Twelve Steps to Engineering Safe Onshore Oil and Gas Facilities

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Summary

Late in the evening of a wintery night, a worker is hurrying to respond to an alarm that has gone off. Suddenly, the unexpected happens. The worker is severely injured. The ensuing investigation finds that the incident could have been prevented if the equipment had been engineered properly.

How many times have you heard of incidents that have severely injured a person and you thought, "That incident could have been prevented if only the equipment had been engineered properly?" One of the first lines of defense in preventing incidents is to "engineer out the hazards." However, equipment is often installed without taking into consideration how it can be engineered properly to minimize or eliminate operating risks.

The safety of an onshore facility is a function of how safely the facility is designed. People are hurt and sometimes killed when explosions, fires, and toxic-gas releases occur at oil- and gas-producing facilities that were designed without regard to measures that could have prevented such incidents. The safety of people and equipment needs to be considered and included along every step in the engineering of oil and gas facilities. Properly designed oil and gas facilities can eliminate injuries and deaths.

Many wellsites, tank batteries, and production facilities are at risk because of design or installation errors. These errors may have occurred when the facility was built or occurred over time because the facility had been continually "added on to" through the years. Lack of proper engineering design can lead to equipment failure, lost production, human injury, or harm to the environment.

This paper reviews the key areas for facility designers and engineers to include when designing facilities to ensure safe facilities. Use and incorporation of all safety engineering principles outlined in this paper should enable facility engineers and designers to build safe facilities that reduce the risk of major incidents.

Getting Management "On Board"

One of the first questions asked by corporate executives and investors after a new discovery is, "How in the world are we going to produce this?" The completion engineers quickly figure out how to get the highly valuable well fluids to the surface. Then, everyone turns to the production and surface-equipment experts and asks, "What equipment are we going to need to treat and sell oil and gas from this new discovery?" The answer to this question will impact the safety and health of perhaps generations of workers who will be working on and near this equipment for decades while the oil and gas is being produced.

At this point, companies have the option of following two different paths. The first path is the "high road" of making sure that all facilities are designed and operated in accordance with good engineering practices, standards, and regulatory requirements. The other path available is that of doing what inevitably leads to equipment failure, personnel injuries, and environmental damage.

Your first reaction to this is to ask yourself, "Why would any company choose not to follow the high road?" The answer to this question is multifaceted.

First, the company, particularly if it is a new exploration company, may not understand all of the detailed design work that goes into building safe surface facilities. Often, personnel from other companies or other operating areas are asked to design and build facilities in new areas where production characteristics and production hazards are totally different. Cost is another factor, because well-engineered facilities may be perceived as being more expensive. These and other reasons lead some companies to take a different path when designing and installing facilities.

Twelve Steps

1. Set a Design-Standard Policy. Each producing company, no matter how small, must implement a policy regarding the use of industry design standards on how surface facilities should be built that can be articulated to the production-operations groups.

Companies must first justify internally the need for adopting a design standard. Usually, companies will consider the impacts and ramifications of how employees, shareholders, regulatory bodies, and the public will react to facilities that are not built to current industry standards or regulatory requirements. A major incident at a facility not meeting general industry standards or regulatory requirements can result in fines or judgments that can negatively affect the company.

Setting a design policy to use industry standards will also reduce the risk of injury to personnel or the occurrence of an environmental event at the facility. Most industry standards and regulations were developed in response to safety-related events. Many standards, such as American Society of Mechanical Engineers (ASME) B31.3 *Chemical Plant and Petroleum Refinery Piping* (1993), are continually evolving over time to incorporate "lessons learned" from safety-related events. Building a facility to industry standards provides the user with industry-accepted safety criteria.

Another reason for a design policy standard is to make it clear to engineering design firms, construction firms, and other contractors what the company expects. Facilities may be built to criteria other than industry standards if the design firm is directed to do so by the operator. Some operators feel that industry standards establish the mimium criteria and choose to use more-stringent standards.

An example of a policy on design standards would be for a company to state: "All facilities will be designed in accordance with good industry design practices and codes, and also to meet all regulatory requirements."

2. Lay Out the Site for Safety. One of the first tasks when building a new facility is to properly lay it out on the pad. In planning the equipment layout, one must obtain a plot plan of the site and an equipment list showing the equipment to be installed.

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Start first by locating the most-hazardous items of equipment on the site. The most-hazardous items of equipment would include

a) Vents that may discharge poisonous gases (hydrogen sulfide) or flammable gases. Examples of such equipment may include amine-unit process vents, tank vent lines, pressure-relief header lines, and glycol-unit vents.

Vents should be placed downwind of the facility and where the prevailing wind will disperse the released gases to an area that is not inhabited or not expected to impact human life. The placement of the vent should also include provisions for accidental ignition by lightning or other sources.

The engineer should conduct both air-dispersion and radiant-heat modeling to make sure that vented or burned vapors do not impact personnel at the facility, nor at any other nearby public receptor (i.e., an occupied structure, road, park, or other area where people may be present).

Standards relating to vent design include American Petroleum Institute (API) recommended practice (RP) 521 *Pressure-relieving and Depressuring Systems* (2007).

b) As with vents, flares should be located as far away downwind from other equipment as possible. Additionally, they should be located such that any public receptors are not in danger from burned vapors or noncombusted discharge components in the event of a flame failure. Hazards with flares include radiant heat and oxidized (burned) vapors that may pose a threat to human health.

The engineer should also consider impacts if the igniter or pilot fails or if the flare's flame goes out from other causes. As with vents, dispersion calculations need to be carried out to determine if a flame failure could result in any type of harm to human health or the environment.

Standards relating to flare and vent design include API RP 521 *Pressure-relieving and Depressuring Systems* (2007).

c) Fired process equipment should next be located on the plot plan. Examples of fired equipment include heater treaters, heater/separators, glycol reboilers, amine reboilers, and process heaters. Hazards from fired equipment include those associated with a flame being present as a source of ignition, hot surfaces that may be above the flash point of hydrocarbons, and the fact that fire tubes are in direct contact with flammable liquids that can result in a fire if a fire tube leaks.

