National Iranian Petrochemical Co.
HSE Directorship

# 3 Process Safety

## Design Basis Safety Concepts For Petrochemical Plants and Projects

IN THE NAME OF GOD

# 3 Process Safety

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# 3 PROCESS SAFETY

## Design Basis Safety Concepts For Petrochemical Plants and Projects

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Concessionaire : National Iranian Petrochemical Co. Health, Safety and Environment Directorship
Published by : HAK Publishing www.irannashr.ir

Circulation : 1000 Copies
ISBN: 978-600-6682-43-3
Design and layout : Torfeh Graphic Group www.graphicgroup.ir

Hak Publisher

National Iranian Petrochemical Co.
HSE Directorship.

# ۳ ایمنی فرآیند

## الزامات پایه ایمنی فرآیند در طراحی تاسیسات پتروشیمی

**عنوان و نام پدید آور:** Process Safety3
Design Basis Safety Concepts For Petrochemical Plants and Projects

**مشخصات نشر:** تهران: حک، ۱۳۹۴.

**مشخصات ظاهری:** ۱۱۲ص. جدول.

**شابک:** ۹۷۸-۶۰۰-۶۶۸۲-۴۳-۳

**وضعیت فهرست نویسی:** فیپای مختصر.

**یادداشت:** فهرستنویسی کامل این اثر در نشانی:
http://opac.nlai.ir قابل دسترسی است.

**یادداشت:** انگلیسی.

**یادداشت:** گردآورندگان: قدرت‌الله نصیری، علیرضا نریمان نژاد،
شهرام احمدی، معصومه جوادی مقدم، مسعود رفیعی.

**آوانویسی عنوان:** پروسس سیفتی تری...

**شناسه افزوده:** نصیری، قدرت الله، ۱۳۵۰ -

**شناسه افزوده:** شرکت ملی صنایع پتروشیمی واحد بهداشت، ایمنی و محیط زیست.

**شماره کتابشناسی ملی:** ۳۸۲۵۴۶۷

انتشارات حک

شرکت ملی صنایع پتروشیمی

## پیشگفتار

تولیـد پایـدار و ایمـن همـراه بـا توجـه ویـژه بـه مقوله سـلامت کارکنـان و حفـظ محیط زیسـت جـزء اولویت هـای اساسـی در واحدهـای صنعت پتروشـیمی می باشـد، که یکی از عوامـل مهـم در تحقق اهداف فـوق، لحاظ نمودن اصول ایمنی فرآینـد و طراحی ذاتاً ایمن این تاسیسات می باشد.

با توجه به روند توسعه صنعت پتروشیمی توسط بخش خصوصی در کشور و تنوع صاحبان لیسـانس و مشـاوران/طراحان بعضاً شـاهد سـطوح متفاوتی از طراحی ذاتاً ایمن توسـط ایـن مجریـان هسـتیم. از آنجائیکه شـرکت ملی صنایع پتروشـیمی (NPC) نقـش حاکمیتی در توسـعه ایـن صنعـت را بعهـده دارد، لذا بمنظـور اطمینـان از یکپارچگی و لحاظ شـدن حداقـل الزامـات در طرح ها و پروژه ها در طی مراحل مختلف انتخاب لیسـانس، طراحی پایه و مفهومی و عملیات ساختمان و نصب، این مدیریت نسبت به گردآوری و تدوین الزامات پایه ایمنی فرآیند شامل ۱۲ عنوان مدرک به عنوان سند بالادستی در قالب مجموعه ای سه جلدی اقدام نموده است که لازم است کلیه مشاوران/طراحان و پیمانکاران جهت ایجاد محیطی ایمن و پیشگیری از حوادث احتمالی از این الزامات پیروی نمایند.

قدرت ا... نصیری

مدیر بهداشت، ایمنی و محیط زیست

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# NPC-HSE-S-09

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## 1. Scope

This document describes the basic principles and Minimum Requirements for the evaluation of overpressure Protection and appropriate pressure relieving facilities as point of safety view. Other design aspects such as process, Mechanical, and calculations…shall be followed as per proper design standards and international practices. Blow down drums and flares aren't covered in this document.

## 2. References

- *ASME - Section I, Power Boilers.*
- *ASME - Section VIII, Pressure Vessels.*
- *ANSI B31.3, Petroleum Refinery Piping Code.*
- *API RP-520, Sizing, Selection and Installation of Pressure Relieving Devices in Refineries*
- *API RP-521, Guide for Pressure Relieving and Depressuring Systems*
- API RP-526 Flanged Steel Safety-Relief Valves.

## 3. Definitions

**Accumulation:** pressure increase over the maximum allowable working pressure or design pressure (in psi or kPa) of the vessel during discharge through the pressure relief valve, expressed as a percent of that pressure.

**Back Pressure:** pressure on the discharge side of a pressure relief valve. Total back pressure is the sum of superimposed and built-up back pressures.

**Superimposed Back Pressure:** pressure at the outlet of the pressure relief valve while the valve is in a closed position. This type of back pressure comes from other sources in the discharge system; it may be constant or variable; and it may govern whether a conventional or balanced valve should be used in specific applications.

**Built-up Back Pressure:** increase in pressure at the outlet of a pressure relief device that develops (typically due to friction but also static) as a result of flow through the discharge system after the pressure relief valve opens.

**Balanced Pressure Relief Valve**: A pressure relief valve which is designed to minimize the effect of back pressure on its performance characteristics.

**Balanced Bellows Pressure Relief Valve:** A balanced pressure relief valve that incorporates a vented bellows as the means for minimizing the effect of back pressure on the performance characteristics, opening pressure, closing pressure, lift and relieving capacity.

**Blow down:** Blow down is the difference between the set pressure and the reseating pressure of a pressure relief valve, expressed as percent of set pressure.

**Closed Discharge System:** discharge piping for a PR valve which releases to a collection system, such as a blow down drum and flare header. However, a closed system can also be a process vessel or other equipment at a pressure lower than the set pressure of the PR valve.
**Cold Differential Test Pressure:** the pressure at which the valve is adjusted to open on the test stand. This cold differential test pressure includes the corrections for service conditions of superimposed back pressure and temperature.
**Common Cause Failure Mode:** A coincident failure in two or more similar elements of a system caused by a single event. An example of a common cause failure mode is the simultaneous failure of two independent level instruments due to freezing of the process fluid in the instrument leads when exposed to low ambient temperatures.
**Conventional Pressure Relief Valve:** a closed-bonnet spring-loaded pressure relief valve that has the bonnet vented to the discharge side of the valve and is therefore unbalanced. The performance characteristics, i.e., opening pressure, closing pressure, lift and relieving capacity, are directly affected by changes in the back pressure on the valve.
**Design Capacity:** The capacity used to determine the required area of a relief device based on the limiting contingency.
**Design Contingency:** An abnormal condition including Maloperation, equipment malfunction, or other event which is not planned, but is foreseen to the extent that the situations involved are considered in establishing equipment design conditions.
**Design Pressure:** pressure in the equipment or piping under consideration at the most severe combination of coincident pressure, temperature, liquid level and vessel pressure drop expected during service, which results in the greatest required component thickness and the highest component rating (e.g., highest ASME B16.5 flange class). More than one set of design conditions should be specified if the most severe pressure, temperature, liquid level and vessel pressure drop will not occur at the same time. For pressure vessels, it is the pressure at the top of the vessel. Maximum liquid level and vessel pressure drop (if appropriate) should also be specified. Design pressure is equal to or less than the maximum allowable working pressure.
**Double or Multiple Contingency:** Two or more independent, unrelated, abnormal events that, if they occurred simultaneously or within a restricted short time interval, could result in an emergency.
**Emergency:** An interruption from normal operation in which personnel, equipment or the environment may be affected.
**Fire Risk Area:** Fire Risk Areas are established by the provision of access ways or clear spacing at least 20 ft. (6.1 m) wide on all sides with drainage to catch basins located within the fire risk area. This is used to determine the combined requirement for pressure relief due to fire exposure and should not be confused with the areas used to determine fire water and sewer capacities.
**High Integrity Protective System (HIPS):** An arrangement of instruments and other

equipment, including sensors, logic controllers and final control elements used to isolate or remove a source of pressure from a system or to trip a shut down or Depressuring device such that the design pressure and/or temperature of the protected system will not be exceeded. Typical HIPS applications include load reduction to existing flare systems and the protection of systems where conventional protective systems such as pressure relief valves have proven to be unreliable or impractical. By definition, HIPS is a safety critical system and must be independent from all other control schemes and from shut down systems whose failure can lead to an event requiring HIPS activation. Functionally, a HIPS must provide equal or lower (better) unavailability on demand than a typical pressure relief valve. To ensure that this criterion is met, HIPS should be specified to meet Safety Integrity Level (SIL) 3 or more.

