of tools and machinery, or mistakes by personnel. These types of accidents may be prevented or minimized through safe design of tools and machinery, safe operating procedures for personnel and equipment, and personnel training. Figure 3-1 indicates the manner in which external accidents may affect the process.

3.3 MODES OF SAFETY SYSTEM OPERATION

The operating modes of the safety system should be (a) automatic monitoring and automatic protective action if an abnormal condition indicating an undesirable event can be detected by a sensor, (b) automatic protective action if manually actuated by personnel who observe or are alerted to an unsafe condition by an alarm, and (c) continuous protection by support systems that minimize the effects of escaping hydrocarbons. The Emergency Shutdown (ESD) System is important, even on platforms that are not continuously manned, because most accidents and failures are caused by personnel. Thus, personnel may be available to actuate the ESD System.

3.4 PREMISES FOR BASIC ANALYSIS AND DESIGN

The recommended analysis and design procedures for a platform safety system are based on the following premises:

- a. The process facility will be designed for safe operation in accordance with good engineering practices.
- b. The safety system should provide two levels of protection to prevent or minimize the effects of an equipment failure within the process. The two levels of protection should be independent of and in addition to the control devices used in normal process operation. In general, the two levels should be provided by functionally different types of safety devices for a wider spectrum of coverage. Two identical devices would have the same characteristics and might have the same inherent weaknesses.
- c. The two levels of protection should be the highest order (primary) and next highest order (secondary) available. Judgment is required to determine these two highest orders for a given situation. As an example, two levels of protection from a rupture due to overpressure might be provided by a PSH and a PSL. The PSH prevents the rupture by shutting in affected equipment before pressure becomes excessive, and

the PSL shuts in affected equipment after the rupture occurs. However, a PSV is selected in lieu of the PSL because it prevents the rupture by relieving excess volumes to a safe location. Moreover, its fast response could prevent a rupture in situations where the PSH might not effect corrective action fast enough.

d. The use of proven systems analysis techniques, adapted to the production process, will determine the minimum safety requirements for a process component. If such an analysis is applied to the component as an independent unit, assuming worst case conditions of input and output, the analysis will be valid for that component in any process configuration.

e. All process components on a production platform comprise the entire process from the wellhead to the most downstream discharge point; thus, all process equipment and functions are incorporated into the safety system.

f. When fully protected process components are combined into a facility, no additional threats to safety are created. Therefore, if all process component safety devices are logically integrated into a safety system, the entire facility will be protected.

g. The analysis procedure should provide a standard method to develop a safety system and provide supporting documentation.

4. PROTECTION CONCEPTS AND SAFETY ANALYSIS

4.1 INTRODUCTION

Section 3.1 emphasizes that most threats to safety from the production process involve the release of hydrocarbons. Thus, the analysis and design of a production platform safety system should focus on preventing such releases, stopping the flow of hydrocarbons to a leak if it occurs, and minimizing the effects of hydrocarbons that are released.

Section 4.2 explains the basic concepts of protection used in the analysis. These concepts are repeated in Appendix A, as applicable to individual component analysis.

Section 4.3 discusses methods of analyzing the process and establishing design criteria for an integrated safety system covering the entire platform process. These methods are exemplified in the example analysis illustrated in Appendix E.

Section 4.4 is a step-by-step summary for performing a safety analysis in accordance with this document. It is pointed out that this method initially considers each component independently from the rest of the process, and may recommend safety devices that are not required after larger segments of the process are considered. For example, many safety devices initially considered on headers are not normally required because their safety function is performed by devices on other components.

4.2 PROTECTION CONCEPTS

The basic protection concepts used in the safety system analysis are discussed in this paragraph. Section 4.2.1 describes each undesirable event that could affect a process component and considers its cause, effect, and protective measures. Section 4.2.2 discusses safety device selection criteria. Section 4.2.3 discusses protective shut in action for isolating a process component. Section 4.2.4 discusses ignition preventing measures that can be used to minimize the possibility of combustible concentrations of hydrocarbons contacting an ignition source. Section 4.2.5 discusses protective

measures to prevent accidental contact of hot surfaces by personnel. Section 4.2.6 discusses the function of the Emergency Support System (ESS). Section 4.2.7 discusses the function of other support systems.

4.2.1 Undesirable Events

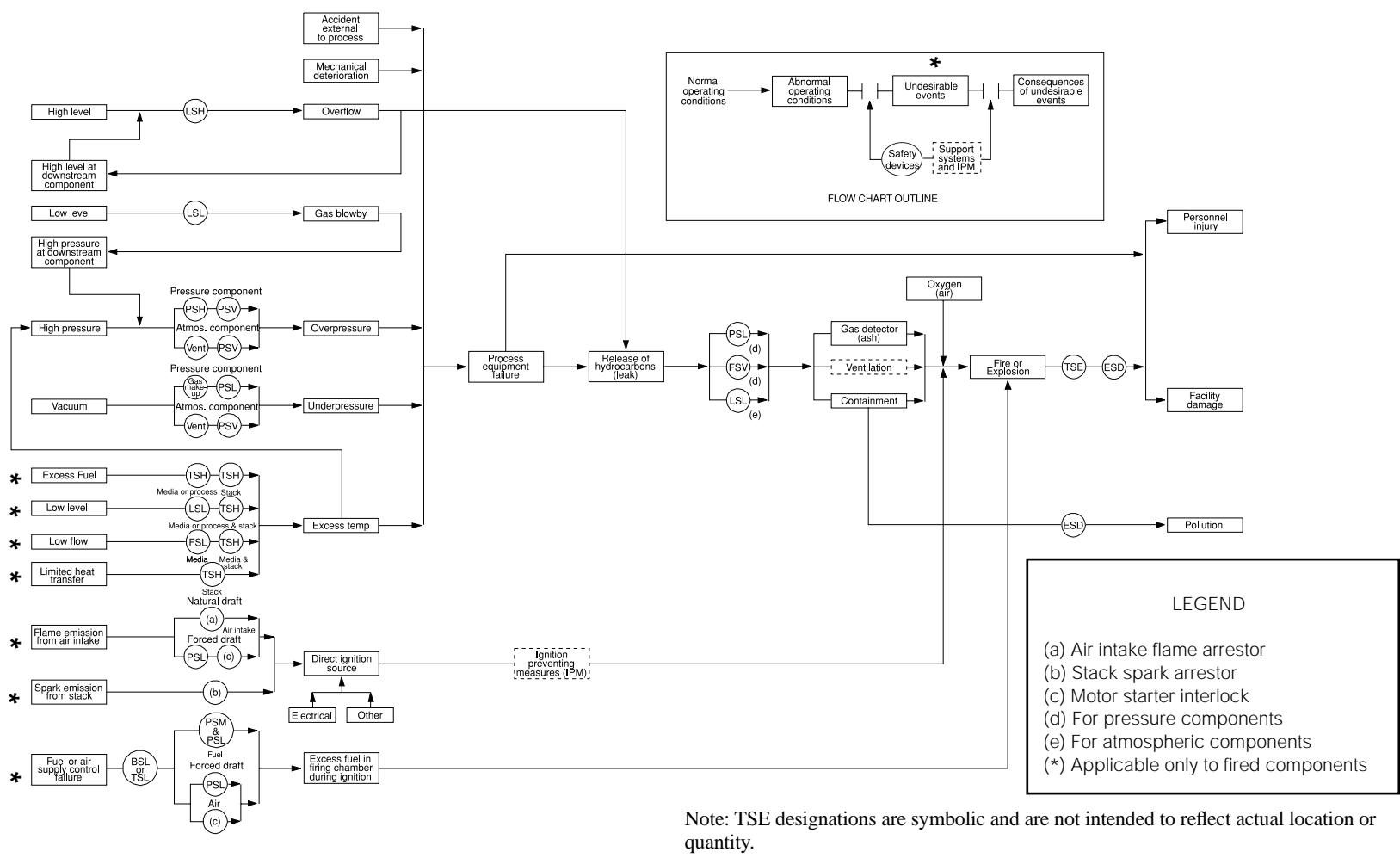
An undesirable event is an adverse occurrence in a process component that poses a threat to safety. The undesirable events discussed in this paragraph are those that might develop in a process component under worst-case conditions of input and output. An undesirable event may be indicated by one or more process variables ranging out of operating limits. These abnormal operating conditions can be detected by sensors that initiate shut down action to protect the process component. Each undesirable event that can affect a process component is discussed according to the following format: (a) cause, (b) effect and detectable abnormal condition, and (c) primary and secondary protection that should prevent or react to its occurrence.

4.2.1.1 Overpressure

Overpressure is pressure in a process component in excess of the maximum allowable working pressure.

4.2.1.1.1 Cause

Overpressure can be caused by an input source that will develop pressure in excess of a process component's maximum allowable working pressure if inflow exceeds outflow. Inflow may exceed outflow if an upstream flowrate control device fails, if there are restrictions or blockage in the component's outlets, or if overflow or gas blow-by from an upstream component occurs. Overpressure can also be caused by thermal expansion of fluids within a component if heat is added while the inlets and outlets are closed.



Note: TSE designations are symbolic and are not intended to reflect actual location or quantity.

Figure 3-1—Safety Flow Chart—Offshore Production Facility

4.2.1.1.2 Effect and Detectable Abnormal Condition

The effect of overpressure can be a sudden rupture and leak of hydrocarbons. High pressure is the detectable abnormal condition that indicates that overpressure may occur.

4.2.1.1.3 Primary Protection

Primary protection from overpressure in a pressure component should be provided by a PSH sensor to shut off inflow. If a vessel is heated, the PSH sensor should also shut off the fuel or source of heat. Primary protection for atmospheric components should be provided by an adequate vent system.

4.2.1.1.4 Secondary Protection

Secondary protection from overpressure in a pressure component should be provided by a PSV. Secondary protection for atmospheric components should be provided by a second vent. The second vent may be identical to the primary vent, a gauge hatch with a self-contained PSV or an independent PSV.

4.2.1.1.5 Location of Safety Devices

In a process component with both a liquid and a gas section, the PSH sensor, PSV, or vent should be installed to sense or relieve pressure from the gas or vapor section. The sensing connections for the safety devices should be located at the highest practical location on the component to minimize the chance of fouling by flow stream contaminants. The installation of PSVs and vents on atmospheric tanks should be in accordance with API Standard 2000 or other applicable standards.

4.2.1.2 Leak

A leak is the accidental escape of fluids from a process component to atmosphere. In this recommended practice, “leak” implies that the escaping fluids are hydrocarbons.

4.2.1.2.1 Cause

A leak can be caused by deterioration from corrosion, erosion, mechanical failure, or excess temperature; by rupture from overpressure; or by accidental damage from external forces.

4.2.1.2.2 Effect and Detectable Abnormal Conditions

The effect of a leak is the release of hydrocarbons to the atmosphere. Low pressure, backflow, and low level are the abnormal conditions that might be detectable to indicate that a leak has occurred.

4.2.1.2.3 Primary Protection

Primary protection from leaks of sufficient rate to create an abnormal operating condition within a pressure component should be provided by a PSL sensor to shut off inflow and a FSV to minimize backflow. Primary protection from leaks from the liquid section may also be provided by an LSL sensor to shut off inflow. On an atmospheric component, primary protection from liquid leaks should be provided by an LSL sensor to shut off inflow. A containment system should provide primary protection from small liquid leaks that cannot be detected by the safety devices on a process component. Primary protection from small gas leaks that occur in an inadequately ventilated area and cannot be detected by component sensing devices should be provided by a combustible gas detection system.

4.2.1.2.4 Secondary Protection

Secondary protection from all detectable leaks and small gas leaks in an inadequately ventilated area should be provided by the Emergency Support Systems (ESS). Secondary protection from small liquid leaks should be provided by an LSH sensor installed on the sump tank to shut in all components that could leak into the sump.

4.2.1.2.5 Location of Safety Devices

In a process component with both a liquid and a gas section, the PSL sensor should be connected to sense pressure from the gas or vapor section. The PSL sensor should be installed at the highest practical location on the component to minimize the chances of fouling by flow stream contaminants. FSVs should be installed in each component operating outlet line subject to significant backflow. The LSL sensor should be located a sufficient distance below the lowest operating liquid level to avoid nuisance shutdowns, but with adequate volume between the LSL sensor and liquid outlet to prevent gas blowby before shutdown is accomplished.

4.2.1.3 Liquid Overflow

Liquid overflow is the discharge of liquids from a process component through a gas or vapor outlet.

4.2.1.3.1 Cause

Liquid overflow can be caused by liquid input in excess of liquid outlet capacity. This may be the result of failure of an upstream flow rate control device, failure of the liquid level control system, or blockage of a liquid outlet.

4.2.1.3.2 Effect and Detectable Abnormal Condition

The effects of liquid overflow can be overpressure or excess liquids in a downstream component, or release of

hydrocarbons to the atmosphere. High level is the detectable abnormal condition that indicates that overflow may occur.

4.2.1.3.3 Primary Protection

Primary protection from liquid overflow should be provided by an LSH sensor to shut off inflow into the component.

4.2.1.3.4 Secondary Protection

Secondary protection from liquid overflow to the atmosphere should be provided by the Emergency Support Systems. Secondary protection from liquid overflow to a downstream component should be provided by safety devices on the downstream component.

4.2.1.3.5 Location of Safety Devices

The LSH sensor should be located a sufficient distance above the highest operating liquid level of a component to prevent nuisance shutdowns, but with adequate volume above the LSH sensor to prevent liquid overflow before shutdown is accomplished.

4.2.1.4 Gas Blowby

Gas blowby is the discharge of gas from a process component through a liquid outlet.

4.2.1.4.1 Cause

Gas blowby can be caused by failure of a liquid level control system or inadvertent opening of a bypass valve around a level control valve.

4.2.1.4.2 Effect and Detectable Abnormal Condition

The effect of gas blowby can be overpressure in a downstream component. Low level is the detectable abnormal condition that indicates gas blowby may occur.

4.2.1.4.3 Primary Protection

Primary protection from gas blowby should be provided by an LSL sensor to shut off inflow or shut off the liquid outlet.

4.2.1.4.4 Secondary Protection

Secondary protection from gas blowby to a downstream component should be provided by safety devices on the downstream component.

4.2.1.4.5 Location of Safety Devices

The LSL sensor should be located a sufficient distance below the lowest operating liquid level to avoid nuisance

shutdowns, but with an adequate volume between the LSL sensor and liquid outlet to prevent gas blowby before shutdown is accomplished.

4.2.1.5 Underpressure

Underpressure is pressure in a process component less than the design collapse pressure.

4.2.1.5.1 Cause

Underpressure can be caused by fluid withdrawal in excess of inflow that may be the result of failure of an inlet or outlet control valve, blockage of an inlet line during withdrawal, or thermal contraction of fluids when the inlets and outlets are closed.

4.2.1.5.2 Effect and Detectable Abnormal Condition

The effect of underpressure can be collapse of the component and a leak. Low pressure is the detectable abnormal condition that indicates underpressure may occur.

4.2.1.5.3 Primary Protection

Primary protection from underpressure in an atmospheric component should be provided by an adequate vent system. Primary protection for a pressure component subject to underpressure should be provided by a gas makeup system.

4.2.1.5.4 Secondary Protection

Secondary protection for an atmospheric component should be provided by a second vent or by a PSV. Secondary protection for a pressure component subject to underpressure should be provided by a PSL sensor to shut off inflow and outflow.

4.2.1.5.5 Location of Safety Devices

The PSL sensor should be installed at the highest practical location on the component to minimize the chances of fouling by flow stream contaminants. Vents and PSVs should be installed in accordance with API Standard 2000 or other applicable standards.

4.2.1.6 Excess Temperature (Fired and Exhaust Heated Components)

Excess temperature is temperature above that in which a process component is designed to operate. This undesirable event in fired and exhaust heated components is categorized as excess medium or process fluid temperature and excess stack temperature. Excess temperature in unfired components is discussed in individual component analyses in Appendix A.

4.2.1.6.1 Cause

Excess medium or process fluid temperature can be caused by excess fuel or heat input due to failure or inadvertent bypassing of the fuel or exhaust gas control equipment, extraneous fuel entering the firing chamber through the air intake, or a leak of combustible fluids into the fired or exhaust heated chamber; insufficient volume of heat transfer fluid due to low flow in a closed heat transfer system (where the heated medium is circulated through tubes located in the firing or exhaust heated chamber); or low liquid level in a fired component with an immersed fire or exhaust gas tube. Excess stack temperature in a fired component can be caused by any of the above or by insufficient transfer of heat because of accumulation of foreign material (sand, scale, etc.) in the heat transfer section. Excess stack temperature in an exhaust heated component can result from ignition of a combustible medium leak into the exhaust heated chamber.

4.2.1.6.2 Effect and Detectable Abnormal Condition

The effects of high medium or process fluid temperature can be a reduction of the working pressure and subsequent leak or rupture of the affected component and/or overpressure of the circulating tubes in a closed heat transfer system, if the medium is isolated in the tubes. The effect of high stack temperature can be a direct ignition source for combustibles coming in contact with the stack surface. High temperature, low flow, and low level are the detectable abnormal conditions that indicate that excess temperature may occur.

4.2.1.6.3 Primary Protection

Primary protection from excess medium or process fluid temperature resulting from excess or extraneous fuel, heat, or medium leaks into the fired or heated chamber should be provided by a TSH sensor. If caused by low liquid level, protection should be provided by an LSL sensor. The TSH and LSL sensors on fired components should shut off fuel supply and inflow of combustible fluids. The TSH and LSL sensors on exhaust heated components should divert or shut off the fuel or heat source. If excess medium temperature is due to low flow in a closed heat transfer system containing combustible fluid, primary protection should be provided by an FSL sensor to shut off fuel supply to a fired component or to divert the exhaust flow from an exhaust heated component. Primary protection from excess stack temperature should be provided by a TSH (stack) sensor to shut off the fuel or exhaust gas source and inflow of combustible fluids.

4.2.1.6.4 Secondary Protection

Secondary protection from excess medium or process fluid temperature in a fired component, if caused by excess or extraneous fuel, should be provided by a TSH (stack) sensor,

and, if caused by low flow, by a TSH (medium) sensor and TSH (stack) sensor. If caused by low level, secondary protection should be provided by a TSH (medium or process fluid) sensor and TSH (stack) sensor. Secondary protection from excess medium or process fluid temperature in an exhaust heated component, if caused by low level or low flow, should be provided by a TSH (medium) sensor. These TSH sensors should perform the same function as the primary protection. Secondary protection for excess stack temperature should be provided by the Emergency Support Systems and an FSV, where applicable.

4.2.1.6.5 Location of Safety Devices

Temperature sensors, other than fusible or skin contact types, should be placed in a thermowell for ease of removing and testing. In a two-phase (gas/liquid) system the TSH sensor should be located in the liquid section. In a tube-type heater, where the heated medium flows through tubes located in the firing or heating chamber, the TSH sensor should be located in the tube outlet as close as is practical to the heater. An FSV should be installed on medium tube outlet piping.

4.2.1.7 Direct Ignition Source (Fired Components)

A direct ignition source is an exposed surface, flame, or spark at sufficient temperature and heat capacity to ignite combustibles. Direct ignition sources discussed in this paragraph are limited to fired components. Electrical systems and other ignition sources are discussed in 4.2.3.

4.2.1.7.1 Cause

Direct ignition sources can be caused by flame emission from the air intake due to the use of improper fuel (e.g., liquid carryover in a gas burner), reverse draft from a natural draft burner, or extraneous fuel entering the air intake; spark emission from the exhaust stack; or hot surfaces resulting from excess temperature.

4.2.1.7.2 Effect and Detectable Abnormal Condition

The effect of a direct ignition source can be a fire or explosion if contacted by a combustible material. High temperature and low air flow (forced draft burners only) are the detectable abnormal conditions that indicate a direct ignition source may occur.

4.2.1.7.3 Primary Protection

Primary protection from flame emission through the air intake of a natural draft burner should be provided by a flame arrestor to contain the flame in the firing chamber. Primary protection from flame emission through the air intake of a forced draft burner should be provided by a PSL (air intake)

sensor to detect low air flow and shut off the fuel and air supply. A stack arrestor should provide primary protection from exhaust stack spark emission. Primary protection from hot surfaces due to excess temperature should be provided by a TSH (medium or process fluid) sensor and TSH (stack) sensor. The TSH sensor should shut off fuel supply and inflow of combustible fluids.

4.2.1.7.4 Secondary Protection

Secondary protection from flame emission through the air intake of a natural draft burner should be provided by the emergency support system. Secondary protection from flame emission through the air intake of a forced draft burner should be provided by a blower motor interlock to detect blower motor failure and to initiate a signal to shut off the fuel and air supply. Secondary protection from exhaust stack spark emission and hot surfaces should be provided by the Emergency Support Systems and an FSV where applicable.

4.2.1.7.5 Location of Safety Devices

The location of air intake flame arrestors and exhaust stack spark arrestors is fixed. These items should be installed to facilitate inspecting and cleaning. TSH (stack, media, process fluids) sensors should be installed as discussed in 4.2.1.6. A PSL (air intake) sensor should be installed downstream of the blower fan inside the air intake on a forced draft burner. Forced draft burners should have starter interlocks installed on the blower motor starter. An FSV should also be installed in medium tube outlet piping.

4.2.1.8 Excess Combustible Vapors in the Firing Chamber (Fired Component)

Excess combustible vapors in the firing chamber are combustible vapors in addition to those required for normal ignition of either the pilot or main burner.

4.2.1.8.1 Cause

Accumulation of excess combustible vapors in the firing chamber can be caused by a failure of the fuel or air supply control equipment or improper operating procedures.

4.2.1.8.2 Effect and Detectable Abnormal Condition

The effect of excess combustible vapors in the firing chamber, on ignition, could be an explosion and possible rupture of the component. Flame failure and high or low fuel supply pressure are detectable abnormal conditions that could indicate excess combustible vapors in the firing chamber. Low air supply pressure and blower failure may also indicate this condition in forced draft burners.

4.2.1.8.3 Primary Protection

Primary protection from excess combustible vapors in the firing chamber caused by a mechanical failure of the fuel control equipment should be provided by a flame failure sensor. The sensor should detect a flame insufficient to ignite the entering vapors and shut off the fuel. The sensor may be the light detecting type (BSL), such as an ultraviolet detector, or the heat sensing type (TSL).

4.2.1.8.4 Secondary Protection

Secondary protection from excess combustible vapors in the firing chamber due to fuel control failure should be provided by a PSH (fuel) sensor to shut off the fuel. On a forced draft burner, a PSL sensor should be installed on the fuel supply; also, a PSL (air) sensor and motor starter interlock should be installed to detect an inadequate air supply and initiate a signal to shut off the fuel and air. An FSL sensor may be installed in place of a PSL sensor in the air intake to sense low air flow. In addition to the above safety devices, safe operating procedures should also be followed to prevent fire-box explosions during ignition of the pilot or main burner. Recommended safe operating procedures are shown in Appendix A, Table A-6.3.

4.2.1.8.5 Location of Safety Devices

A BSL or TSL sensor should be installed in the firing chamber to monitor the pilot and/or main burner flame. PSH and PSL sensors in the fuel supply should be installed downstream of all fuel pressure regulators. A PSL (air intake) sensor should be installed in the air intake downstream of the forced draft blower.

4.2.2 Safety Device Selection

The required safety device protection is categorized into primary and secondary protective devices. The primary device will react sooner, safer, or more reliably than the secondary device. The primary device will provide the highest order of protection and the secondary device should provide the next highest order of protection.

- a. A single safety device may not provide complete primary or secondary protection because the results of a failure may vary by degree or sequence. Thus, several devices or systems may be shown, the combination of which will provide the necessary level of protection. For example, a PSL sensor and an FSV may be required to stop flow to a leak. These two devices would provide the primary level of protection.
- b. The protection devices determined in the SAT, in conjunction with necessary SDVs or other final control devices, protect the process component in any process configuration. It is important that the user understand the SAT logic and how the SATs are developed.

c. The location of SDVs and other final control devices must be determined from a study of the detailed flow schematic and from a knowledge of operating parameters. When an undesirable event is detected in a process component, the component can be isolated from all input process fluids, heat, and fuel, by either shutting in the sources of input or diverting the inputs to other components where they can be safely handled. If the process input is to be shut in, it is preferably done at the primary source.

d. All safety devices shown in the figures in Appendix A for each component would be considered and would be installed unless conditions exist whereby the function normally performed by a safety device is not required or is performed adequately by another safety device(s). The Safety Analysis Checklists (SACs) in Appendix A list equivalent protection methods, thereby allowing the exclusion of some devices.

e. If a process component is used that is not covered in Appendix A, an SAT for that component would be developed as discussed in (a) and (b) above.

4.2.3 Protective Shut-In Action

When an abnormal condition is detected in a process component by a safety device or by personnel, all input sources of process fluids, heat, and fuel should be shut off or diverted to other components where they can be safely handled. If shut-off is selected, process inputs should be shut off at the primary source of energy (wells, pump, compressor, etc.). It is not advisable to close the process inlet to a component if this could create an abnormal condition in the upstream component, causing its safety devices to shut it in. This would be repeated for each component back through the process until the primary source is shut in. Each component would therefore be subjected to abnormal conditions and must be protected by its safety devices every time a downstream component shuts in. This cascading effect depends on the operation of several additional safety devices and may place undue stress on the equipment.

a. It may be desirable to shut in the inlet to a process component for additional protection or to prevent upstream components from equalizing pressure or liquid levels after the primary source is shut in. If this is desirable, the primary source of energy should be shut in simultaneously with or prior to closing of the component inlet valve.

b. There may be special cases where shut in by cascading is acceptable. As examples:

1. The source of input to a separator is frequently changed as wells are periodically switched into the separator. If the well(s) producing to the separator is to be directly shut in when an abnormal condition is detected, the safety system logic must be changed each time different wells are switched into the unit. This creates the possibility of oversight in changing the logic. In this case, it may be preferable to close the separator inlet, and let the

resulting high flowline pressure cause the well(s) to shut in by action of the flow line PSH sensor. The header and the flow line should be rated for the maximum pressure that could be caused by this action.

2. A platform receives production through a flow line from a satellite well. Although the source of energy to the system is the satellite well, detection of an abnormal condition on the platform should cause activation of an SDV on the incoming flowline. If it is desired to shut in the satellite well following closure of the flow line SDV at the platform, this may be accomplished by use of a flow line PSH sensor installed at the satellite location.

3. A compressor installation is equipped with an automatic divert valve that permits production to be maintained from wells capable of producing against pipeline pressure when a compressor shut down occurs. In this case, wells incapable of producing against pipeline pressure may be shut in by action of the individual flow line PSH sensors to minimize potential safety system logic problems as discussed in (a) above.

4.2.4 Ignition Preventing Measures

The Safety Flow Chart shown in Figure 3-1 illustrates that the principal threat to platform safety is the release of hydrocarbons. However, if ignition of released hydrocarbons can be prevented, the consequences of the hydrocarbon release can be reduced. Thus, prevention of ignition is another protection method that must be considered along with safety devices and Emergency Support Systems. Ignition of hydrocarbons could be caused by electric arcs, flame, sparks, and hot surfaces. Protection from these sources is provided by design considerations that decrease the possibility of hydrocarbons contacting an ignition source or preventing gaseous hydrocarbons from reaching a combustible concentration. Collectively, these methods are referred to in this recommended practice as "Ignition Preventing Measures" (IPM) and include: (a) ventilation, (b) application of electrical codes and recommended practice, (c) location of potential ignition sources, and (d) protection of hot surfaces.

4.2.4.1 Ventilation

Ignition of a combustible gas requires that the concentration of the gas mixed with air (oxygen) reaches the lower explosive limit (LEL). The safety system is designed to minimize the amount of hydrocarbon released by shutting off the hydrocarbon source on detecting an abnormal condition. Another method for preventing a combustible mixture is to provide a volume of air sufficient to maintain the hydrocarbon concentration below the LEL. To prevent the accumulation of combustible mixtures, process areas should be as open as practicable to allow the free movement of air. Enclosed areas containing hydrocarbon handling or fueled equipment should have adequate ventilation so that the gases or vapors

will dissipate before reaching the LEL. If adequate ventilation is not provided for enclosed areas, a combustible gas detector (ASH) should be installed to initiate a signal at a preset concentration below the LEL to shut off the hydrocarbon source.

4.2.4.2 Electrical Codes and Recommended Practices

Protection from ignition by electrical sources should be provided by designing and maintaining electrical equipment in accordance with API Recommended Practice 14F or other applicable standards, and by classification of platform areas according to API Recommended Practice 500.

- a. API Recommended Practice 14F defines criteria for electrical equipment and wiring methods that can be used safely in classified and unclassified areas on offshore production platforms.
- b. API Recommended Practice 500 presents methods for classifying areas surrounding drilling rigs and production facilities on land and on marine fixed and mobile platforms for safe installation of electrical equipment.

4.2.4.3 Location

Potential ignition sources, such as fired process components and certain rotating machinery, are normally equipped to minimize the possibility of igniting released hydrocarbons. Additional protection can be provided by locating equipment in areas where exposure to inadvertently released hydrocarbons is minimized. API Recommended Practice 14J provides guidance for locating equipment. Some other potential ignition sources are those related to housekeeping such as boilers, water heaters, stoves, clothes dryers, etc. These should be located in electrically unclassified areas. If such equipment is gas fueled and installed in an inadequately ventilated building, a combustible gas detector (ASH) should be installed to close fuel shutdown valves located outside the building.

4.2.4.4 Hot Surface Protection

Any surface with a temperature in excess of 400°F (204°C) should be protected from exposure to hydrocarbon liquids due to spillage or leakage. Surfaces with a temperature in excess of 725°F (385°C) (approximately 80 percent of the ignition temperature of natural gas) should be protected from exposure to accumulations of combustible gases and vapors. Methods of protection can be insulation, barriers, water cooling, etc. However, if such surfaces on permanent or portable equipment are in an area classified by API Recommended Practice 500, they should be insulated. Some mechanical components such as turbochargers, exhaust manifolds and the like (including associated piping) that cannot be insulated without causing mechanical failure should be protected by other means.

4.2.5 Hot Equipment Shielding

Any surface with a temperature in excess of 160°F (71°C) should have protection when accidental contact of the hot surface could be made by personnel within normal work or walk areas. Protection may be in the form of guards, barriers, or insulation. Some mechanical components such as turbochargers, exhaust manifolds, compressor heads, expansion bottles, and the like (including associated piping) are exceptions; in these cases, warning signs are acceptable.

4.2.6 Emergency Support Systems (ESS)

The Emergency Support Systems (discussed in detail in Appendix C) minimize the effects of escaped hydrocarbons on offshore production platforms. The ESS includes:

- a. The combustible gas detection system to sense the presence of escaped hydrocarbons and initiate alarms and platform shutdown before gas concentrations reach the LEL.
- b. The containment system to collect escaped liquid hydrocarbons and initiate platform shutdown.
- c. The fire loop system to sense the heat of a fire and initiate platform shutdown.
- d. Other fire detection devices (flame, thermal, and smoke) that are used to enhance fire detection capability.
- e. The Emergency Shutdown System to provide a method to manually initiate platform shutdown by personnel observing abnormal conditions or undesirable events.
- f. The SSSVs that may be self actuated (SSCSV) or actuated by an ESD system and/or a fire loop (SCSSV).