These equipment items should be located away from equipment that store or process flammable hydrocarbons. Examples of these devices would include atmospheric tanks, separators, compressors, scrubbers, pumps, meters, and pipeways. Fired process equipment should also be located away from devices, such as pig receivers and vents, where hydrocarbons are released or known to be present.

d) Engines and rotating equipment, such as pumps, should be located on the site to prevent harm from possible hydrocarbon releases, ignition, noise, and other factors. Engine-driven compressors have an inherent danger of natural gas being ignited by the ignition system or from the hot exhaust manifolds. Pumps are known to periodically lose seals, which can result in liquid hydrocarbons being released to the ground or atmosphere.

The engineer should always provide some form of catchment or secondary containment around pumps and compressor skids. Compressors usually leak small amounts of oil that, if not properly handled, can result in soil contamination around the unit. Likewise, the failure of a pump seal can cause leaks, resulting in contaminated soil or waterways.

e) Separators, tanks, and unfired vessels should be the next set of equipment items to be located on the plot plan. Separators and unfired pressure vessels should be located so that their associated relief devices are designed to relieve to a safe area. A safe area for relief can be defined as one that does not cause direct harm to personnel or the environment.

Atmospheric tanks are usually located inside of berms or other secondary containment devices. The intent of the secondary containment device is to capture any fluids in the event of a tank leak or failure. Regulations concerning the design and construction of tank berms can be found in the US Environmental Protection Agency's (EPA) Spill Prevention, Control, and Countermeasure (SPCC) regulations (US EPA 2005).

The vents off of tanks should be treated just as other process vents or vent headers. The discharge of the vent should be located in a safe location so that vapors are dispersed so as not to cause any danger to personnel or the environment.

f) Site offices, electronic control equipment, batteries, and electrical switchgear should be placed at the site in the safest location possible. Usually, this is far away from vents, flares, fired vessels, and engine-driven components. Site offices usually have the highest occupancy level of any structure on the site. Nonclassified electrical equipment, such as computers, air conditioners, heaters, electrical outlets, and other devices that could be a source of ignition, are located in site offices.

Electrical equipment needs to be located so that its electrical classification meets the requirements found in API RP 500 *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2* (1997). The guidance provided in API RP 500 is to be used for electrical classification only.

There are three key documents that can assist the engineer in determining proper spacing. The first of these is National Fire Protection Association (NFPA) 30 Flammable and Combustible Liquids Code (1996). This document specifies minimum distances between tanks and property lines and from tanks to buildings on the same property. The Industrial Risk Insurers (IRI 1991) has developed charts showing distances between plant equipment. The Process Industry Practices (PIP), in June 2007, published *PIP PNE00003 Process Unit and Offsites Layout Guide.* This guide was developed to bring together the many regulatory and industry practices by "…harmonizing these technical requirements into a single set of practice."

3. Personnel Safety. Personnel safety at the oil and gas site needs to be examined to make sure employees do not place themselves at risk performing routine operations and that the site conforms to US Occupational Safety and Health Administration (OSHA) requirements. OSHA regulations (see OSHA *STD 29 CFR 1910.106* 2006) provide excellent guidance when designing walking surfaces, exit routes, stairways, ladders, elevated platforms, and equipment guarding.

There are many simple things, such as installing platforms, to enable operators to more easily change filters or refill equipment with lubricating oils or chemicals. Walkways should be provided that are free from small-diameter lines or tripping hazards.

Here are some other key personnel-safety items that need to be included when constructing a lease site:

- Exit route (see *OSHA STD 29 CFR 1910.36* 2006): OSHA requires that facilities have at least two exits. The minimum width for an exit walkway or gate is 28 in. Exits need to be clearly marked.
- Stairs (see *OSHA STD 29 CFR 1910.24* 2006): Fixed stairs (e.g., leading to the top of a tank or at a compressor) must be at least 22 in. in width. The stairs can be at an angle from 30 to 50°. All stairs must have railings on each side.
- Elevated platforms [see *OSHA STD 29 CFR 1910.23(c)* 2006]: Elevated platforms may be found on tanks or around compressors and other pieces of equipment. Every elevated platform must be equipped with handrails, midrails, and toe boards.
- Guarding of equipment (see *OSHA STD 29 CFR 1910.219* 2006): Couplings on compressors, pumps, fans, flywheels, rotating weights, and other rotating equipment must be guarded in accordance with OSHA regulations. Make sure that personnel are not able to come in contact with any rotating piece of equipment.

Additionally, the design team should consider human factors and technical safety requirements in the design. Human factors might include making sure that computer displays, equipment controls, and manually actuated devices (i.e., switches and valves) are easily identifiable and can indeed be operated in a timely manner. Poorly designed alarm points, valves that cannot be reached, or equipment located too far from the operators often creates hazards that become apparent during an emergency situation.

Techncial safety includes making sure that proper safety limits are specified, control settings are designed to prevent a safety event, proper surveillance is "built in," and other factors.

4. Design Piping Properly. In order to design a safe and reliable facility, it is imperative that the piping system be properly designed. OSHA addresses this topic in STD *29 CFR 1910.106(c)(1)(i)* (2006), stating that "The design (including selection of materials), fabrication, assembly, test, and inspection of piping systems containing flammable or combustible liquids shall be suitable for the expected working pressures and structural stresses. Conformity with the applicable provisions of Pressure Piping, ANSI B31 series and the provisions of this paragraph, shall be considered prima facie evidence of compliance with the foregoing provisions."