**Intermediate - Time pressure Allowance (for piping only):** Per ASME B31.3, an increase of not more than 20% above the design pressure or the allowable stress for pressure design at the temperature of the increased condition. It is permitted for a maximum of 50 hours at any one time and for less than 500 hours per year.

**Maximum Allowable Working Pressure (MAWP):** For pressure vessels, per the ASME Code, MAWP is the maximum (gauge) pressure permissible at the top of a vessel in its normal operating position at the designated coincident temperature and liquid level specified for that pressure. MAWP does not apply to piping.

**Open Disposal System:** discharge piping of a PR valve which releases to the atmosphere either directly or via a collection system (could include a K.O. drum).

**Operating Pressure:** The gauge pressure to which the equipment is normally subjected in service.

**Overpressure:** the pressure increase over the set pressure of the relieving device during discharge. It is the same as accumulation when the relieving device is set at the maximum allowable working pressure of the vessel. It is also used as a generic term to describe an emergency which may cause the pressure to exceed the maximum allowable working pressure.

**Pilot-Operated Pressure Relief Valve:** a PR valve that has the major flow device combined with and controlled by a self-actuated auxiliary pressure relief valve. This type of valve does not utilize an external source of energy and is balanced if the auxiliary PR valve is vented to the atmosphere.

**Pressure Relief Device:** A device actuated by inlet static pressure and designed to open during an emergency or abnormal condition to prevent the rise of internal fluid pressure in excess of a specified value. The device may also be designed to prevent excessive vacuum. The device may be a pressure relief valve, a non-reclosing pressure relief device or a vacuum relief valve.

**Pressure Relief Valve:** This is a generic term applying to relief valves, safety valves or safety relief valves. It is commonly abbreviated to "PR Valve."

**Rated Capacity:** The capacity that pressure relief device can pass when fully open at accumulated pressure. This rate is greater than or equal to the design capacity. The relationship between *rated and design capacity is determined by the following ratio:* (design capacity / required area) = (rated capacity / selected area).

**Relief Valve:** an automatic pressure-relieving device actuated by the static pressure upstream of the valve, and which opens in proportion to the increase in pressure over the opening pressure. It is used primarily for liquid service.

**Remote Contingency:** An abnormal condition which could result in exceeding design pressure at the coincident temperature, but whose probability of occurrence is so low it is not considered as a design contingency.

**Rupture Disc Device:** A rupture disc device is actuated by inlet static pressure and is designed to function by the bursting of a pressure-retaining diaphragm or disc. Usually assembled between mounting flanges, the disc may be of metal, plastic, or metal and plastic. It is designed to withstand pressure up to a specified level, at which it will fail and release the pressure from the system being protected.

**Safety Critical Device:** any device (mechanical, pneumatic, hydraulic, electrical, or electronic), system or sub-system whose failure to operate properly may result in loss of containment leading to possible explosion, fire, or uncontrollable release of hazardous material. The term "safety critical" is usually applied to instrumentation, but any device may qualify as safety critical if its failure could lead to serious consequences. For example, heat tracing systems (steam or electric) used to prevent plugging of pressure relief devices due to solidification of process fluids are considered safety critical and should be identified as such. Check valves can also be safety critical under certain conditions. Other examples of safety critical devices include restriction orifices that limit the flow rate to a pressure relief device and Emergency Block Valves (EBVs).

**Safety Critical Instrument:** Any instrument, electrical, electronic or analytical device or system whose failure to operate properly may result in one or more of the following:

*a. A serious threat to the safety of plant personnel or the community through loss of containment and subsequent explosion, fire or personnel exposure to hazardous materials*

*b. Serious equipment damage with associated safety risk to plant personnel or the community*

*c. A serious environmental or industrial hygiene risk to plant personnel or the community.*

**Safety Relief Valve:** An automatic spring-loaded pressure relieving device suitable for use either as a safety valve or a relief valve, depending on application. It is used for vapor / gas service or for liquid service.

**Safety Valve:** An automatic spring-loaded pressure-relieving device actuated by the static pressure upstream of the valve and characterized by a rapid full opening or pop action. It is used for vapor or gas service.

**Set Pressure:** the inlet pressure at which the pressure relief valve is adjusted to open under service conditions. For a relief or safety relief valve in liquid service, the set pressure is to be considered the inlet pressure at which the valve starts to discharge with a significant volume under service conditions. For a safety or safety relief valve in gas or vapor service, the set pressure is to be considered the inlet pressure at which the valve pops open under service conditions.

**Short-Time Pressure Allowance (for piping only):** Per ASME B31.3, an increase of not more than 33% above the design pressure or the allowable stress for pressure design at the temperature of the increased condition. It is permitted for a maximum of 10 hours at any one time and for less than 100 hours per year.

**Single Risk:** The equipment affected by a design contingency.

**Spring Pressure:** The spring pressure is equal to the set pressure minus the superimposed back pressure for a conventional PR valve. For a balanced pressure relief valve, the spring pressure equals the set pressure.

**1.5 Times Design Pressure Rule:** Equipment design per ASME Code Section VIII, Division 1, is considered to be adequately protected against overpressure from remote contingencies if the maximum pressure during the remote contingency event cannot exceed the proof test pressure, or 1.5 times design pressure whichever is lower.

## 4. Basic Design Consideration

Overpressure is the result of an unbalance or disruption of the normal flows of material and energy that cause material or energy, or both, to build up in some part of the system. Any circumstance that reasonably constitutes a hazard under the prevailing conditions for a system should be considered in the design. Overheating above design temperature may also result in overpressure, due to the reduction in allowable stress. A pressure relief valve cannot protect against this type of contingency. Thus, to provide some degree of protection, safety critical instrumentation, Depressuring and fireproofing shall be considered.

Every unit or piece of equipment must be studied individually and every contingency must be evaluated. The safety equipment for an individual unit shall be sized to handle the largest load resulting from all possible design contingencies. If a certain abnormal situation would involve more than one unit, then all affected units must be considered together. In analyzing the system to identify all design contingencies that may occur and the resulting relief requirements (and overpressure protection system design), no credit may be taken for operator intervention in preventing a potential overpressure incident. No credit may be taken for the actions of process control or safety critical instrumentation other than High Integrity Protective Systems (HIPS) as the final protection layer in preventing a potential overpressure incident. When taking credit for HIPS or safety critical instrument systems, the designer must confirm that the dynamic response of the system as a whole, including sensing elements, transmitters control valves and the protected system as a whole is adequate to prevent the protected system pressure from reaching the relief device set pressure. Where warranted, a rigorous dynamic simulation of the system should be performed. Unless a rigorous dynamic simulation shows otherwise, it shall be assumed that the residual heat input from fired heaters following activation of the main fuel cut-out is 10% of the design heat duty.

The equipment judged to be involved in any one emergency is termed a “single risk.” The single risk which results in the largest load on the safety facilities in any system is termed the “largest single risk” and forms the design basis for the common collection system, such as the flare header, blow down drum and flare. The emergency which results in the largest single risk on the overall basis may be different from the emergency which forms the basis for each individual piece of equipment. While generally only a design contingency is considered for design purposes, there may be situations where two or more simultaneous contingencies should be taken into account, e.g., if there is some remote interrelationship between them, and pressures or temperatures developed could result in catastrophic failure. Such remote contingencies are also considered, but the “1.5 Times Design Pressure” rule may be applied in this situation. Overpressure which may occur at normal or below normal pressures, as a result of reduced allowable stresses at higher than design temperatures, are also evaluated and appropriate protective features applied in the design. For example, such conditions may result from chemical reactions, startup or upset conditions. Likewise, low metal temperature must be considered, such as from auto refrigeration, to make sure that brittle fracture conditions do not develop.