4.2.7 Other Support Systems

The integrity of a platform surface safety system depends on proper operation of several other support systems. These ancillary support systems carry the same degree of importance as other portions of the platform safety system and should be equally as well maintained. Those discussed in Appendix C are the pneumatic supply system and systems for discharging gas to the atmosphere.

- a. The pneumatic supply system is installed to provide power for actuators and supply for instruments.
- b. Systems for discharging gas to the atmosphere are installed to provide a means for conducting discharged gas from process components to safe locations for final release to the atmosphere.

4.3 SAFETY ANALYSIS

4.3.1 Safety Analysis Table (SAT)

Safety Analysis Tables (SATs) for the basic process components of a platform production facility are presented in Appendix A. The SATs are applicable to a component regardless of its position in the process flow. The boundaries of each

process component include the inlet piping, control devices, and the outlet piping to another component. Every outlet pipe and pipe branch should be included up to the point where safety devices on the next component provide protection.

a. The safety analysis of each process component highlights undesirable events (effects of equipment failures, process upsets, accidents, etc.) from which protection should be provided, along with detectable abnormal conditions that can be monitored for safety surveillance. These detectable conditions are used to initiate action through automatic controls to prevent or minimize the effect of undesirable events. The tables present the logical sequence of safety system development, including undesirable events that could be created in downstream process components because of failures in the equipment or safety devices of the component under consideration.

b. The generic causes of each undesirable event are listed. The primary causes are equipment failures, process upsets, and accidental, but all primary causes in a category will create the same undesirable event. Thus, a blocked line could be due to plugging, freezing, or other failure of a control valve, or the inadvertent closing of a manual valve. The undesirable events should be determined from a detailed investigation of the failure modes of the component and its ancillary equipment. These failure modes are grouped under causes, according to the manner in which they may generate the undesirable event.

c. The protective safety devices and Emergency Support Systems that prevent or react to minimize the effects of undesirable events should be designed in accordance with 4.2.

4.3.2 Safety Analysis Checklist (SAC)

Table B-1 is a composite SAC for normally used process components. Individual SACs are shown in Appendix A as an aid for discussing the application of the safety analysis to each individual component. The SAC lists the safety devices that would be required to protect each process component if it were viewed as an individual unit with the worst probable input and output conditions. Listed under each recommended device are certain conditions that eliminate the need for that particular device when the component is viewed in relation to other process components. This action is justified because safety devices on other components will provide the same protection, or because in a specific configuration, the abnormal condition that the device detects will not lead to a threat to safety.

4.3.3 Safety Analysis Function Evaluation (SAFE) Chart

The Safety Analysis Function Evaluation (SAFE) chart, shown in Figure B-1, is used to relate all sensing devices, SDVs, shutdown devices, and emergency support systems to

their functions. The SAFE chart should list all process components and Emergency Support Systems with their required safety devices, and should list the functions to be performed by each device. If the device is not needed, the reason should be listed on SAFE by referring to the appropriate SAC item number. If the reason for eliminating a device is that a device on another component provides equivalent protection, this alternate device should also be shown on SAFE. The relation of each safety device with its required function can be documented by checking the appropriate box in the chart matrix. *Completion of the SAFE chart provides a means of verifying the design logic of the basic safety system.*

4.4 ANALYSIS AND DESIGN PROCEDURE SUMMARY

The analysis and design of a platform surface safety system should include the following steps:

- a. Describe the process by a detailed flow schematic and establish the operating parameters. The flow schematic and operating parameters should be developed based on equipment design and process requirements.
- b. From the Safety Analysis Tables (SATs), verify the need for basic safety devices to protect each process component viewed as an individual unit. The Safety Analysis Checklist (SAC) for individual components is then used to justify the elimination of any safety device when each process component is analyzed in relation to other process components. The SAC lists specific conditions under which some safety devices may be eliminated when larger segments of the process are considered.
- c. If a process component significantly different from those covered in this recommended practice is used in a process, an SAT and an SAC table should be developed for that component.
- d. Using the Safety Analysis Function Evaluation (SAFE) chart, logically integrate all safety devices and self-protected equipment into a complete platform safety system. List on SAFE all process components and their required safety devices. Enter the functions the devices perform and relate each device to its function by checking the appropriate box in the chart matrix.
- e. If designing a new facility, show all devices to be installed on the process flow schematic.
- f. If analyzing an existing facility, compare SAFE with the process flow schematic and add the devices required but not shown.

The analyses should define the monitoring devices (sensors) and self-actuating safety devices needed for a process facility. They also establish the safety function required (shutdown, diverting the input, pressure relief, etc.).

APPENDIX A—PROCESS COMPONENT ANALYSIS

Appendix A presents a complete safety analysis of each basic process component normally used in a platform production process system. The component analysis includes the following:

- a. A description of each process component.
- b. A typical drawing of each process component showing all recommended safety devices that should be considered based on individual component analysis. A discussion of each process component is included outlining recommended safety device locations.
- c. A safety analysis table (SAT) for each process component analyzing the undesirable events that could affect the component.
- d. A safety analysis checklist (SAC) for each process component listing all recommended safety devices and showing conditions under which particular safety devices may be excluded. A discussion of the rationale for including or excluding each safety device is presented.

A.1 Wellheads and Flow Lines

A.1.1 DESCRIPTION

Wellheads furnish surface control (manual and automatic) and containment of well fluids and provide downhole access for well servicing. Flow lines transport hydrocarbons from the wellhead to the first downstream process component.

For analysis purposes and assignment of safety devices, flow lines are divided into flow line segments. A flow line segment is any portion of a flow line that has an assigned operating pressure different from other portions of the same flow line. These flow line segments can be classified as either initial (beginning at wellhead), intermediate, or final (terminating at another process component) segments. Thus, a flow line that experiences a reduction in operating pressure due to some inline pressure reducing device, such as a choke, and has two different assigned operating pressures, will have an initial and final segment. A flow line that experiences no reduction in operating pressure due to a pressure reducing device will have only one segment. In this case, the initial and final flow line segment will be the same. Each flow line segment must be analyzed to determine appropriate safety devices. Recommended safety devices for typical wellheads and flow lines are shown in Figures A-1.1, A-1.2, and A-1.3.

A.1.2 SAFETY ANALYSIS

A.1.2.1 Safety Analysis Table

The Safety Analysis Table (SAT) for a flow line segment is presented in SAT Table A-1.1. The undesirable events that can affect a flow line segment are overpressure and leak.

A.1.2.2 Safety Analysis Checklist

The Safety Analysis Checklist (SAC) for a flow line segment is presented in SAC Table A-1.2.

A.1.2.2.1 Pressure Safety Devices (PSH, PSL, and PSV)

Because wells are the primary source of pressure, a PSH sensor to shut in the well should always be provided on each flow line to detect abnormally high pressure. A PSH sensor to shut in the well should be installed on the final flow line segment and on any other segment that has a maximum allowable working pressure less than the maximum shut in tubing pressure of the well. A PSL sensor to shut in the well should be provided on each flow line segment, except the initial segment if the first choking device is less than 10 feet (3m) from the wellhead or, in the case of an underwater installation, reasonably close to that distance. A PSV is not required if the maximum allowable working pressure of a flow line segment is greater than the maximum shut in tubing pressure of the well, or if the segment is protected by a PSV located on an upstream flow line segment. An SDV (in addition to the SSV) with an independent PSH sensor connected to a separate relay and sensing point is an acceptable alternate to a PSV, providing the flow line volume upstream of block valves is adequate to allow sufficient time for the SDVs to close before exceeding the maximum allowable working pressure. This alternative should be approached with caution after thorough consideration of other alternatives. In some cases, installation of a PSV in addition to two SDVs might be desirable even at locations having no containment system.

A.1.2.2.2 Flow Safety Device (FSV)

A check valve (FSV) is only necessary in the final flow line segment to minimize backflow to the flow line.

A.1.3 SAFETY DEVICE LOCATION

The recommended location for safety devices is given in A.1.3.1–A.1.3.3.

A.1.3.1 Pressure Safety Devices (PSH, PSL, and PSV)

The PSH and PSL sensors should be located for protection from damage due to vibration, shock, and accidents. The sensing point should be located on top of a horizontal run or in a vertical run. An independent sensing point should be provided for a second PSH used with an SDV as alternate protection for a PSV. The PSV should be located upstream of the first blocking device in the flow line segment and should not be set higher than the rated working pressure of the segment.

A.1.3.2 Flow Safety Device (FSV)

The check valve (FSV) should be located in the final flow line segment so that the entire flow line is protected from backflow.

A.1.3.3 Shutdown Devices (SSV or USV)

The SSV should be located on the wellhead as the second valve in the flow stream from the wellbore. The SSV should be actuated by the flow line pressure sensors, ESD system, fire loop system, and sensors on downstream pro-

cess components. An SDV (in addition to the SSV) may be installed on the wellhead. If an SDV is installed, it may be actuated, in lieu of the SSV, by the flow line pressure sensors and sensors on downstream process components. The USV should be in a practical location in the wellhead flowstream and within a reasonable proximity of the wellbore. The USV should be actuated by the flow line pressure sensors located upstream of any SDV, by the ESD system, and by the fire loop system. The SSV is optional on subsea installations equipped with USVs.

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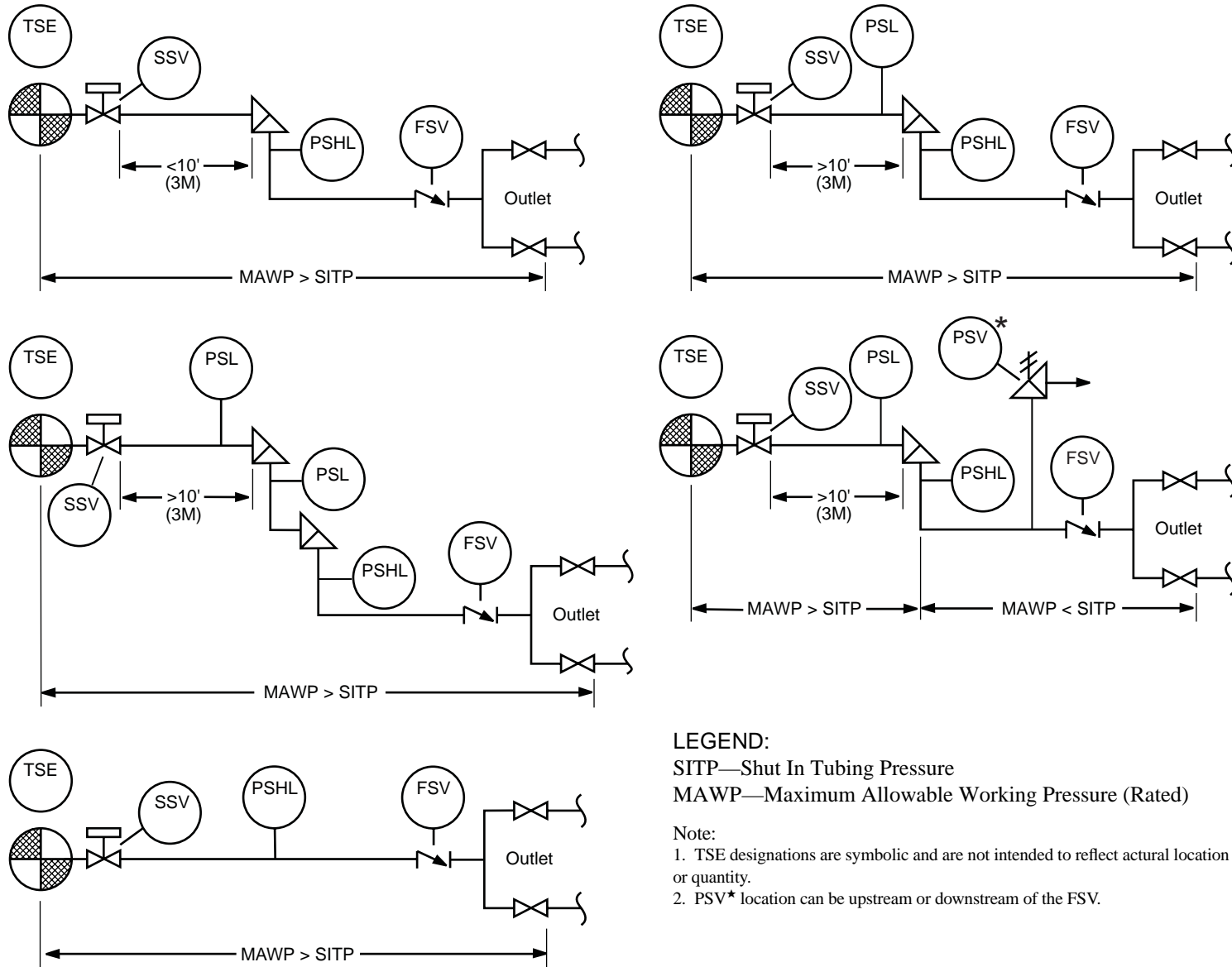


Figure A-1.1—Recommended Safety Devices—Wellhead Flow Lines

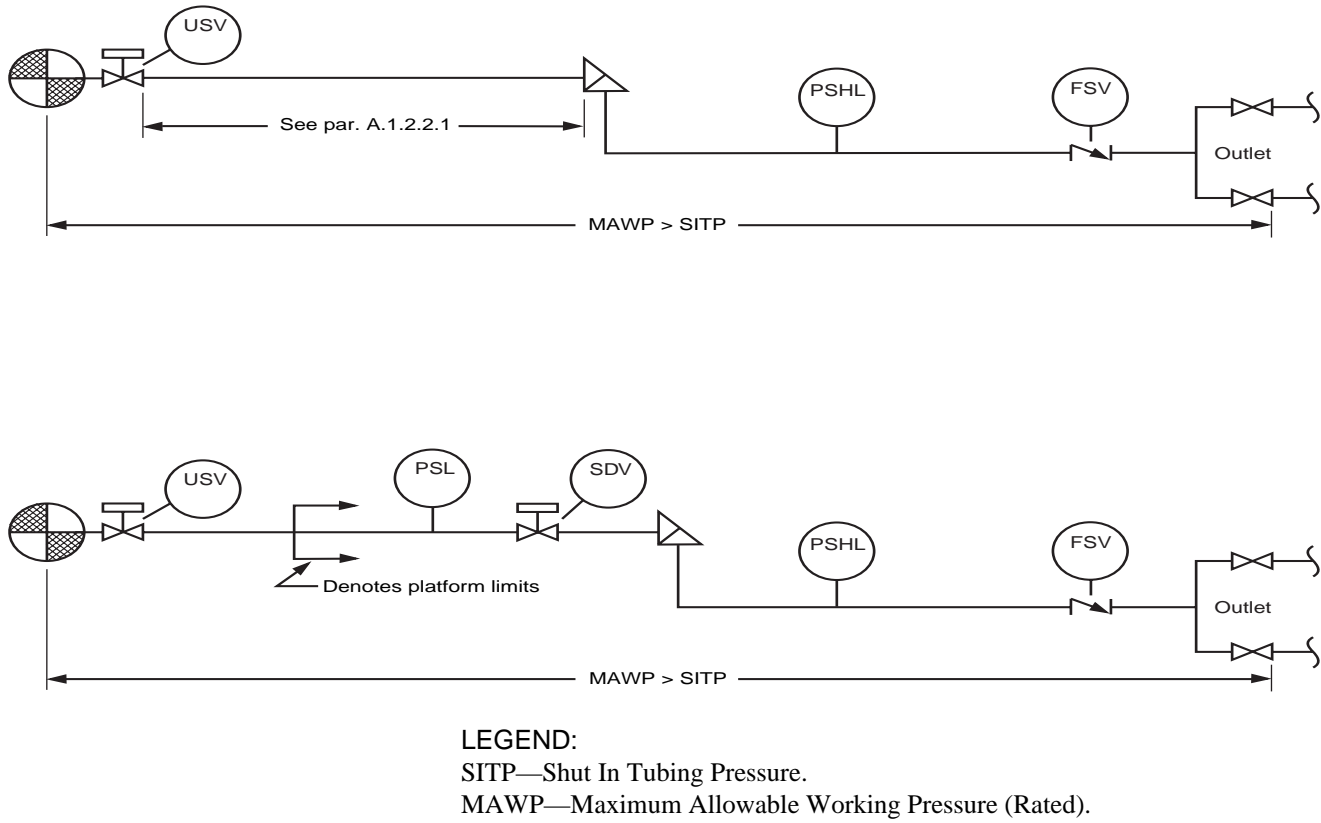
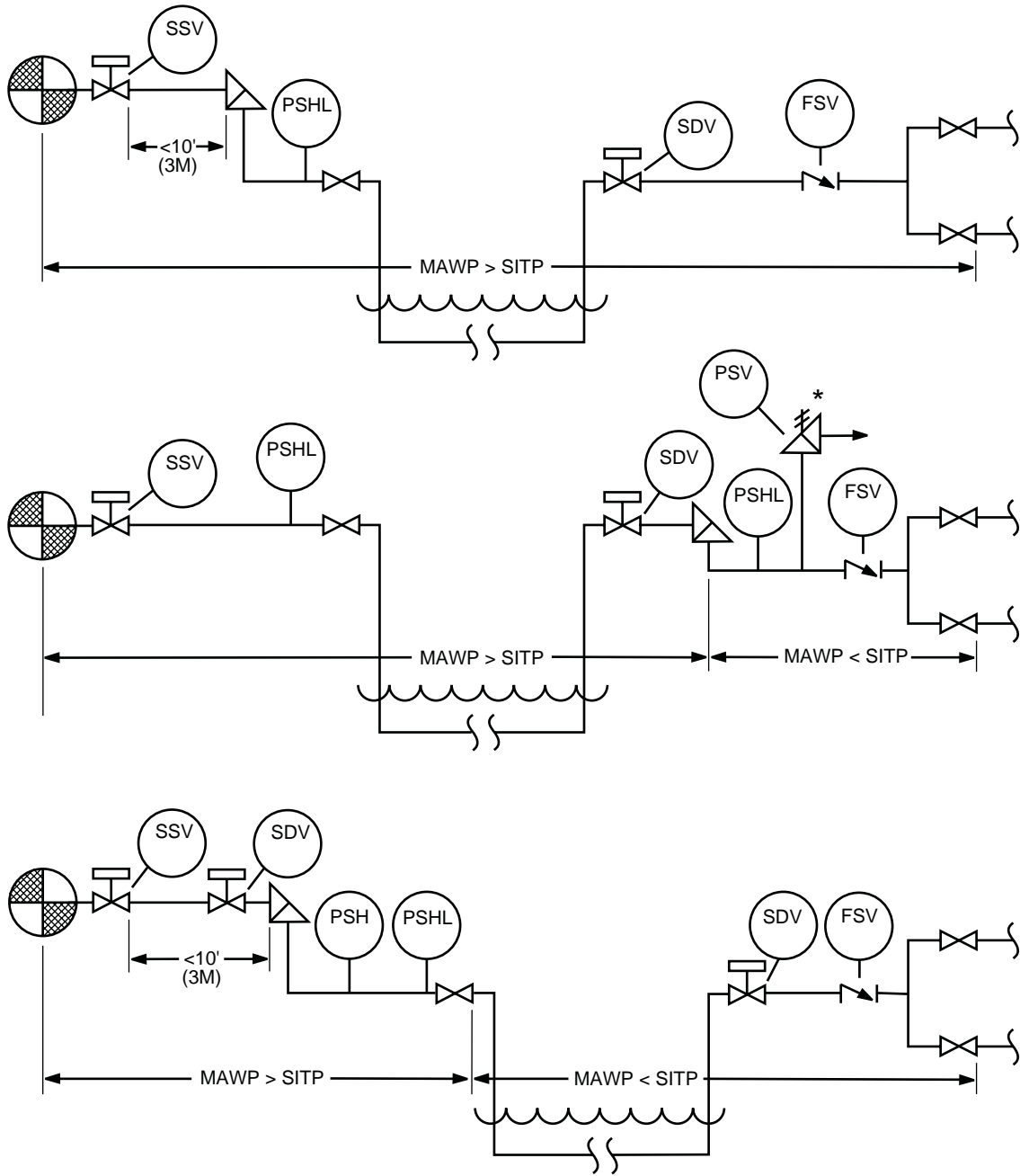


Figure A-1.2—Recommended Safety Devices—Underwater Wellhead Flow Lines



Note: *PSV Location can be upstream or downstream of FSV.

Figure A-1.3—Satellite Well

Table A-1.1—Safety Analysis Table (SAT)—Flow Line Segment

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Overpressure	Blocked or restricted line Downstream choke plugged Hydrate plug Upstream flow control failure Changing well conditions Closed outlet valve	High pressure
Leak	Deterioration Erosion Corrosion Impact damage Vibration	Low pressure

Table A-1.2—Safety Analysis Checklist (SAC)—Flow Line Segment

- a. High Pressure Sensor (PSH).
 1. PSH installed.
 2. Flow line segment has a maximum allowable working pressure greater than maximum shut in pressure and is protected by a PSH on a downstream flow line segment.
- b. Low Pressure Sensor (PSL).
 1. PSL installed.
 2. Flow line segment is between the well and the first choking device and is less than 10 feet (3 m) in length or, in the case of an underwater installation, reasonably close to that distance.
- c. Pressure Safety Valve (PSV).
 1. PSV installed.
 2. Flow line segment has a maximum allowable working pressure greater than the maximum shut in pressure.
 3. Two SDVs (one of which may be the SSV) with independent PSHs, relays, and sensing points are installed where there is adequate flow line volume upstream of any block valves to allow sufficient time for the SDVs to close before exceeding the maximum allowable working pressure.
 4. Flow line segment is protected by a PSV on upstream segment.
 5. Flow line segment is protected by a PSV on downstream component that cannot be isolated from the flow line segment and there are no chokes or other restrictions between the flow line segment and the PSV.
- d. Flow safety Valve (FSV).
 1. FSV installed.
 2. Flow line segment is protected by FSV in final flow line segment.

A.2 Wellhead Injection Lines

A.2.1 DESCRIPTION

Injection lines transfer fluids to the wellbore for artificial lift or reservoir injection. Recommended safety devices for typical wellhead injection lines are shown in Figure A-2.

A.2.2 SAFETY ANALYSIS

A.2.2.1 Safety Analysis Table

The Safety Analysis Table (SAT) for wellhead injection lines is presented in SAT Table A-2.1. The undesirable events that can affect an injection line are overpressure and leak.

A.2.2.2 Safety Analysis Checklist

The Safety Analysis Checklist (SAC) for wellhead injection lines is presented in SAC Table A-2.2.

A.2.2.2.1 Pressure Safety Devices (PSH, PSL, and PSV)

Pressure protection is usually provided by a PSH and a PSL sensor on the injection source, such as a compressor or pump, to shut off inflow. If the PSH and PSL sensors also protect the injection line, wellhead, and other equipment, these devices are not required on the injection line. A PSV is not necessary if the injection line is designed to withstand the maximum pressure that can be imposed by the injection source. Usually, a PSV is provided on the injection source that will also protect the injection line, wellhead, and other equipment.

A.2.2.2.2 Flow Safety Device (FSV)

A check valve (FSV) should be provided on each injection line to minimize backflow.

A.2.3 SAFETY DEVICE LOCATION

The recommended location for safety devices is given in A.2.3.1 - A.3.3.

A.2.3.1 Pressure Safety Devices (PSH, PSL, and PSV)

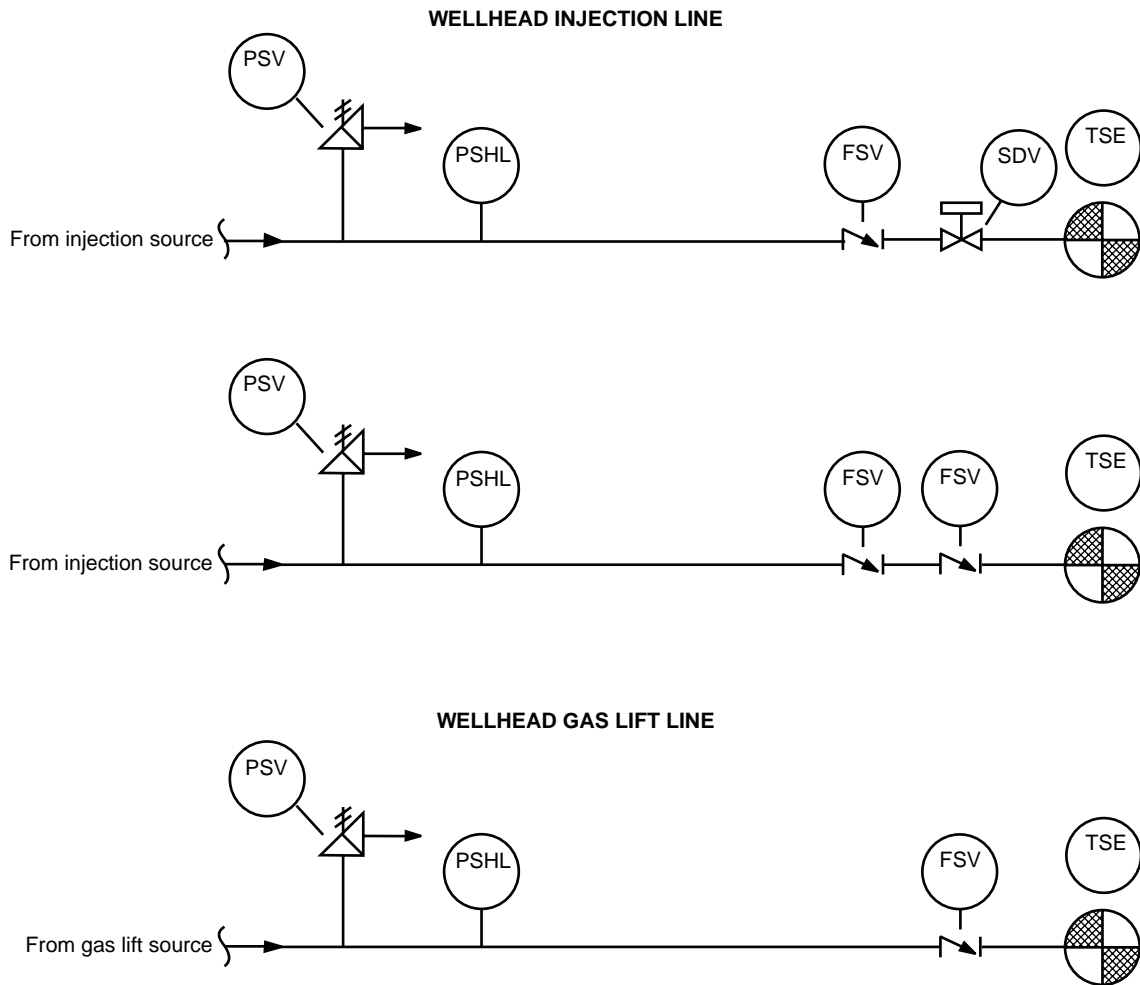
The PSH and PSL sensors should be located upstream of the FSV, and the sensing point should be on top of a horizontal run or in a vertical run. The PSV should be located so that it cannot be isolated from any portion of the injection line.

A.2.3.2 Flow Safety Device (FSV)

The check valve (FSV) should be located on each injection line as near the wellhead as is practical so that the entire line is protected from backflow.

A.2.3.3 Shutdown Devices (SDV)

Injection line SDVs should be located as near the wellhead as is practical to minimize the amount of line exposed. SDVs are not required on gas lift lines if they are protected at an upstream component and if they are not subject to backflow from the producing formation. Also, an SDV is not required if the injection line is for the purpose of injecting water and the subsurface formation is incapable of backflowing hydrocarbons. If closing an SDV could cause rapid pressure buildup in the injection line, consideration should be given to shutdown of the injection source and/or use of a second FSV in lieu of an SDV.



Note: TSE designations are symbolic and are not intended to reflect actual location or quantity.

Figure A-2—Recommended Safety Devices—Wellhead Injection Lines

Table A-2.1—Safety Analysis Table (SAT)—Wellhead Injection Lines

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Overpressure	Blocked or restricted outlet Hydrate plug Upstream control failure Plugged formation	High pressure
Leak	Deterioration Erosion Corrosion Impact damage Vibration	Low pressure

Table A-2.2—Safety Analysis Checklist (SAC)—Wellhead Injection Lines

- a. High Pressure Sensor (PSH).
 1. PSH installed.
 2. Line and equipment are protected by an upstream PSH.
- b. Low Pressure Sensor (PSL).
 1. PSL installed.
 2. Line and equipment are protected by an upstream PSL.
- c. Pressure Safety Valve (PSV).
 1. PSV installed.
 2. Line and equipment have a maximum allowable working pressure greater than the maximum pressure that can be imposed by the injection source.
 3. Line and equipment are protected by an upstream PSV.
- d. Check Valves (FSV).
 1. FSV(s) installed.

A.3 Headers

A.3.1 DESCRIPTION

Headers receive production from two or more flow streams and distribute production to the required process systems, such as the low, intermediate, or high pressure production and test separation facilities. Recommended safety devices for typical headers are shown in Figure A-3.

A.3.2 SAFETY ANALYSIS

- a. The Safety Analysis Table (SAT) for headers is presented in SAT Table A-3.1. The undesirable events that can affect a header are overpressure and leak.
- b. The Safety Analysis Checklist (SAC) for headers is presented in SAC Table A-3.2.