For oil and gas facilities, the primary ASME [formerly American National Standards Institute (ANSI)] piping codes are

- ASME B31.3 C*hemical Plant and Petroleum Refinery Piping* (1993)
- ANSI/ASME B31.4 *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids* (2010)
- ANSI/ASME B31.8 *Gas Transmission and Distribution Piping Systems* (2007)

Because "upstream" oil and gas facilities are not specifically covered by any of these codes, it is at the user's discretion to select the applicable piping code. The code most often referenced for surface facilities is ASME B31.3 *Chemical Plant and Petroleum Refinery Piping* (1993). Another very important standard that needs to be used is ANSI/NACE MR0175 *Materials for use in H_2S-containing environments in oil and gas production* (2009). This standard should be used whenever hydrogen sulfide gas is present or could become present as the field is produced. Interconnecting underground pipelines between wells and surface facilities are usually designed and built to either ANSI/ASME B31.8 (2007) for gas pipelines or ANSI/ASME B31.4 (2010) for liquid pipelines. Interestingly, the flowline from a remote well to the first separator is specifically excluded from ANSI/ASME B31.8. Because the well flowlines are multiphase service (oil, water, and gas), several operators have adopted the practice of building the lines to ANSI/ASME B31.8 with a design factor of $F=0.50$. This practice yields pipe-wall thickness approximately equal to ASME B31.3 for comparable materials and pipe sizes.

It should be noted that API does not have a piping design code similar to the ASME codes. API has extensive specifications for piping materials, but it does not issue any documents covering design, selection of materials, fabrication, assembly, test, and inspection.

The most common joining methods are welded and flanged, threaded and coupled, and grooved and coupled. Each method has advantages and disadvantages, and it is up to the user to select the joining method that is best suited. The following are general comments about each of the joining methods:

- Welded and flanged
  - o There are two basic welding standards:
    - ■ API STD 1104 *Welding of pipelines and related facilities* (2005). Usually for ANSI/ASME B31.4 and B31.8 codes.
    - ■ ASME Section IX *Welding and Brazing Qualifications* (2010). Part of the Boiler and Pressure Vessel Code (BPVC). Usually used for pressure vessels and ASME B31.3 piping, but can also be used for pipeline welding.
  - o There are three parts of a qualified weld:
    - ■ Welding-procedure specification (WPS): The WPS must contain the minimum requirements that are specified by the code. The WPS provides guidance for welding by specifying ranges for each variable.
    - ■ Procedure-qualification record (PQR): A PQR is used to verify the WPS. The WPS is qualified by welding-procedure-qualification test coupons. The variables and tests used are recorded on a PQR.
    - ■ Welder-performance qualification (WPQ): The performance of the welders is verified by welding-performance-qualification test coupons. The variables and tests used with the particular variable ranges qualified are recorded on a WPQ record.
  - o Weld inspection: Inspection is necessary to ensure quality. Each piping code defines the amount of inspection that is required.
- Threaded and coupled
  - o The ASME B31.3 code does not allow threaded connections greater than 2-in. nominal pipe size.
  - o In all codes (ASME B31.3 and ANSI/ASME B31.4 and B31.8), thread depth must be included as an "allowance."
- Grooved and coupled
  - o In all codes (ASME B31.3 and ANSI/ASME B31.4 and B31.8), groove depth must be included as a wall-loss "allowance."
  - o When field cutting grooves, care must be taken so as not to cut grooves excessively deep.
  - o Many operators limit the use of grooved connections to 150 Class (285 psig).

With all steel piping systems, it is usually necessary to include a corrosion allowance (CA). Typical CA numbers range from 1/32 in. for mildly corrosive systems up to 3/32 in. or more for aggressive corrosion attack. It is up to the user to select the most appropriate CA. Additional information on piping materials and specification breaks can be found in paper SPE 121031 (Johnstone 2009).

5. Select the Proper Pressure Vessel. Pressure vessels are generally defined by ASME Section VIII-DIV 1 of the BPVC as having an internal pressure greater than 15 psig and an internal diameter greater than 6 in. The US Department of Labor's OSHA has set rules that require pressure vessels used in flammable- and combustible-liquid service to be "built in accordance with the Code for Unfired Pressure Vessels, Section VIII of the ASME Boiler and Pressure Vessel Code" (OSHA S*tandard 1910.106* 2006). OSHA later made it clear to the oil- and gas-producing industry that all pressure vessels must conform to ASME Section VIII in a letter from Richard E. Fairfax, Director, Directorate of Enforcement Programs to Charles H. Morgan (Fairfax 2006).

The manufacturer's name plate, which should remain permanently affixed to the pressure vessel, must display the "U" stamp as an indication that the design, fabrication, and testing were completed in accordance with the BPVC. In addition, the purchaser should obtain a copy of the U1A form from the manufacturer, which contains additional information on materials, fabrication, and inspection.

In order to maintain the integrity of pressure vessels, they must be inspected periodically. As a result of the inspection, sometimes the vessel must be repaired or rerated. The most common inspection code is API 510 *Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration* (2006). An alternative inspection, repair, and rerating code is ANSI/NBBPVI NB23-2007 *National Board Inspection Code* (NBIC) (2007). API 510 8.1 states "All repairs and alterations shall be performed by a repair organization in accordance with the applicable principles of the ASME Code, or the applicable construction or repair code."

Any pressure vessel that has been repaired or rerated should have an additional nameplate added with an "R" stamp displayed.

6. Picking the Right Tank. In upstream oil and gas operations, there are two types of "tanks" according to OSHA:

- Low-pressure tanks—maximum allowable working pressure (MAWP) from 0.5 to 15 psig

• Atmospheric tanks—MAWP from 0.0 to 0.5 psig

For low-pressure tanks, the OSHA requirements are very similar to those for pressure vessels. The design code is ASME Section VIII or API STD 620 *Design and Construction of Large, Welded, Low-Pressure Storage Tanks* (2010). The inspection code is API 510 or ANSI/NBBPVI NB23-2007, and the repair code is API 510.