Compliance with Codes and Standards mentioned in References of this Doc. such as ASME Boiler and Pressure Vessel Code and ANSI B.31.3 is a requirement. Where more stringent codes apply, the local requirements must be met. Therefore, local codes must be checked to determine their requirements. The essential steps in the design of protection against overpressure are summarized below:

**1. Consideration of Contingencies -** All contingencies which may result in equipment overpressure shall be considered, including external fire exposure of equipment, utility failure, equipment failures and malfunctions, abnormal processing conditions, thermal expansion, startup and shutdown, and operator error. For each contingency, the resulting overpressure is evaluated and the need for appropriately increased design pressure or pressure-relieving facilities to prevent overpressure is established.

**2. Selection of Pressure Relief Device -** From the range of available pressure relief valves and other devices, selection shall be made of the appropriate type for each item of equipment subject to overpressure. Instrumentation, check valves, and similar devices are generally not acceptable as means of overpressure protection.

**3. Pressure Relief Device Specification -** Standard calculation procedures shall be applied to determine the size of the pressure relief device (usually a pressure relief valve) required for the maximum relieving rate, together with other information necessary to specify the device.

**4. Design of Pressure Relief Device Installation -** pressure relief device installation shall be designed in detail, including location, sizing of inlet and outlet piping, valving and drainage, selection of open or closed discharge, and design of closed discharge system to a flare or other location.

**5. Summation and Documentation of Contingencies -** The Design Specification shall include a tabulation of all major contingencies considered, together with their relief requirements.

# 5. Design Contingencies

## 5.1. General

All unfired pressure vessels designed to the ASME Code Section VIII must be protected by pressure relieving devices that will prevent accumulation (of excessive pressure) within the vessel exceeding 10% of the design pressure unless the design pressure of the vessel equals or exceeds the maximum pressure that could be developed.

Fired pressure vessels are covered by the ASME Code Section I (Power Boilers), which requires pressure relief devices to prevent accumulation exceeding 6%.

Selection of design pressure for equipment shall comply with relative design codes and standards. Design for overpressure protection in most cases consists of providing pressure relief devices sized to handle the calculated relieving rates necessary to prevent emergency pressures from rising above the design pressure (plus allowable accumulation).

For remote contingencies, the *"1.5 Times Design Pressure Rule"* is applicable. For situations where the relief area calculated for the remote contingency on the basis of the *"1.5 Times Design Pressure Rule"* exceeds the relief area calculated for the limiting design contingency, or when the remote contingency is the only overpressure scenario applicable to a pressure relief valve, the required PR valve relief area shall be set equal to the relief area calculated for the remote contingency based on applying the *"1.5 Times Design Pressure Rule"*. The relief flow rate reported in the specification sheet shall be set equal to the calculated capacity of a pressure relief valve having an effective relief area equal to the required relief area calculated above at the Code allowable accumulation.

In addition, the pressure drop between the vessel and the location of the PR valve (including inlet line losses) must be taken into account. For some equipment, the *"1.5 Times Design Pressure Rule"* may not apply. The yield stress must be reviewed based on the actual condition (physical and operational) of the equipment.

## 5.2. Fire

Equipment in a plant area handling flammable or combustible fluids is subject to potential exposure from an external fire, which may lead to overpressure resulting from vaporization of contained liquids. This hazard may exist even in items of equipment containing non-flammable materials. All vessels must be protected from overpressure. In addition, all vessels subject to overpressure by fire must be protected by PR valves, with the following exceptions:

**1.** If allowed by the applicable pressure vessel code, fire may be excluded as a contingency for PR device sizing for a vessel which normally contains no liquid, since failure of the shell from overheating would probably occur even if a PR valve were provided. Examples are fuel gas knockout drums and compressor suction knockout drums where a liquid level is not maintained.

Some jurisdictions require pressure relief valve protection for "dry drum" situations. However, it should be recognized that a pressure relief valve will only prevent the pressure from rising above the allowable accumulation and will not necessarily prevent (although it may delay) vessel failure due to overheating. In these cases, consideration should be given to the use of non-reclosing devices such as a rupture pin valve, rupture disc or fusible plug, since such devices will depressure the vessel upon actuation and reduce the risk of vessel failure due to overheating.

**2.** Interconnected vessels may be treated as one unit for pressure relief purposes during a fire (and also other contingencies) if the piping and valving between them meet applicable criteria as described in this document.

**3.** Except for special situations, (or unless required by local codes) pressure relief devices are not individually provided for fire exposure of piping. Special situations which may require individual pressure relief device include congestion and substandard spacing, or unusually large equipment with normal liquid holdup over 1,000 gallons (4 $m^3$) or which represents over 15% of the total wetted surface of the system to which it is directly connected for pressure relief.

**4.** Fire exposure overpressure protection for filters: Filters are typically designed to be blocked off from the process flow for periods of time and remain filled with liquid. Therefore, filters that can be blocked off should be provided with PR valves to protect them against fire exposure unless the filter falls in either of the following categories:

*(1) filter is made of pipe sections 24 in. (0.6 m) or less in diameter, or*

*(2) filter contains a non-flammable fluid, is not located within the diked area of a tank, and is located at least 20 ft. (6 m) in all directions from all sources of hydrocarbon or potential fire locations.*

Note that filters made of low melting alloys require special consideration since they require additional protection, such as fireproofing.

**5.** Fire exposure overpressure protection for heat exchangers: In situations where a fail-close control valve or an EBV can isolate the heat exchanger from the PR valve providing protection against fire exposure, a separate PR valve to protect the exchanger is required.

**6.** Vessels filled with both a liquid and a solid (such as molecular sieves or catalysts).

In this case, the behavior of the vessel contents normally precludes the cooling effect of liquid boiling. Hence rupture discs, fireproofing and depressuring should be considered as alternatives to protection by PR valves.

In calculating fire loads from individual vessels, assume that vapor is generated by fire exposure and heat transfer to contained liquids at operating conditions. For determining PR valve capacity for several interconnected vessels, each vessel shall be calculated separately, rather than determining the heat input on the basis of the summation of the total wetted surfaces of all vessels. Vapors generated by normal process heat input on compression, etc., are not considered. No credit is taken for any escape path for fire load vapors other than through the PR valve (which may be a common relief valve for more than one connected vessel), nor is credit allowed for reduction in the fire load by the continued functioning of condensers or coolers.

In order to determine the total vapor capacity to be relieved when several vessels are exposed to a single fire, a processing area may be divided into a number of smaller single fire risk areas by increased spacing. The selection of single fire risk areas within a plant or unit must, in addition, consider the design of the drainage system and the equipment layout. If a situation occurs which involves more than one fire risk area simultaneously (such as an entire plant), it would be classed as a remote contingency event, and the "1.5 Time Design Pressure Rule" may be applied.

Pressure relief valves cannot protect a vessel that becomes locally overheated on an unwetted surface, although they do prevent the pressure from rising beyond accumulation pressure. However, in such a case the vessel shall be effectively protected against failure by either one of two methods for mitigating the effect of fire:

- The Reduction of Pressure by Depressuring - Depressuring can be achieved by use of rupture discs or instrumented emergency Depressuring (vapor blow down) systems. When over pressure protection is only required because of fire exposure, rupture discs should be considered.
- Effective Limitation of the Heat Input - Application of firewater from fixed and mobile firefighting facilities is the primary method of cooling equipment which is exposed to fire. Further protection by fixed water deluge or spray systems, or fireproofing, is applied in areas of particularly high fire risk. However, in sizing PR valves, no credit is taken for reduced heat input due to application of cooling water, since it cannot be considered 100% effective in all fire conditions.

### 5.3. Utility Failure

Failure of the utility supplies (including (not limited to) electric power, cooling water, steam, instrument air or instrument power, or fuel) will in many instances result in emergency conditions with potential for overpressuring equipment. Although utility supply systems are designed for reliability by the appropriate selection of multiple generation and distribution systems, spare equipment, backup systems, etc., the possibility of failure still remains. Possible failure mechanisms of each utility must, therefore, be examined and evaluated to determine the associated requirements for overpressure protection.

Evaluation of the effects of overpressure attributable to the loss of a particular utility supply must include the chain of developments that could occur and the reaction time involved.

In some cases, the loss of utility supply is not a direct cause of overpressure, but it initiates a plant upset or emergency (e.g., power failure leading to loss of tower reflux), which in turn may result in overpressure. Failure of other utilities, such as inert gas to seals and purge systems, or compressed air (when used by the process) may in some cases determine pressure relief requirements. These cases are evaluated on a design contingency failure basis.