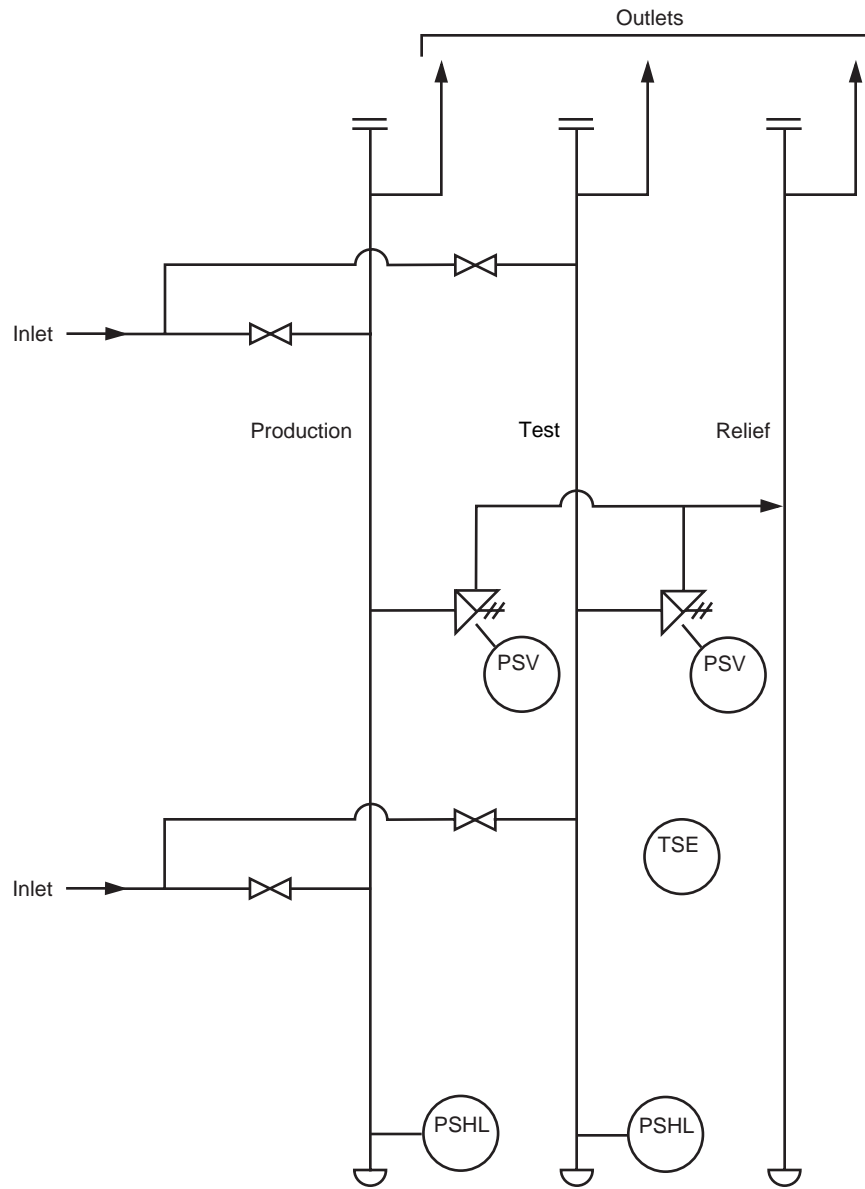
A.3.2.1 Pressure Safety Devices (PSH, PSL, and PSV)

PSH and PSL sensors are not required on headers if each input source is equipped with a PSH and a PSL sensor and the PSH sensor is set less than the rated working pressure of the header. Also, a PSH sensor is not required if the header is protected by a PSH sensor on a downstream process component and the header cannot be isolated from the downstream component. A PSL is not required if the header is for flare, relief, vent, or other atmospheric service. If the header requires a PSH and a PSL sensor, the signal from each should shut off all input sources to the header.

A PSV is not required on a header if: (a) the maximum allowable working pressure is greater than the maximum shut in pressure of any connected input source, (b) pressure relief protection is provided on all connected input sources that have a maximum shut in pressure greater than the maximum allowable working pressure of the header, (c) the header is protected by a PSV on a downstream process component that cannot be isolated from the header, (d) the header is for flare, relief, vent, or other atmospheric service and has no valving in the outlet piping, or (e) the input source is a well(s) having a pressure greater than the maximum allowable working pressure of the header and is equipped with two SDVs (one of which may be the SSV) controlled by independent PSHs connected to separate relays and sensing points. Other input sources having a pressure greater than the maximum allowable working pressure of the header are protected by PSVs. The use of two SDVs in lieu of a PSV should be approached with caution after thorough consideration of other alternatives. In some cases, installation of a PSV in addition to two SDVs might be desirable even at locations having no containment system.

A.3.3 SAFETY DEVICE LOCATION

Pressure Safety Devices, PSH and PSL sensors or a PSV, if required, should be located to sense pressure throughout the header. If different pressure conditions exist in separate sections of the header, each section should have the required protection.



Note: TSE designations are symbolic are not intended to reflect actual location or quantity.

Figure A-3—Recommended Safety Devices—Headers

Table A-3.1—Safety Analysis Table (SAT)—Headers

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Overpressure	Blocked or restricted outlet Hydrate plug Upstream control failure Excess inflow	High pressure
Leak	Deterioration Erosion Corrosion Impact damage Vibration	Low pressure

Table A-3.2—Safety Analysis Checklist (SAC)—Headers

- a. High Pressure Sensor (PSH).
 1. PSH installed.
 2. Each input source is equipped with a PSH set less than the maximum allowable working pressure of the header.
 3. Header is protected by downstream PSH that cannot be isolated from the header.
 4. Header is for flare, relief, vent, or other atmospheric service and has no valving in the outlet piping.
- b. Low Pressure Sensor (PSL).
 1. PSL installed.
 2. Each input source is protected by a PSL and there are no pressure control devices or restrictions between the PSL and the header.
 3. Header is for flare, relief, vent, or other atmospheric service.
- c. Pressure Safety Valve (PSV).
 1. PSV installed.
 2. Header has a maximum allowable working pressure greater than the maximum shut in pressure of any connected well.
 3. Pressure relief protection is provided on each input source having a maximum shut in pressure greater than the maximum allowable working pressure of the header.
 4. Header is protected by downstream PSV that cannot be isolated from the header.
 5. Header is for flare, relief, vent, or other atmospheric service and has no valving in the outlet piping.
 6. Input source is a well(s) having a pressure greater than the maximum allowable working pressure of the header and is equipped with two SDVs (one of which may be the SSV) controlled by independent PSHs connected to separate relays and sensing points. Other input sources having a pressure greater than the maximum allowable working pressure of the header are protected by PSVs.

A.4 Pressure Vessels

A.4.1 DESCRIPTION

Pressure vessels handle hydrocarbons under pressure for liquid-gas separation, dehydration, storage, and surge. Some pressure vessel applications require heat input. This discussion covers only the effects of heat input to the process section of a heated vessel. Heating equipment is covered in A.6 and A.10. Pressure vessels associated with compressors, other than compressor cylinders should be protected in accordance with this section. Compressor cylinders and cases are covered in A.8. Recommended safety devices for typical pressure vessels are shown in Figure A-4.

A.4.2 SAFETY ANALYSIS

A.4.2.1 Safety Analysis Table

The Safety Analysis Table (SAT) for pressure vessels is presented in SAT Table A-4.1. The undesirable events that

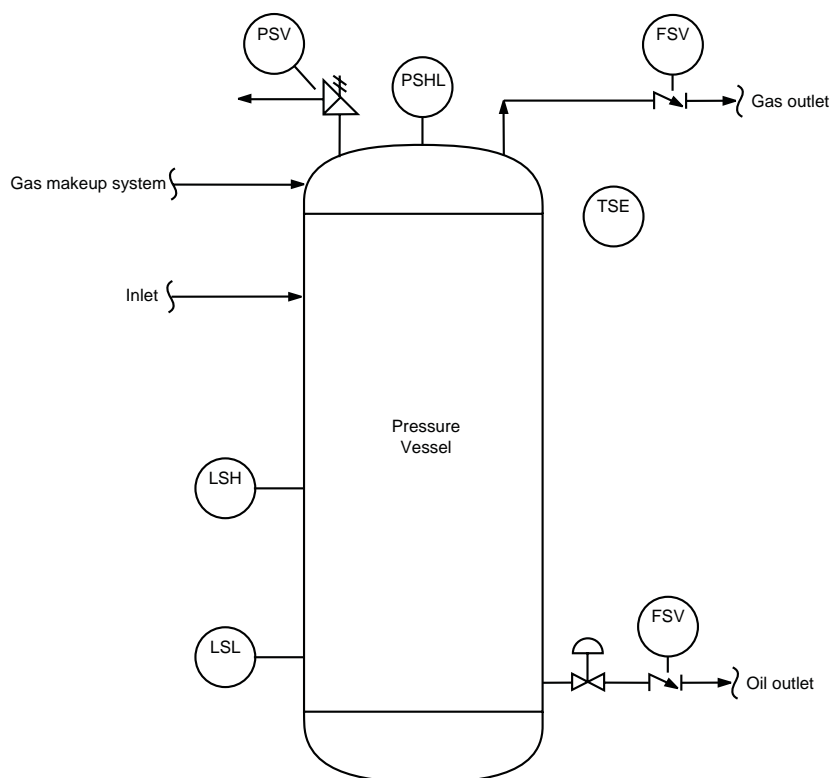
can affect a pressure vessel are overpressure, underpressure, overflow, gas blowby, leak, and excess temperature if the vessel is heated.

A.4.2.2 Safety Analysis Checklist

The Safety Analysis Checklist (SAC) for pressure vessels is presented in SAC Table A-4.2.

A.4.2.2.1 Pressure Safety Devices (PSH, PSL, and PSV)

- a. A pressure vessel that receives fluids from a well or from other sources that can cause overpressure should be protected by a PSH sensor to shut off inflow to the vessel. The PSH sensor need not be provided on the vessel if a PSH sensor on other process components will sense vessel pressure and shut off inflow to the vessel, and the PSH sensor cannot be isolated from the vessel; or if the vessel is the final scrubber in a flare, relief, or vent system and is designed to withstand maximum built-up back pressure; or if the vessel operates at atmo-



Notes:

1. TSE designations are symbolic and are not intended to reflect actual location or quantity.
2. If pressure vessel is heated, TSH should be installed.

Figure A-4—Recommended Safety Devices—Pressure Vessel

spheric pressure and has an adequate vent system. A vessel receiving fluids from a well should always be protected by a PSH sensor because the pressure potential of a well may increase due to changes in reservoir conditions, artificial lift, workover activities, etc.

b. A pressure vessel should be provided with a PSL sensor to shut off inflow to the vessel when leaks large enough to reduce pressure occur, unless PSL sensors on other components will provide necessary protection and the PSL sensor cannot be isolated from the vessel when in service. A PSL sensor should not be installed if the vessel normally operates at atmospheric pressure or frequently varies to atmospheric while in service. In this case, the complexity of lockout devices to keep the vessel from shutting in during these operating modes could more than offset the protection afforded by the PSL sensor.

c. A pressure vessel should always be protected by one or more PSVs with sufficient capacity to discharge maximum vessel input rates. At least one PSV should be set no higher than the maximum allowable working pressure of the vessel. API Recommended Practice 521 may be used as a guide in determining set pressures of multiple relief valve installations.

A PSV need not be provided on a vessel if the vessel is the final scrubber in a flare, relief, or vent system; and is designed so that back pressure, including inertial forces, developed at maximum instantaneous flow conditions will not exceed the working pressure of the lowest pressure rated element; and has no internal or external obstructions, such as mist extractors, back pressure valves, or flame arrestors. If obstructions exist, a PSV, or, as an alternative, a PSE should be installed to bypass the restriction. A PSV need not be provided on a vessel if PSVs on other process components provide adequate relief capacity, relieve at or below vessel maximum allowable working pressure, and cannot be isolated from the vessel when in service. If such PSVs are located on downstream components, they must not be isolated from the vessel at any time. Moreover, if upstream PSVs provide necessary protection when the vessel is in service, but can be isolated when the vessel is shut in, a PSV should be installed on the vessel for pressure relief due to thermal expansion or fire exposure.

d. If a pressure vessel is subject to underpressure that could cause it to collapse, the vessel should be provided with a gas makeup system that will maintain adequate pressure in the vessel.

Table A-4.1—Safety Analysis Table (SAT) Pressure Vessels

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Overpressure	Blocked or restricted outlet Inflow exceeds outflow Gas blowby (upstream component) Pressure control system failure Thermal expansion Excess heat input	High pressure
Underpressure (vacuum)	Withdrawals exceed inflow Thermal contraction Open outlet Pressure control system failure	Low pressure
Liquid overflow	Inflow exceeds outflow Liquid slug flow Blocked or restricted liquid outlet Level control system failure	High liquid level
Gas blowby	Liquid withdrawals exceed inflow Open liquid outlet Level control system failure	Low liquid level
Leak	Deterioration Erosion Corrosion Impact damage Vibration	Low pressure Low liquid level
Excess temperature	Temperature control system failure High inlet temperature	High temperature

A.4.2.2.2 Level Safety Devices (LSH and LSL)

A pressure vessel that discharges to flare should be protected from liquid overflow by an LSH sensor to shut off inflow to the vessel. Vessels that do not discharge to flare should also be protected by an LSH sensor unless downstream process components can safely handle maximum liquids that could overflow. A pressure vessel should be protected from gas blowby by an LSL sensor to shut off inflow to the vessel or close the liquid outlet. The LSL sensor is not required if a liquid level is not maintained in the vessel during normal operation, or downstream equipment can safely handle gas that could blowby. An LSL sensor to shut off the fuel supply should be provided in a heated vessel if the heating element is immersed.

Level devices are not required on pressure vessels that are not designed for liquid-gas separation or on small traps from which liquids are manually drained. This includes such vessels as pressure-surge bottles, desanders, gas volume bottles, gas meter drip traps, fuel gas filters, etc.

A.4.2.2.3 Temperature Safety Devices (TSH)

If a pressure vessel is heated, a TSH sensor should be provided to shut off the source of heat when process fluid temperature becomes excessive.

A.4.2.2.4 Flow Safety Devices (FSV)

A check valve (FSV) should be installed in each gas and liquid discharge line if significant fluid volumes could backflow from downstream components in the event of a leak. An FSV is not required if a control device in the line will effectively minimize backflow. Whether backflow is significant is a judgement decision. If a line discharges to a pressure vessel at a point above the liquid level range, the backflow of liquids should be insignificant. Whether or not the gas volume is insignificant should depend on the size and pressure of the gas section and the conditions where a leak might occur.

A.4.3 SAFETY DEVICE LOCATION

The recommended location for safety devices is given in A.4.3.1-A.4.3.4.

A.4.3.1 Pressure Safety Devices (PSH, PSL, and PSV)

The PSH and PSL sensors and the PSV should be located to sense or relieve pressure from the gas or vapor section of the vessel. This is usually on or near the top. However, such devices may be located on the gas outlet piping if the pressure drop from the vessel to the sensing point is negligible and if the devices cannot be isolated from the vessel. Such isolation

Table A-4.2—Safety Analysis Checklist (SAC)—Pressure Vessels

-
- a. High Pressure Sensor (PSH).
 - 1. PSH installed.
 - 2. Input is from a pump or compressor that cannot develop pressure greater than the maximum allowable working pressure of the vessel.
 - 3. Input source is not a wellhead flow line(s), production header, or pipeline and each input source is protected by a PSH that protects the vessel.
 - 4. Adequately sized piping without block or regulating valves connects gas outlet to downstream equipment protected by a PSH that also protects the upstream vessel.
 - 5. Vessel is final scrubber in a flare, relief, or vent system and is designed to withstand maximum built-up back pressure.
 - 6. Vessel operates at atmospheric pressure and has an adequate vent system.
 - b. Low Pressure Sensor (PSL).
 - 1. PSL installed.
 - 2. Minimum operating pressure is atmospheric pressure when in service.
 - 3. Each input source is protected by a PSL and there are no pressure control devices or restrictions between the PSL(s) and the vessel.
 - 4. Vessel is scrubber or small trap, is not a process component, and adequate protection is provided by downstream PSL or design function (e.g., vessel is gas scrubber for pneumatic safety system or final scrubber for flare, relief, or vent system).
 - 5. Adequately sized piping without block or regulating valves connects gas outlet to downstream equipment protected by a PSL that also protects the upstream vessel.
 - c. Pressure Safety Valve (PSV).
 - 1. PSV installed.
 - 2. Each input source is protected by a PSV set no higher than the maximum allowable working pressure of the vessel and a PSV is installed on the vessel for fire exposure and thermal expansion.
 - 3. Each input source is protected by a PSV set no higher than the vessel's maximum allowable working pressure and at least one of these PSV's cannot be isolated from the vessel.
 - 4. PSV's on downstream equipment can satisfy relief requirement of the vessel and cannot be isolated from the vessel.
 - 5. Vessel is final scrubber in a flare, relief or, vent system, is designed to withstand maximum built-up back pressure, and has no internal or external obstructions, such as mist extractors, back pressure valves, or flame arrestors.
 - 6. Vessel is final scrubber in a flare, relief or, vent system, is designed to withstand maximum built-up back pressure, and is equipped with a rupture disk or safety head (PSE) to bypass any internal or external obstructions, such as mist extractors, back pressure valves, or flame arrestors.
 - d. High Level Sensor (LSH).
 - 1. LSH installed.
 - 2. Equipment downstream of gas outlet is not a flare or vent system and can safely handle maximum liquid carry-over.
 - 3. Vessel function does not require handling separated fluid phases.
 - 4. Vessel is a small trap from which liquids are manually drained.
 - e. Low Level Sensor (LSL).
 - 1. LSL installed to protect each liquid outlet.
 - 2. Liquid level is not automatically maintained in the vessel, and the vessel does not have an immersed heating element subject to excess temperature.
 - 3. Equipment downstream of liquid outlet(s) can safely handle maximum gas rates that can be discharged through the liquid outlet(s), and vessel does not have an immersed heating element subject to excess temperature. Restrictions in the discharge line(s) may be used to limit the gas flow rate.
 - f. Check Valve (FSV).
 - 1. FSV installed on each outlet.
 - 2. The maximum volume of hydrocarbons that could backflow from downstream equipment is insignificant.
 - 3. A control device in the line will effectively minimize backflow.
 - g. High Temperature Sensor (TSH).

High temperature sensors are applicable only to vessels having a heat source.

 - 1. TSH installed.
 - 2. (Deleted in Second Edition.)
 - 3. Heat source is incapable of causing excess temperature.

could be caused externally (e.g., by blocked valves on gas outlet) or internally (e.g., by plugged mist extractors).

A.4.3.2 Level Safety Devices (LSH and LSL)

The LSH sensor should be located a sufficient distance above the highest operating liquid level to prevent nuisance shutdowns but with adequate vessel volume above the LSH sensor to prevent overflow before shutdown can be effected. The LSL sensor should be located a sufficient distance below the lowest operating liquid level to prevent nuisance shutdowns but with adequate liquid volume between the LSL sensor and liquid outlet to prevent gas blowby before shutdown can be effected. In fire-tube heated components, the LSL should be located above the fire tubes. The LSH and LSL sensors should preferably be installed in external columns that can be isolated from the vessel. This will permit testing the devices without interrupting the process. However, if solid deposits or foam cause fouling or false indication of devices in external columns, the level sensors may be installed directly in the vessel. In this case, a pump may be required to manipulate vessel liquid level for testing.

A.4.3.3 Flow Safety Device (FSV)

Check valves (FSVs) should be located in outlet piping.

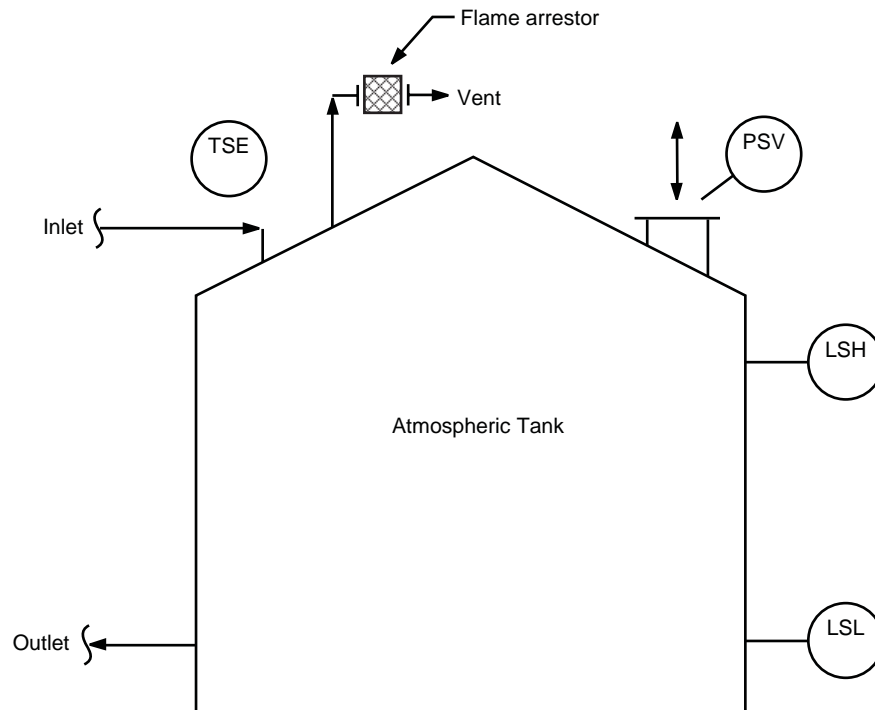
A.4.3.4 Temperature Safety Devices (TSH)

The TSH sensors, other than fusible or skin contact types, should be installed in thermowells for ease of removing and testing. The thermowell should be located where it will be accessible and continuously immersed in the heated fluid.

A.5 Atmospheric Vessels

A.5.1 DESCRIPTION

Atmospheric vessels are used for processing and temporary storage of liquid hydrocarbons. Some applications require heat input to the vessel. This discussion covers only the effects of heat input to the process section of an atmospheric vessel. Heating equipment is covered in A.6 and A.10. Recommended safety devices for typical atmospheric vessels used in a production process system are shown in Figure A-5. Vessels such as those used for diesel fuel and chemical storage that are ancillary to the production process system are not covered by this recommended practice. However, some of the recommendations contained in Appendix C.1, "Emergency Support Systems," might be applicable when installing such equipment.



Notes:

1. TSE designations are symbolic and are not intended to reflect actual location or quantity.
2. If atmospheric vessel is heated, TSH should be installed.
3. A vent line might contain pressure and/or vacuum relief device.
4. A second vent may be installed in lieu of the pressure-vacuum relief device.

Figure A-5—Recommended Safety Devices—Atmospheric Vessels

A.5.2 SAFETY ANALYSIS

A.5.2.1 Safety Analysis Table

The Safety Analysis Table (SAT) for atmospheric vessels is presented in Table A-5.1. The undesirable events that can affect an atmospheric vessel are overpressure, underpressure, overflow, leak, and excess temperature if the vessel is heated.

A.5.2.2 Safety Analysis Checklist

The Safety Analysis Checklist (SAC) for atmospheric vessels is presented in Table A-5.2.

A.5.2.2.1 Pressure Safety Devices (Vent and PSV)

An atmospheric vessel should be protected from overpressure and underpressure by an adequately-sized vent system. API Standard 2000 may be used as a guide for sizing vent systems. A flame arrestor should be included in the vent sys-

tem to prevent flame migration back to the vessel. A pressure-vacuum relief device (PSV) or a second vent should be installed to protect the vessel in case the primary vent control device(s) fouls or otherwise obstructs flow. The PSV or second vent is not required when (a) a pressure vessel not subject to collapse is used in atmospheric service, or (b) an atmospheric vessel has no pressure sources (except blanket gas) piped to it. A blanket gas system may be desirable to exclude air from an atmospheric vessel.

A.5.2.2.2 Level Safety Devices (LSH and LSL)

Protection from liquid overflow from an atmospheric vessel should be provided by an LSH sensor to shut off inflow unless fill operations are continuously attended or overflow is diverted to other process components.

An LSL sensor should be provided to shut off the heat source if the vessel has an immersed heating element subject to excess temperature. Unless liquid level is not automatically

Table A-5.1—Safety Analysis Table (SAT)—Atmospheric Vessels

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Overpressure	Blocked or restricted outlet Inflow exceeds outflow Gas blowby (upstream component) Pressure control system failure Thermal expansion Excess heat input	High Pressure

Table A-5.2—Safety Analysis Checklist (SAC)—Atmospheric Vessels

- a. Vent. (Refer to Note)
 1. Vent installed.
- b. Pressure-vacuum Relief Device (PSV).
 1. PSV installed.
 2. Vessel has second vent capable of handling maximum gas volume.
 3. Component is a pressure vessel, not subject to collapse, that operates in atmospheric service and is equipped with an adequately sized vent.
 4. Vessel has no pressure sources (except blanket gas and/or manual drains) and is equipped with an adequately sized vent.
- c. High Level Sensor (LSH).
 1. LSH installed.
 2. Fill operations are continuously attended.
 3. Overflow is diverted or contained by other process components.
- d. Low Level Sensor (LSL).
 1. LSL installed.
 2. Adequate containment system is provided.
 3. Liquid level is not automatically maintained in the vessel, and vessel does not have an immersed heating element subject to excess temperature.
 4. Component is final vessel in a containment system designed to collect and direct hydrocarbon liquids to a safe location.
- e. High Temperature Sensor (TSH).

High temperature sensors are applicable only to vessels having a heat source.

 1. TSH installed.
 2. (Deleted in Second Edition.)
 3. Heat source is incapable of causing excess temperature.

Note: A vent is a pipe or fitting on a vessel that opens to atmosphere. A vent line might contain a pressure and/or vacuum relief device.

maintained in the vessel an LSL sensor should be provided to protect against leaks by shutting of inflow. A containment system to collect leakage is preferable to a low level sensor when normal inflow of liquids would preclude the sensor's detection of a leak.

A.5.2.2.3 Temperature Safety Devices (TSH)

If an atmospheric vessel is heated, a TSH sensor should be provided to shut off the source of heat when process fluid temperature becomes excessive.

A.5.3 SAFETY DEVICE LOCATION

The recommended location for safety devices is given in A.5.3.1-A.5.3.3.

A.5.3.1 Pressure Safety Devices (Vent and PSV)

The vent and PSV should be located on the top (highest practical elevation in the vapor section) of atmospheric vessels.

A.5.3.2 Level Safety Devices (LSH and LSL)

The LSH sensor should be located at a sufficient distance above the highest operating liquid level to prevent nuisance shutdowns but with adequate vessel volume above the LSH sensor to contain liquid inflow during shut in. The LSL should be located at a sufficient distance below the lowest operating liquid level to avoid nuisance shutdowns. In fire-tube heated components, the LSL should be located above the fire tubes. The LSH and LSL sensors should preferably be located in external columns for ease of testing without interrupting the process. However, internally mounted sensors are also acceptable as discussed in A.4.3.2.

A.5.3.3 Temperature Safety Devices (TSH)

The TSH sensors, other than fusible or skin contact types, should be installed in thermowells for ease of removal and testing. The thermowell should be located for accessibility and should be continuously immersed in the process fluid.

A.6 Fired and Exhaust Heated Components

A.6.1 DESCRIPTION

Fired and exhaust heated components are used for processing and heating hydrocarbons. Included are both direct and indirect fired atmospheric and pressure vessels and tube-type heaters equipped with either automatically controlled natural or forced draft burners. Also included are exhaust heated components that use exhaust gases from other equipment such as turbines and engines as a heat source, and that may or may not be supplementary fired. This section discusses the

required protection for firing equipment of a fired component and for the heating section of exhaust heated components. Protection for the process portion of a fired or exhaust heated component is discussed under the appropriate component. Recommended safety devices for a typical fired vessel equipped with a natural draft burner or a forced draft burner are shown in Figures A-6.1 and A-6.2, respectively. Recommended safety devices for a typical exhaust heated component are shown in Figure A-6.3.

A.6.2 SAFETY ANALYSIS

A.6.2.1 Safety Analysis Table

The Safety Analysis Table (SAT) is presented for fired components with natural draft burners in Table A-6.1, for those with forced draft burners in Table A-6.2, and for exhaust heated components in Table A-6.3. The undesirable events that can affect a fired component or supplementary fired exhaust heated component are excess temperature, direct ignition source, excess fuel in the firing chambers, and overpressure. The undesirable events that can affect an exhaust heated component are excess temperature and overpressure.

A.6.2.2 Safety Analysis Checklist

The Safety Analysis Checklist (SAC) for fired and exhaust heated components is presented in Table A-6.2.

A.6.2.2.1 Temperature Safety Devices (TSH)

- a. The medium or process fluid temperature in a fired component should be monitored by a TSH sensor to shut off the fuel supply and the inflow of combustible fluids. If a component is exhaust heated, the exhaust should be diverted or the source of exhaust shut down. A TSH sensor is not necessary on a steam generator protected by a PSH sensor to detect high pressure caused by high temperature and by an LSL sensor to detect a low level condition that could cause high temperature. A TSH to sense medium or process fluid temperature is generally not necessary for an indirect water bath heater in atmospheric service since the maximum temperature is limited by the boiling point of the water bath.
- b. The flow of combustible medium in a closed heat transfer system, where the medium is circulated through tubes located in the firing or exhaust heated chamber, should not be shut off until the chamber has cooled. An ESD system and fire loop should immediately shut off medium flow if an uncontrolled fire has occurred in the area or the medium is escaping from a closed system.
- c. Temperature in the burner exhaust stack should be monitored by a TSH sensor to shut off the fuel supply and the inflow of combustible fluids. Temperature in the exhaust heated component stack should be monitored by a TSH sen-

sor to shut off the inflow of combustible medium and to shut down the exhaust source. A TSH sensor is not required on a fired component located in an isolated area not handling combustibles other than fuel.

A.6.2.2.2 Flow Safety Devices (FSL and FSV)

When a combustible medium is circulated through tubes located in the firing or exhaust heated chamber, the medium flow rate should be monitored by an FSL sensor to shut off the fuel supply to a fired component or to divert the exhaust flow from an exhaust heated component. In this type of component, high temperature in the medium could occur before being detected by a TSH (medium) sensor located outside the heater. An FSL sensor is not required in other types of heaters because the TSH (medium) sensor is located in the medium section and should immediately detect the high temperature condition. A check valve (FSV) should be located in tube outlet piping to prevent backflow into the fired or heated chamber in the event of tube rupture.

A.6.2.2.3 Pressure Safety Devices (PSH, PSL, and PSV)

The pressure in the fuel supply line should be monitored by a PSH sensor to shut off the fuel supply to the burner. On a forced draft burner, a PSL sensor should be installed on the fuel supply; also, the air intake pressure of a forced draft burner should be monitored by a PSL sensor to shut off the fuel and air supply. An air velocity device may be used to monitor air supply in lieu of a PSL sensor. The PSL sensor is not required on a natural draft burner because of the low air intake pressure. Flow tubes located in the firing or exhaust heated chamber of a tube type heater should be protected by a PSV from overpressure caused by expansion of the medium or process fluid.

A.6.2.2.4 Ignition Safety Devices

a. The air intake of a natural draft burner should be equipped with a flame arrestor to prevent flame migration back through the air intake. A flame arrestor is not required on a forced draft burner because the air velocity through the air intake prevents flame migration, or the PSL sensor in the air intake and fan motor starter interlock shut off the air intake.

b. The stack on a natural draft burner should be equipped with a stack arrestor to prevent spark emission. When the fired component is not handling combustibles other than fuel and is located in an isolated area, the arrestor is not necessary. A stack arrestor may not be necessary on a forced draft burner due to the higher combustion efficiency that prevents carbon build-up. A stack arrestor is required if the fluid being heated is flammable or the burner draft pressure at the exit of the transfer section is lower than the fluid pressure (head).

c. The motor on a forced draft fan should be equipped with a motor starter interlock to sense motor failure and shut off the fuel and air supply.

d. The flame in the firing chamber should be monitored by a BSL or TSL sensor that will detect a flame insufficient to immediately ignite combustibles entering the firing chamber and will shut off fuel supply.

A.6.3 SAFETY DEVICE LOCATION

The recommended location for safety devices is given in A.6.3.1-A.6.3.4.

A.6.3.1 Temperature Safety Devices (TSH)

Temperature sensors, other than fusible or skin contact types, should be installed in a thermowell for ease of removal and testing. When the fire tube is immersed, the TSH sensor should be located in the heated liquid medium or process fluid. When the liquid medium or process fluid flows through tubes within the firing or exhaust heated chambers, the TSH sensor should be located in the discharge line as close as is practical to the heater and upstream of all isolating devices. A TSH sensor in the stack should be located near the base of the exhaust stack.