For atmospheric tanks, the regulations are similar to those for pressure vessels in that "tanks built in accordance" with API SPEC 12B *Specification for Bolted Tanks for Storage of Production Liquids* (2008), API SPEC 12D Specification for Field Welded Tanks for Storage of Production Liquids (2008), or API SPEC 12F *Specification for Shop Welded Tanks for Storage of Production Liquids* (2008) "shall be used only as production tanks for storage of crude petroleum in oil-producing areas." Basically, the API has provisions for manufacturers to self-regulate themselves. A nameplate can be installed on the tank showing that the tank was built to the particular listed API specification with or without the API monogram. Those using the API monogram must meet more-stringent requirements set forth by the API and enter into a licensing agreement with the API. An API monogram on the tank nameplate is not required, but the other information required by the applicable API specification must be on the nameplate. In addition to the API series, tanks may also be built in accordance with the Underwriters Laboratory standards.

For atmospheric tanks, the inspection and repair code is API RP 12R1 *Recommended Practice for Setting, Maintenance, Inspection, Operation and Repair of Tanks in Production Service* (2008).

Additional information on venting capacity issues, corrosion control, and containment may be found in paper SPE 121031 (Johnstone 2009).

7. Specifying Rotating Equipment for Safety. Pumps. Centrifugal pumps are specified by either ANSI/ASME B73.1 *Specification for Horizontal End Suction Centrifugal Pumps for Chemical Process* (2007) or API RP 610 *Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries* (2010). API RP 610 is generally used for pumps in severe service, being defined as hydrocarbon liquids in a high-temperature environment. ANSI/ASME B73.1 specifications can be used in pumps with less rigorous service, where intrinsic reliability and high-temperature service are not required.

The discharge piping of pumps should be equipped with a relief valve to prevent overpressure of downstream piping, a check valve to prevent backflow, and a pressure high/low switch to alert the operators in the event of a problem with the discharge.

Questions are often asked about the need for a pressure safety valve (PSV) on the discharge of a centrifugal pump when the downstream piping is rated higher than the shut-in head of the pump. Centrifugal pumps can heat up the discharge fluids if the discharge valve is closed while the pump continues to run. The increased temperature can cause seal failure in a short time. For this reason, it is a good practice to install a relief valve or a recycle valve on the discharge of a centrifugal pump.

A shut-in valve on the inlet to pumps in light hydrocarbon or crude service should be installed. This safety device can close off flow to the pump in the event that there is a leak or fire downstream of the pump.

Internal-Combustion Reciprocating Gas Engines. Engine manufactures generally follow International Standards Organization (ISO) 3046-1:2002 *Reciprocating internal combustion engines—Performance—Part 1: Declarations of power, fuel and lubricating oil consumptions, and test methods—Additional requirements for engines for general use* (2002) when reporting engine horsepower ratings. Engine ratings will be degraded by ancillary equipment (e.g., fans, pumps), altitude, ambient temperature, and fuel composition. The engineer should work with the engine manufacturer to properly determine the available horsepower in accordance with ISO 3046-1:2002.

Engines will typically have shutdowns for high jacket water temperature, low oil pressure, and low fuel pressure. Pressurized natural gas is often used to start the units, and it can cause a fire hazard unless the gas is vented properly. The air exchangers and drive shaft need to be guarded properly to prevent personnel injury. Engines should also be equipped with a device to close off the incoming air to prevent the engine from overspeeding if there is a gas leak at the facility.

The fuel used for a gas engine should be free of liquids and hydrogen sulfide gas. Liquids in the fuel can cause premature engine damage by washing off the lubricating oil film from the cylinders. Additionally, slugs of liquid can cause the engine to overheat and also can cause damage to catalytic converters that may be placed on the engines.

Reciprocating Compressors. API STD 618 *Reciprocating Compressors for Petroleum, Chemical, and Gas Industry Services* (2007) deals with low- to moderate-speed compressors, typically in the 300- to 700-rev/min range, whereas API RP 11P *Petroleum and Natural Gas Industries—Packaged Reciprocating Gas Compressors* (2002) covers high-speed compressors (typically 900–1,800 rev/min) used in field compression applications.

All pressure vessels need to be protected with relief valves on compressors. Relief valves are generally placed on the inlet scrubber(s) and downstream of each stage of compression. High/low pressure switches should also be placed on the inlet and outlet of each stage. High temperature shutdowns should be placed on the discharge of each stage to shut the unit down in the event of a mechanical (i.e., worn valves) problem. A check valve should be placed downstream of the final discharge stage to prevent backflow in the event of a leak or piping failure.

Electric Motors. The National Electrical Manufacturers Association (NEMA) specifies motor enclosure types, insulation systems, and ratings for winding temperature rise. The NEMA standard for general-purpose industrial alternating-current squirrel-cage induction motors is designated as NEMA MG 1-2009 *Motors and Generators* (2010). Within this standard, descriptions are provided for various classifications of protection for motor enclosures in *Section 1—Classification According To Environmental Protection and Methods of Cooling.*

NEMA provides definitions for various motor enclosures. In general, there are two primary categories: open and totally enclosed. An open motor has openings that allow external air to pass over and around the motor windings to provide the required cooling. Although it is not airtight, the enclosure of a totally enclosed motor limits cooling of the windings from the external atmosphere. Motor cooling for totally enclosed motors is typically achieved by some external means, such as a fan or water cooling.

For Class I, Division 2 locations within the process area of a production facility, NEMA framed motors shall be totally enclosed fan cooled (TEFC). Class I, Division 1 locations require that NEMA frame motors be explosion proof motors that are totally enclosed and supplied with positive-pressure ventilation from a source of noncontaminated air.