### 5.4. Equipment Malfunction

In addition to utility supply failures, items of equipment are subject to individual failure through mechanical malfunction. Such items include pumps, fans, compressors, mixers, instruments and control valves. The process upset resulting from such malfunctions (e.g., loss of a reflux pump) may in turn result in emergency conditions and the potential for overpressure.

In applying these rules, credit can generally be taken for pressure and temperature conditions existing under relieving or accumulated pressure conditions.

### 5.5. Purging / Clean out

During air or hydrocarbon purging or clean out, facilities used for these purposes might subject the vessels to pressures beyond their design. Each operation should be individually evaluated for adequate pressure protection requirements.

During purging or clean out, the possibility of failure of any valve in the system that could overpressure equipment shall be considered as a design contingency and dealt with appropriately, e.g., install a pressure relief valve to protect the system or uprate the design pressure of the equipment involved. However, if permanent blinding points or break-away connections and safety critical procedures are provided to avoid accidental overpressuring of equipment during purging or clean out, maloperation of valves in utility hookups may not need to be considered in evaluating pressure relief facilities. The complexity of the procedures and the frequency of their use are important factors to be addressed in this analysis.

### 5.6. Liquid Overfill

In all cases, if overfill can result in a pressure above the design pressure of the vessel, the PR valve must be sized to prevent overpressure due to liquid overfill. In analyzing liquid overfill, two general scenarios must be considered:

a. Liquid outflows stop while liquid inflows continue at design flow rates.

b. Liquid inflows increase above design flow rate (for example, due to a control valve failing open) while liquid outflows continue at the nominal turndown rates (typically, 50% of design). For this case, the extent of overfill possible may be limited by the upstream vessel inventory.

***CAUTION: The flow from the safety valve because of the overfill contingency may be two phase flow, especially if the inlet flow normally contains vapor. In the event of two phase flow, the PR valve must be designed to relieve the vapor plus liquid, minus the flow available through remaining normally open outlets, unless a dedicated PR valve is installed to specifically handle the liquid.***

Overfill must be considered as a design contingency for PR valve sizing purposes unless both of the following are provided:

*1. The vessel has a safety critical, independent high level alarm (LHA), and*

*2. The vessel vapor space above the independent LHA is equivalent to a 30 minute (or larger) holdup based on design liquid inlet rate and a stoppage of the liquid outflow.*

If the above are provided, the overfill contingency may be considered a remote contingency to which the "1.5 Times Design Pressure Rule" is applied. It is recognized that situations may arise where protection against overpressure caused by liquid overfill by the use of a pressure relief device may not be practical, and/or may be insufficient to ensure the integrity of the facility. For example, an existing disposal system may lack the capacity to absorb the relief load, or the vessel support structure may not be capable of supporting the weight of a liquid filled vessel without risk of structural failure. In such cases, the use of a High Integrity Protective System (HIPS) to protect against liquid overfill may be considered as an alternative (or in addition) to a pressure relief device. The intent of such a system is to render liquid overfill a double contingency, which need not be evaluated in the overpressure protection analysis. Two alternative architectures for such a system are suggested:

*1. Provide a safety critical, independent high-level alarm (LHA) located such that the vapor space above the LHA is equivalent to at least 30 minutes holdup based on design liquid inlet flow rate with zero liquid outflow (this makes liquid overfill a remote contingency) PLUS provide a safety critical, independent high-level cut-out on all incoming feeds including start up oil (this makes liquid overfill a double contingency), or*

*2. Provide a high-integrity, safety critical, independent high-level cut-out on all incoming feeds including start up .*

Regardless of the architecture chosen, the overall availability of the protective system must be equivalent to Safety Integrity Level (SIL) 3 or better (99.9% or more) for the protective system to qualify as a HIPS. In addition, the dynamics of the HIPS must be evaluated to ensure that the set pressure of the PR device will not be exceeded and that surge pressures associated with the rapid closure of the isolation valves are considered in the design of upstream and downstream piping systems. The use of a HIPS to eliminate the liquid overfill contingency (as described above) does not eliminate the need for a pressure relief device to protect the vessel against other potential overpressure contingencies such as fire, utility failure or operating failure. In addition, the possibility of leakage across the HIPS isolation valves must be considered in determining the required relief capacity of the PR valve protecting the vessel. To account for possible isolation valve leakage, the PR valve should have sufficient capacity to handle at least 10% of the relief load that would arise from liquid overfill without exceeding the allowable accumulation. For exceptional cases where the structural supports for a vessel are not designed for the weight of the vessel full of liquid and leakage cannot be tolerated, the use of double isolation valves with an intervening bleeder discharging to the flare (all actuated by the HIPS) shall be considered.

## 5.7. Operator Error

Operator or human error is considered a potential cause of overpressure. Contingencies of sabotage, gross negligence or incompetence are generally not considered. Gross negligence type items which generally are not included are: failure to install or remove blinds, bypassing of emergency devices, operating with closed block valves around pressure relief devices and misalignment of process flow during startup. While closing and opening of CSO and CSC valves in process streams could also be considered as gross negligence, these incidents are sufficiently severe that they must be considered, although the “1.5 Times Design Pressure Rule” may be applied in such cases.

## 5.8. Emergency Conditions Overpressure Evaluation

### 5.8.1. Failure of Automatic Control

Automatic control devices are generally actuated directly from the process or indirectly from a process variable (cascade), e.g., pressure, flow, liquid level, or temperature. When the transmission signal or operating medium fails, the control device will assume either a fully open or fully closed position according to its basic design (the fail-safe position), although some devices can be designed to remain stationary in the last controlled position. Such “remain stationary” control valves will, however, drift in the direction in which the spring drives the valve and this drift must be considered if it results in a more conservative design.

The failure of a process-measuring element in a transmitter or controller without coincidental failure of the operating power to the final controlled element should also be reviewed to determine the effect on the final controlled element.

However, when examining a process system for overpressure potential, one should assume that any one automatic control device could be either open or closed, regardless of its fail-safe action under loss of its transmission signal or operating medium. The following individual control valve failures shall be included in the analysis of control systems for determination of pressure relief requirements:

*a. Failure in the closed position of a control valve in an outlet stream from a vessel or system.*

*b. Failure in the wide open position of a control valve admitting fluid (liquid or vapor / gas) from a high-pressure source into a lower pressure system.*

*c. Failure in the wide open position of a control valve which normally passes liquid from a high-pressure source into a lower pressure system, followed by loss of liquid level in the upstream vessel and flow of high-pressure vapor. No credit is allowed for the response of the level* *controller which, under normal conditions, would close the control valve upon loss of liquid level, since this scenario could be caused by level controller failure. If detailed analysis indicates that flow through the wide open control valve is mixed phase, then this should be considered when determining the maximum flow through the control valve. High pressure may also be generated in the piping system as a result of liquid slugs being pushed by the vapor, hence the potential for excessive pressure from this mechanism should also be evaluated.*

*d. Failure in the closed position of a control valve in a stream removing heat from a system.*

*e. Failure in the open position of a control valve in a stream providing energy (heat) to a system.*

The following three scenarios must be analyzed for all fail open contingencies for control valves and the larger relief requirement used to evaluate the adequacy for overpressure protection:

*(1) The control valve fails wide open with its bypass valve partly open. This scenario is evaluated as a design contingency.*

*(2) The control valve fails wide open with its bypass valve also wide open (open 100%). This scenario is evaluated as a remote contingency.*

*(3) The control valve fails wide open with the bypass fully closed during startup. This scenario is evaluated as a design contingency.*

When the "bypass" valve consists of a duplicate control valve instead of a manual throttling valve (globe valve or equivalent), the same rules apply as for the case of manual bypass valves, provided that the duplicate control valve is operated as a "standby" or "spare" for the control valve normally in service (i.e., both control valves are never in service simultaneously).

However, if the level controller acts on both valves simultaneously or through a split-range arrangement, or if the failure position of both control valves is fail-open (FO) or fail-hold drifting open (FH (O)), then failure of both valves in the fully open position must be treated as a design contingency.

When vapor blow-through is possible due to failure of a high-pressure liquid letdown valve in the open position, the pressure-temperature rating for piping downstream of a high-pressure liquid letdown valve should be such that the maximum operating pressure of the equipment upstream of the letdown valve does not exceed the short-term allowable pressure for the pressure-temperature rating of the downstream piping at the operating temperature of the upstream system. The short-term allowable pressure is equal to 133% of the maximum continuous pressure allowed for a given pressure-temperature rating.