A.6.3.2 Flow Safety Devices (FSL and FSV)

In a closed heat transfer system with a combustible medium, an FSL sensor should be located in the medium circulating tube piping. The sensor should be located in the medium outlet line as close to the heater as is practical and should monitor total flow through the heater. A check valve (FSV) should be installed in the tube outlet piping.

A.6.3.3 Pressure Safety Devices (PSH, PSL, and PSV)

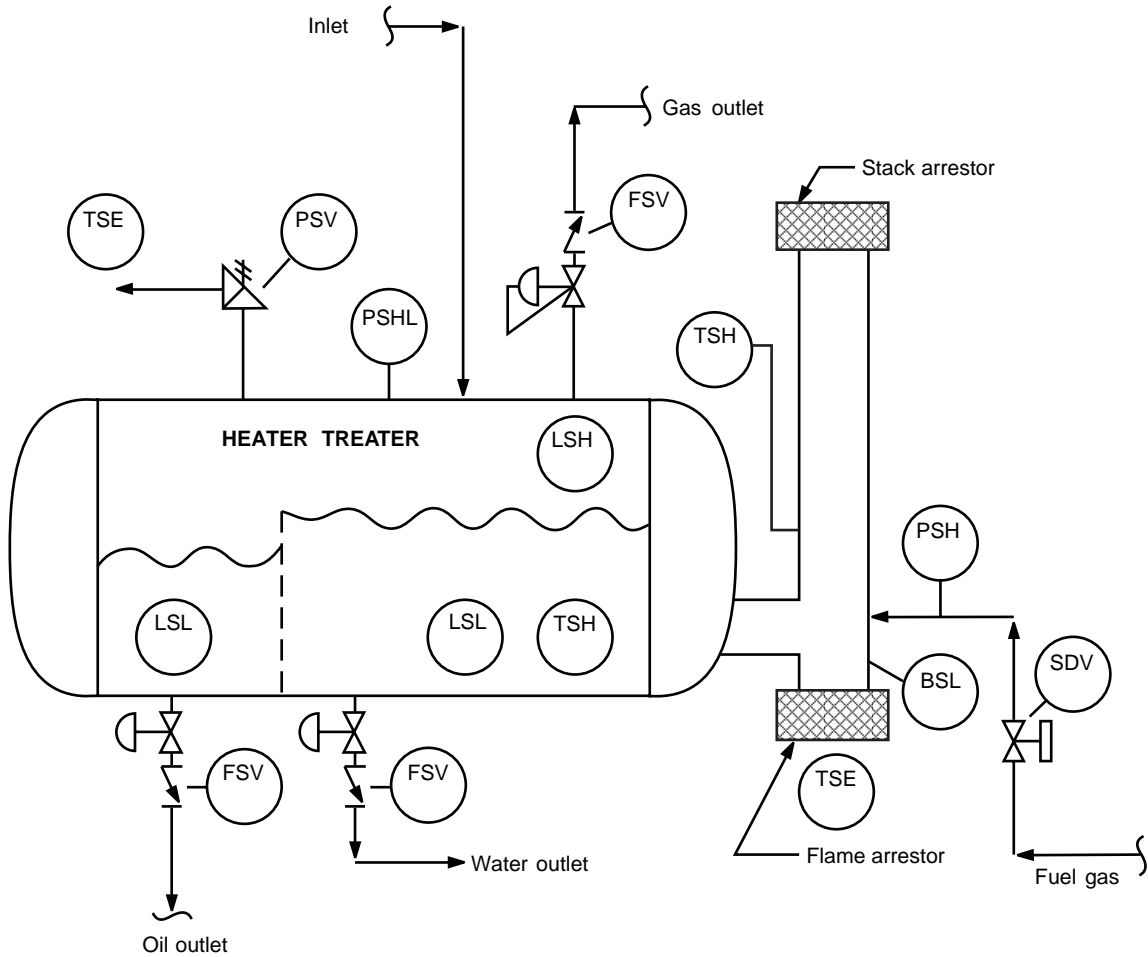
A PSL sensor in the air intake of a forced draft burner should be located downstream of the blower. The PSH and PSL sensor in the fuel supply line should be located between the last pressure regulator and the fuel control valve. A PSV on the tubes of a tube type heater should be located where it cannot be isolated from the heated section of the tubes.

A.6.3.4 Ignition Safety Devices

The flame and stack arrestors on fired components should be located to prevent flame emission from the air intake and spark emission from the exhaust stack. The BSL sensor should be located in the firing chamber.

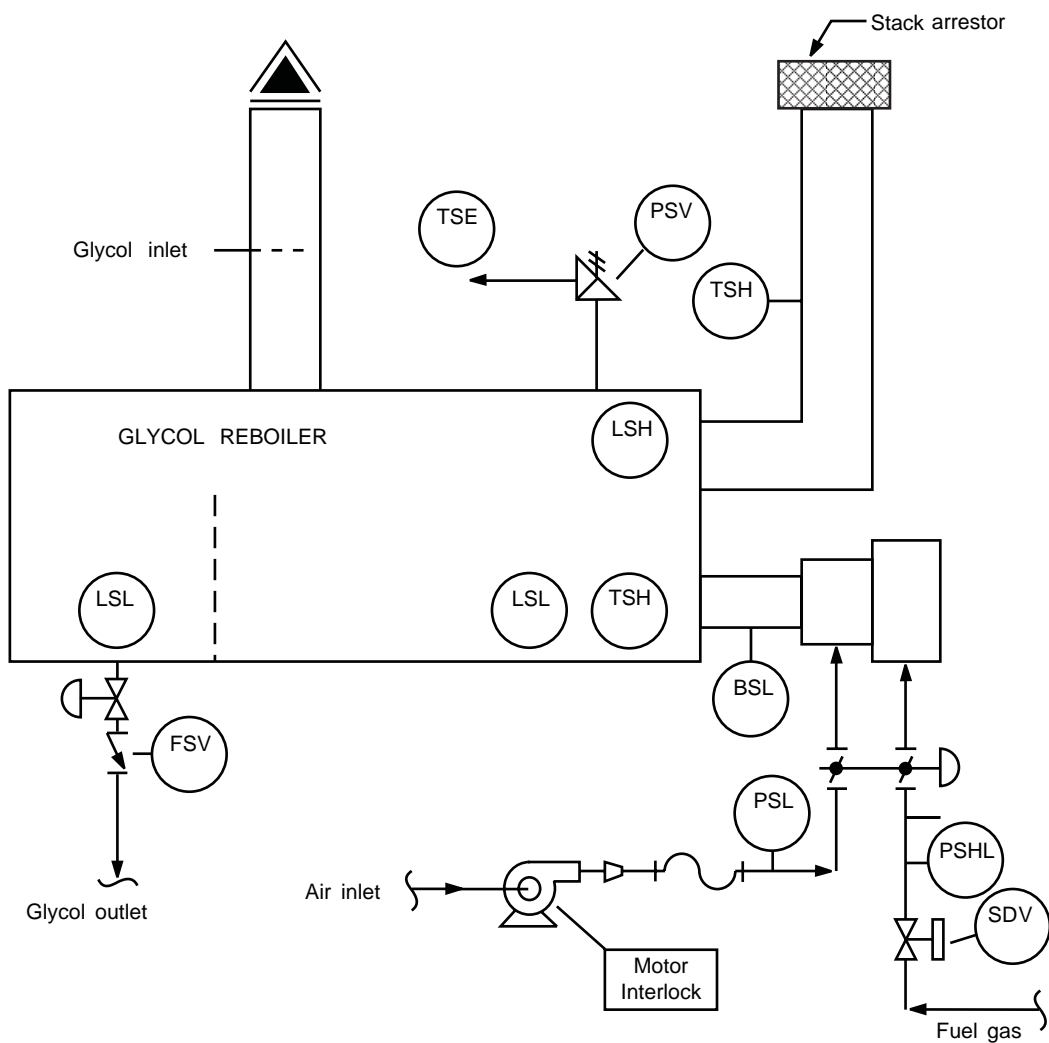
A.6.4 SAFE OPERATING PROCEDURES

In addition to the safety devices indicated in SAC Tables A-4.2, A-5.2, and A-6.2, the procedures shown in the Table A-6.3 are required to safely operate a fired or exhaust heated component.



- Notes:
1. TSE designations are symbolic and are not intended to reflect actual location or quantity.
 2. The vessel portion should be analyzed according to Section A.4 or A.5.

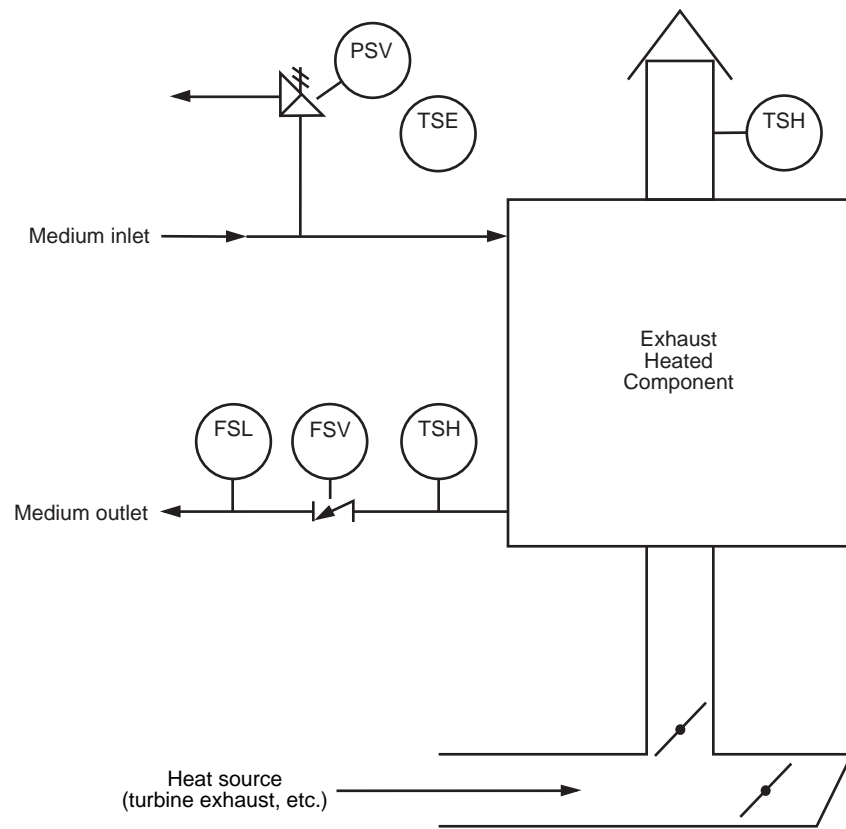
Figure A-6.1—Recommended Safety Devices—Typical Fired Vessel (Natural Draft)



Notes:

1. TSE designations are symbolic and are not intended to reflect actual location or quantity.
2. The vessel portion should be analyzed according to Section A.4 or Section A.5.
3. Stack arrestor could be eliminated— refer to Par. A.6.2.b

Figure A-6.2—Recommended Safety Devices—Typical Fired Vessel (Forced Draft)



Note:

TSE designations are symbolic and are not intended to reflect actual location or quantity.

Figure A-6.3—Recommended Safety Devices—Exhaust Heated Component

Table A-6.1—Safety Analysis Table (SAT)—Fired Components Natural Draft

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Excess temperature	Temperature control system failure	High temperature (process)
	Inadequate flow	High temperature (stack)
	Limited heat transfer	Low flow rate
	Ignition of medium leak into fired	Low liquid level
	Exposed chamber heat transfer surface	
Direct ignition source	Flame emission from air intake	Fire
	Spark emission from exhaust stack	High temperature stack
	Excess stack temperature	
	Exposed hot surface	
Excess combustible vapors in firing chamber	Fuel control system failure	Flame failure
		High fuel pressure

Table A-6.2—Safety Analysis Table (SAT)—Fired Components Forced Draft

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Excess temperature	Temperature control system failure	High temperature (process)
	Inadequate flow	High temperature (stack)
	Limited heat transfer	Low flow rate
	Ignition of medium leak into fired	Low liquid level
	Exposed chamber heat transfer service	
Direct ignition source	Flame emission from air intake	Fire
	Spark emission from exhaust stack	High temperature (stack)
	Excess stack temperature	
	Exposed hot surface	
Excess combustible vapors in firing chamber	Fuel control system failure	Low air pressure
	Air supply control system failure	Flame failure
	Blocked air inlet	High fuel pressure
	Blower failure	Low fuel pressure
		Low air velocity

Table A-6.3—Safety Analysis Table (SAT)—Exhaust Heated Components

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Excess temperature	Temperature control system failure	High temperature (medium)
	Inadequate flow	High temperature (stack)
	Limited heat transfer	Low flow rate
	Ignition of medium leak into	Low liquid level
	Exposed heated chamber heat transfer surface	
Direct ignition source	Spark emission from exhaust stack	High temperature (stack)
	Excess stack temperature	Fire
	Exposed hot surface	

Note: When supplemental firing is used, component should also be analyzed in accordance with Table A-6.1 or Table A-6.2, as applicable.

Table A-6.2—Safety Analysis Checklist (SAC)—Fired and Exhaust Heated Components

-
- a. High Temperature Sensor (medium or process fluid) (TSH).
 - 1. TSH installed.
 - 2. Component is a steam generator protected by a PSH and, if fired, by an LSL.
 - 3. Component is an indirect water bath heater in atmospheric service and is protected by an LSL.
 - b. High Temperature Sensor (stack) (TSH).
 - 1. TSH installed.
 - 2. Component is isolated and does not handle combustible medium or process fluids other than fuel.
 - 3. Component is exhaust heated without supplemental firing and medium is not combustible.
 - c. (Deleted in Second Edition.)
 - d. Low Pressure Sensor (air supply) (PSL).
 - 1. PSL installed.
 - 2. Component is equipped with a natural draft burner.
 - 3. Forced draft burner is equipped with another type of low air supply sensor.
 - 4. Component is exhaust heated without supplemental firing.
 - e. High Pressure Sensor (fuel supply) (PSH).
 - 1. PSH installed.
 - 2. Component is exhaust heated without supplemental firing.
 - f. Low Pressure Sensor (fuel supply) (PSL).
 - 1. PSL installed.
 - 2. Component is equipped with a natural draft burner.
 - 3. Component is exhaust heated without supplemental firing.
 - g. Flame Failure Sensor (BSL).
 - 1. BSL installed.
 - 2. Component is exhaust heated without supplemental firing.
 - h. Low flow Sensor (heated medium) (FSL).
 - 1. FSL installed.
 - 2. Component is not a closed heat transfer type in which a combustible medium flows through tubes located in the firing or exhaust heated chamber.
 - i. Motor Interlock (forced draft fan motor).
 - 1. Motor interlock installed.
 - 2. Component is equipped with a natural draft burner.
 - 3. Component is exhaust heated without supplemental firing.
 - j. Flame Arrestor (air intake).
 - 1. Flame arrestor installed.
 - 2. Component is equipped with a forced draft burner.
 - 3. Component is located in an isolated area and not handling combustible medium or process fluids other than fuel.
 - 4. Component is exhaust heated without supplemental firing.
 - k. Stack Arrestor.
 - 1. Stack arrestor installed.
 - 2. Component is equipped with a forced draft burner and (i) the fluid being heated is non-flammable, or (ii) the burner draft pressure at the exit of the transfer section is higher than the fluid pressure (head).
 - 3. Component is isolated so process fluids will not contact stack emissions.
 - 4. Component is exhaust heated without supplemental firing.
 - l. Pressure Safety Valve (medium circulating tube) (PSV).
 - 1. PSV installed.
 - 2. Component is not a tube type heater.
 - 3. PSV installed on another component will provide necessary protection and the PSV cannot be isolated from the tube section.
 - m. Check Valve (medium circulating tube) (FSV).
 - 1. FSV installed on each outlet.
 - 2. The maximum volume of combustible medium that could backflow from downstream equipment is insignificant, or medium is not combustible.
 - 3. Component is not a tube type heater.

Table A-6.3—Safe Operating Procedures

Assure complete fuel shut off.

Void firing chamber of excess combustibles prior to pilot ignition.

Limit time on trial for ignition of pilot and main burner to prevent excess fuel accumulation in fire chamber. After the time limit is exceeded, the fuel should be shut off and a manual reset start-up required.

Prove pilot and assure fuel-air proportioning dampers and burner controls are in low fire position prior to opening fuel supply to main burner.

Manually reset start-up controls following a flame failure of either the pilot or main burner.

Assure fuel is clean from all residue and foreign materials by providing adequate fuel cleaning equipment.

Assure that exhaust is diverted around exhaust heated component prior to starting up heat source, if applicable.

A.7 Pumps

A.7.1 DESCRIPTION

Pumps transfer liquids within the production process and into pipelines leaving the platform. Pipeline pumps transfer produced hydrocarbons from the process system to a pipeline. Pumps that occasionally transfer small volumes of hydrocarbons from ancillary equipment (swab tanks, sumps, etc.) to a pipeline that receives the bulk of its volume from another source are not considered pipeline pumps. Glycol powered glycol pumps circulate glycol within a closed system. Other pumps transfer produced liquids, heat transfer liquids, or chemicals within the production process system or from the containment system to the process system (booster/charge pumps, sump pumps, chemical injection pumps, heating medium circulating pumps, glycol pumps, etc.). Recommended safety devices for typical pump installations are shown in Figures A-7.1, A-7.2, and A-7.3.

A.7.2 SAFETY ANALYSIS

A.7.2.1 Safety Analysis Table

The Safety Analysis Table (SAT) for pumps is presented in SAT Table A-7.1. The undesirable events that can affect a pump are overpressure and leak.

A.7.2.2 Safety Analysis Checklist

The Safety Analysis Checklist (SAC) for pumps is presented in SAC Table A-7.2.

A.7.2.2.1 Pressure Safety Devices (PSH, PSL, and PSV)

PSH and PSL sensors should be provided on all hydrocarbon pipeline pump discharge lines to shut off inflow and shut down the pump. A PSH sensor to shut down the pump should be provided on the discharge line of other pumps, unless the maximum pump discharge pressure does not exceed 70% of the maximum allowable working pressure of the discharge line or the pump is manually operated and continuously attended. A PSH sensor is not required on glycol powered glycol pumps. Other hydrocarbon pumps should also be provided with a PSL sensor to shut down the pump, unless the pump is manually operated and continuously attended or adequate containment is provided. PSL sensors should be provided on glycol powered glycol pumps to shut off wet glycol flow to the pump.

A PSV should be provided on all pipeline pump discharge lines, unless the pump is a kinetic energy type, such as a centrifugal pump, and is incapable of generating a head greater than the maximum allowable working pressure of the discharge piping. A PSV should be provided in the discharge line of all other pumps unless the maximum pump discharge pressure is less than the maximum allowable working pressure of the line, or the pump has an internal pressure relief capability. A PSV should be provided in the wet glycol low pressure discharge line of glycol powered glycol pumps unless the line is rated higher than the maximum pump discharge pressure or is protected by a PSV on a downstream component that cannot be isolated from the pump.

A.7.2.2.2 Flow Safety Devices (FSV)

A check valve (FSV) should be provided in the pump discharge line to minimize backflow.

A.7.3 SAFETY DEVICE LOCATION

The recommended location for safety devices is given below:

A.7.3.1 Pressure Safety Devices (PSH, PSL, and PSV)

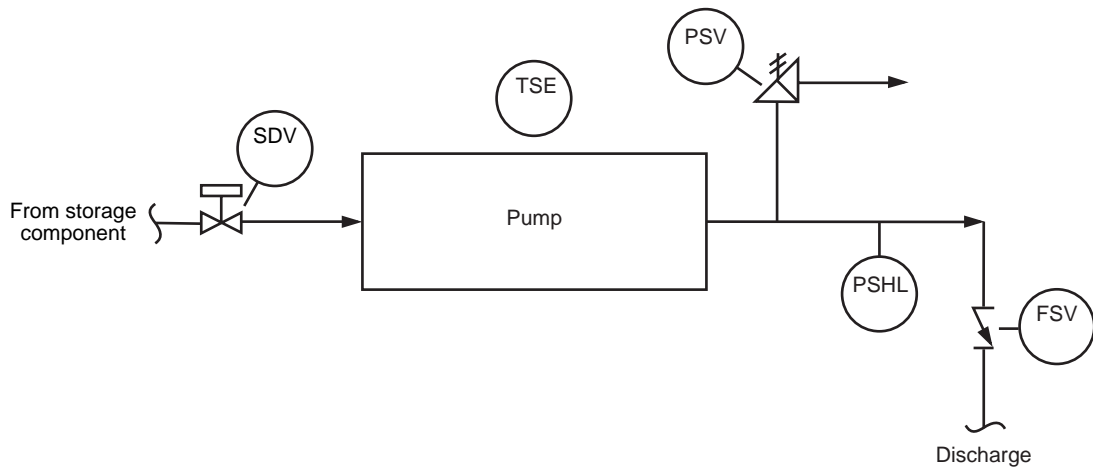
The PSH and PSL sensors should be located on the pump discharge line upstream of the FSV or any block valve. In a glycol powered glycol pump, the PSL on the wet glycol high pressure line should be located between the pump and the SDV. On pipeline pumps and other pumps where it is required, the PSV should be located on the discharge line upstream of any block valve.

A.7.3.2 Flow Safety Devices (FSV)

The check valve (FSV) should be located on the pump discharge line to minimize backflow.

A.7.3.3 Shutdown Devices (SDV)

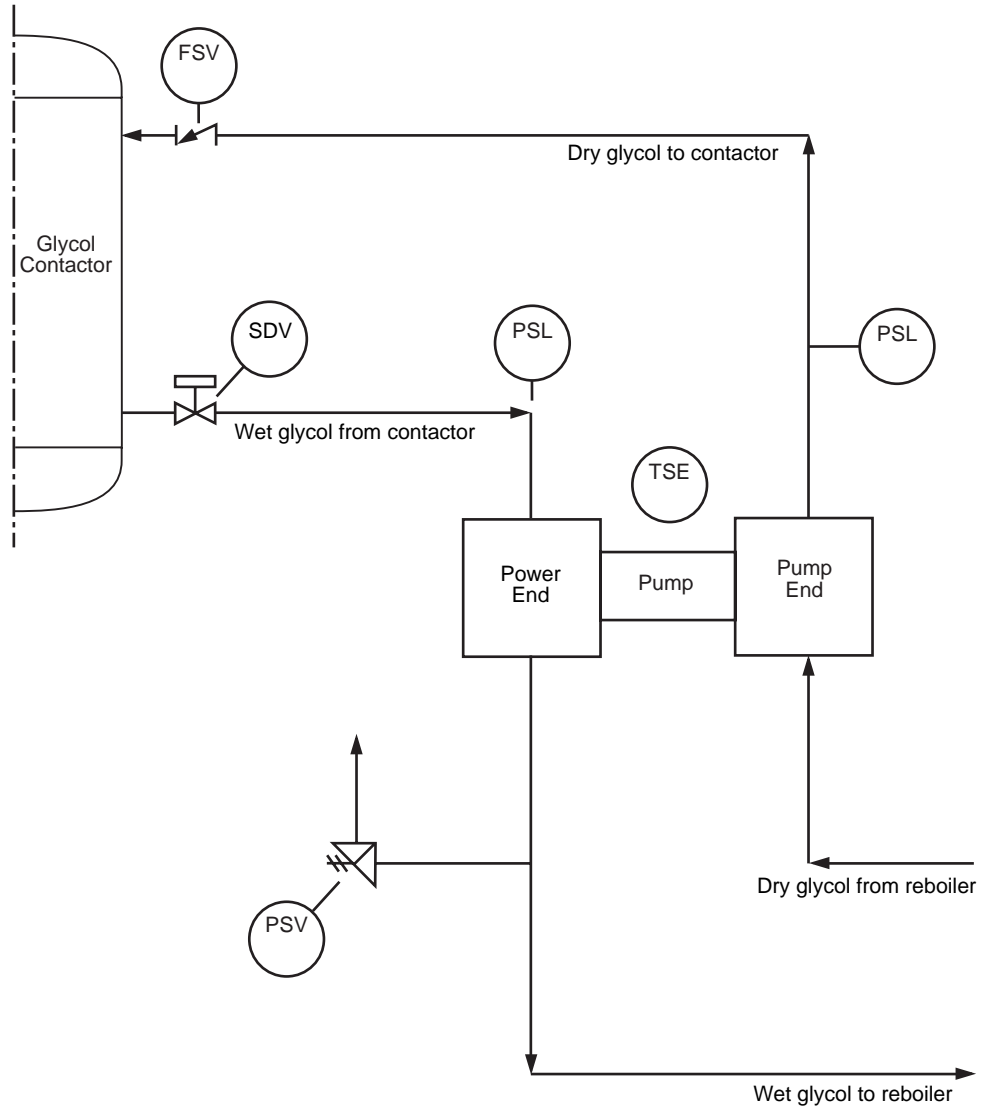
An SDV should be located near the outlet of a storage component (tank, separator, etc.) that delivers production to a pipeline pump to prevent the flow of hydrocarbons through the pipeline pump and into the pipeline in the event of a pipeline leak. When glycol powered pumps are used, a SDV should be located near the high pressure wet glycol outlet of the glycol contactor to shut off flow from the contactor and to shut down the pumps.



Note:
TSE designations are symbolic and are not intended to reflect actual location or quantity.

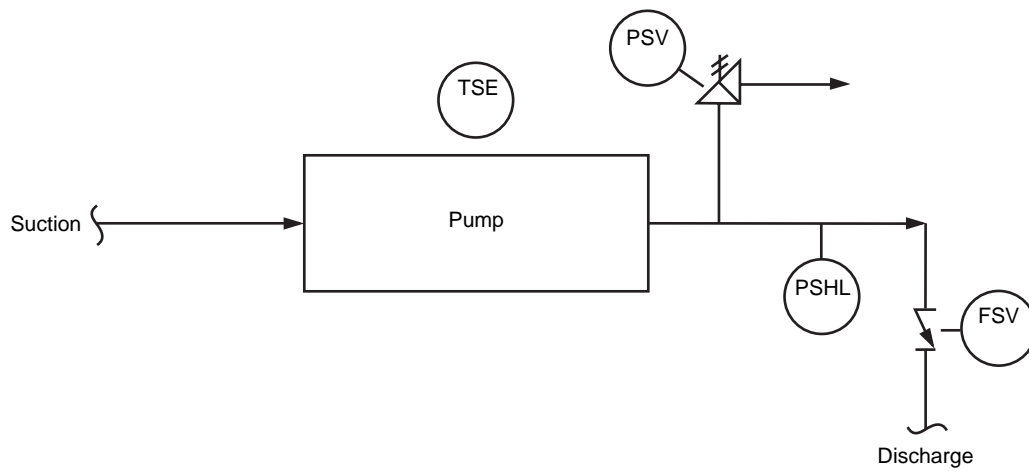
Figure A-7.1—Recommended Safety Devices—Pipeline Pump

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Note:

Figure A-7.2—Recommended Safety Devices—Glycol Powered Glycol Pump



Note:

Figure A-7.3—Recommended Safety Devices—Other Pump

Table A-7.1—Safety Analysis Table (SAT)—Pumps

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Overpressure	Blocked or restricted discharge line Excess back pressure High inlet pressure (centrifugal) Overspeed Fluid density increase	High pressure
Leak	Deterioration Erosion Corrosion Impact damage Vibration	Low pressure

Table A-7.2—Safety Analysis Checklist (SAC)—Pumps

- a. High Pressure Sensor (PSH)—pipeline pumps.
 1. PSH installed.
- b. High Pressure Sensor (PSH)—other pumps.
 1. PSH installed.
 2. Maximum pump discharge pressure does not exceed 70 percent of the maximum allowable working pressure of the discharge piping.
 3. Pump is manually operated and continuously attended.
 4. Small, low volume pumps, e.g. chemical injection.
 5. Pump discharges to an atmospheric vessel.
 6. Pump is a glycol powered glycol pump.
- c. Low Pressure Sensor (PSL)—pipeline pumps.
 1. PSL installed.
 2. Pump does not handle hydrocarbons.
- d. Low Pressure Sensor (PSL)—other pumps.
 1. PSL installed.
 2. Pump is manually operated and continuously attended.
 3. Adequate containment is provided.
 4. Small, low volume pumps, e.g. chemical injection pumps.
 5. Pump discharges to an atmospheric vessel.
- e. Pressure Safety Valves (PSV)—pipeline pumps.
 1. PSV installed.
 2. Pump is kinetic energy type and incapable of generating a head greater than the maximum allowable working pressure of the discharge piping.
- f. Pressure Safety Valves (PSV)—other pumps.
 1. PSV installed.
 2. Maximum pump discharge pressure is less than the maximum allowable working pressure of discharge piping.
 3. Pump has internal pressure relief capability.
 4. Pump is a glycol powered glycol pump, and the wet glycol low pressure discharge piping is rated higher than the maximum discharge pressure.
 5. Pump is a glycol powered glycol pump, and the wet glycol low pressure discharge piping is protected by a PSV on a downstream component that cannot be isolated from the pump.
- g. Check Valve (FSV)—all pumps.
 1. Check valve installed.

A.8 Compressor Units

A.8.1 DESCRIPTION

Compressor units transfer hydrocarbon gases within the production process and into pipelines leaving the platform. Recommended safety devices for a typical compressor unit are shown in Figure A-8.

A.8.2 SAFETY ANALYSIS

A.8.2.1 Safety Analysis Table

The Safety Analysis Table (SAT) for compressor units is presented in SAT Table A-8.1. The SAT analyzes the compressor cylinder or case and the suction, discharge, and fuel gas piping of a compressor unit. Hydrocarbon handling equipment associated with compressors, other than compressor cylinders or cases, should be protected in accordance with appropriate sections of this recommended practice. The compressor and prime mover are normally furnished with devices to prevent mechanical damage. The undesirable events that can affect a compressor unit are overpressure, leak, and excess temperature.

A.8.2.2 Safety Analysis Checklist

The Safety Analysis Checklist (SAC) for compressor units is presented in SAC Table A-8.2.

A.8.2.2.1 Pressure Safety Devices (PSH, PSL, and PSV)

PSH and PSL sensors should be provided on each suction line of a compressor unit unless each input source is protected by PSH and PSL sensors that will also protect the compressor. Also, PSH and PSL sensors should be provided on each compressor discharge line. The PSH and PSL sensors should shut off all process inflow and fuel gas to the compressor. A PSV should be provided on each compressor suction line, unless each input source is protected by a PSV that will protect the compressor. A PSV should be provided on each compressor discharge line. A PSV is not necessary on the discharge of a kinetic energy compressor if the compressor is incapable of developing a pressure greater than the maximum allowable working pressure of the compressor or discharge piping.

A.8.2.2.2 Flow Safety Devices (FSV)

A check valve (FSV) should be provided in each final discharge line to minimize backflow.

A.8.2.2.3 Gas Detecting Devices (ASH)

If a compressor unit is installed in an inadequately ventilated building or enclosure, as defined in C.1.4, gas detectors

(ASHs) should be provided to shut off all process inflow and fuel gas to the compressor and blowdown the compressor.