Other applicable standards for motors include:

• IEEE 841-2009 *IEEE Standard for Petroleum and Chemical Industry-Premium-Efficiency, Severe-Duty, Totally Enclosed Fan-Cooled (TEFC) Squirrel Cage Induction Motors-Up to and Including 370 kW (500 hp)* (2009): This standard covers motors that are a cast iron, heavy duty, industrial design motor, intended for the chemical and petroleum industries.

• API 541 *Form-wound Squirrel-Cage Induction Motors—500 Horsepower and Larger* (2004): This standard provides minimum requirements for large, all form-wound squirrel-cage induction motors, 500 hp and larger.

• API 547 *General-purpose Form-wound Squirrel Cage Induction Motors—250 Horsepower and Larger* (2005): This standard provides minimum requirements for form-wound squirrel-cage induction motors that are used in general-purpose petroleum, chemical, and other industrial severe-duty applications.

8. Relief-System Design Is Critical. The purpose of a relief system is to protect piping and equipment from an excessive overpressure. Relief devices must comply with the appropriate ASME vessel codes, and relief systems must also comply with state and federal laws and codes. State and federal regulations cover environmental considerations as well as safety. The most common industry references are

- API 520 *Sizing, Selection, and Installation of Pressure-relieving Devices in Refineries, Part I—Sizing and Selection* (2008)
- API STD 521 *Pressure-relieving and Depressuring Systems* (2007)
- API 537 *Flare Details for General Refinery and Petrochemical Service* (2008)
- ASME *Boiler Pressure and Vessel Code, Section VIII-DIV 1—Rules for Construction of Pressure Vessels, 2005 Addenda* (2004)

An initial concern that should be addressed early in the design is whether a relief system is necessary or if atmospheric vents are acceptable. This decision should be made primarily on the basis of the type of fluids being handled and public exposure. In many cases, the safest, simplest, and most dependable means is direct venting to the atmosphere. However, releases of flammable liquids, condensing vapors, and toxic vapors, and/or ignition of vented streams, need to be assessed carefully.

When a vent or flare system is required, care should be taken to ensure that high-pressure reliefs dumping into a common system with low-pressure reliefs do not affect the operation of low-pressure relief devices. When a great divergence in pressures exists at a single facility, it may be advantageous to use two systems.

Relief-system design begins with the criteria for individual relief devices. The initial considerations are set pressure, allowable overpressure, and relief capacity requirements. Overpressure is the pressure increase over the set pressure of the primary relieving device. For single-relief-device systems, the set pressure of the device can be no higher than the MAWP of the system. For multiple device systems, the supplemental devices may be set higher than the MAWP, the exact set pressure being determined by the purpose for the additional capacity of the device.

Relief capacity requirements for a device or set of devices are determined by the worst-case upset scenario that can cause an overpressure condition. The most common upsets are as follows:

- Blocked discharge: This condition occurs, for example, if the equipment has been shut in and isolated, and an inlet valve has been opened without opening the outlet valve or this can also occur during an emergency shutdown (ESD), when several vessels and systems can be depressurized simultaneously.
- Fire exposure: The relief valve must be sized to handle the gases evolving from liquid if the equipment is exposed to an external fire.
- Tube rupture: In a heat exchanger, a tube rupture can allow gas to flow into the shell at the maximum rate from both sides of the tube break, which can overpressure the shell side if the design and operating pressure of the shell side is lower than that of the tube side.
- Control-valve failure (blow-by): Failure of an upstream control valve feeding a pressure vessel in the open position can send large volumes of high-pressure gas to the vessel.
- Thermal expansion: Blocked-in liquids can expand because of heating, which may cause an overpressure situation.
- Utility failure: Failure of electric power to shut down pumps, fans, compressors, or motor-operated valves can cause overpressure. Similarly, loss of cooling system (e.g., water, refrigeration) can create hazardous situations.

The allowable overpressure is normally 10% of the set pressure and is a consideration when evaluating the size for a relief device. Depending on the relieving scenario, the overpressure can vary from 10 to 21%.

When more than one relief device (or set of relief devices) relieves into a disposal system, determination of the maximum loading for system design can be complex. For system sizing, it is necessary to evaluate the upset conditions in order to determine the most likely case that will give the highest loading in the system. The most likely flow rate should be used for sizing the relief-system piping and determining the backpressures at each relief device.

Typically (but not always), the highest loading cases occur because of fire exposure. A conservative fire-circle diameter would be 100 ft, with an assumed height of 25 ft.

After overpressure, capacity, and backpressure are determined, the relieving device can be sized. Sizing equations for vapor and liquid flow are presented in the *GPSA Engineering Data Book* (GPSA 1987). The API has worked with the valve manufacturers to establish standard orifice sizes for relief valves. After the exact size for the orifice required has been calculated, the next larger standard orifice is selected.

The four main types of relief devices are as follows:

- Conventional: Conventional safety valves can be specified to vent either to the atmosphere or to a pressure-relief system. The conventional safety valve should be used when the discharge is routed independently to the atmosphere. If the discharge is connected to a header system, backpressure buildup when one device is relieving will affect the relief setting. For this reason, the use of a conventional safety valve should be avoided if backpressure exceeds 10% of the set pressure.
- Balanced: Balanced relief valves are springloaded and contain a bellows arrangement to keep backpressure from affecting the set point. Balanced relief valves are recommended when backpressure exceeds 10% of the set pressure and can fluctuate up to a maximum of 30% backpressure.
- Pilot-operated: Pilot-operated relief valves use the pressure in the vessel to hold the valve closed, with a pilot to activate the mechanism. Pilot-operated relief valves have the advantage of allowing operation near the set point with no chatter and are not affected by backpressure. However, they will not function if the pilot fails.
- Rupture disks: Rupture disks are diaphragms held between flanges and calibrated to burst at a specified static inlet pressure. A rupture disk is normally used as backup to a relief valve and, in this case, should be set at 120% of the MAWP at the maximum. Normal system pressure should not be more than 70% of the disk rupture pressure except for the reverse bucking type, which can be up to 80%. Rupture disks are also used under relief valves to protect them from corrosion. Rupture disks are very sensitive to the operating temperature.