When analyzing such individual control valve failures, one should consider the actions of other control valves in the system in accordance with Item 2, Control Valve System Analysis. However, the PR valve must be sized to handle the peak flow condition calculated from the various possible contingency scenarios for control valves. Although control devices, such as diaphragm-operated control valves, are specified and sized for normal operating conditions, they are also expected to operate during upset conditions, including periods when pressure relieving devices are relieving. Valve design and valve-operator capability must be selected to ensure operation of the valve plug in accordance with control signals during abnormal pressure conditions. When wide discrepancies exist between normal and emergency conditions, the higher valve-actuator pressure requirements should be covered in the Design Specification.

When determining pressure relief requirements, one should calculate the capacities of control valves at the temperature and pressure that occur during the relieving conditions, since these are in many cases significantly different from capacities at normal operating conditions. Downstream equipment must be analyzed under relieving conditions.

**5.8.2. Cooling Failure in Condenser / Cooler**

In addition to the general failure of cooling water, failure of cooling water flow to each individual condenser or cooler must be considered. Normally, no credit is taken for any residual cooling in a shell and tube condenser after the cooling stream fails, because it is time-limited and dependent on physical configuration of piping.

**1. Total Condensing -** The relief requirement is the total incoming vapor rate to the condenser. If desired, credit may be taken for reduced relieving rate, when recalculated at a temperature corresponding to the new vapor composition at the PR valve set pressure plus overpressure, and heat input prevailing at the time of relief.

In the case of a fractionator, the overhead accumulator surge capacity at normal liquid level is typically limited to less than 10 minutes. Therefore, if the duration of cooling failure exceeds normal liquid holdup time, reflux is lost and the overhead composition, temperature, and vapor rate from the tower may change significantly. Hence, for many designs loss of a significant portion of tower overhead condensing capacity should be evaluated as loss of reflux. Also, the vapor load at the time of relief may be reduced below the normal operating rate, due to the higher pressure, which may suppress vaporization at the time of the overpressure. Pinchout of a reboiler is such a situation. In such a case, maximum steam process design conditions should be used, rather than the maximum steam pressure which could exist under pressure relieving conditions of the steam system.

**2. Partial Condensing -** The relief requirement is the difference between the incoming and outgoing vapor rates at relieving conditions. The incoming vapor rate should be calculated on the same basis as stated in Item 1. For a tower, if the reflux is changed in composition or rate, the incoming vapor rate to the condenser should be determined for the new conditions.

**5.8.3. Air Fin Exchanger Failure**

Loss of air fin exchanger capacity may result from fan failure, inadvertent louver closure, pitch control failure, or variable speed motor driver failure.

**1. Fan Failure -** For pressure relief design, the design contingency failure of one fan shall be considered. (Failure of all fans that would result from a general power failure would be included under utility failure considerations.)
**2. Louver Failure -** For pressure relief design, the design contingency closure of one set of louvers is assumed. (Failure of all louvers, that would result from a general instrument air or power failure, would be included in utility failure considerations.) No credit may be taken for continuing heat transfer due to natural convection, since the closed louvers would interfere with free air circulation.
**3. Pitch Control Failure -** For the purpose of pressure relief design, the fan pitch position that result in the least air flow (therefore least cooling) is assumed as a design contingency. Credit may be taken for continued cooling at this air flow.
**4. Variable Speed Motor Driver Speed Control Failure -** Failure of the driver speed control may result in a significant loss of cooling depending on the last speed of the fan. For the purposes of pressure relief design, the speed that results in the least air flow (therefore least cooling) is assumed as a design contingency.

### 5.8.4. Special Conditions in Closed Circuit

Where heating or cooling is used in a closed loop circuit (e.g., hot oil and refrigeration system), consideration must be given to overpressure conditions that might occur on loss of fluid flow, loss of heat input or loss of heat removal.

### 5.8.5. Reflux Flow Failure

In some cases, failure of reflux (e.g., pump shut down or valve closure) will cause flooding of the condenser, which is equivalent to PR valve capacity required for total loss of coolant. Compositional changes caused by loss of reflux may produce different vapor properties, which affect the relieving capacity. Usually, a PR valve sized for total tower overhead will be adequate for this condition, but each case must be examined in relation to the particular components and system involved.

### 5.8.6. Pump-around Flow Failure

The relief requirement is the vaporization rate caused by an amount of heat equal to that removed in the pump-around circuit. The latent heat of vaporization would correspond to the temperature and pressure at PR valve relieving conditions. “Pinchout” of steam heaters may be considered, if appropriate. When pump-around duty is high, or the feed to the fractionator is highly superheated, loss of a pump-around may cause a significant reduction in tower cooling and result in dry-out of the tower. Therefore, the potential for dry-out should be evaluated. The relief load due to fractionators dry out is usually the sum of all the vapor feeds entering the fractionators plus any stripping steam or Reboiler vapor (where applicable).

### 5.8.7. Absorbent Flow Failure

In a unit where large quantities of inlet vapor may be removed in the absorber, loss of absorbent could cause a pressure rise to relief pressure, since the downstream system may not be adequate to handle the increased flow. In such cases, the effect of this additional vapor flow into downstream equipment must be analyzed.

### 5.8.8. Loss of Heat in Series Fractionation System

In series fractionation, i.e., where the bottoms from the first column feeds into the second column and the bottoms from the second feeds into the third, it is possible for the loss of heat input to a column to overpressure the following column. Loss of heat results in some of the light ends remaining with the bottoms and being transferred to the next column as feed. Under this circumstance, the overhead load of the second column would consist of its normal vapor load, plus the light ends from the first column. If the second column does not have the condensing capacity for the additional vapor load, excessive pressure could occur.

### 5.8.9. Abnormal Process Heat Input

The required capacity is the maximum vapor generation rate at PR valve relieving conditions, including any non-condensable produced from overheating, less the normal condensation or vapor outflow rate. In every case, the designer should consider the potential behavior of a system and each of its components. For example, the fuel or heating medium control valve or the tube heat transfer may be the limiting consideration. Consistent with the practice in other causes of overpressure, design values should be used for an item such as valve size (except maximum trim is used for control valves). However, built-in over capacity, such as the common practice of specifying burners capable of 125 percent of heater design heat input, must be considered. Where limit stops are installed on valves, the wide-open capacity should be used rather than the capacity at the stop setting. In shell and tube heat exchange equipment, heat input should be calculated on the basis of clean, rather than fouled, conditions.

### 5.8.10. Emergency Conditions in Integrated Plants

In integrated plants, a process upset in one unit may have an effect on other units. All possibilities such as these must be carefully considered and the potential for resulting overpressure evaluated.

### 5.8.11. Accumulation of Non-condensable

Non-condensable do not accumulate under normal conditions since they are released with the process vapor streams. However, with certain piping configurations, it is possible for non-condensable to accumulate to the point that a condenser is "blanketed." Such a condition could occur if an automatic vent control valve failed closed for a period of time. This effect is equal to a total loss of coolant, and thus need not be considered separately.

### 5.8.12. Water or Light Hydrocarbon into Hot Oil

In some situations, the quantity of water present and the heat available in the process stream are known, or can be estimated hence, the PR valve size can be calculated. For example, in the case of a hot feed accumulator, it may be possible to estimate the pressure that would be developed if water were pumped into the vessel at various rates. Other examples where it may be possible to estimate the potential quantity of water that may enter the equipment include towers where loss of level in the overhead separator may send an oil-water mixture or even water as reflux to the tower, and in heat exchangers where a tube failure can introduce low boiling liquid or water.

Since the expansion in volume from liquid to vapor is so great (approximately 1,400-fold at atmospheric pressure in the case of water) and the speed of vapor generation is very great, it is questionable whether the PR valve could open fast enough to be of value. However, a rupture disc could provide relief for these explosion-like events and therefore, may be the most appropriate pressure relief device for this contingency.

### 5.8.13. Internal Equipment Blockage

Contingencies such as collapsed reactor bed vessel internals (e.g., fixed-bed reactor grids, reactor outlet collector collapse / plug, coked catalyst beds, accumulation of catalyst fines, plugging of screens and strainers, lines blocked with coke, etc.), should be considered, to identify any overpressure situations that could result. The use of the “1.5 Times Design Pressure Rule” is generally applicable in such cases, if this is a remote contingency.