A.8.2.3 Temperature Safety Devices (TSH)

A TSH sensor should be provided to protect each compressor cylinder or case. The TSH sensor should shut off all process inflow and fuel gas to the compressor.

A.8.3 SAFETY DEVICE LOCATION

The recommended location for safety devices is given in A.8.3.1-A.8.3.5.

A.8.3.1 Pressure Safety Devices (PSH, PSL, and PSV)

The PSH and PSL sensors should be located on each suction line as close to the compressor as is practical, and on each discharge line upstream of the FSV and any block valve. The PSVs should be located on each suction line as close to the compressor as is practical, and on each discharge line so that the PSV cannot be isolated from the compressor. If a PSV is located inside a building, its discharge outlet should be piped to a safe location outside the building.

A.8.3.2 Flow Safety Devices (FSV)

A check valve (FSV) should be located on each compressor unit's final discharge line to minimize backflow. If the compressor unit is inside a building, the FSV should be located outside the building.

A.8.3.3 Gas Detecting Devices (ASH)

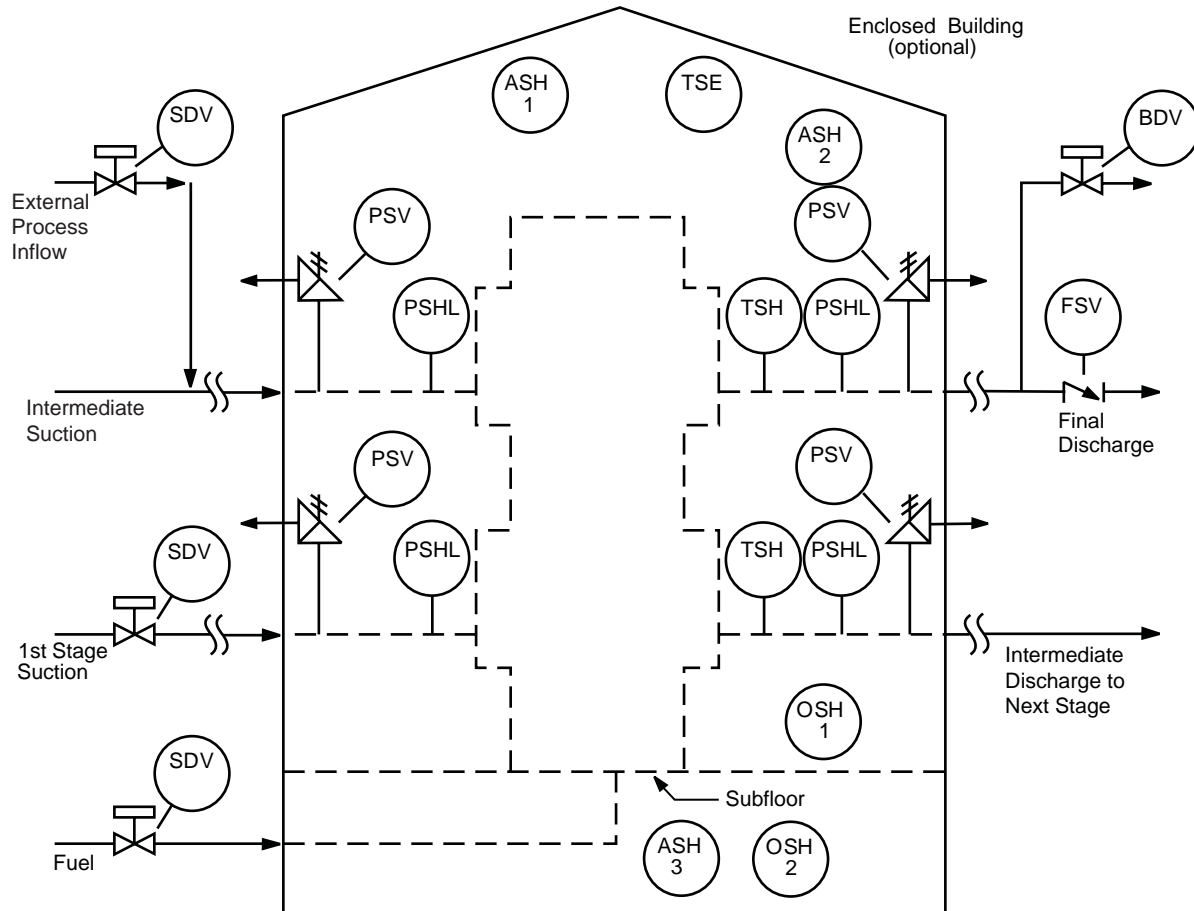
Should the compressor unit be installed in an inadequately ventilated building or enclosure, gas detectors (ASHs) should be located in areas where combustible gases can accumulate.

A.8.3.4 Temperature Safety Devices (TSH)

A TSH sensor should be located in the discharge piping of each compressor cylinder or case as close as practical to the cylinder or case.

A.8.3.5 Shutdown Devices (SDV)

A SDV should be located on each process inflow line and fuel gas line so that the compressor can be isolated from all input sources. If the compressor unit is installed in a building, SDVs should be located outside the building. All SDVs should be actuated by a signal from the ESD system and fire loop, and by any abnormal pressure condition sensed in the suction and discharge lines. A blowdown valve should be located on the compressor unit final discharge line(s). The blowdown valve(s) may be actuated by a signal from the compressor's fire loop, gas detectors, and compressor ESD system.



Notes:

1. TSE designations are symbolic and are not intended to reflect actual location or quantity.
2. ASH 1, 2 & OSH 1, 2 are not required if compressor is not installed in an enclosed building.
3. ASH 3 is not required if compressor does not have piping or other potential source of gas leak below a solid subfloor.
4. Suction scrubbers are not shown; they should be analyzed according to Section A.4.
5. OSH should be considered based on the conditions stated in Appendix F, Pars. F-1.1 and F-1.2.
6. Shell-tube type discharge coolers are not shown; they should be analyzed according to section A.10.

Figure A-8—Recommended Safety Devices—Compressor Unit

Table A-8.1—Safety Analysis Table (SAT)—Compressors

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Overpressure (suction)	Excess inflow Failure of suction pressure control system Compressor or driver malfunction	High pressure
Overpressure (discharge)	Blocked or restricted discharge line Excess back pressure High inlet pressure Overspeed	High pressure
Leak	Deterioration Erosion Corrosion Impact damage Vibration	Low pressure High gas concentration (building)
Excess temperature	Compressor valve failure Cooler failure Excess compression ratio Insufficient flow	High temperature

Table A-8.2—Safety Analysis Checklist (SAC)—Compressors

- a. High Pressure Sensor (PSH)—suction.
 1. PSH installed.
 2. Each input source is protected by a PSH that will also protect the compressor.
- b. High Pressure Sensor (PSH)—discharge.
 1. PSH installed.
 2. Compressor is protected by a downstream PSH, located upstream of any cooler, that cannot be isolated from the compressor.
- c. Low Pressure Sensor (PSL)—suction.
 1. PSL installed.
 2. Each input source is protected by a PSL that will also protect the compressor.
- d. Low Pressure Sensor (PSL)—discharge.
 1. PSL installed.
 2. Compressor is protected by a downstream PSL that cannot be isolated from the compressor.
- e. Pressure Safety Valve (PSV)—suction.
 1. PSV installed.
 2. Each input source is protected by a PSV that will also protect the compressor.
- f. Pressure Safety Valve (PSV)—discharge.
 1. PSV installed.
 2. Compressor is protected by a downstream PSV, located upstream of any cooler, that cannot be isolated from the compressor.
 3. Compressor is kinetic energy type and incapable of generating a pressure greater than the maximum allowable working pressure of the compressor or discharge piping.
- g. Check Valve (FSV)—final discharge.
 1. FSV installed.
- h. High Temperature Sensor (TSH).
 1. TSH installed.

A.9 Pipelines

A.9.1 DESCRIPTION

Offshore pipelines direct liquids and gases between platforms or between a platform and a shore facility. Pipelines are classified as (a) incoming, (b) departing, or (c) bidirectional, depending on the direction of flow at the platform. An incoming pipeline directs fluids onto the platform and a departing pipeline transports fluids from the platform. A bidirectional pipeline can transport fluids in either direction. Pipelines can be further classified according to the delivery or receiving point as follows:

- a. Incoming pipelines:
 1. Deliver to platform facilities.
 2. Deliver to departing pipeline.
- b. Departing pipelines:
 1. Receive from platform facilities.
 2. Receive from incoming pipeline(s).
 3. Receive from both platform facilities and incoming pipeline(s).
- c. Bidirectional pipelines:
 1. Deliver to and receive from platform facilities.
 2. Deliver to and receive from another bidirectional pipeline.
 3. Deliver to and receive from other bidirectional pipelines and receives from platform facilities.

A.9.2 SAFETY ANALYSIS

A.9.2.1 Safety Analysis Table

The Safety Analysis Table (SAT) for pipelines is presented in SAT Table A-9.1. The undesirable events that can affect a pipeline are overpressure and leak.

A.9.2.2 Safety Analysis Checklist

The Safety Analysis Checklist (SAC) for pipelines is presented in SAC Table A-9.2.

A.9.2.2.1 Pressure Safety Devices (PSH, PSL, and PSV)

PSH and PSL sensors are required on departing pipelines to shut off all input sources. PSH and PSL sensors are not provided on an incoming pipeline that is protected by sensors provided at the upstream platform. Bidirectional pipelines should be provided with PSH and PSL sensors. Protection may be provided by PSH and PSL sensors located at each input source or on a parallel component (looped pipeline) if the sensors cannot be isolated from the pipeline.

Each pipeline input source is normally protected by a PSV set also to protect the pipeline. A PSV is not required if (a) the pipeline has a maximum allowable operating pressure greater than the maximum pressure of any input source; (b) each input source having a pressure greater than the pipeline's

maximum allowable operating pressure is protected by a PSV set no higher than the pipeline's maximum allowable operating pressure; or (c) input source is a well(s) having a pressure greater than the pipeline's maximum allowable operating pressure and is equipped with two SDVs (one of which may be the SSV) controlled by independent PSHs connected to separate relays and sensing points. The use of two SDVs in lieu of a PSV should be approached with caution after thorough consideration of other alternatives. In some cases, installation of a PSV in addition to two SDVs might be desirable even at locations having no containment system.

A.9.2.2.2 Flow Safety Devices (FSV)

A FSV is provided on an incoming pipeline to minimize backflow to a leak or rupture in the pipeline, and on a departing pipeline to minimize backflow to a leak or rupture in a component on the platform. When an incoming pipeline connects only to a departing pipeline, the FSV on the departing pipeline also protects the incoming pipeline. A FSV may be eliminated on a departing pipeline if all input sources are equipped with FSVs located so that no significant length of piping is unprotected from backflow from the pipeline. A FSV cannot be installed on a bidirectional pipeline.

A.9.3 SAFETY DEVICE LOCATION

The recommended location for safety devices is given in A.9.3.1-A.9.3.3.

A.9.3.1 Pressure Safety Devices (PSH, PSL, and PSV)

The PSH and PSL sensors should be located downstream of any platform input source and upstream of a departing pipeline FSV. If a PSV is required, it should be located downstream of all input sources and installed so that it cannot be isolated from inlet sources.

A.9.3.2 Flow Safety Devices (FSV)

Incoming pipelines delivering to a platform process station should have a FSV located immediately upstream from the process station. The FSV on a departing pipeline should be located as far downstream as is practical, but upstream of a block valve.

A.9.3.3 Shutdown Devices (SDV)

Pipeline SDVs should be located to minimize the portion of pipeline exposed on the platform. All SDVs should be actuated by the platform ESD system, fire loop, and sensors on any downstream component through which the pipeline fluids flow. The SDV on a pipeline delivering to a departing pipeline should be actuated by the departing pipeline's PSH and PSL sensors, the ESD system, and the fire loop. Bidirectional pipelines should be equipped with SDVs on each platform terminus.

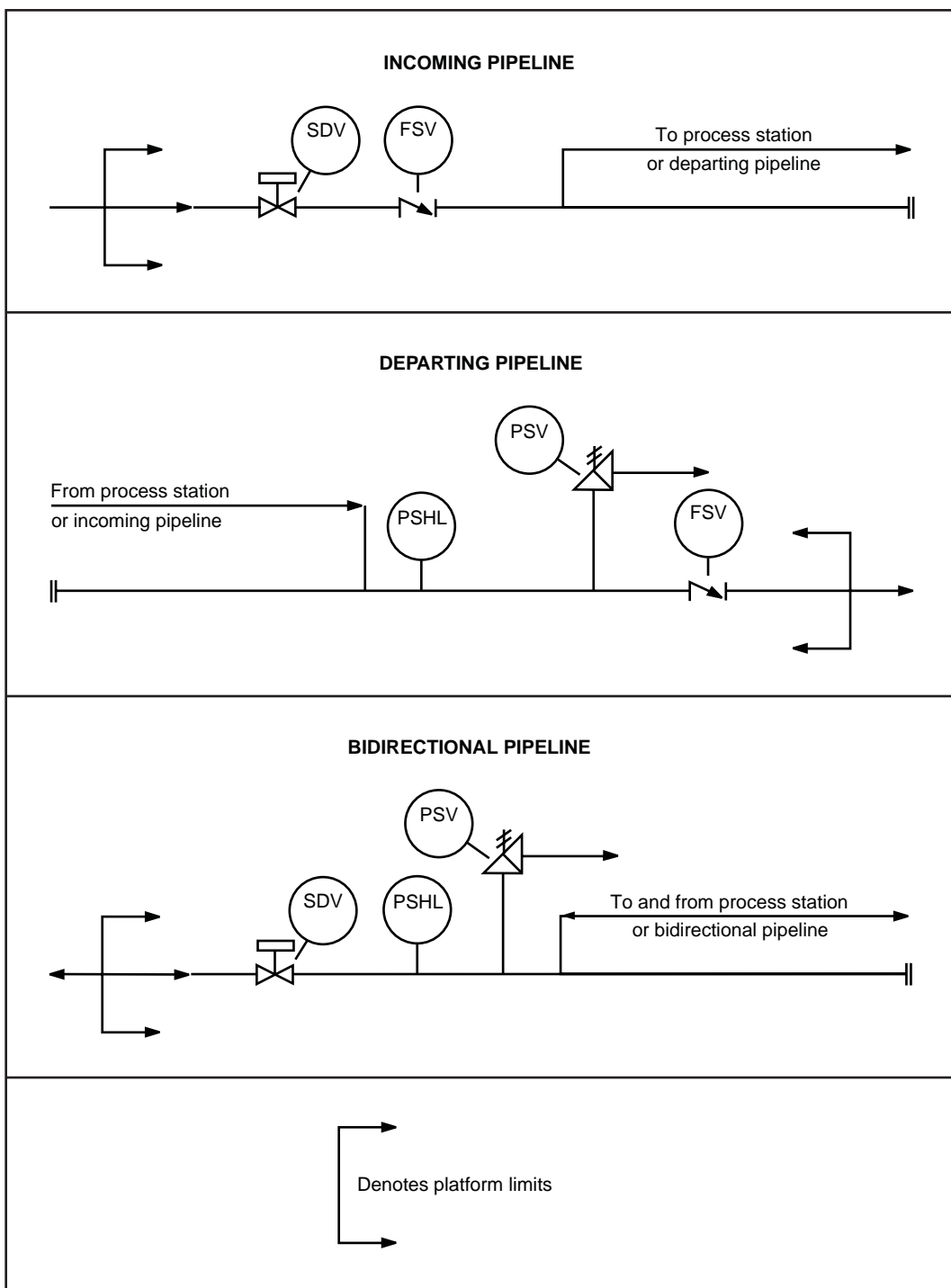


Figure A-9—Recommended Safety Devices—Pipelines

Table A-9.1—Safety Analysis Table (SAT)—Pipelines

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Overpressure	Blocked or restricted line Thermal expansion Inflow exceeds outflow	High pressure
Leak	Deterioration Erosion Corrosion Impact damage Vibration	Low pressure

Table A-9.2—Safety Analysis Checklist (SAC)—Pipelines

- a. High Pressure Sensor (PSH).
 1. PSH installed.
 2. Delivering pipeline protected by PSH located on upstream component.
 3. Each input source is protected by a PSH that also protects a departing or bidirectional pipeline.
 4. The pipeline is protected by a PSH located on a parallel component.
- b. Low Pressure Sensor (PSL).
 1. PSL installed.
 2. Delivering pipeline protected by PSL located on upstream component.
 3. Each input source is protected by a PSL that also protects a departing or bidirectional pipeline.
 4. The pipeline is protected by a PSL located on a parallel component.
- c. Pressure Safety Valve (PSV).
 1. PSV installed.
 2. Pipeline has a maximum allowable operating pressure greater than the maximum pressure of any input source.
 3. Each input source having a pressure greater than the maximum allowable operating pressure of the pipeline is protected by a PSV set no higher than the maximum allowable operating pressure of the pipeline.
 4. The pipeline does not receive input from the platform process.
 5. Input source is a well(s) having a pressure greater than the maximum allowable operating pressure of the pipeline and is equipped with two SDVs (one of which may be the SSV) controlled by independent PSHs connected to separate relays and sensing points. Other input sources having a pressure greater than the maximum allowable operating pressure of the pipeline are protected by PSVs.
- d. Check Valve (FSV).
 1. FSV installed.
 2. Departing pipeline is equipped with an SDV controlled by a PSL.
 3. Each input source is protected by an FSV located so that no significant length of pipeline is unprotected from backflow.
 4. Pipeline is used for bidirectional flow.

A.10 Heat Exchangers (Shell-Tube)

A.10.1 DESCRIPTION

Heat exchangers transfer thermal energy from one flow stream to another while maintaining isolation of the two flow streams. Recommended safety devices for a typical shell-tube heat exchanger are shown in Figure A-10.1. This section does not apply to exchangers used with primary heat sources such as turbine exhaust exchangers that should be analyzed under A.6, "Fired Components." This section may be used to analyze heating or cooling coils inserted into vessels, but the vessels themselves should be analyzed under A.4 or A.5, as appropriate. This section may also be used to analyze heat exchangers using air to cool or heat hydrocarbons, in which case only the hydrocarbon section need be considered.

A.10.2 SAFETY ANALYSIS

A.10.2.1 Safety Analysis Table

The Safety Analysis Table (SAT) for heat exchangers is presented in SAT Table A-10.1. The undesirable events that can affect a heat exchanger are overpressure and leak.

A.10.2.2 Safety Analysis Checklist

The Safety Analysis Checklist (SAC) for exchangers is presented in SAC Table A-10.2.

A.10.2.2.1 Pressure Safety Devices (PSH, PSL, and PSV)

a. In analyzing heat exchangers for pressure safety devices, both sections (the heat receiving section and the heat input section) should be analyzed separately since each section may have different design and operating pressure requirements. A section of a heat exchanger that receives fluids from a source that can cause overpressure should be protected by a PSH sensor to shut off inflow of the source to that section of the heat exchanger. Also, a section of the heat exchanger that could be overpressured because of a rupture or leak of another section of the heat exchanger should be protected by a PSH sensor to shut off inflow of the source of overpressure to that section. The PSH sensor need not be provided for a section of a heat exchanger if an upstream PSH sensor on other process components will sense the pressure in the heat exchanger section and shut off inflow to the heat exchanger, or if a downstream PSH sensor will sense pressure in the heat exchanger section and cannot be isolated. Also, the PSH sensor need not be provided on a section of a heat exchanger if the maximum allowable working pressure of that section is

greater than the potential pressure of any input source to that section.

b. A heat exchanger section containing hydrocarbons should be provided with a PSL sensor to shut off inflow to the heat exchanger when leaks large enough to reduce pressure occur, unless PSL sensors on other components will provide necessary protection and the PSL sensor cannot be isolated from the heat exchanger section when in service. A PSL sensor should not be installed if the heat exchanger section normally operates at atmospheric pressure or frequently varies to atmospheric while in service. In this case, the complexity of lock-out devices to keep the heat exchanger from shutting in during these operating modes could more than offset the protection afforded by the PSL sensor.

c. A heat exchanger section should be provided with a PSV with sufficient capacity to discharge maximum input rates. A PSV need not be provided on a heat exchanger section if PSVs on other process components provide adequate relief capacity, relieve at or below heat exchanger section working pressure, and cannot be isolated from the section when in service. If such PSVs are located on downstream components, they must not be isolated from the heat exchanger section at any time. Also, the PSV need not be provided on a section of a heat exchanger if the maximum allowable working pressure of that section is greater than the potential pressure of any input source to that section. Moreover, if PSVs on other components provide necessary protection when the heat exchanger section is in service, but can be isolated when the heat exchanger section is shut in, a PSV should be installed on the heat exchanger section for pressure relief due to thermal expansion or fire exposure.

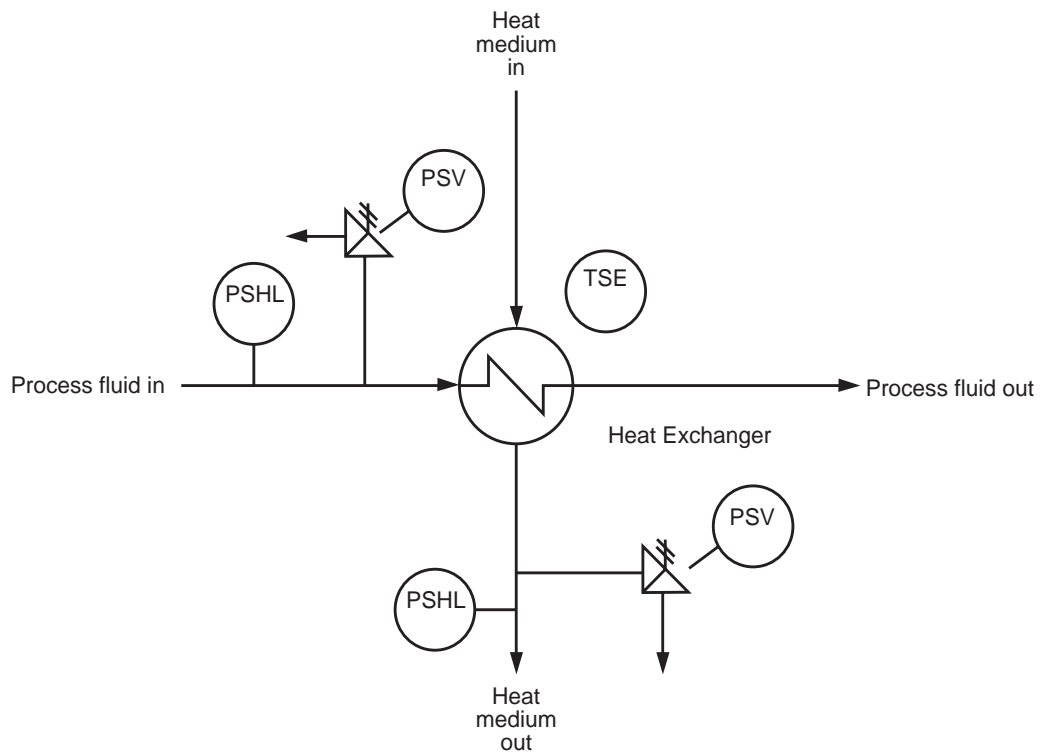
A.10.2.2.2 Temperature Safety Devices (TSH)

A TSH is not generally required in a shell-tube exchanger because both sections are normally rated for the maximum temperature of the heat medium.

A.10.3 SAFETY DEVICE LOCATION —PRESSURE SAFETY DEVICES (PSH, PSL, AND PSV)

A.10.3.1 Pressure Safety Devices (PSH, PSL, and PSV)

The PSH and PSL sensors and the PSV should be located to sense pressure in or relieve it from each section of the heat exchanger. Such devices may be located in the inlet or outlet piping if the pressure drop from the heat exchanger section to the sensing point is negligible and if the devices cannot be isolated from the heat exchanger section.



Note:

TSE designations are symbolic and are not intended to reflect actual location or

Figure A-10—Recommended Safety Devices—Heat Exchangers (Shell-Tube)

Table A-10.1—Safety Analysis Table (SAT)—Heat Exchangers (Shell-Tube)

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Overpressure	Blockage or restriction Inflow exceeds outflow Thermal expansion Tube leak Vaporization	High pressure
Leak	Deterioration Erosion Corrosion Impact damage Vibration	Low pressure

Table A-10.2—Safety Analysis Checklist (SAC)—Heat Exchangers (Shell-Tube)

- a. High Pressure Sensor (PSH).
 1. PSH installed.
 2. Input source to heat exchanger section cannot develop pressure greater than the maximum allowable working pressure of the heat exchanger section.
 3. Each input source is protected by a PSH that also protects the heat exchanger section.
 4. A PSH is installed on a downstream component and cannot be isolated from the heat exchanger section by block or regulating valves.
- b. Low Pressure Sensor (PSL).
 1. PSL installed.
 2. Minimum operating pressure is atmospheric pressure when in service.
 3. PSL installed on another component will provide necessary protection and the PSL cannot be isolated from the heat exchanger section when the heat exchanger is in service.
- c. Pressure Safety Valve (PSV).
 1. PSV installed.
 2. Each input source is protected by a PSV that is set no higher than the maximum allowable working pressure of the heat exchanger section and a PSV is installed on the heat exchanger section for fire exposure and thermal relief.
 3. Each input source is protected by a PSV that is set no higher than the maximum allowable working pressure of the heat exchanger section and that cannot be isolated from the heat exchanger section.
 4. PSVs on downstream equipment can satisfy relief requirement of the heat exchanger section and cannot be isolated from the heat exchanger section.
 5. Deleted in Fourth Edition.
 6. Input sources to the heat exchanger section cannot develop pressure greater than the maximum allowable working pressure of the heat exchanger section and the heat exchanger section cannot be overpressured due to temperature or pressure in the other section.
 7. Each input source is protected by a PSV set no higher than the maximum allowable working pressure of the heat exchanger section and the heat exchanger section cannot be overpressured due to temperature or pressure in the other section.

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APPENDIX B—ANALYSIS TABLES

Table B-1—Safety Analysis Table (SAT)

Undesirable Event	Cause	Detectable Abnormal Condition at Component

Table B-1—Composite Safety Analysis Checklist (SAC)

A.1 Flow Line Segment

- a. High Pressure Sensor (PSH).
 1. PSH installed.
 2. Flow line segment has a maximum allowable working pressure greater than maximum shut in pressure and is protected by a PSH on a downstream flow line segment.
- b. Low Pressure Sensor (PSL).
 1. PSL installed.
 2. Flow line segment is between the well and the first choking device and is less than 10 feet (3m) in length or, in the case of an underwater installation, reasonably close to that distance.
- c. Pressure Safety Valve (PSV).
 1. PSV installed.
 2. Flow line segment has maximum allowable working pressure greater than the maximum shut in pressure.
 3. Two SDVs (one of which may be the SSV) with independent PSHs, relays, and sensing points are installed where there is adequate flow line volume upstream of any block valves to allow sufficient time for the SDVs to close before exceeding the maximum allowable working pressure.
 4. Flow line segment is protected by a PSV on upstream segment.
 5. Flow line segment is protected by a PSV on downstream component that cannot be isolated from the flow line segment and there are no chokes or other restrictions between the flow line segment and the PSV.
- d. Flow Safety Valve (FSV).
 1. FSV installed.
 2. Flow line segment is protected by FSV in final flow line segment.

A.2 Wellhead Injection Lines

- a. High Pressure Sensor (PSH).
 1. PSH installed.
 2. Line and equipment are protected by an upstream PSH.
- b. Low Pressure Sensor (PSL).
 1. PSL installed.
 2. Line and equipment are protected by an upstream PSL.
- c. Pressure Safety Valve (PSV).
 1. PSV installed.
 2. Line and equipment have a maximum allowable working pressure greater than the maximum pressure that can be imposed by the injection source.
 3. Line and equipment are protected by an upstream PSV.
- d. Check Valve (FSV).
 1. FSV(s) installed.

A.3 Headers

- a. High Pressure Sensor (PSH).
 1. PSH installed.
 2. Each input source is equipped with a PSH set less than the maximum allowable working pressure of the header.
 3. Header is protected by downstream PSH that cannot be isolated from the header.
 4. Header is for flare, relief, vent, or other atmospheric service and has no valving in the outlet piping.
- b. Low Pressure Sensor (PSL).
 1. PSL installed.
 2. Each input source is protected by a PSL and there are no pressure control devices or restrictions between the PSL and the header.
 3. Header is for flare, relief, vent, or other atmospheric service.
- c. Pressure Safety Valve (PSV).
 1. PSV installed.
 2. Header has a maximum allowable working pressure greater than the maximum shut in pressure of any connected well.
 3. Pressure relief protection is provided on each input source having a maximum shut in pressure greater than the maximum allowable working pressure of the header.
 4. Header is protected by downstream PSV that cannot be isolated from the header.
 5. Header is for flare, relief, vent, or other atmospheric service and has no valving in the outlet piping.
 6. Input source is a well(s) having a pressure greater than the maximum allowable working pressure of the header and is equipped with two SDVs (one of which may be the SSV) controlled by independent PSHs connected to separate relays and sensing points. Other input sources having a pressure greater than the maximum allowable working pressure of the header are protected by PSVs.

Table B-1—Composite Safety Analysis Checklist (SAC) (Continued)

A.4 Pressure Vessels

- a. High Pressure Sensor (PSH).
 1. PSH installed.
 2. Input is from a pump or compressor that cannot develop pressure greater than the maximum allowable working pressure of the vessel.
 3. Input source is not a wellhead flow line(s), production header, or pipeline and each input source is protected by a PSH that protects the vessel.
 4. Adequately sized piping without block or regulating valves connects gas outlet to downstream equipment protected by a PSH that also protects the upstream vessel.
 5. Vessel is final scrubber in a flare, relief, or vent system and is designed to withstand maximum built up back pressure.
 6. Vessel operates at atmospheric pressure and has an adequate vent system.
- b. Low Pressure Sensor (PSL).
 1. PSL installed.
 2. Minimum operating pressure is atmospheric pressure when in service.
 3. Each input source is protected by a PSL and there are no pressure control devices or restrictions between the PSL(s) and the vessel.
 4. Vessel is scrubber or small trap, is not a process component, and adequate protection is provided by downstream PSL or design function (e.g., vessel is gas scrubber for pneumatic safety systems or final scrubber for flare, relief, or vent system).
 5. Adequately sized piping, without block or regulating valves connects to gas outlet to downstream equipment protected by a PSL that also protects the upstream vessel.
- c. Pressure Safety Valve (PSV).
 1. PSV installed.
 2. Each input source is protected by a PSV set no higher than the maximum allowable working pressure of the vessel and a PSV is installed on the vessel for fire exposure and thermal expansion.
 3. Each input source is protected by a PSV set no higher than the vessel's, at least one of these PSVs cannot be isolated from the vessel.
 4. PSVs on downstream equipment can satisfy relief requirement of the vessel and cannot be isolated from the vessel.
 5. Vessel is final scrubber in a flare, relief, or vent system, is designed to withstand maximum built up back pressure, and has no internal or external obstructions, such as mist extractors or back pressure valves.
 6. Vessel is final scrubber in a flare, relief, or vent system, is designed to withstand maximum built up back pressure, and is equipped with a rupture disk or safety head (PSE) to bypass any internal or external obstructions, such as mist extractor or back pressure valves.
- d. High Level Sensor (LSH).
 1. LSH installed.
 2. Equipment downstream of gas outlet is not a flare or vent system and can safely handle maximum liquid carry-over.
 3. Vessel function does not require handling separated fluid phases.
 4. Vessel is small trap from which liquids are manually drained.
- e. Low Level Sensor (LSL).
 1. LSL installed to protect each liquid outlet.
 2. Liquid level is not automatically maintained in the vessel and the vessel does not have an immersed heating element subject to excess temperature.
 3. Equipment downstream of liquid outlet(s) can safely handle maximum gas rates that can be discharged through the liquid outlet(s) and vessel does not have an immersed heating element subject to excess temperature. Restrictions in the discharge line(s) may be used to limit the gas flow rate.
- f. Check Valve (FSV).
 1. FSV installed on each outlet.
 2. The maximum volume of hydrocarbons that could backflow from downstream equipment is insignificant.
 3. A control device in the line will effectively minimize backflow.
- g. High Temperature Sensor (TSH).