The relieved stream is either vented to the atmosphere at a safe location or flared. The decision to vent or flare will depend on the prevailing local environmental and OSHA regulations. However, in small facilities and remote locations, the relief valves are normally vented to the atmosphere through a tail pipe that points the discharge vertically upward for better dispersion. In larger facilities where the relieved streams can be a source of pollution or ignition, relief valves usually will discharge into a common header leading to an atmospheric vent or to flare systems. When venting to the atmosphere, make certain that all piping is securely braced in the event that moments are created because of fluid velocity in the nozzles. It is recommended to consider a vent scrubber or a flare knockout drum to separate liquids from the relieved stream before venting or flaring. The introduction of slugs of liquids in the atmospheric vent or the flare tip is a potential safety hazard.

9. Determining the Right Electrical-Area Classification. The presence of electrical equipment continues to escalate, and surely will well into the future. Electrical equipment is used at an increasing rate to automate remote-lease facilities. Solar panels have brought electricity to remote production facilities. Personnel are also carrying more electronic equipment such as cell phones and laptop computers, which are usually "nonclassified," as part of their work. Along with the increase in electrical devices is the need to make sure that installed equipment meets the requirements of hazardous locations as defined by the National Electrical Code (NEC) (C2-1990).

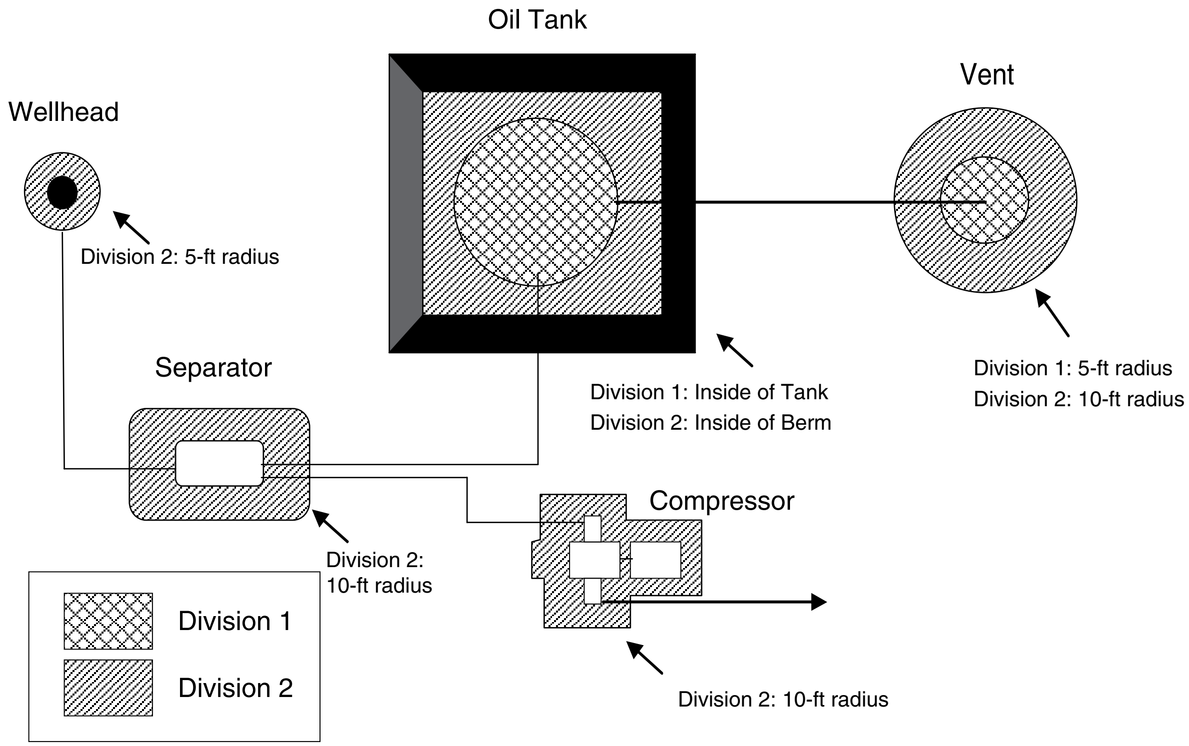

Fig. 1—Electrical-area classification for a basic production facility.

The NEC classifies hazardous locations generally into two different "divisions" for the oil and gas industry. The first classification, Class I, Division 1 locations, are defined as locations where ignitable concentrations of flammable gases or vapors can exist under normal operations; may exist frequently because of repair or maintenance or because of leakage; or may exist because of equipment breakdown that simultaneously causes the equipment to become a source of ignition.

The second classification, Class I, Division 2 locations, are defined as locations where volatile flammable liquids or flammable gases or vapors exist, but are normally confined within closed containers; where ignitable concentrations of gases, vapors, or liquids are normally prevented by positive mechanical ventilation; or adjacent to a Class I, Division 1 location where ignitable concentrations might be communicated occasionally.

The NEC also recognizes the International Electrochemical Commission (IEC) method for classification of areas. The two methods are compatible, and users can obtain equipment that meets the requirements of both the NEC and the IEC.

Many sites have been observed where the latest in low-voltage automation systems have been installed, but often these are not rated for classified areas. In many instances, this equipment has been used in other industries and has not yet been rated for hazardous locations. Personnel also need to recognize that carrying a "nonclassified" device into a "classified" area is in violation of the code.

The first step is to develop an "area classification" drawing for the site. API RP 500 *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2* (1997) provides a detailed guide on determining the classification for each area around drilling rigs, production facilities, and gas plants. API RP 500 is based on and is consistent with NFPA 497 *Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas* (1997). Refer to **Fig. 1** for an example of an area classification drawing based on API RP 500.