### 5.8.14. Manual Valve

Inadvertent operation of a block valve while the plant is on-stream may expose equipment to a pressure that exceeds the maximum allowable working pressure. A PR valve is required if the block valve is not locked or car sealed in the open position and if closure of such valve can result in overpressure.

The quantity of material to be relieved should be determined at conditions corresponding to the PR valve set pressure plus overpressure, not at normal operating conditions. Frequently, there is an appreciable reduction in required PR valve capacity when this difference in conditions is considerable. The effect of friction pressure drop in the connecting line between the source of pressure and the system being protected should also be considered in determining the capacity requirement. If the valve passes a liquid which flashes or the heat content causes vaporization of liquid, this must be considered in determining PR valve size.

### 5.8.15. Hydraulic Surge

Pressure surge occurs in liquid filled piping systems when the velocity of the liquid changes rapidly due to sudden valve closure, sudden pressure letdown, pump start up, pump shut down or similar events. When pressure surge occurs, forces produced in the piping system may exceed the design capability. Various mechanical relief devices can be used to limit the magnitude of this pressure surge: rupture discs, accumulators, and proprietary devices.

#### 5.8.16. Startup, Shutdown and Alternate Operations

Not only design steady-state conditions, but also start up, shut down, wash out, regeneration, alternate feed stocks, blocked operations and other possible different conditions must be evaluated for overpressure protection.

#### 5.8.17. Increased Plant Capacity

When an existing plant capacity is increased, the entire pressure relieving system shall be re-evaluated, even though no new equipment has been added.

### 5.9. Overpressure in Specific Equipment Items

In addition to equipment malfunctions which can cause process overpressure in associated equipment, certain items of equipment are themselves subject to overpressure due to mechanical reasons. Such items include heat exchangers, pumps, compressors, turbines and fired heaters.

#### 5.9.1. Heat Exchanger Split Tube and Tube Leakage

In heat exchangers, tube failure must be considered as a potential contingency for overpressure of the low-pressure side. The low pressure side of an exchanger must be protected by pressure relief devices if the design pressure on the high pressure side is more than ”C” times the design pressure of the low pressure side and the low pressure side cannot handle the discharge from a split tube without exceeding ”C” times the low pressure side design pressure, where “C” is the multiplier applied to the low-pressure side design pressure to determine the hydrostatic test pressure. In determining whether the piping and equipment on the low-pressure side can handle a discharge from a split tube, any control valve present shall be assumed to be positioned for the minimum (turndown) normal design flow rate. If the control valve is normally closed or if the tube failure may cause the control valve to close, then no pressure relief can be assumed to occur through the piping. The entire low-pressure system must be examined for potential overpressure by a split tube. If the decision is to up rate the design pressure of the low pressure system in order to eliminate a split tube contingency, the complete low pressure system must be up rated or the entire low pressure side must be checked to ascertain that the “1.5 Times Design Pressure Rule” is met.

If a PR valve is required to protect the low-pressure side, the relief rate is defined by the maximum flow through the two open ends resulting from a guillotine cut of a single tube. The effect of flashing as liquid flows from the high pressure side to the low pressure side, vaporization of any liquid in the low pressure side due to resultant high temperature fluid, and loss of normal process flow in the low pressure side must be taken into consideration in determining the relieving rate for the PR valve.

In the event of a tube failure, transient pressures on the low-pressure side of the heat exchanger should be evaluated when the differential pressure between the high pressure side and the low pressure side equals or exceeds 1000 psi (6,900 kPa).

When the design pressure of the high pressure side exceeds the design pressure of the low pressure side by 1000 psi (6,900 kPa) or more and where an active corrosion mechanism is present, the probability and potential consequence of a multiple tube rupture shall be assessed at least qualitatively. Experience shows that in such exchangers the rupture of one tube has resulted in the rupture of several adjacent tubes due to a sudden pressure surge and deteriorated conditions of tubes in the exchanger.

This assessment shall consider both the Safety, Health and Environmental risks and the operational risk due to the likelihood that the event may render the affected equipment unfit for service, which will require replacement before normal operations are resumed.

In addition to evaluating the effect of a split tube, it should be recognized that internal tube sheet or tube leakage can occur, often unknowingly, under normal operation. Where the single action of deliberately blocking the low pressure side of the exchanger would result in the low pressure side of the exchanger exceeding 1.5 times its design pressure or its proof test pressure, whichever is lower, as a result of an internal leak, the low pressure side of the exchanger should be up rated; or a PR valve sized for the leakage through a 0.25 in. (6 mm) hole or a minimum size PR valve [1 in. x 2 in. (25 mm x 50 mm)] should be installed. Atlernatively, permanent signs warning against closing the block valves on the low pressure side unless a bleeder has been opened or the high pressure side has been isolated and blinded should be attached to the block valves on the low pressure side. If blockage of the low-pressure side can occur as a result of an operating event such as total closure of a control valve, the contingency is no longer considered remote and must be treated as a design contingency for the purposes of overpressure protection.

Where brittle fracture conditions might occur in the low pressure side, various procedures to minimize the chance of tube failure (such as welding the tubes into the tube sheet and upgrading the tube materials to obtain better corrosion resistance) are acceptable alternatives to specifying brittle fracture resistant materials throughout the low pressure side.

### 5.9.2. Pumps and Downstream Equipment

A PR valve is required for a pump when the shut-off pressure of the pump is greater than the design pressure of the pump casing, the discharge piping, or any downstream equipment that may be blocked-in against the pump. Positive displacement pumps normally require a PR valve for overpressure protection since the pump shut-off pressure cannot generally be defined. When a PR valve is required, the PR valve set pressure is normally equal to the design pressure of the equipment being protected. When the equipment being protected has different design pressures, the set pressure of the PR valve must take into consideration the lowest design pressure in the system (which may be in the pump auxiliary equipment such as flushing / seal systems). The PR valve is sized such that the accumulation during relief will not exceed allowable overpressure (1.1 or 1.16 times the lowest design pressure, depending upon the number of relief devices used). However, where only piping is involved, a short-term pressure allowance may apply. If the pump casing design pressure or the mechanical seal design pressure is lower than the maximum pressure at shut-off of the pump, the maximum pressure at shut-off of an associated operating pump, or the design pressure of the pump auxiliary equipment (such as external flushing or seal systems), a PR valve must be installed to protect the pump. The set pressure for a pump PR valve is the lower of the pressure rating of the mechanical seal, the pump casing pressure or the design pressure of any other limiting component. The PR valve is sized for the potential source of excessive pressure, as follows:

1. *If external flushing or seal systems are the only source of excessive pressure, a pump suction PR valve is sized for the maximum flow from these systems.*
2. *If the only source of excessive pressure is an associated pump, a pump suction PR valve is sized for reverse flow through the downstream check valve. When drilled check valves or check valve bypasses are specified for pump warm-up purposes, the pump suction PR valve shall include capacity for the normal flow associated with these facilities.*
3. *If the source of excessive pressure can be both the external flushing / seal system and an associated pump, a pump suction PR valve is sized for the greater of 1 or 2.*
4. *If the source of excessive pressure is the discharge of the pump, a pump discharge PR valve is sized for the maximum actual rate that the pump can deliver at the accumulated pressure of the PR valve.*

The design pressure of a steam-driven reciprocating pump and downstream equipment may be set by the maximum process pressure which the steam cylinder is able to produce at maximum steam pressure, in which case no pressure relief facilities are required. For reciprocating pumps driven by electric motors, PR valves serve the dual purposes of protecting the pump and downstream piping from overpressure, and protecting the driver from overload. Other positive displacement pumps, such as rotary, gear, and diaphragm pumps, normally require PR valve protection for both the pump and downstream equipment.

For any pump requiring a PR valve for its protection or for protection of downstream equipment, the PR valve set pressure should be higher than the normal pump discharge pressure. Note, however, that in some cases a higher PR valve set pressure may be desirable to assure a sufficient differential when the pump is to be operated under lower than normal design pumping rate. This will recognize the higher pump discharge pressure under low flow conditions. In the case of reciprocating pumps protected by spring loaded PR valves, the PR valve should be set above the maximum pulsation pressure or 15 percent above the operating pressure, whichever is greater. When this is not possible because of equipment design pressure or specified operating pressure level, pilot-operated valves should be considered.

The capacity of a pump discharge PR valve should equal the capacity of the pump at the pressure conditions existing while the PR valve is relieving. To reduce the size of a PR valve installed at the discharge of a centrifugal pump with a known pump curve, advantage can be taken for the reduction in pump capacity as it backs up on its performance curve. Pump PR valves should discharge to a closed system. In many cases discharge paths may be routed to the suction line or suction vessel.