High temperature sensors are applicable only to vessels having a heat source.

 1. TSH installed.
 2. (Deleted in Second Edition.)
 3. Heat source is incapable of causing excess temperature.

Table B-1—Composite Safety Analysis Checklist (SAC) (*Continued*)**A.5 Atmospheric Vessels**

- a. Vent.
 - 1. Vent installed.
- b. Pressure-Vacuum Relief Device (PSV).
 - 1. PSV installed.
 - 2. Vessel has second vent capable of handling maximum gas volume.
 - 3. Component is a pressure vessel, not subject to collapse, that operates in atmospheric service and is equipped with an adequately sized vent.
 - 4. Vessel has no pressure sources (except blanket gas and/or manual drains) and is equipped with an adequately sized vent.
- c. High Level Sensor (LSH).
 - 1. LSH installed.
 - 2. Fill operations are continuously attended.
 - 3. Overflow is diverted or contained by other process components.
- d. Low Level Sensor (LSL).
 - 1. LSL installed.
 - 2. Adequate containment system is provided.
 - 3. Liquid level is not automatically maintained in the vessel and vessel does not have an immersed heating element subject to excess temperature.
 - 4. Component is final vessel in a containment system designed to collect and direct hydrocarbon liquids to a safe location.
- e. High Temperature Sensor (TSH).
High temperature sensors are applicable only to vessels having a heat source.
 - 1. TSH installed.
 - 2. (Deleted in Second Edition.)
 - 3. Heat source is incapable of causing excess temperature.

A.6 Fired and Exhaust Heated Components

- a. High Temperature Sensor (medium or process fluid) (TSH).
 - 1. TSH installed.
 - 2. Component is a steam generator protected by a PSH and, if fired, by a LSL.
 - 3. Component is an indirect water bath heater in atmospheric service and is protected by an LSL.
- b. High Temperature Sensor (stack) (TSH).
 - 1. TSH installed.
 - 2. Component is isolated and does not handle combustible medium or process fluids other than fuel.
 - 3. Component is exhaust heated without supplemental firing and medium is not combustible.
- c. (Deleted in Second Edition.)
- d. Low Pressure Sensor (air supply) (PSL).
 - 1. PSL installed.
 - 2. Component is equipped with a natural draft burner.
 - 3. Forced draft burner is equipped with another type of low air supply sensor.
 - 4. Component is exhaust heated without supplemental firing.
- e. High Pressure Sensor (fuel supply) (PSH).
 - 1. PSH installed.
 - 2. Component is exhaust heated without supplemental firing.
- f. Low Pressure Sensor (fuel supply) (PSL).
 - 1. PSL installed.
 - 2. Component is equipped with a natural draft burner.
 - 3. Component is exhaust heated without supplemental firing.
- g. Flame Failure Sensor (BSL).
 - 1. BSL installed.
 - 2. Component is exhaust heated without supplemental firing.
- h. Low flow Sensor (heated medium) (FSL).
 - 1. FSL installed.
 - 2. Component is not a closed heat transfer type in which a combustible medium flows through tubes located in the firing or exhaust heated chamber.
- i. Motor Interlock (forced draft fan motor).
 - 1. Motor interlock installed.
 - 2. Component is equipped with a natural draft burner.
 - 3. Component is exhaust heated without supplemental firing.

Table B-1—Composite Safety Analysis Checklist (SAC) (Continued)

-
- j. Flame Arrestor (air intake).
 - 1. Flame arrestor installed.
 - 2. Component is equipped with a forced draft burner.
 - 3. Component is located in an isolated area and not handling combustible medium or process fluids other than fuel.
 - 4. Component is exhaust heated without supplemental firing.
 - k. Stack Arrestor.
 - 1. Stack arrestor installed.
 - 2. Component is equipped with a forced draft burner and (i) the fluid being heated is non-flammable, or (ii) the burner draft pressure at the exit of the transfer section is higher than the fluid pressure (head).
 - 3. Component is isolated so process fluids will not contact stack emissions.
 - 4. Component is exhaust heated without supplemental firing.
 - l. Pressure Safety Valve (medium circulating tube) (PSV).
 - 1. PSV installed.
 - 2. Component is not a tube type heater.
 - 3. PSV installed on another component will provide necessary protection and the PSV cannot be isolated from the tube section.
 - m. Check Valve (medium circulating tube) (FSV).
 - 1. FSV installed on each outlet.
 - 2. The maximum volume of combustible media that could backflow from downstream equipment is insignificant, or medium is not combustible.
 - 3. Component is not a tube type heater.

A.7 Pumps

- a. High Pressure Sensor (PSH) pipeline pumps.
 - 1. PSH installed.
- b. High Pressure Sensor (PSH)—other pumps.
 - 1. PSH installed.
 - 2. Maximum pump discharge pressure does not exceed 70 percent of the maximum allowable working pressure of discharge piping.
 - 3. Pump is manually operated and continuously attended.
 - 4. Small, low volume pumps, e.g., chemical injection pumps.
 - 5. Pump discharges to an atmospheric vessel.
 - 6. Pump is a glycol powered glycol pump.
- c. Low Pressure Sensor (PSL)—pipeline pumps.
 - 1. PSL installed.
 - 2. Pump does not handle hydrocarbons.
- d. Low Pressure Sensor (PSL)—other pumps.
 - 1. PSL installed.
 - 2. Pump is manually operated and continuously attended.
 - 3. Adequate containment is provided.
 - 4. Small, low volume pumps, e.g., chemical injection pumps.
 - 5. Pump discharges to an atmospheric vessel.
- e. Pressure Safety Valves (PSV)—pipeline pumps.
 - 1. PSV installed.
 - 2. Pump is kinetic energy type and incapable of generating a head greater than the maximum allowable working pressure of the discharge piping.
- f. Pressure Safety Valves (PSV)—other pumps.
 - 1. PSV installed.
 - 2. Maximum pump discharge pressure is less than the maximum allowable working pressure of discharge piping.
 - 3. Pump has internal pressure relief capability.
 - 4. Pump is a glycol powered glycol pump, and the wet glycol low pressure discharge piping is rated higher than the maximum discharge pressure.
 - 5. Pump is a glycol powered glycol pump, and the wet glycol low pressure discharge piping is protected by a PSV on a downstream component that cannot be isolated from the pump.
- g. Check Valve (FSV)—all pumps.
 - 1. Check valve installed.

Table B-1—Composite Safety Analysis Checklist (SAC) (*Continued*)**A.8 Compressors**

- a. High Pressure Sensor (PSH)—suction.
 - 1. PSH installed.
 - 2. Each input source is protected by a PSH that will also protect the compressor.
- b. High Pressure Sensor (PSH)—discharge.
 - 1. PSH installed.
 - 2. Compressor is protected by a downstream PSH, located upstream of any cooler, that cannot be isolated from the compressor.
- c. Low Pressure Sensor (PSL)—suction.
 - 1. PSL installed.
 - 2. Each input source is protected by a PSL that will also protect the compressor.
- d. Low Pressure Sensor (PSL)—discharge.
 - 1. PSL installed.
 - 2. Compressor is protected by a downstream PSL that cannot be isolated from the compressor.
- e. Pressure Safety Valve (PSV)—suction.
 - 1. PSV installed.
 - 2. Each input source is protected by a PSV that will also protect the compressor.
- f. Pressure Safety Valve (PSV)—discharge.
 - 1. PSV installed.
 - 2. Compressor is protected by a downstream PSV, located upstream of any cooler, that cannot be isolated from the compressor.
 - 3. Compressor is kinetic energy type and incapable of generating a pressure greater than the maximum allowable working pressure of the compressor or discharge piping.
- g. Check Valve (FSV)—final discharge.
 - 1. FSV installed.
- h. High Temperature Sensor (TSH).
 - 1. TSH installed.

A.9 Pipelines

- a. High Pressure Sensor (PSH).
 - 1. PSH installed.
 - 2. Delivering pipeline protected by PSH located on upstream component.
 - 3. Each input source is protected by a PSH that also protects a departing or bidirectional pipeline.
 - 4. The pipeline is protected by a PSH located on a parallel component.
- b. Low Pressure Sensor (PSL).
 - 1. PSL installed.
 - 2. Delivering pipeline protected by PSL located on upstream component.
 - 3. Each input source is protected by a PSL that also protects a departing or bidirectional pipeline.
 - 4. The pipeline is protected by a PSL located on a parallel component.
- c. Pressure Safety Valve (PSV).
 - 1. PSV installed.
 - 2. Pipeline has a maximum allowable operating pressure greater than the maximum pressure of any input source.
 - 3. Each input source having a pressure greater than the maximum allowable operating pressure of the pipeline is protected by a PSV set no higher than the maximum allowable operating pressure of the pipeline.
 - 4. The pipeline does not receive input from the platform process.
 - 5. Input source is a well(s) having a pressure greater than the maximum allowable operating pressure of the pipeline and is equipped with two SDVs (one of which may be the SSV) controlled by independent PSHs connected to separate relays and sensing points. Other input sources having a pressure greater than the maximum allowable operating pressure of the pipeline are protected by PSV.
- d. Check Valve (FSV).
 - 1. FSV installed.
 - 2. Departing pipeline is equipped with an SDV controlled by a PSL.
 - 3. Each input source is protected by an FSV located so that no significant length of pipeline is unprotected from backflow.
 - 4. Pipeline is used for bidirectional flow.

Table B-1—Composite Safety Analysis Checklist (SAC) (Continued)

A.10 Heat Exchangers

- a. High Pressure Sensor (PSH).
 - 1. PSH installed.
 - 2. Input source to heat exchanger section cannot develop pressure greater than the maximum allowable working pressure of the heat exchanger section.
 - 3. Each input source is protected by a PSH that also protects the heat exchanger section.
 - 4. A PSH is installed on a downstream component and cannot be isolated from the heat exchanger section by block or regulating valves.
- b. Low Pressure Sensor (PSL).
 - 1. PSL installed.
 - 2. Minimum operating pressure is atmospheric pressure when in service.
 - 3. PSL installed on another component will provide necessary protection and the PSL cannot be isolated from the heat exchanger section when the heat exchanger is in service.
- c. Pressure Safety Valve (PSV).
 - 1. PSV installed.
 - 2. Each input source is protected by a PSV set no higher than the maximum allowable working pressure of the heat exchanger section and a PSV is installed on the heat exchanger section for fire exposure and thermal relief.
 - 3. Each input source is protected by a PSV that is set no higher than the maximum allowable working pressure of the heat exchanger section and that cannot be isolated from the heat exchanger section.
 - 4. PSVs on downstream equipment can satisfy relief requirement of the heat exchanger section and cannot be isolated from the heat exchanger section.
 - 5. (Deleted in Fourth Edition.)
 - 6. Input sources to the heat exchanger section cannot develop pressure greater than the maximum allowable working pressure of the heat exchanger section and the heat exchanger section cannot be overpressured due to temperature or pressure in the other section.
 - 7. Each input source is protected by a PSV set no higher than the maximum allowable working pressure on the heat exchanger section and the heat exchanger section cannot be overpressured due to temperature or pressure in the other section.

PROCESS COMPONENT		DEVICE I.D.	ALTERNATE PROTECTION		FUNCTION PERFORMED
IDENTIFICATION	SERVICE		SAC REF NUMBER	ALTERNATE DEVICE IF APPLICABLE	
<p style="text-align: center;">SHEET ___ OF ___ SHEETS</p> <p style="text-align: center;">FIGURE B1 SAFETY ANALYSIS FUNCTION EVALUATION CHART (SAFE)</p> <p>PLATFORM IDENTIFICATION _____</p> <p>_____</p> <p>_____</p>		SHUTDOWN OR CONTROL DEVICE I.D.	<p>_____</p> <p>_____</p> <p>_____</p>		

Figure B-1—Safety Analysis Function Evaluation Chart (SAFE)

APPENDIX C—SUPPORT SYSTEMS

Emergency Support Systems (ESS) and other support systems provide a method of performing specific safety functions common to the entire platform. The ESS includes ESD, fire detection, gas detection, ventilation, containment systems and sumps, and SSSV systems. These are essential systems that provide a level of protection to the facility by initiating shut-in functions or reacting to minimize the consequences of released hydrocarbons.

The other support systems include the pneumatic supply systems, systems for discharging gas to the atmosphere, systems for containing leaks or spills, and any other service system that might enhance platform safety. The pneumatic supply system provides a control medium for the safety system, and the systems for discharging gas to the atmosphere provide a means of discharging gases to the atmosphere under safe, controlled conditions.

C.1 Emergency Support Systems (ESS)

C.1.1 EMERGENCY SHUTDOWN (ESD) SYSTEM

C.1.1.1 Purpose

An Emergency Shutdown (ESD) system is a system of manual control stations strategically located on a platform that, when activated, will initiate shutdown of all wells and other process stations. This system may include a number of independent process shutdown systems that can also be actuated separately. Activation of the ESD system should result in the termination of all production activity on the platform, including the closing of all pipeline SDVs. The ESD system should be designed to permit continued operation of electric generating stations and fire fighting systems when needed in an emergency.

The ESD system provides a means for personnel to manually initiate platform shutdown when an abnormal condition is observed. Fusible elements of the fire loop may be integrated with the ESD control loop.

C.1.1.2 Shutdown Stations

Stations for activation of the ESD system for complete platform shutdown should be located as follows:

- a. Helicopter decks.
- b. Exit stairway landings at each deck level.
- c. Boat landings.
- d. At the center or each end of a bridge connecting two platforms.
- e. Emergency evacuation stations.
- f. Near the driller's console during drilling and workover operations.
- g. Near the main exits of living quarters.

h. Other locations as needed to provide stations accessible to all platform areas.

ESD stations should be conveniently located but should be protected against accidental activation. ESD stations should be identified by shutdown function, and the shutdown position should be clearly indicated. The manually operated ESD valve should be quick-opening and non-restricted to enable rapid actuation of the shutdown system. Electric ESD stations should be wired as de-energise to trip or as supervised circuits. Because of the key role of the ESD system in the platform safety system, all ESD components should be of high quality and corrosion resistant. ESD stations at boat landings may utilize a loop of synthetic tubing in lieu of a valve or electric switch.

C.1.2 FIRE DETECTION SYSTEM

C.1.2.1 Purpose

A method of automatically detecting fires on an offshore platform should be provided to allow for early response. Pneumatic fusible element (TSE) systems or various electrical fire detection devices, including flame (USH), thermal (TSH), or smoke (YSH) detection devices, should be installed in all areas classified (Division 1 or 2) by API Recommended Practice 500 and in all buildings where personnel regularly or occasionally sleep.

C.1.2.2 Pneumatic Fusible Element Systems

One reliable and widely used method of detecting fires is a pneumatic line containing strategically located fusible elements. This system should be capable of providing a signal to shut down production activities except for equipment required to control the fire. Fusible elements normally are metallic plugs that melt at a designed temperature or a section of fusible synthetic tubing.

C.1.2.3 Electrical Fire Detection Systems

In addition to pneumatic fusible element systems, various electrical fire detection devices (flame, thermal, and smoke) are commonly used on offshore production platforms. These devices are utilized to activate alarms, initiate shut-in actions, or activate fire suppression systems (e.g., CO₂, or water).

C.1.2.4 Installation and Operation

All electrical fire detection devices should be approved by a nationally recognized testing laboratory and installed in accordance with manufacturer's recommendations. Electrical fire detection devices should be capable of operating a minimum of 8 hours without primary platform electrical power.

The installation and operation of a fire detection system should be suitable for the area it is designed to protect. Fire detection systems should be installed for process equipment, enclosed classified areas, and enclosed unclassified areas as follows:

- a. Process equipment. Table C-1 presents guidelines for the installation of fusible plugs. When fusible tubing or other devices (e.g., ultraviolet flame detectors, infrared sensors, etc.) are used in lieu of fusible plugs, they should provide at least the same coverage as outlined in Table C-1. Fusible elements may be installed in the various pneumatic lines of the safety system if the signal generated initiates the proper shut-in functions. Fusible elements should not be installed in a combustible gas supply line that would continue to bleed after shutdown.
- b. Enclosed classified areas. Enclosed areas that are classified (Division 1 or Division 2) by API Recommended Practice 500 should be equipped with fire (flame, thermal, or smoke) detection devices that automatically shut in the hydrocarbon sources causing the enclosed areas to be classified. A fusible plug system using either combustible or non-combustible gas is acceptable in these areas.
- c. Enclosed unclassified areas. All rooms in which personnel regularly or occasionally sleep should be equipped with smoke detectors that activate an audible alarm. Rooms containing heat sources (e.g., water heaters, clothes dryers, kitchen ranges, ovens, space heaters, etc.) should be equipped with smoke and/or thermal rate of rise detectors that activate an audible alarm. Fusible plug systems utilizing a combustible gas should not be used for fire detection in buildings where personnel regularly or occasionally sleep (even if the building is classified because of its proximity to a hydrocarbon source).

C.1.3 COMBUSTIBLE GAS DETECTION SYSTEM

C.1.3.1 Purpose

The accumulation of combustible gases in the atmosphere on offshore platforms could create a threat to safety. Accumulations are more likely to occur in enclosed areas. Two methods for increasing safety are providing adequate ventilation and installing combustible gas detector systems. The gas detector (ASH) system should alert personnel by audible and/or visual alarm to the presence of low level concentrations of flammable gas or vapor. Also, it should either shut off the gas source or remove all sources of ignition if the concentration approaches the lower explosive limit (LEL) of the gas present.

C.1.3.2 Installation

Combustible gas detecting sensors should be located (a) in all enclosed areas that are classified (Division 1 or Division 2)

by API Recommended Practice 500, (b) in all enclosed areas that contain natural gas-fueled prime movers, and (c) in buildings where personnel regularly or occasionally sleep and that contain a flammable gas source. Gas detection instruments should be approved by a nationally recognized testing laboratory (NRTL) and should meet requirements put forth by ANSI/ISA S12.13, Part I: *Performance Requirements, Combustible Gas Detectors*. Shutdown devices controlled by gas detector systems should be “normally energized” (commonly referred to as “fail-safe”). Gas detection systems should be installed, operated, and maintained in accordance with ANSI/ISA S12.13, Part II: *Installation, Operation, and Maintenance of Combustible Gas Detection Instruments*.

In enclosed areas containing flammable gas compressors, the minimum number of sensors is one per compressor unit, plus an additional sensor per three units or fractional part thereof.

Note: This requires a minimum of two sensors in all enclosed compressor buildings. In enclosed areas containing other natural gas-fueled prime movers (e.g., engines driving generators or pumps), the minimum number of sensors is one per prime mover.

Providing adequate ventilation (refer to C.1.4) is an acceptable alternative to installing gas detection systems except in buildings where personnel regularly or occasionally sleep, or in enclosed areas that contain compressors handling flammable gas. Likewise, gas detection may be omitted in enclosed areas on platforms not provided with continuous AC power if the enclosed area contains no ignition source, contains no compressor handling flammable gas, and is not a building where personnel regularly or occasionally sleep.

C.1.3.3 Operation and Maintenance

Gas detection instruments should be able to detect at least two gas concentration levels. An audible alarm signal (visual signal in high noise areas where an audible alarm is ineffective) should be activated at no greater than 25 percent LEL to alert operating personnel. Automatic corrective action, e.g., closing SDVs on gas sources or disconnecting electrical power to equipment not suitable for locations classified as hazardous, should be initiated at no greater than 60 percent LEL. In lieu of total process shut in, it is acceptable to isolate alarmed areas; an example is closing a fuel valve to a generator building. Careful consideration should be given to the form of automatic corrective action taken to ensure that the situation is not made more hazardous. If machinery or equipment shutdown could create an ignition source, consideration should be given to actuation of a fire inerting system, e.g., Halon, prior to shutdown. Gas detection systems monitoring more than one area should identify the location where flammable gas or vapor is detected.

Note: In special cases, detection at lower concentrations is required to comply with the provisions of API Recommended Practice 500, to reduce the area classification.

C.1.4 ADEQUATE VENTILATION

Adequate ventilation is ventilation (natural or artificial) that is sufficient to prevent the accumulation of significant quantities of vapor-air mixtures in concentrations above 25 percent of their lower explosive limit (LEL). Refer to API Recommended Practice 500 for additional details, including recommended methods of achievement.

C.1.5 CONTAINMENT SYSTEM

A containment system is installed to collect and direct escaped liquid hydrocarbons to a safe location. All equipment subject to leaks or overflow should be protected by curbs, gutters, or drip pans that drain to a sump. Containment systems are optional on structures that do not have process vessels or other equipment subject to leak or overflow (e.g., structures with only wells, headers, pipelines, cranes, and/or instrument gas scrubbers).

All gravity drain piping networks should be designed to prevent escape of gas from sumps through the drains. This is typically accomplished by water seals located at each drain, or each drain pipe header, or with a total network water seal located in the sump inlet piping. Check valves are not considered appropriate for this service and should not be used as alternative protection for water seals. Pressure drains should not be combined with gravity drains prior to sump entry.

C.1.6 SUMPS

C.1.6.1 General

A sump may be a tank, a closed-end pile, or an open-end pile. All sumps should be equipped with an automatic discharge to handle maximum inflow. Vents are installed on atmospheric sumps for the purpose of safely dissipating hydrocarbon vapors. Depending upon design and location, a sump pile vent may fulfill this purpose without a flame arrestor being installed. Due to possible plugging from corrosion, the low flow/low pressure (no static electricity), and distance from potential ignition/flash back sources, a flame arrestor could be eliminated in a sump pile located close to the water level.

C.1.6.2 Open-end Sump Piles

Properly designed open-end sump piles are occasionally used to collect deck drainage or drips and to dispose of treated produced water. Except during emergency upset condition, vessels (e.g. flare scrubbers, condensate accumulators, and various fuel filter scrubbers) should not discharge liquid hydrocarbons directly into an open-end sump pile. Open-end sump piles should be protected against hydrocarbon discharge (overflow and/or underflow). The type of protection should be determined on a case-by-case basis. Some factors

that should be considered include pile length, liquid properties, maximum inflow rate, wave action, and tidal fluctuation.

C.1.7 SUBSURFACE SAFETY VALVES (SSSVs)

SSSVs are installed below the wellhead to prevent uncontrolled well flow in the event of an emergency situation. Sub-surface controlled SSSVs (SSCSV) should shut in if well rate exceeds a predetermined rate that might indicate a large leak. Surface controlled SSSVs (SCSSV) should shut in when activated by an ESD system and/or a fire loop. Guidance for the design and installation of SSSVs is covered in API Recommended Practice 14B.

C.2 Other Support Systems

C.2.1 PNEUMATIC SUPPLY SYSTEM

C.2.1.1 Purpose

The pneumatic supply system provides the control medium for the surface safety system. The platform safety and shut-down systems generally require a power supply at a pressure adequate to operate valve actuators and an instrument supply at a lower pressure.

C.2.1.2 Pneumatic Supply Properties

Proper functioning of the safety system is dependent on the pneumatic supply; therefore, a reliable source of high quality gas is essential. The following are properties of a good pneumatic supply:

- a. Free of liquid hydrocarbons.
- b. Free of water and water vapor.
- c. Free of solids.
- d. Non-corrosive.

C.2.1.3 Pneumatic Supply Sources

Usually, air, natural gas, or nitrogen is the pneumatic control medium. When air is used as a pneumatic supply source, the system should be designed to prevent the mixing of air and hydrocarbon gases from the process or utility systems under both normal and abnormal conditions. If an alternate pneumatic supply source is provided, the alternate medium must be of a composition that will not create a combustible mixture when combined with the primary source.

C.2.1.4 Supply and Response

The pneumatic supply distribution systems should be sized to assure adequate volume and pressure to all safety devices. Pneumatic supply usage should be calculated for the maximum condition that could be experienced at any one time. The time it takes for any safety device (e.g. PSH, BSL, ESD station, etc.) to effect component or platform shutdown

should not exceed 45 seconds. To achieve this response, consideration should be given to pneumatic line sizes, safety device bleed port size and the use of auxiliary quick bleed devices. Pneumatic lines that supply and bleed should be sized for optimum bleed conditions. Because of volume and flow characteristics a line that is either too large or too small will require excessive time to bleed. API Recommended Practice 550 should be used as a guide when designing instrument and control systems.

C.2.2 SYSTEMS FOR DISCHARGING GAS TO ATMOSPHERE

C.2.2.1 Purpose

Systems for discharging gas to the atmosphere provide a means for conducting discharged gas from process components under normal conditions (flare, vent) and abnormal conditions (relief) to safe locations for final release to the atmosphere. These should be locations where the gas will be diluted with air to below the LEL so it will not be a threat to the facility or where it can safely be burned.

C.2.2.2 Description

These systems originate at the normal gas exit or pressure relief device of a process component and terminate at the designated safe locations. They can vary from an exit nipple on an individual PSV or control valve to a piping network connected to the outlet of several valves. If gas is discharged from a pressure vessel during normal operation (flare, vent), a scrubbing vessel should be provided to remove liquid hydrocarbons.

C.2.2.3 Discharge Point

The final discharge point for atmospheric gas may be through a vertical, cantilevered, or underwater pipe. In some cases the discharge point may be remote from the platform. The following should be considered in selecting a safe discharge point:

- a. Personnel safety.
- b. The discharge volume.
- c. The location in relation to other equipment, particularly fired vessels or other ignition sources, personnel quarters, fresh air intake systems, and helicopter and boat approaches.
- d. Prevailing wind direction and, in the case of underwater discharges, the prevailing current.

C.2.2.4 Design Considerations

Atmospheric gas discharge systems should be designed in accordance with API Recommended Practice 520 and API Recommended Practice 521, API Specification 2000, and Section VIII of the ASME *Boiler and Pressure Vessel Code*. Systems should be designed so that back pressure, including inertial forces developed at maximum instantaneous flow conditions, will not exceed the working pressure of the lowest pressure rated item. Flame arrestors can be used in vent systems to reduce the danger of combustion within the component from an external source. A flare scrubber should be a pressure vessel designed to handle maximum anticipated flow.

Table C-1—Guidelines for Fusible Plug Installations

Component	Fusible Plug Arrangement	Minimum Number of Plugs
Wellheads	One for each wellhead ^b	—
Headers	One for each 10 feet (3m) of header length ^b	2
Pressure vessels:		1
Vertical vessel	One for each 12 inches (0.3m) of OD to a maximum of five.	
Horizontal vessel	a. Less than 48 inches (1.2m) OD—One for each 5 feet (1.5m) of length. b. Greater than 48 inches (1.2m) OD—two for each 5 feet (1.5m) of length in two parallel rows.	2 4
Atmospheric vessels	One for each vessel process inlet, outlet, and hatch.	—
Fired vessels and exhaust heated components	Same as pressure vessels. Additionally, one outside the flame arrestor on fired components.	—
Heat exchangers (shell-tube)	One for each end of heat exchanger.	2
Pumps:		—
Reciprocating	One over rod packing.	
Centrifugal	One over each packing box.	—
Compressors:		—
Reciprocating	One for each cylinder ^a	
Centrifugal	One over compressor case.	—
Engines:		—
Spark ignition	One over each carburetor or fuel injection valve ^a	
Diesel	One for pump supplying injectors ^a	—
Combustion turbines	One for each fuel solenoid, governor valve, and PTO pump	—

^aOr equivalent coverage.

^bNot applicable to underwater wellheads or headers.

Note: When fusible tubing or other devices (such as ultraviolet flame detectors, etc.) are used instead of fusible plugs, they should provide at least the same coverage as outlined above.

APPENDIX D—TESTING AND REPORTING PROCEDURES

Performance testing provides a practical method of confirming the system's ability to perform the design safety functions. On initial installation, tests should be conducted to verify that the entire system, including the final shutdown valve or control device, is designed and installed to provide proper response to abnormal conditions. Thereafter, periodic operational tests should be performed, at least annually, to substantiate the integrity of the entire system, including process station or platform shutdown, if necessary. Specific test procedures for individual safety devices are presented in Table D-2. A reporting method should provide for orderly accumulation of test data that can be used for operational analyses, reliability studies, and reports that may be required by regulatory agencies.

D.1 Design and Installation Verification

D.1.1 PURPOSE

Before a production system is placed in initial operation, or when re-commissioning a platform after being shut in for 30 days or more, or when a modification is made to the platform safety system, the complete safety system should be thoroughly checked to verify that each device is installed, operable, performs its design function and, if applicable, is calibrated for the specific operating conditions.

D.1.2 SAFETY ANALYSIS FUNCTION EVALUATION (SAFE) CHART

The Safety Analysis Function Evaluation (SAFE) chart shown in Figure B-1 of Appendix B and discussed in 4.3.3 provides a checklist for the initial design and installation verification. Each sensing device is listed in the column headed "DEVICE I.D.," and its respective control function is indicated under the column headed "FUNCTION PERFORMED." It must be determined that a safety device is operable, properly calibrated, and accomplishes the design control function within the prescribed time period. This fact can be noted on the SAFE Chart. When all initiating devices have been tested and their "function performed" confirmed, the design and installation is verified.

D.2 Safety System Testing

D.2.1 PURPOSE

Safety Systems should be tested to verify that each sensing device operates within established limits and the control circuit performs its shutdown function as specified. Testing is required to maintain the reliability of the safety system; in systems subjected to higher stresses (corrosion, heat, etc.),

test intervals may need to be shortened to maintain the reliability of the system.

D.2.2 FREQUENCY

Safety devices and systems should be tested at specified regular intervals at least annually. Recommended test intervals for pressure safety high and pressure safety low sensors (PSHLs) and level safety high and level safety low sensors (LSHLs) are as follows:

Monthly (once each calendar month)

- (1) PSHLs (pneumatic/electronic switch)
- (2) LSHLs (pneumatic/electronic switch/electric analog with mechanical linkage)

Quarterly (Every third calendar month)

- (1) PSHLs (Electronic analog transmitters connected to programmable electronic systems)
- (2) LSHLs (Electronic analog transmitters connected to programmable electronic systems)

It should be noted that these recommended test intervals do not supersede the testing requirements for testing safety systems when initially installed or modified as outlined in Paragraph D.1.1 of this appendix.