Generally, API RP 500 sets Class I, Division 1 areas as being confined areas where vapors are normally present and 5 ft around vents or stacks. Class I, Division 2 areas are generally confined areas where vapors are not normally present and 10 ft around stacks or vents. The area inside of a bermed area is also classified as Class I, Division 2.

The area classification drawing should be used to determine the placement and rating of electrical equipment. Only equipment that is certified by the manufacturer or allowed by the code should be used in a classified area. An example of nonclassified equipment is any electrical fitting or enclosure not labeled "Class I, Div 1 or 2." Other examples would be nonrated junction boxes, exposed wiring, batteries, transformers, light fixtures, controllers. or computers.

Nonclassified electrical equipment should be kept away from classified areas around vents, tanks, wellheads, separators, meter runs, compressors, and pumps, and outside of bermed areas. Areas with straight runs of piping (all-welded closed-piping systems without valves or flanges) are generally nonclassified and are suitable for the installation of electrical equipment.

10. Design the Instrumentation and Control System for Safety. Instrument alarms and shutdowns provide the first level of safety in the event that a process upset occurs. Control systems using programmable-logic controllers, distributed control systems, and supervisory-control and data-acquisition systems have greatly improved the safety of facilities by enabling advanced logic in safety systems and by making it easier to add alarm and shutdown points.

Safety systems can be examined in terms of levels of protection to prevent or minimize the effects of equipment failure within the process. Generally, facilities are built to have at least two levels of protection. API 14C *Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms* (2001) provides an excellent reference to help the engineer design in two levels of safety. Having two levels of safety allows for safe operation in the event that one of the protection means fails to operate as designed.

The two levels of safety should be independent and in addition to the control devices being used in the normal process operation. It is good practice for the two levels of safety to be provided by functionally different types of safety devices, the reason being that

TABLE 1—PROTECTING FOR ABNORMAL CONDITIONS

Condition	Cause	Effect	Primary Protection	Secondary Protection	Location of Safety Devices
Overpressure	High inflow pressure; thermal expansion	Sudden rupture or leak	Pressure safety high (PSH)	PSV	Gas vapor section
Leak	Corrosion, erosion, mechanical failure, rupture, external damage	Release of hydrocarbons to the atmosphere	Pressure safety low (PSL) to shut off inflow; check valve to prevent backflow; level safety low (LSL) on an atmospheric tank or vessel	Sump/drain system; LSH on sump system	PSL in vapor section; LSL at lowest point in atmospheric tank
Liquid overflow	High liquid inflow; upstream failure of a device; blockage of liquid outflow	Overpressure or excess liquids in downstream devices; release of hydrocarbons to atmosphere	Level safety high (LSH)	Sump/drain system; LSH on sump system	LSH at high point in vessel or tank
Gas blow-by	Failure of liquid level system; opening of bypass	Overpressure of downstream components	LSL	Safety devices on downstream component	LSL at lowest point in vessel or tank
Underpressure	Withdrawal in excess of inflow; thermal contraction when blocked in	Collapse of the component; leak	Atmospheric vessels: vent; pressurized vessels: gas makeup system	Atmospheric vessels: second vent or PSV; pressurized vessels: PSL to shut off inflow and outflow	PSL at highest practical point; PSVs and vents in accordance with good engineering practices
Excessive temperature	High inlet temperature; heater malfunction; fouling; fires	Reduction of working pressure and subsequent metal failure	Temperature safety high (TSH) if caused by fire or heated element; LSL if caused by low level; flow safety high by low flow	TSH for a fired component; TSH for heat medium oil systems	TSH in exhaust gas for fired system; TSH in liquid for heat medium system

if one device fails, an identical device could easily fail from the same causes. An example case of two functionally different safety devices is a high-pressure alarm and a springloaded pressure-relief valve, to provide two levels of protection in the event of a high pressure. Each of these devices works in a very different way and has different failure modes.

The engineer usually determines the minimum safety requirements for each process component. By examining each component as an independent unit, and assuming the worst-case conditions for input and output, the analysis will be valid for that component in any process configuration. **Table 1** illustrates how to determine protection requirements for a broad range of abnormal conditions.

11. Conducting a Process Hazard Analysis. A process hazard analysis (PHA) (US DOE 2004) is a systematic method to identify and analyze the potential hazards associated with a facility. The goal of the PHA should be to recommend any necessary design changes to make the facility "safe" during any abnormal or unplanned operating condition. Each facility should be designed to ensure that personnel, the environment, and equipment are "safe" if control equipment fails (i.e., liquid dump valves or pressure regulators), human operating errors occur (i.e., turning of the wrong valve or tanks overflowing), mechanical equipment fails (i.e., compressor valves or pump seals), or if natural causes occur (i.e., rain, freezing weather, or change of wind direction). Often PHAs are conducted during the design phase of the project, but the final design of the facility should undergo a PHA.

The benefits of conducting a PHA for facilities include

• Increased safety for personnel working at the facility.

• A greater understanding of how the facility functions and operates by those working with the PHA process.

• Reduced downtime and maintenance because potential problems are identified "up front."

• Optimization of equipment and potentially reduced equipment purchases. Often, PHAs will identify valves, piping runs, and other equipment items that are not needed.

There are many different types of PHAs that can be used to analyze a facility for hazards. Each different type of PHA has its advantages and disadvantages. Some techniques are performed in a team format (e.g., what-if, hazard and operability study) while others are performed by experts in a particular technique (e.g., failure-mode and effects analysis, fault-tree analysis). Usually, the best PHAs are those where the operations, engineering, and safety personnel can meet as a team and work through the hazards of the facility.

The results of the PHA should include findings, a risk ranking of the findings, and recommendations to resolve any of the findings. Recommendations should be followed up with a list showing the responsible party for making corrections and also the time frame in which the corrections must be made.

Any additions or changes to the facility that might impact the safety or materially change the PHA need to be reviewed. Companies usually employ a "management-of-change" process to make sure that changes do not degrade the safety systems put in place at the facility.