**5.9.3. Compressor and Downstream Equipment**

PR valves are required for any compressor where the maximum pressure which can be generated during surge or restricted discharge conditions exceeds the design pressure of the discharge piping, downstream equipment compressor seals, or compressor casing.

if Low-pressure stage casings and inter-stage circuits on both centrifugal and positive displacement multi-stage compressors are not normally designed for full discharge pressure ,

they must also be provided with overpressure protection. Where inter-stage PR valves are required, PR valve capacity should be equal to the compressor capacity at the emergency conditions. If recycle and/or anti-surge lines are provided, inter-stage PR valves should be sized for the greater of the compressor capacity or the flow through the recycle lines with fully opened recycle valves, assuming check valve leakage. Where a reciprocating compressor is used, the compressor internals may be considered the same as a single check valve.

For reciprocating compressors, if an operating compressor stops running, vapor may backflow through the compressor and overpressure equipment upstream of the compressor. To calculate the amount of vapor which may backflow through a reciprocating compressor consider each compressor stage as a single check valve. If there is a check valve in the discharge of the stage, consider it as an additional check valve.

Note some multi-stage machines have recycle lines around individual cylinders, with control valves, for start up or capacity control. These must be assessed separately, similar to the standard low flow recycle loops.

For centrifugal compressors, the combination of PR valve set point and relieving capacity should be such as to avoid surge conditions over the anticipated combinations of emergency conditions and operating variables. Compressor PR valves should discharge to an appropriate atmospheric or closed system, and not directly to the suction of the machine. Since many variables are involved, it may be advisable to consult the Machinery Engineering Section on specific problems.

**5.9.4. Steam Turbines**

A PR valve is required on the steam inlet to any steam turbine if the maximum steam supply pressure is greater than the design pressure of the casing inlet. The PR valve shall be set at the casing inlet design pressure and sized such that overpressure of the casing is prevented under conditions of wide open steam supply and no exhaust flow. Protection of the exhaust end of steam turbines is dependent on whether they are in condensing or no condensing service, as per international practices and design standards.

**5.9.5. Fired Heaters and Boilers**

Two potential forms of overpressure may apply to fired heaters and boilers: overpressure of the firebox by forced-draft fans or tube rupture; and overpressure of tubes due to outlet blockage or from overheating due to loss of process flow.

**1. Firebox Overpressure -** The firebox of a forced-draft fired heater or boiler shall be designed to withstand the overpressure that can be generated by the fans with dampers in their closed position. This needs to be specially checked when both forced and induced-draft fans are provided to discharge combustion products through heat recovery facilities, since higher than normal fan pressures may be used to overcome pressure drop. When excessive pressure can be developed, protection can be provided by use of a high pressure cut-out or pressure relief doors.

In the case of high pressure process fired heaters, a tube rupture could also be the cause of firebox overpressure. In this case, “explosion” doors can be used to provide protection. When the tube pressure exceeds 1,000 psig (6900 kPa gauge), the analysis is complex and combustion specialist should be consulted.

**2. Boiler Steam Side Overpressure -** All fired boilers shall be provided with PR valves sized to relieve the full steam rate in the event of closure of the normal outlet, in accordance with the ASME Code, Section I (Power Boilers), or other applicable regulations.

Overpressure protection for waste heat boilers shall be designed in accordance with the ASME Code requirements for pressure vessels.

**3. Process Fired Heater Coil Overpressure -** The coil of any fired heater where the process flow can be stopped by inadvertent closure of a valve in the fired heater outlet (operator error) or as a result of planned emergency action, is subject to potential overpressure and tube failure due to overheating and consequent reduction in allowable stress. Unless such mechanisms of flow interruption (arising from a design contingency) can be effectively eliminated, the fired heater must be protected against loss of process flow, which can lead to overheating and tube failure, and against overpressure from upstream equipment such as pumps or compressors.

Protection against loss of process flow is required for all fired heaters, whether or not they are equipped with a block valve and/or a PR valve at the coil outlet. All fired heaters shall have a safety critical low flow cut-out with pre-alarm which shuts off the main fuel(s) on low process feed flow. The provision of a PR valve on the outlet of a fired heater to ensure continuity of process flow if the coil outlet is blocked is not recommended because of the potential for coking at the PR valve inlet and for thermally shocking the discharge piping when the PR valve blows.

Protection against overpressure can be achieved by setting the coil design pressure at or above the shut-off pressure of the feed source(s) or by providing a PR valve. If a PR valve is provided, it should preferentially be located at the coil inlet. When a PR valve is provided on the fired heater feed line, the valve should be located upstream of the orifice which senses low fired heater feed flow and actuates the fuel cut-out, so that the fuel will be cut out in case the fired heater should be blocked at the outlet.

The design features required reducing the likelihood of fired heater tubes overheating and subsequent overpressure shall be considered.:

When an EBV (Emergency Block Valve) is installed in a fired heater outlet for emergency isolation purposes, it is necessary to rapidly cut out the main fuel supply to prevent tube rupture in case the EBV should inadvertently be closed. This is achieved by providing a low-flow cut-out on the total feed to the fired heater. In addition, the EBV should be equipped with a limit switch that will trip the main fuel supply to the fired heater and shut down the pump(s) and/or compressor(s) feeding the fired heater when the valve reaches the half-closed position.

### 5.9.6. Fractionator Overhead Systems

In addition to the design contingencies valid for the tower, the overhead system is also subject to a number of unusual contingencies. Guidance on how to consider these, assuming the main means of protection are pressure relief (PR) valves in the tower itself or in the overhead line follows:

**1. Tube Rupture -** In many designs the overhead duty as well as tower reboilers and pre heaters are divided into a number of different services for heat integration purposes. Since some of these services may be at a considerably higher pressure than the tower, tube rupture in the shell & tube exchanger and its impact on tower PR valves needs to be assessed. Key considerations are the following:

**a.** Tube rupture is a remote contingency.

**b.** When the tube rupture occurs, all other equipment continues to function at its normal minimum (turndown) capacity unless there are automatic systems that would be triggered by the contingency and cause equipment operation to change. If this change in operation (triggered by the automatic system) would increase the relief available through normal routes, credit may not be taken for the additional relief above the normal minimum (turndown) out-flow form the system. If the change in operation (triggered by the automatic system) would decrease the relief available through normal routes, this debit should be taken into account to the full extent.

**c.** Since the tube rupture is already assumed to be a remote contingency, when it occurs the operator is assumed to take no action; neither positive (that would reduce the overpressure) nor negative (that would result in even greater overpressure).

**2. Overhead Drum Overfilling -** Overfilling of an overhead drum occurs when the incoming liquid from the condenser exceeds the outflow because flow ceased in this route. This contingency should be reviewed.

Once the vessel overfills, if the PR valves protecting the drum are located on the tower overhead, the level in the overhead system will continue to rise up to the condenser inlet. At this point the level will not increase further since there will no longer be any incoming liquid. Instead the lack of a disposal route for the overhead vapor will cause the tower PR valves to open. Therefore, at a minimum the tower PR valves must be designed for the full overhead flow.

Regardless whether the drum overfilling contingency is judged a design or a remote contingency, the design pressure of the overhead drum must take into account the maximum fill level that will be reached during the contingency. Hence, if the overfill is a design contingency, the drum design pressure must be equal to the set pressure of the tower PR valves plus the static head up to the flooded condenser.

**3. Tower Overfilling -** tower overfill must be considered as an overpressure contingency. As with the overhead drum overfill contingency, regardless whether the tower overfill contingency is judged a design or a remote contingency, the design pressure of the overhead drum must take into account the maximum fill level that will be reached during the contingency. Hence, if the overfill is a design contingency, the overhead drum and associated equipment design pressure must be equal to or greater than the set pressure of the tower PR valve plus the static head up to the tower PR valve elevation. If the overfill is a remote contingency, the overhead drum design pressure must be equal to or greater than two-thirds of the sum of the accumulated pressure of the tower PR valve plus the static head up to the tower PR valve elevation. In addition, for the tower overfill contingency, the complete overhead system and all attached equipment (e.g., side stream stripper) must be designed to be liquid filled with the maximum specific gravity liquid. This may require special considerations for the support of affected equipment.