Alternative test intervals may be established based on field experience, operator's policy, or governmental regulations. In order to establish a alternative test interval beyond the frequency recommended herein or outside of those dictated by governmental regulations, the alternative test interval should ensure device reliability equal to or greater than the reliability demonstrated by the recommended/required test frequency. The following parameters should be verified and documented in order to justify use of such a test interval:

1. A *statistical analysis* of the test history of the specific devices to develop a device failure probability, or conversely, device reliability, and should likewise define the optimum test frequency to insure device repeatability.
2. A comprehensive *historical testing record* for each device to support the statistical analysis. The historical records should be maintained in a database that records and reports the results of the device testing and inspection.
3. A *monitoring program* based on the results of the statistical analysis to establish acceptance criteria for devices in this program as well as methods to continuously monitor, review and update test results to verify that the established level of device reliability is maintained.

D.2.3 SENSOR TESTING

Safety device tests should confirm that sensors properly detect the abnormal conditions and transmit a signal to perform specific shutdown functions. Sensors are usually tested

by simulating an abnormal condition that the device senses to initiate shutdown functions.

D.2.4 SHUTDOWN DEVICE AND CONTROL CIRCUIT TESTING

Shutdown valves and other shutdown controls should be tested to ensure they receive the signal transmitted by the sensor and perform their design function. Before testing a sensor, the final shutdown or control device activated by the sensor may be de-activated or bypassed to prevent actual shutdown of the process station or platform. However, the entire shutdown or control circuit, including the final shutdown valve or control device, should be tested at least annually.

D.2.5 AUXILIARY DEVICES

All auxiliary devices in the safety system between the sensing device and the final shut-in device should be tested at least annually to verify the integrity of the entire shutdown system. These devices, including master or intermediate panels, should be tested in addition to the sensing devices.

D.2.6 INSTALLATION FOR TESTING

Devices should be installed with operational testing in mind. Test bypasses may be installed so that individual devices or entire circuits can be tested without actual shutdowns. Safety devices should be located for easy access, and multiple device test manifolds and quick connect fittings should be considered to minimize test time. Consideration must be given to platform and safety systems design and operation while safety devices are bypassed.

D.2.7 TEST PROCEDURES

Due to the varied makeup of individual shutdown systems and control circuits, no attempt is made here to describe the steps for testing these systems. However, the individual operators should be responsible for identifying these procedures for each installation. Testing of common safety devices should be performed in accordance with test procedures shown in Table D-2.

- a. The many types and models of safety devices preclude detailed procedures for each; however, general test procedures for the principal types will cover most safety devices. If a device in use is not covered or does not fit the general procedures, specific test procedures should be developed by the operator.
- b. Because of the many possible equipment arrangements, test procedure steps to deactivate a shutdown or control device or to take a component out of service during testing are not given. Devices or equipment taken out of service for testing should be clearly tagged to minimize the possibility of their being left in an inactive condition.

D.2.8 PERSONNEL QUALIFICATION

Testing of surface safety systems should be performed only by a qualified person.

D.2.9 DEFICIENT DEVICES

A safety device that fails, malfunctions, or is otherwise found inoperable during the test procedure should be promptly replaced, repaired, adjusted, or calibrated, as appropriate. Until such action can be completed, the device should be clearly tagged as inoperable and equivalent surveillance should be provided, the process component taken out of service, or the platform shut in.

D.3 Test Tolerances

D.3.1 SAFETY RELIEF VALVE (PSV)

PSV set pressure tolerances are plus or minus 2 psi (14 kPa) for pressure up to and including 70 psi (480 kPa), and plus or minus 3 percent for pressure above 70 psi (480 kPa).

D.3.2 HIGH AND LOW PRESSURE SENSOR (PSHL)

PSHL set pressure tolerance for set pressures greater than 5 psi (35 kPa) is plus or minus 5 percent or 5 psi (35 kPa), whichever is greater; however, the trip pressure should not exceed the pressure rating of the equipment protected. A PSHL with a set pressure of 5 psi (35 kPa) or less must function properly within the service range for which it is installed.

D.3.3 HIGH LEVEL SENSOR (LSH)

An LSH must operate with sufficient remaining volume in vessel to prevent carry-over before shut in. Test tolerance for analog level transmitters is ± 3 inches (7.5 cm) of the LSH set point.

D.3.4 LOW LEVEL SENSOR (LSL)

An LSL must operate with sufficient liquid volume above the highest liquid discharge to prevent gas discharge into liquid outlet before shut in. Test tolerance for analog level transmitters is ± 3 inches (7.5 cm) of the LSL set point.

D.3.5 COMBUSTIBLE GAS DETECTOR (ASH)

ASH set point tolerance is plus or minus 5 percent of full scale reading; however, the trip point must not exceed 60 percent of LEL at the high level setting or 25 percent of LEL at the low level setting.

D.3.6 FLOW LINE CHECK VALVE (FSV)

Flowline FSVs should be tested for leakage. If sustained liquid flow exceeds 400 cc/min. or gas flow exceeds 15 cubic

feet/min. (0.4 cubic meter/min.), the valve should be repaired or replaced.

D.3.7 HIGH AND LOW TEMPERATURE SENSOR (TSHL)

If temperature devices are used to initiate shutdown in the event of fire or surface temperatures approaching ignition temperature, the danger point is usually much higher than normal operating temperature. Thus, the instrument may be checked at one point on the scale, as described in Table D-2, and the set point adjusted sufficiently below the danger point to assure that any working instrument will operate before reaching the danger point. If the set temperature is near the operating temperature range, specific test tolerances should be established. Calibration and testing procedures discussed in this section are not applicable to eutectic devices.

D.3.8 TOXIC GAS DETECTOR (OSH)

OSH set point tolerance shall not vary from the test gas concentration (known to a tolerance of 5 percent or 1 ppm, whichever is greater) by more than 2 ppm or 10 percent.

D.4 Reporting Methods

D.4.1 PURPOSE

Safety device test result records should be maintained in a manner that will enable the performance of operational analyses and equipment reliability studies, and the providing of reports that are required by regulatory agencies. These records should document that standards and regulatory requirements are met.

D.4.2 TEST INFORMATION

The minimum test information for different safety devices is shown in Table D-1. Test results and operating conditions must be recorded to adequately assess the performance of safety devices.

D.4.3 DEFICIENT DEVICES

Records of deficient devices are essential for reliability analyses. As a minimum, the record should include the cause of the deficiency in addition to the data required in Table D-1.

Table D-1—Safety Device Test Data Safety Device

DATA	ASH	ESD	FSV	LSH	LSL	PSH	PSL	PSV	SDV	SSV	TSH	TSL	BSL	BDV	USV	OSH
Device Identification	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Maximum W.P.						X	X	X								
Operating Range						X	X				X	X				
Response Time		X														
Required Setting	X					X	X	X			X	X				X
Observed Setting	X					X	X	X			X	X				X
Adjusted Setting	X					X	X	X			X	X				X
Proper Operation				X	X				X	X			X	X	X	
Proper Calibration	X															X
Leakage			X							X					X	
Corrective Action if Required	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

Table D-2—Safety Device Test Procedures

-
- a. Burner Flame Detector (BSL).
1. To check pilot flame-out control:
 - (a) Light pilot.
 - (b) Block fuel supply to main burner.
 - (c) Shut off fuel supply to pilot and check BSL for detection.
 2. To check burner flame-out control:
 - (a) Light main burner.
 - (b) Block fuel supply to pilot.
 - (c) Shut off fuel supply to main burner and check BSL for detection.
- b. Combustible Gas Detector (ASH).
1. Adjust the zero control, if necessary, so that meter reads 0% LEL with all gas positively eliminated from sensor.
 2. Place sensing adapter of portable purge calibrator over probe head and open shut-off valve on sample container.
 3. When meter reaches maximum level and stabilizes, record meter reading, calibration gas concentration, low alarm and high shutdown set points (% LEL).
 4. If necessary, adjust meter to read % LEL of calibration gas.
 5. Close shut-off valve on sample container and remove sensing adapter.
 6. Actuate test control or zero control, as appropriate, and observe low and high trip points. Check shutdown relay for actuation.
- c. Emergency Shutdown System (ESD).
1. Operate a manual remote station, preferably one at the boat landing, and observe that appropriate shut in relays operate. This may be done individually or as a group, depending on platform design, in order to avoid actual platform shutdown, unless desired. Record the time (seconds) after operating the manual remote station for a flowline surface valve to close.
 2. Check each ESD station by moving valve handle to the shutdown position. Observe for free valve movement and unobstructed gas bleed. Limit bleed to prevent actual shutdown.
- d. Flow Line Check Valve (FSV).
1. Close upstream valve and associated header valves.
 2. Open bleeder valve and bleed pressure from flow line between closed valves.
 3. Close bleeder valve.
 4. Open appropriate header valve.
 5. Open bleeder valve.
 6. Check bleed valve for back flow. If there is a continuous backflow from bleeder valve, measure the flow rate. Rate should not exceed 400 cc/min. or 15 cubic feet/min. (0.4 cubic meter/min.)
 7. Close bleeder valve and open upstream valve.
- e. High and Low level Sensors (LSH) and (LSL)—installed internally.
1. Manually control vessel dump valve to raise liquid level to high level trip point while observing level liquid in gauge glass.
 2. Manually control vessel dump valve to lower liquid level to low level trip point while observing liquid level in gauge glass.
- Alternate procedure 1:
1. Open fill line valve and fill vessel to high level trip point.
 2. Close fill line valve.
 3. Drain vessel to low level trip point.
- Alternate procedure 2: (for pressure differential transmitter used for level sensors)
- Note: Source pressures utilized for testing transmitters must be external sources separate from the process, utilizing test gauges to observe trip points and verify the zero and span of the transmitters.
1. Close valve connecting high side of transmitter to vessel.
 2. Close valve connecting low side of transmitter to vessel.
 3. Connect external test pressure source to high side of transmitter. External pressure source shall have means to measure pressure (or equivalent level) utilizing an external test gauge.
 4. Vent to atmosphere low side of transmitter.
 5. Introduce pressure at high side of transmitter equal to high liquid level and verify LSH actuates within test tolerance.
 6. Introduce pressure at high side of transmitter equal to low liquid level and verify LSL actuates within test tolerance.
 7. Disconnect test pressure source.
 8. Close vent valve of low side of transmitter.
 9. Open valves to vessel and return transmitter to service.
- Note: For transmitters without low side connections to vessel, steps 2,4 and 8 can be omitted.
- f. High and Low Level Sensors (LSH) and (LSL)—installed in outside cages.
1. Close isolating valve on float cage(s).
 2. Fill cage(s) with liquid to high level trip point.
 3. Drain cage(s) to low level trip point.
 4. Open cage(s) isolating valves.

Table D-2—Safety Device Test Procedures (*Continued*)

-
- Alternate procedure:
1. Close isolating valve on float cage(s).
 2. Drain cage to low level trip point.
 3. Open lower cage isolating valve.
 4. Slowly bleed pressure from the top of the cage, allowing vessel pressure to push fluid from inside the vessel to the high level trip point.
 5. Open upper cage isolating valve.
- g. High and Low Pressure Sensors (PSH) and (PSL)—external pressure test.
1. Close isolating valve on pressure sensing connection.
 2. Apply pressure to sensor(s) with a hydraulic pump, high-pressure gas or nitrogen, and record sensor trip pressure observed from an external test gauge.
 3. If sensors are installed in series with the high sensor upstream from the low sensor, bleed pressure to reset the high sensor. Bleed pressure from sensors and record low sensor trip pressure.
 4. Adjust sensor, if required, to provide proper set pressure.
 5. Open sensor isolating valve.
- h. High and Low Pressure Sensors (PSH) and (PSL)—bench test.
1. Mount sensors on a test stand and connect pneumatic supply.
 2. Apply pressure as indicated:
 - (a) High pressure sensor (PSH). Apply pressure to sensor with hydraulic pump, high pressure gas or nitrogen bottle, and record high sensor trip pressure.
 - (b) Low pressure sensor (PSL). Apply pressure above set pressure and bleed pressure, and record pressure at which low sensor trips.
 3. Tag sensor with set pressure and date.
- i. Safety Relief Valve (PSV)—external pressure test.
1. Remove lock or seal and close inlet isolating block valve. (Not required for PSVs isolated by reverse buckling rupture disc or check valve or pilot operated PSVs.)
 2. Apply pressure through test connection with nitrogen, high pressure gas or hydraulic pump, and record pressure at which the relief valve or pilot starts to relieve.
 3. The safety valve or pilot should continue relieving down to reseal pressure. Hold test connection intact until the pressure stops dropping to ensure that valve has reseated.
 4. Open inlet isolating block valve and lock or seal.
- j. Safety Relief Valve (PSV)—bench test.
1. Mount on a test stand.
 2. Apply pressure through test connection with nitrogen, high pressure gas, or a hydraulic pump, and record pressure at which the relief valve starts to relieve test pressure.
 3. The safety valve should continue relieving down to reseal pressure. Hold test connections intact until the pressure stops dropping to ensure that valve has reseated.
 4. Tag PSV with the set pressure and the date of test.
- k. Pipeline and Process Shutdown Valve (SDV).
- Option 1—operation test.
1. Bleed pressure off the actuator and allow valve to reach three-quarter closed position.
 2. Return supply pressure to actuator.
- Option 2—Full valve closure test.
1. Initiate signal to close SDV from either remote or local switch.
 2. Close SDV.
 3. Open SDV.
- l. Surface Safety Valve (SSV) operation test.
1. Shut in well.
 2. Close SSV.
 3. Open SSV.
 4. Return well to production.
- m. Surface Safety Valve (SSV)—pressure holding test.
1. Shut in well and SSV as for operations test.
 2. Position wing and flow line valves to permit pressure to be bled off downstream of SSV.
 3. With pressure on upstream side of SSV, open bleed valve downstream of SSV and check for continuous flow. If sustained liquid flow exceeds 400 cc/min. or gas flow exceeds 15 cubic feet/min. (.4 cubic meter/min.) during the pressure holding test, the SSV should be repaired or replaced.
 4. Close bleeder valve.
 5. Return well to production.
- n. High and Low Temperature (TSHL)—operation test.
1. Adjust set point until controller trips.
 2. Reset controller set point based on observed temperature as follows:
 - (a) Indicating controller—Add or subtract the difference between indicated temperature and trip temperature to the desired trip temperature.
 - (b) Non-indicating controller with graduated dials—Add or subtract the difference between dial reading at trip point and actual temperature to calculate the desired trip setting.
 - (c) Devices that neither indicate nor have graduated dials—Reset according to manufacturer's instructions.

Table D-2—Safety Device Test Procedures (*Continued*)

-
- o. High and Low Temperature (TSHL)—temperature bath test.
1. Remove temperature sensing probe.
 2. Place a thermometer in a hot liquid bath.
 3. Insert temperature sensing probe in the liquid bath and set manual dial on temperature controller at the same temperature indicated on the thermometer. Record high temperature set point. If the controller does not trip at the temperature of the liquid bath, adjust the controller to trip at that temperature.
 4. Remove temperature sensing probe from liquid bath, allow it to cool, and record low temperature set point.
 5. Remove sensing probe to original location and adjust controller to desired temperature.

- p. Underwater Safety Valve (USV)—combined operation and leakage test.

Each operator should use a method appropriate to the system that demonstrates the pressure integrity of the USV and quantifies leak rates. Following are two options offered for general guidance only.

Option 1:

Perform test as in Table D-2, Item m.

Option 2:

1. Shut in well and USV as for operations test (Refer to Table D-2, Items 1.1. & 1.2.) and close downstream header or flow line valve.
 2. With pressure on upstream side of USV, measure pressure buildup in the flow line versus time. If the absolute pressure buildup in the confined line segment downstream of the USV is in excess of that which represents a flow rate of 400 cc/min. of liquid or 15 cubic feet/min, (0.4 cubic meter/min.) of gas, the USV should be repaired or replaced. An example with calculations is given in Appendix A of API Recommended Practice 14H
 3. Return well to production.
- q. Toxic gas detector (OSH).

Toxic gas detectors should be tested in accordance with the manufacturer's specifications.

APPENDIX E—EXAMPLES OF SAFETY ANALYSIS FLOW DIAGRAM AND SAFETY ANALYSIS FUNCTION EVALUATION (SAFE) CHART

E.1

Figures E-1.1 and E-1.2 present a completed safety analysis flow diagram and a Safety Analysis Function Evaluation (SAFE) chart for an example platform production process. Each process component is listed on the SAFE chart with its recommended safety devices determined from the individual components analysis (Appendix A). Each shut down and safety function is also listed. For each safety device, a specific shut down and/or safety function(s), or a SAC reference (Appendix B) should be documented on the SAFE chart. Provisions are also made for documenting alternate or substitute safety devices used in lieu of recommended safety devices.

The flow diagram (Figure E-1.1) is not intended as a recommended method for handling produced fluids, but is included for illustrative purposes only.

Section E.2 provides an example method for analysis of a natural draft burner on a pressure vessel. Figure E-2.1 shows the process component with all possible safety devices prior to analysis. Figure E-2.2 shows the resulting component after analysis with installed safety devices designated by solid circles, and safety devices that have been eliminated with appropriate SAC references indicated by dashed circles. Figure E-2.3 is the corresponding SAFE Chart for the analysis.

E.2 Natural Draft Burner on a Heater Treater Pressure Vessel

To analyze this combination, it is necessary to refer to A.4 for the pressure vessel and A.6 for the fired component.

Draw a simplified diagram with all required safety devices per A.4 and A.6 (refer to Figure E-2.1).

It is suggested that the component identification (refer to Table 2-2) for both the vessel and the fired component have the same component identifier (e.g., XXX-2000, YYY-2000).

Using A.4 and A.6 as guidelines, analyze Figure E-2.2.

Explanation

The PSL sensor in the fuel supply line is not required on a natural draft burner because of the low air intake pressure.

The LSL cannot be eliminated because of fire tube exposure.

Due to the internal design of the vessel, an additional LSL (LSL 2) is required. The blowby of the level control valve was calculated and it exceeded the process capacity of the downstream component. LSL 2 and an SDV were added to protect the downstream component from blowby.

FSV 3 is not required because the regulator effectively minimizes backflow.

It is not necessary to install two media TSHs in the vessel, one for the vessel, the other for the fired component. One TSH provides adequate protection, and it is mounted in the liquid portion of the vessel.

Figure E-2.2 represents the heater after analysis. Figure E-2.3 is the corresponding SAFE Chart for Figure E-2.2.

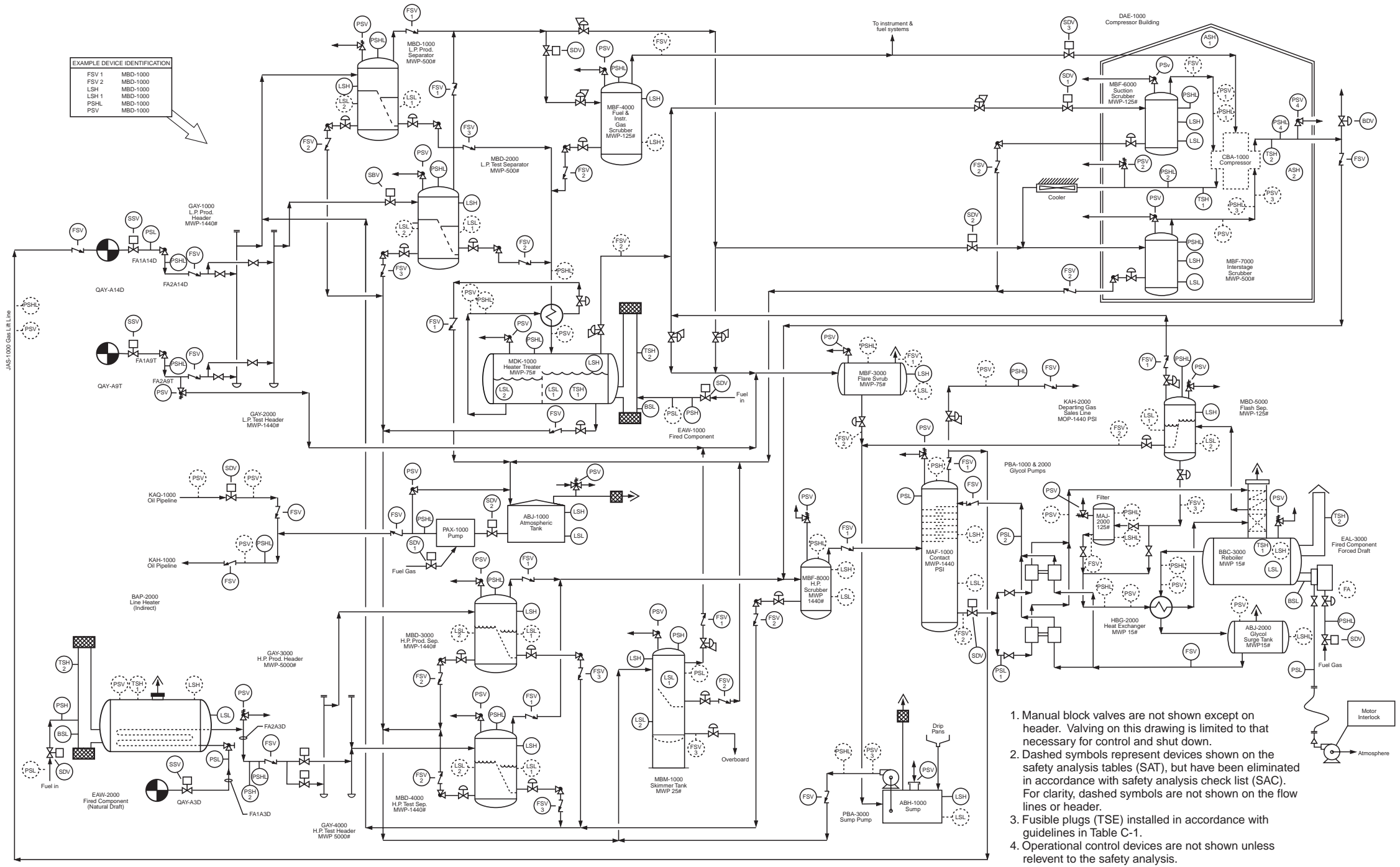


Figure E-1.1—Example Safety Analysis Flow Diagram of Platform Production Process

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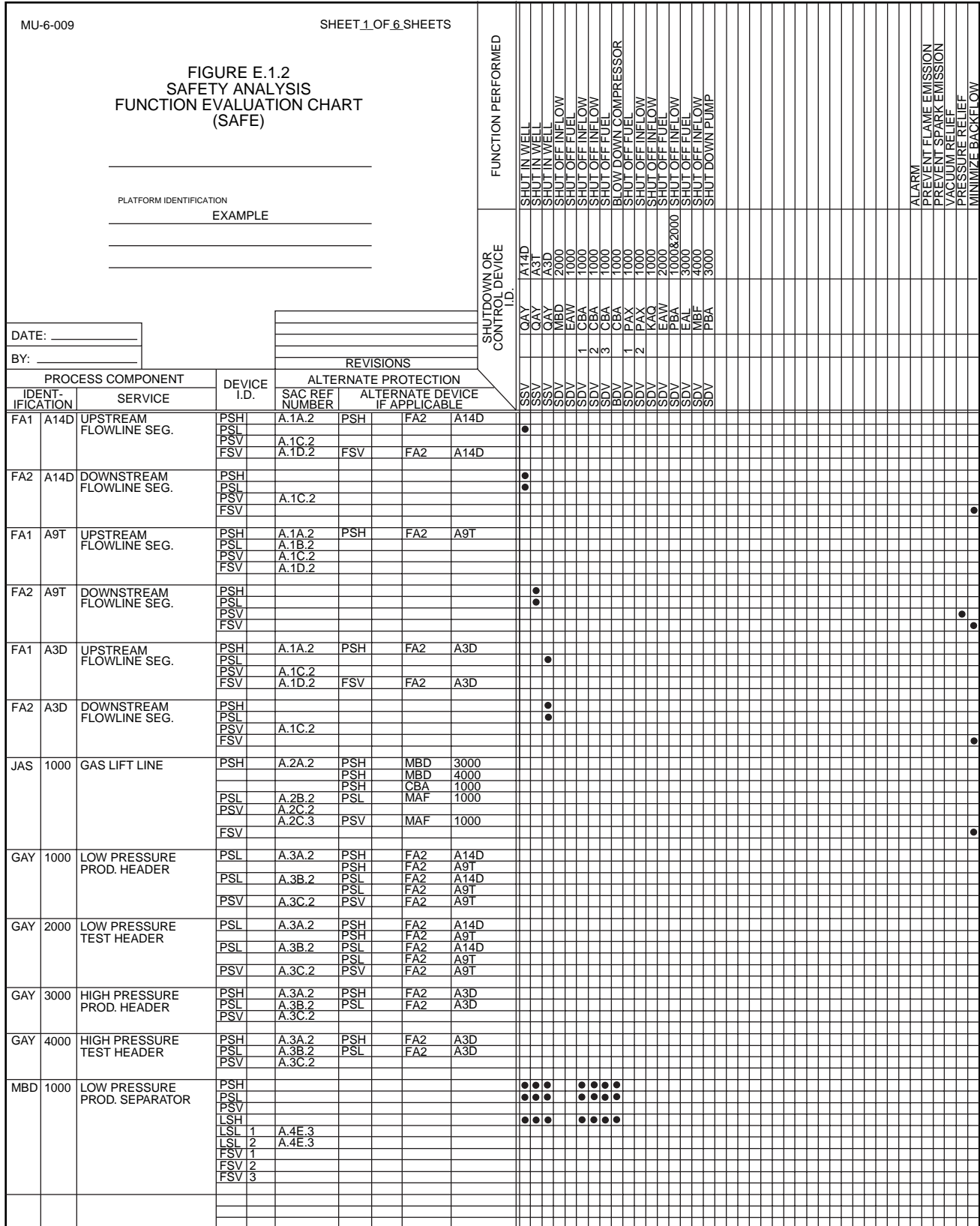


Figure E-1.2—Safety Analysis Function Evaluation Chart (SAFE) Example

MU-6-010		SHEET 2 OF 6 SHEETS		FUNCTION PERFORMED	
<p>FIGURE E.1.2 (cont'd) SAFETY ANALYSIS FUNCTION EVALUATION CHART (SAFE)</p> <p>PLATFORM IDENTIFICATION EXAMPLE</p>				SHUTDOWN OR CONTROL DEVICE I.D.	
				FUNCTION PERFORMED	SHUTDOWN OR CONTROL DEVICE I.D.
DATE: _____		REVISIONS			
BY: _____		ALTERNATE PROTECTION			
PROCESS COMPONENT		DEVICE I.D.			
IDENTIFICATION	SERVICE	SAC REF NUMBER	ALTERNATE DEVICE IF APPLICABLE	SSV	SDV
MBD 2000	LOW PRESSURE TEST SEPARATOR	PSH			
		PSL			
		PSV			
		LSH			
		LSL 1	A.4E.3		
		LSL 2	A.4E.3		
		FSV 1			
MBD 3000	HIGH PRESSURE PROD. SEPARATOR	PSH			
		PSL			
		PSV			
		LSH			
		LSL 1	A.4E.3		
		LSL 2	A.4E.3		
		FSV 1			
MBD 4000	HIGH PRESSURE TEST SEPARATOR	PSH			
		PSL			
		PSV			
		LSH			
		LSL 1	A.4E.3		
		LSL 2	A.4E.3		
		FSV 1			
MBD 5000	GLYCOL FLASH SEP.	PSH			
		PSL			
		PSV			
		LSH			
		LSL 1	A.4E.3		
		LSL 2	A.4E.3		
		FSV 1			
MBF 3000	FLARE SCRUBBER	PSH	A.4A.6		
		PSL	A.4B.2		
		PSV			
		LSH			
		LSL 1	A.4E.3		
		FSV 1	A.4F.2		
		FSV 2	A.4F.2		
MBF 4000	FUEL & INSTRUMENT GAS SCRUBBER	PSH			
		PSL			
		PSV			
		LSH			
		LSL 1	A.4E.3		
		FSV 1	A.4F.2		
		FSV 2			
MBM 1000	SKIMMER TANK	PSH			
		PSL	A.4B.2		
		PSV			
		LSH			
		LSL 1			
		LSL 2			
		FSV 1			
FSV 2	A.4F.2				
FSV 3	A.4F.2				

Figure E-1.2—Safety Analysis Function Evaluation Chart (SAFE) Example

PROCESS COMPONENT		DEVICE I.D.	ALTERNATE PROTECTION		SHUTDOWN OR CONTROL DEVICE I.D.	FUNCTION PERFORMED
IDENTIFICATION	SERVICE		SAC REF NUMBER	ALTERNATE DEVICE IF APPLICABLE		
MAJ 2000	GLYCOL FILTER	PSH PSL PSV LSH LSL FSV	A.4A.3 A.4B.4 A.4C.2 A.4D.3 A.4E.2 A.4F.2	PSH PSV (Thermal)	MBD 5000	SHUT IN WELL SHUT IN WELL SHUT OFF INFLOW SHUT OFF FUEL SHUT OFF INFLOW SHUT OFF FUEL SHUT OFF INFLOW SHUT OFF FUEL BLOW DOWN COMPRESSOR SHUT OFF FUEL SHUT OFF INFLOW SHUT OFF FUEL SHUT OFF INFLOW SHUT OFF FUEL SHUT OFF INFLOW SHUT OFF FUEL SHUT OFF INFLOW SHUT OFF FUEL SHUT DOWN PUMP
MBF 6000	SUCTION SCRUBBER	PSH PSL PSV LSH LSL FSV 1 FSV 2	A.4F.2			••••• ••••• ••••• ••••• ••••• ••••• •••••
MBF 7000	INTERSTAGE SCRUBBER	PSH PSL PSV LSH LSL FSV 1 FSV 2	A.4F.2			••••• ••••• ••••• ••••• ••••• ••••• •••••
MBF 7500	INTERSTAGE SCRUBBER	PSH PSL PSV LSH LSL FSV 1 FSV 2	A.4A.3 A.4B.3 A.4C.3 A.4E.3 A.4F.2	4 CBA 4 CBA 4 CBA	1000 1000 1000	••••• ••••• ••••• ••••• ••••• ••••• •••••
MBF 8000	HIGH PRESSURE SCRUBBER	PSH PSL PSV LSH LSL FSV 1 FSV 2	A.4A.3 A.4B.3 A.4D.2 A.4E.3	PSH MBD 3000 PSH MBD 4000 PSH 6 CBA 1000 PSL MBD 3000 PSL MBD 4000 PSL 6 CBA 1000		••••• ••••• ••••• ••••• ••••• ••••• •••••
MAF 1000	CONTACTOR	PSH PSL PSV LSH LSL FSV 1 FSV 2	A.4C.3 A.4D.2 A.4D.3 A.4E.2	PSH MBD 3000 PSH MBD 4000 PSH 6 CBA 1000		••••• ••••• ••••• ••••• ••••• ••••• •••••
ABJ 1000	ATMOSPHERIC TANK	Vent PSV LSH LSL				••••• ••••• ••••• •••••
ABJ 2000	GLYCOL SURGE TANK	Vent PSV LSH LSL	A.5B.3 A.5C.2 A.5D.2			••••• ••••• ••••• •••••
ABH 1000	SUMP	Vent PSV LSH LSL	A.5D.4			••••• ••••• ••••• •••••