12. Design Verification and Commissioning. The successful prestartup safety review (PSSR) is a formal process to ensure that each component and system in a facility is thoroughly checked and ready to be brought into service. It is customary to use checklists so that nothing is overlooked and signoff can be achieved as each section is completed. The checklists focus attention on each key item and usually assign responsibility for completion. It is important that all disciplines be involved so that no detail is overlooked. Therefore, the checklists are as extensive as necessary for the particular facility, but not so detailed that they become cumbersome and ineffective. In the signoff process, any individual or group has the ability to delay startup until the issue of concern is resolved.

As part of the PSSR process, it is customary to generate "punch lists" describing actions that are necessary before startup as well as any items that will not hinder the startup but should be addressed as appropriate after startup.

Typical individual components of the PSSR process include the following topics. This is not meant to be an all-inclusive list, but experience has found these to be commonly overlooked.

• Instructions/Directions: Details of who should be involved, what the schedule is, what material is required, and a definition of the expectations.

• Engineering: Verification that proper facilities design has been performed. Typical documentation should include the project design basis, material and equipment specifications, documentation of equipment testing, material safety data sheet (MSDS), and other baseline data.

• Drawings: Typical drawings include process flow diagrams, piping and instrumentation diagrams, piping isometrics, equipment, civil, electrical/automation, and safety systems.

• Procedures: Including initial startup, normal operation, normal shutdown, emergency shutdown, temporary and simultaneous operations, and measurement.

• Training: Verify that all affected employees have been adequately trained and the training has been documented.

• Piping: Document that all piping components, valves, and controls are installed properly. Verify that components function properly and are identified properly.

• Pressure-relief devices: Verify that all devices have been verified for proper relief setting and are installed properly with any isolation valves sealed open.

• Blinds: Ensure that all construction blinds and skillets have been removed and that the proper documentation is in place. Also, document any isolation devices that are used to block flow into other systems that are not yet in service.

• Startup screens: Document that startup orifices, screens, and/or filters have been installed.

• Hydrotest: Verify that the system has been hydrotested to the appropriate pressure according to code and has been flushed, pigged, cleaned, and/or dried.

• Purging: Verify that the system has been purged properly to remove oxygen.

• Civil: Perform visual inspection for cracks, deformations, or other defects on all slabs, floors, block piers, vessel foundations, and sleepers. Verify that dikes are installed and are of appropriate height to hold required fluid volumes.

• General equipment: Verify that control valves fail to the correct position. Ensure that all flare lines, relief lines, and vent lines are free of liquid traps or low points. Check to be sure that equipment lubrication oil has been installed properly and that all valves have been lubricated.

• Pumps and compressors: Check to be sure that all equipment is installed properly according to the manufacturer's instructions.

• Electrical: Verify that all equipment is properly grounded and that all necessary seals are in place.

• Instrumentation: Check calibration, set points, and operation of all devices. Verify presence of proper identification tag.

In addition to the items just listed, the following general site-safety questions should be answered as a final check:

• Are all valves upstream and/or downstream of PSVs locked open?

• Are all atmospheric vents directed to safe locations and at safe elevations?

• Are all outlets of drain valves directed to avoid personnel injury (e.g., from liquid, flying gravel)?

• Has the facility ESD been updated?

• Is new/existing gas (e.g., toxic, combustible) detection equipment operational?

• Is equipment installed to prevent an emergency egress problem?

• Have appropriate signs (e.g., H2S, restricted entry, no smoking, confined space) and/or safety paint for marking potential hazards (e.g., tripping) been installed?

• Have cages and/or fall protection devices been installed on fixed ladders where required?

• Have cables for safety harnesses been installed?

• Have additional safety apparatus (e.g., showers, eye-wash stations) been installed where required?

• Has the emergency response plan been updated?

• Are there an appropriate number of fire extinguishers?

• Have appropriate measures been taken to minimize the noise from the new installation?

• Does the lighting for the area meet OSHA requirements?

• Do steps (concrete and others) and handrails meet OSHA requirements?

• Are vessels, tanks, and bulk-chemical-storage containers properly labeled or placarded?

• Are MSDSs readily available to the work force?

• Have valves, switches, and similar equipment been installed in a manner to avoid pinch points and other potential causes of injury during operation?

• Have reasonable ergonomic issues (e.g., computer work-station setups, valves, and similar equipment conveniently located in facilities, including proper tools) been addressed properly?

• Is the appropriate personal protective equipment (e.g., electrical, head, hand, chemical) available to the work force?

• Have equipment-specific energy-isolation procedures been prepared and communicated?

• Have company and/or contractor safety orientations been performed?

• Was a PHA conducted?

Conclusions

Many incidents and injuries can be prevented if production facilities are designed properly. The first step is to get management to "buy-in" that all injuries are preventable and that the company's facilities should be built to good industry practices and to regulatory requirements.

The recommended practices, codes, and standards for building safe facilities are readily available. Most of these items were first conceived after a major incident and have continued to evolve over the years. Engineers and operations personnel need to take the time to acquaint themselves with these recommended practices, codes, and standards so that they are comfortable in using them.

After the facilities are built, there are still two more things that should be done. First, a final PHA should be conducted to make sure that all of the needed safety systems are in place and that the operations personnel are not placed at risk. The second step is to conduct a PSSR to make sure that the piping, tanks, engines, pumps, and compressors have all been installed as planned.

There are numerous other topics that could be addressed in subsequent papers after these twelve basic parameters are covered. These might include setting project goals, cost management, integrity and knowledge management, constructability, mechanical handling, risk management, interface management, drain-system design, document control, and end-result realization.

The bottom line is that we as engineers need to do our best to make sure that field facilities are designed to be started, operated, and shut down so that no incident can ever occur from an unsafe design leading to personnel injury or property loss.

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