Figure E-1.2—Safety Analysis Function Evaluation Chart (SAFE) Example

PROCESS COMPONENT		DEVICE I.D.	ALTERNATE PROTECTION		SHUTDOWN OR CONTROL DEVICE I.D.	FUNCTION PERFORMED	ALARM	PREVENT FLAME EMISSION	PREVENT SPARK EMISSION	VACUUM RELIEF	PRESSURE RELIEF	MINIMIZE BACKFLOW
IDENTIFICATION	SERVICE	SAC REF NUMBER	ALTERNATE DEVICE IF APPLICABLE									
<p>MU-6-012 SHEET 4 OF 6 SHEETS</p> <p>FIGURE E.1.2 (cont'd) SAFETY ANALYSIS FUNCTION EVALUATION CHART (SAFE)</p> <p>PLATFORM IDENTIFICATION EXAMPLE</p> <p>DATE: _____</p> <p>BY: _____</p> <p>REVISIONS</p>												
NBK	1000	HEATER TREATER	PSH PSL PSV LSH LSL 1 LSL 2 FSV 1 FSV 2 FSV 3 TSH 1	A.4F.3								
BAP	2000	LINE HEATER (INDIRECT)	Vent PSV LSH 1 LSL TSH	A.5B.4 A.5C.2 A.5E.3								
BBC	3000	REBOILER (GLYCOL)	Vent PSV LSH LSL TSH 1	A.5C.2								
EAW	1000	FIRED COMPONENT (NATURAL DRAFT FOR HEATER TREATER)	TSH 1 TSH 2 PSH PSL BSL FSL FA SA PSV	A.6A.1 A.6F.2 A.6H.2 A.6L.2	TSH 1 NBK 1000							
EAW	2000	FIRED COMPONENT (NATURAL DRAFT FOR LINE HEATER)	TSH 1 TSH 2 PSH PSL BSL FSL FA SA PSV	A.6A.3 A.6F.2 A.6H.2 A.6L.2								
EAL	3000	FIRED COMPONENT (FORCED DRAFT FOR REBOILER)	TSH 1 TSH 2 PSH PSL BSL FSL MI FA SA PSV	A.6A.1 A.6B.2 A.6J.2 A.6K.2	TSH BBC 1000							
PAX	1000	PIPELINE PUMP	PSH PSL PSV FSV									
PBA	1000 2000	GLYCOL PUMPS (TYPICAL OF TWO)	PSH PSL 1 PSL 2 PSV FSV	A.7B.6 A.7F.2								

Figure E-1.2—Safety Analysis Function Evaluation Chart (SAFE) Example

PROCESS COMPONENT			DEVICE I.D.	ALTERNATE PROTECTION		SHUTDOWN OR CONTROL DEVICE I.D.	FUNCTION PERFORMED
IDENTIFICATION	SERVICE	SAC REF NUMBER		ALTERNATE DEVICE IF APPLICABLE			
PBA 3000 SUMP PUMP		PSH A.7B.2				SSV	SHUT IN WELL
		PSL A.7D.5				QAY A31	SHUT IN WELL
		PSV A.7F.2				QAY A30	SHUT IN WELL
		FSV				MED 2000	SHUT OFF INFLOW
						EAW 1000	SHUT OFF FUEL
						SDV 1	SHUT OFF INFLOW
						CBA 1000	SHUT OFF INFLOW
						SDV 2	SHUT OFF INFLOW
						CBA 1000	SHUT OFF FUEL
						BDV	BLOW DOWN COMPRESSOR
						PAX 1000	SHUT OFF FUEL
						PAX 1000	SHUT OFF INFLOW
						SDV 1000	SHUT OFF INFLOW
						QAY 2000	SHUT OFF FUEL
						EAW 1000	SHUT OFF INFLOW
						PSA 1000&2000	SHUT OFF FUEL
						EAW 3000	SHUT OFF FUEL
						EAW 3000	SHUT OFF INFLOW
						MBF 3000	SHUT OFF INFLOW
						PSA 3000	SHUT DOWN PUMP
						SDV 3000	
REVISIONS							
KAH 1000 DEPARTING OIL PIPELINE		PSH A.9C.2				SSV	ALARM
		PSL				QAY	PREVENT FLAME EMISSION
		PSV				QAY	PREVENT SPARK EMISSION
		FSV				QAY	VACUUM RELIEF
KAQ 1000 INCOMING OIL PIPELINE		PSH A.9A.2					PRESSURE RELIEF
		PSL A.9B.2					MINIMIZE BACKFLOW
		PSV A.9C.2					
		FSV					
KAH 2000 DEPARTING GAS SALES LINE		PSH A.9C.2				SSV	
		PSL				QAY	
		PSV				QAY	
		FSV				QAY	
CBA 1000 COMPRESSOR		PSH 1 A.8A.2	PSH	MBF	6000	SSV	
		PSH 2 A.8A.2	PSH	MBF	7000	QAY	
		PSH 3 A.8A.2	PSH	MBF	7000	QAY	
		PSH 4 A.8A.2	PSH	4	CBA	1000	
		PSH 5 A.8A.2	PSH	4	CBA	1000	
		PSH 6 A.8C.2	PSL	MBF	6000	QAY	
		PSL 1 A.8C.2	PSL	MBF	7000	QAY	
		PSL 2 A.8C.2	PSL	MBF	7000	QAY	
		PSL 3 A.8C.2	PSL	4	CBA	1000	
		PSL 4 A.8C.2	PSL	4	CBA	1000	
		PSL 5 A.8C.2	PSV	MBF	6000	QAY	
		PSL 6 A.8E.2	PSV	MBF	7000	QAY	
		PSV 1 A.8E.2	PSV	4	CBA	1000	
		PSV 2 A.8E.2					
		PSV 3 A.8E.2					
		PSV 4 A.8E.2					
		PSV 5 A.8E.2					
		PSV 6					
		FSV					
		TSH 1					
		TSH 2					
		TSH 3					
HBG 1000 HEAT EXCHANGER (HEATER TREATER)		PSH A.10A.3	PSH	NBK	1000		
		PSL A.10B.3	PSL	NBK	1000		
		PSV A.10C.3	PSV	NBK	1000		
		PSH A.10A.4	PSH	NBK	1000		
		PSL A.10B.3	PSL	NBK	1000		
		PSV A.10C.4	PSV	NBK	1000		
HBG 2000 HEAT EXCHANGER (REBOILER)		PSH A.10A.2					
		PSL A.10B.2					
		PSV A.10C.3	PSV	BBC	1000		
		PSH A.10A.3	PSH	MBD	5000		
		PSL A.10B.2					
		PSV A.10C.4	PSV	BBC	1000		

Figure E-1.2—Safety Analysis Function Evaluation Chart (SAFE) Example

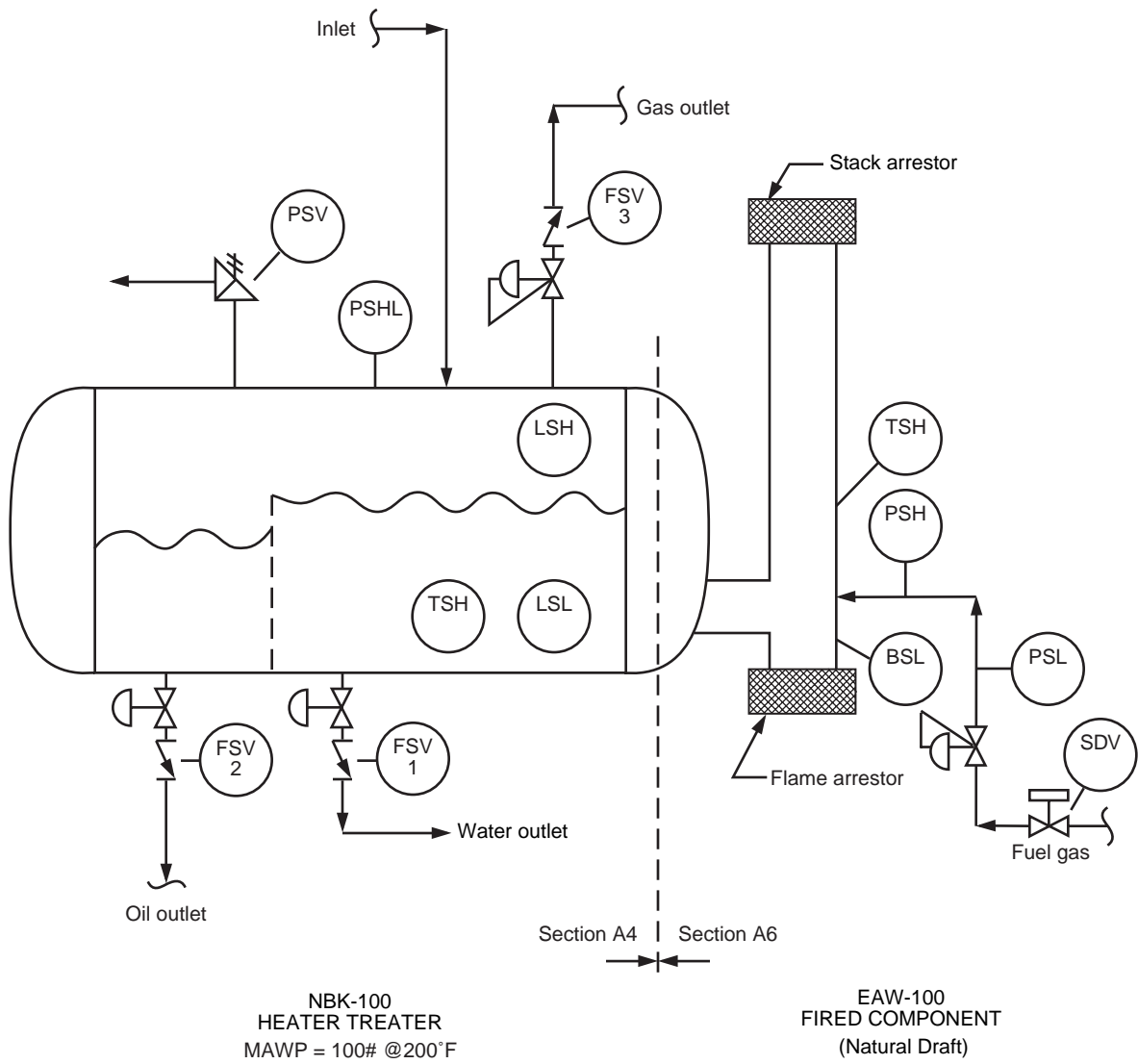


Figure E-2.1

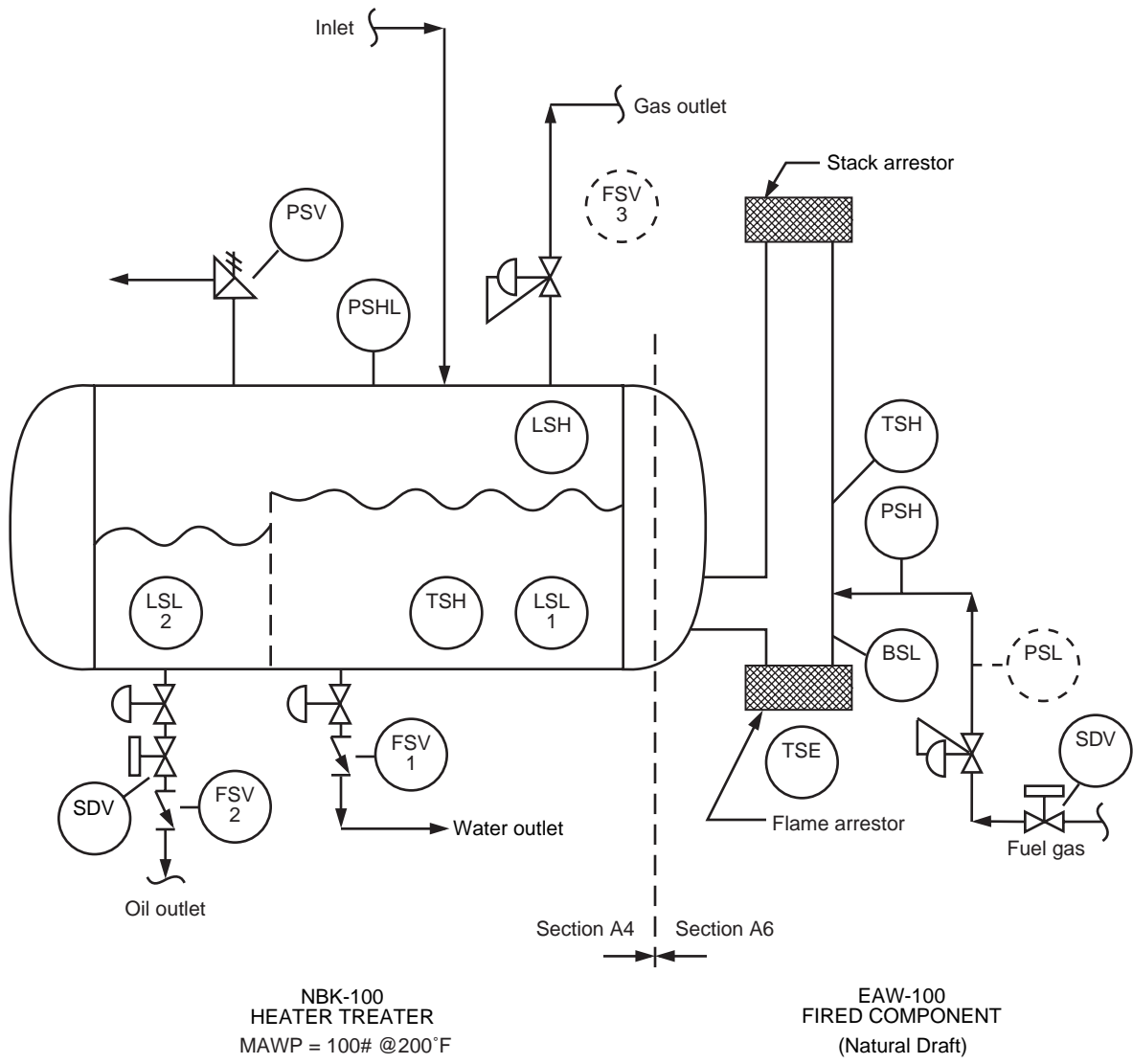


Figure E-2.2

PROCESS COMPONENT				DEVICE I.D.		ALTERNATE PROTECTION		FUNCTION PERFORMED	SHUTDOWN OR CONTROL DEVICE I.D.
IDENTIFICATION		SERVICE		SAC. REF. NO.		ALTERNATE DEVICE IN APPLICABLE			
NBK	100	HEATER TREATER	PSH						
			PSL						
			PSV						
			LSH						
			LSE	1					
			LSE	2					
			FSV	1					
			FSV	2					
			FSV	3	A.4.1.3				
			TSH						
EAW	100	FIRED COMPONENT (NATURAL DRAFT) HEATER TREATER	TSH		A.6.d.2				
			PSL						
			PSH		A.6.f.2				
			BSL						
			FSL		A.6.h.2				
			FA						
			SA						

O.C.S NO. _____	
FIELD: <u>EXAMPLE - FOR FIGURE E2.2</u>	
BLOCK NO. _____	PLATFORM _____
PREV.: _____ DATE: _____ BY: _____	
PRVE. NO. <u>0</u> DATE: _____ BY: _____	
DWG. # _____ SHEET <u>1</u> OF <u>1</u> SHEETS	

FIGURE E2.3
SAFETY ANALYSIS
FUNCTION EVALUATION CHART
(SAFE)

Figure E-2.3—Safety Analysis Function Evaluation Chart (SAFE)

APPENDIX F—TOXIC GASES SECTION

This section provides guidelines and methods of handling sour production (e.g. production containing hydrogen sulfide) on offshore platforms. This section includes discussion of general criteria, toxic gas detectors, and atmospheric discharging systems. These are essential systems and procedures that provide a minimum acceptable level of protection to the facility and personnel by initiating shut-in functions or reacting to minimize the consequences of released toxic gases. In addition to the following recommendations, API Recommended Practice 55, *Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide*, should be consulted.

F.1.1 General

Production of liquid and gaseous hydrocarbons containing hydrogen sulfide (H₂S) in significant amounts can be hazardous to personnel and can cause failure of equipment. The presence of hydrogen sulfide also presents the possibility of exposure to sulfur dioxide (SO₂) that is produced from the combustion of hydrogen sulfide. Hydrogen sulfide gas detectors or alternate detection systems should be installed on offshore production platforms where (a) the concentrations of hydrogen sulfide gas may reach an atmospheric concentration of fifty (50) parts per million (ppm) or greater at a distance determined by dispersion calculations (refer to API Recommended Practice 55) to which personnel could be exposed during normal or abnormal operations, or (b) a process component or piping on the platform contains gas with a hydrogen sulfide concentration of 100 ppm or greater. Sulfur dioxide monitoring equipment should be utilized when flaring operations could result in personnel exposure to atmospheric concentrations of SO₂ of 2 ppm or greater. Sulfur dioxide monitoring equipment should indicate when concentrations reach a level of 2 ppm.

Accumulations of toxic gases or vapors are more likely to occur in poorly ventilated areas containing a source of hydrogen sulfide—particularly enclosed areas. Methods for increasing safety include improving ventilation and installing toxic gas detector (OSH) systems. Toxic gas detector (OSH) systems should alert personnel by unique audible or visual alarms, as appropriate for the area or zone where low level concentrations of toxic gases have been detected. Also, these systems should increase ventilation and shut off the gas source if possible. Since many toxic gases are flammable, combustible gas detectors (ASHs) should be installed to prevent concentrations from reaching the lower explosive limit (LEL) of the gas present and eliminate ignition sources. Electrical installations should be made in accordance with API Recommended Practice 14F, *Design and Installation of Electrical Systems for Offshore Production Platforms*.

Strict controls should be used when exposing materials to an environment containing hydrogen sulfide. Many materials

may suddenly fail by a form of embrittlement known as sulfide stress cracking (SSC) that increases as strength and tensile stress (residual or applied) increase. Material hardness is frequently used as an indirect measurement of strength and sometimes is referenced as a limiting parameter. The failure of certain producing and gas processing components used in the sulfide stress cracking regime could allow the uncontrolled release of hydrogen sulfide to the atmosphere. Guidelines for equipment and materials selection on the basis of resistance to sulfide stress cracking and corrosion is provided by NACE Standard MR0175, *Standard Material Requirements Sulfide Stress Cracking Resistant Metallic Materials For Oil Field Equipment*.

F.1.2 Installation, Operation, and Testing of Fixed Detection Systems

Placement of hydrogen sulfide detectors involves consideration of many variables including concentration of toxic gas in process streams, specific gravity of the gas mixture, process pressure, atmospheric conditions, ventilation, equipment location, type of decking (solid or grated), and direction of prevailing winds. A detailed design analysis that might include dispersion modeling should be performed to determine the need for and placement of detector systems.

When reviewing a platform to determine where H₂S gas detector sensors should be installed, the first step is to prepare drawings that identify all process components or piping handling 100 ppm or greater concentrations of hydrogen sulfide. All fittings, flanges, and valves comprising the piping system and the location of devices subject to leaks to the atmosphere during normal or abnormal conditions should be considered in determining the placement of sensors.

Because hydrogen sulfide gas is heavier than air, sensors normally should be installed no more than 36 inches (0.9 meters) above the floor (deck). To allow for proper maintenance and to reduce the probability of wetting during area washdown, sensors should be installed no less than 12 inches (0.3 meters) above the floor (deck). Installation of protective caps designed for the detector's head should be considered to prevent wetting. Hydrogen sulfide mixed with natural gas may form a lighter-than-air mixture. When such mixtures are anticipated, sensor installations at elevations greater than 36 inches (0.9 meters) may be appropriate.

a. Hydrogen sulfide gas detecting sensors should be located at the following locations:

1. In enclosed areas (see definition in API Recommended Practice 500) that contain sources of hydrogen sulfide that could cause concentrations of 50 ppm or more in the atmosphere,
2. In buildings where personnel regularly or occasionally sleep if the building is located on a platform where toxic gas detectors are installed, and

3. In certain enclosed and non-enclosed areas:
 - (a) as determined by the detailed design analysis (e.g., dispersion modeling), or
 - (b) in a grid pattern with a minimum of one detector for each 400 square feet (37 sq. m) of floor area or fractional part thereof, or
 - (c) within 10 feet (3m) of the following (refer to F.1.1):
 - All applicable vessels.
 - All applicable compressors. Compressors exceeding 50 HP (38 KW) should be provided with at least two (2) sensors.
 - All applicable pumps.
 - All applicable headers.
 - All applicable wellheads. Wells shut in at the master valve and sealed closed are exempt.

When utilizing the 10 feet (3m) criteria for sensor location, one sensor may be utilized to detect hydrogen sulfide gas around multiple pieces of equipment, provided the sensor is no greater than 10 feet (3 m) from all applicable equipment. When utilizing the grid configuration, maximum sensor spacing should be 20 feet (6 m).

b. It is recommended that hydrogen sulfide detection instruments be approved by a nationally recognized testing laboratory (NRTL) and meet ANSI/ISA S12.15, Part I: *Performance Requirements, Hydrogen Sulfide Gas Detectors*. Furthermore, it is recommended that hydrogen sulfide detection systems be installed, operated, and maintained in accordance with ANSI/ISA S12.15, Part II: *Installation, Operation, and Maintenance of Hydrogen Sulfide Gas Detection Instruments*.

c. Detection of 10 ppm of hydrogen sulfide gas in the atmosphere should initiate an audible or visual alarm, as most appropriate for the area where the gas has been detected. A visual warning system should be provided at locations such that personnel in approaching helicopters or boats can be effectively warned of the release of toxic gas when concentrations in the atmosphere around the landing area exceed 10 ppm. Hydrogen sulfide warning alarms should be distinguishable from other alarms at the location.

d. Detection of 50 ppm of hydrogen sulfide gas in the atmosphere should initiate an audible general platform alarm and a visual alarm, as most appropriate for the area where the gas has been detected. Automatic corrective actions to control the source of hydrogen sulfide should be initiated. Signs and flags should be displayed if the concentration of gas exceeds 50 ppm around the landing areas for boats and helicopters or if personnel arriving by boat or helicopter would not have access to safe briefing areas. Corrective action may include the following:

1. A shut-in of the sour production handling equipment, applicable wells, and pipelines/flow lines.

2. Blowdown of certain process equipment.

3. Providing (or increasing) ventilation.

In lieu of total process shut in, it is acceptable to isolate alarmed areas; an example is closing an inlet valve to a compressor building. It may be desirable in certain instances for H₂S detectors not to initiate shut-in/isolation action, but to alarm only.

Careful consideration should be given to the form of automatic corrective action taken to ensure that the situation is not made more hazardous.

Shutdown devices controlled by hydrogen sulfide gas detection systems should be installed “normally energized” (commonly referred to as “failsafe”). Refer to API Recommended Practice 14F, Section 9, “Special Systems”.

e. In addition to being toxic, hydrogen sulfide gas is combustible. The range of combustibility is approximately 4.3 to 45.5% by volume. Areas subject to combustible levels of hydrogen sulfide should be classified as Group C and electrical equipment should be suitable for Groups C & D atmospheres. For mixtures of hydrogen sulfide and natural gas, the mixture should be considered Group D if the hydrogen sulfide constitutes less than 25% of the mixture (by volume) and Groups C and D if greater than 25%. If machinery or equipment shutdown could create an ignition source, consideration should be given to actuation of a fire inerting system prior to shutdown.

f. If sour gas is sweetened to reduce personnel exposure hazard or for equipment protection, the sweetened gas should be continuously monitored for hydrogen sulfide prior to the gas leaving the facility, and preferably before being utilized for fuel or control gas at the facility. Devices specifically designed for analyzing an instream sample for hydrogen sulfide content on a continuous basis should be utilized.

g. To better ensure proper application of H₂S detection instruments, it is recommended that an environment and application checklist (similar to the example shown in Appendix A, ANSI/ISA-RP12.15, Part II) be provided to prospective suppliers by the user.

F.1.3 Systems for Discharging Hydrogen Sulfide and Sulfur Dioxide to Atmosphere

Discharge of pressure relief and normally venting devices should be located away from work areas and designed to provide adequate dispersion and to limit personnel exposure to hydrogen sulfide and sulfur dioxide concentrations not exceeding those discussed in F.1.1. If dispersion modeling determines that ignition of vented gas is required, the flare outlets should be equipped with an automatic ignition system and contain a pilot(s) or other means to ensure combustion. On platforms where flaring is required, failure of the automatic ignition system and loss of flare should shut in the input source.

APPENDIX G—DEFINITIONS

- G.1 abnormal operating condition:** Condition that occurs in a process component when an operating variable ranges outside of its normal operating limits.
- G.2 atmospheric service:** Refers to operation at gauge pressures between $\frac{1}{2}$ ounce per square inch (0.2 kPa) vacuum and 5 pounds per square inch (35 kPa) pressure.
- G.3 automatically fired vessel:** Fired vessel with the burner fuel controlled by an automatic temperature or pressure controller.
- G.4 backflow:** Fluid flow in a process component opposite to the normal flow direction.
- G.5 blowdown valve:** An automatically operated normally open valve used to vent the pressure from a process station on shutdown.
- G.6 classified area:** Any area electrically classified Class I, Group D, Division 1 or 2, following guidelines of API Recommended Practice 500.
- G.7 containment:** Any method used on an offshore platform to collect and direct escaped liquid hydrocarbons to a safe location.
- G.8 detectable abnormal condition:** An abnormal operating condition that can be automatically detected.
- G.9 direct ignition source:** Point of sufficient temperature and heat capacity to ignite a combustible mixture.
- G.10 emergency shutdown (ESD) system:** System of manual stations that, when activated, will initiate platform shutdown.
- G.11 excess temperature:** Temperature in a process component in excess of the rated working temperature.
- G.12 failure:** Improper performance of a device or equipment item that prevents completion of its design function.
- G.13 fired vessel:** A vessel in which the temperature of a fluid is increased by the addition of heat supplied by a flame within the vessel.
- G.14 fire loop:** A pneumatic control line containing temperature sensing elements (fusible plugs, synthetic tubing, etc.) that, when activated, will initiate platform shutdown.
- G.15 flame failure:** A flame that is inadequate to instantaneously ignite combustible vapors entering the firing chamber.
- G.16 flowline:** Piping that directs the well stream from the wellhead to the first downstream process component.
Note: The words “flowline” and “flow line” are used interchangeably throughout this document.
- G.17 flowline segment:** Any portion of a flow line that has an operating pressure different from another portion of the same flow line.
- G.18 gas blowby:** The discharge of gas from a process component through a liquid outlet.
- G.19 gas detection system:** Control system that monitors the concentration of combustible gases and initiates alarm and shutdown functions at predetermined concentrations.
- G.20 high liquid level:** Liquid level in a process component above the highest operating level.
- G.21 high pressure:** Pressure in a process component in excess of the maximum operating pressure but less than the maximum allowable working pressure (for pipelines, maximum allowable operating pressure).
- G.22 high temperature:** Temperature in a process component in excess of the design operating temperature.
- G.23 indirect heated component:** Vessel or heat exchanger used to increase the temperature of a fluid by the transfer of heat from another fluid, such as steam, hot water, hot oil, or other heated medium.
- G.24 leak:** The accidental escape from a process component of liquid and/or gaseous hydrocarbons to atmosphere.
- G.25 liquid overflow:** The discharge of liquids from a process component through a gas (vapor) outlet.
- G.26 lower explosive limit (LEL):** The lowest concentration by volume of combustible gases in mixture with air that can be ignited at ambient conditions.
- G.27 low flow:** Flow in a process component less than the minimum operating flow rate.
- G.28 low liquid level:** Liquid level in a process component below the lowest operating level.
- G.29 low pressure:** Pressure in a process component less than the minimum operating pressure.
- G.30 low temperature:** Temperature in a process component less than the minimum operating temperature.
- G.31 malfunction:** Any condition of a device or an equipment item that causes it to operate improperly, but does not prevent the performance of its design function.

G.32 maximum allowable operating pressure:

The highest operating pressure allowable at any point in a pipeline system during normal flow or static conditions.

G.33 maximum allowable working pressure: The highest operating pressure allowable at any point in any component other than a pipeline during normal operation or static conditions.

G.34 normally closed valve: A valve that will shift to the closed position upon loss of the power medium.

G.35 normally open valve: A valve that will shift to the open position upon loss of the power medium.

G.36 overpressure: Pressure in a process component in excess of the maximum allowable working pressure (for pipelines, maximum allowable operating pressures).

G.37 pipeline: Piping that directs fluids between platforms or between a platform and a shore facility.

G.38 platform safety system: An arrangement of safety devices and emergency support systems to effect platform shutdown. The system may consist of a number of individual process shutdowns and may be actuated by either manual controls or automatic devices sensing detectable abnormal conditions.

G.39 platform shutdown: The shutting in of all process stations of a platform production process and all support equipment for the process.

G.40 pneumatic power system: A system that supplies pressure to operate pneumatic actuators.

G.41 process component: A single functional piece of production equipment and associated piping used in a process station, such as a separator, heater, pump, or tank.

G.42 process shutdown: The isolation of a given process station from the process by closing appropriate SDVs to shut in flow to the process station or divert flow to another process station.

G.43 process station: One or more process components performing a specific process function, such as separating, heating, pumping, etc.

G.44 qualified person: An individual with characteristics or abilities gained through training or experience or

both, as measured against established requirements, such as standards or tests, that enable the individual to perform a required function.

G.45 safety device: An instrument or control used within the safety system.

G.46 sensor: A device that detects an abnormal operating condition and transmits a signal to perform a specific shutdown function.

G.47 shutdown valve (SDV): An automatically-operated, normally closed valve used for isolating a process station.

G.48 SITP: Shut-in tubing pressure.

G.49 subsurface safety valve (SSSV): A device installed in a well below the wellhead with the design function to prevent uncontrolled well flow when actuated.

G.50 subsurface controlled subsurface safety valve (SSCSV): An SSSV actuated by the pressure characteristics of the well.

G.51 surface controlled subsurface safety valve (SCSSV): An SSSV controlled from the surface by hydraulic, electric, mechanical, or other means.

G.52 surface safety valve (SSV): An automatic wellhead valve assembly that will close upon loss of power supply.

G.53 underpressure: Pressure in a process component less than the design collapse pressure.

G.54 underwater safety valve (USV): An automatic valve assembly (installed at an underwater wellhead location) that will close upon loss of power supply.

G.55 undesirable event: An adverse occurrence or situation in a process component or process station that poses a threat to safety, such as overpressure, underpressure, liquid overflow, etc.

G.56 vacuum: Pressure in a process component less than atmospheric pressure.

G.57 vent: A pipe or fitting (e.g., tank flange) on a vessel that opens to the atmosphere. A vent might contain a pressure and/or vacuum relief device.

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