### 5.9.7. Pressurized Storage (Offsites)

In general, offsite pressurized storage is designed as a pressure vessel and PR valves shall be provided for all valid contingencies similar to onsite facilities. However, due to the location of these vessels, a number of special considerations must be considered, as follows:

*1. When overfilling of the pressurized storage is physically possible (i.e., the feed pumps have sufficient head to overcome the liquid level and the PR valve set point), it must be considered as a contingency. The relief rate would be based on the characteristics of the feed pump and credit may be taken for reduced rate at the accumulated PR valve pressure. In addition, consideration must be given to the flashing and auto refrigeration that may occur as the fluid is relieved through the PR valve.*

*2. If pressurized storage vessels are not designed for full vacuum, a vacuum vent / breaker must be installed. In addition, since the vacuum breaker would permit air ingress (which may form a flammable-air mixture), a low pressure cut-in that introduces fuel gas or a suitable inert gas should be provided and its set point adjusted such that it actuates prior to any air entering the vessel.*

#### 5.9.8. Piping

When the piping to be installed does not have the same design pressure as the equipment to which it is connected, it may be protected against overpressure by the use of PR valves. The set pressure for these PR valves would generally equal the design pressure of the piping. Overpressure caused by thermal expansion is a special situation and is covered later in this document.

### 5.10. Chemical Reaction

In chemical reaction processes, decomposition reactions and temperature runaways may occur as a result of feed or quench failure, overheating of feed, contaminants, or other similar causes. These unwanted chemical reactions may result in excessive temperature and pressure in the reactor vessels. The system behavior during the emergency can be characterized as follows:

**1.Tempered -**Tempered systems are those in which the unwanted reaction produces condensable products and the temperature and pressure rise are directly linked by the vapor pressure curve of the reactants and products in the reactor. Typically, tempered systems are liquid phase reactions in which a reactant (or solvent) is a major part of the reactor contents and absorbs the majority of the heat produced by the chemical reaction.

**2.Gassy -** Gassy systems are those in which the unwanted reaction produces a non-condensable product and therefore the pressure and temperature in the reactor are not tied to the vapor pressure characteristics of the reactor contents. Gassy systems may be either liquid phase decompositions or gas phase reactions.

**3.Hybrid -** Hybrid systems are those that exhibit characteristics of both tempered and gassy systems. Many times the hybrid system will initially behave as a tempered system but subsequently develop into a gassy system.

Systems that are tempered can, under some circumstances, be protected against overpressure caused by an unwanted chemical reaction with the use of PR devices. Gassy and hybrid systems tend to overheat and result in requiring excessively high relieving rates. In either case, systems that are gassy or hybrid cannot, in general, be fully protected against overpressure caused by the unwanted chemical reaction with the use of PR devices. For situations where protection cannot be fully provided by PR devices, safety criticritical instrumentation shall be used. Overheating can result in overpressure due to reduction of allowable stress. Therefore, the design of systems prone to these incidents must include monitoring and control features to reduce the occurrence of decompositions and runaway reactions in gassy systems since conventional pressure relieving devices cannot normally provide protection against these contingencies.

Design temperatures for these systems must be specified at a margin above normal operating temperature sufficient to permit the detection of abnormal temperatures and activating of corrective measures by manual or automatic controls. Where the equipment being protected is susceptible to plugging, care must be taken to ensure that depressuring or shutdown facilities will work as intended.

## 5.11. Abnormal Temperature

The inter-relationship of allowable stresses (and hence design pressure of equipment) and temperature must be considered for operating conditions which may exist during upsets, emergencies, startup or shutdown. Low temperatures which may result from ambient conditions, auto refrigeration, etc., must also be evaluated to ensure that vessels which may be subjected to temperatures below embrittlement transition temperatures are designed such that allowable stresses under these conditions are not exceeded.

## 5.12. Thermal Expansion

Lines or equipment which can be left full of liquid under non-flow conditions and which can be heated while completely blocked in, must have some means of relieving pressure built up by thermal expansion of the contained liquid. Solar radiation, as well as other heat sources, must be considered. The following are common examples of some thermal expansion mechanisms.

**1.** Piping or vessels blocked in while filled with liquid, and subsequently heated by heat tracing, coils, or heat transfer from the atmosphere or other equipment.

**2.** Piping or vessels blocked in while filled with liquid at or below ambient temperature, and subsequently heated by direct solar radiation. Cryogenic and refrigeration systems must particularly be examined in this respect. Note that as a result of radiative cooling at night it is possible for piping to be cooled 10°F (6°C) or more below the ambient temperature.

Similarly, solar radiation can increase piping temperature 20°F (11°C) or more above the ambient temperature.

**3.** A heat exchanger blocked in on the cold side with flow continuing on the hot side.

The potential for overpressure due to liquid thermal expansion is recognized by codes and standards, for example, ANSI B31.3. Leakage from the trapped system alleviates the pressure increase but typical leakage rates, particularly for soft seated valves, are insufficient to prevent a significant pressure rise in the trapped section.

The maximum allowable leakage rates in API Std-598 for new valves are as follows:

| Valve Type | Maximum Leakage Allowed,gpm($m^3$/sec) |
|---|---|
| Gate | 0.0003 ($1.9 \times 10^{-8}$) |
| Globe | 0.0003 ($1.9 \times 10^{-8}$) |
| Plug | 0.0003 ($1.9 \times 10^{-8}$) |
| Metal Seated Check | 0.0006 ($3.8 \times 10^{-8}$) |
| All Soft Seated | 0.0 (0.0) |

Note that in attempting to identify the temperature change versus pressure change, consideration must also be given for a constant pressure source such as a running pump. This type of situation may be normal practice when a pump supplies a number of users at remote distances. For example, if a line was blocked-in against a running pump in the evening at 150 psig (1035 kPa) and 50°F (10°C), and the temperature fell to 32°F (0°C) at night with the pump still running, and the next day the line was heated to 90°F (32°C), the $\Delta T$ is 58°F (32°C) instead of a $\Delta T$ of 40°F (22°C).

Protection against thermal expansion overpressure shall be included for specific applications in accordance with the following:

**1. Heat Exchanger -** Heat exchangers, where the cooler side can be blocked in full of liquid while the hot side fluid flow continues, must be protected by either:

*a. A manually operated bleeder valve, plus caution sign when both block valves are located at the exchanger. If both block valves are not at the exchanger, Method b. or c. below must be used.*

*b. A small permanently open bypass around one of the block valves.*

*c. Installation of a PR valve.*

If a bypass or PR valve is provided, its capacity must be adequate to relieve any vapor generated from the cold fluid by heat input from the hot side under design flow conditions. Note that a check valve in the piping upstream of the cooler side of an exchanger is considered as a block valve.

**2. Piping -** Sections of piping in any liquid service, whether onsite or offsite, which can be blocked in while liquid filled and subjected to liquid thermal expansion from subsequent heating, must be protected by one of the following:

*a. Installation of a PR valve.*

*b. Means for withdrawing liquid so that the line does not remain liquid filled (procedures to require drainage must be in place and enforced).*

If a thermal relief valve is provided, it should relieve to a closed system when possible (may be required to relieve to a closed system by local codes).

**3. Vessels -** All vessels and equipment which can be blocked in while liquid filled and subjected to subsequent heating and thermal expansion, must be protected by any one of the methods described above for piping, i.e.,

*a. Installation of a PR valve.*

*b. Means for withdrawing liquid, generally manual, but requiring well defined procedural safeguards.*

In cases where vessels are provided with PR valves for protection against overpressure from fire exposure or an operating failure contingency, additional thermal expansion protection is not required.

**4. Control Valve -** Double-seated control valves are considered to pass sufficient leakage flow that equipment blocked in by such valves need not be provided with thermal expansion protection.

***Notes:***

***1. for onsite locations, thermal expansion PR valves releasing liquid must discharge into a closed system if the liquid within the system is toxic or above its flash point.***

***2. In offsite locations, thermal expansion PR valves may discharge to a flare header upstream of a knockout drum, if available, or to the equipment (e.g., a tank) on the opposite side of one of the blocking-in valves, or to the atmosphere. Atmospheric discharges where permitted by local regulations, must be at grade level in a safe location.***

***3. Thermal expansion PR valves in onsite or offsite locations which release severely toxic fluids discharge to an appropriate closed system.***

***4. Each thermal expansion PR valve should be provided with an inlet CSO valve (and an outlet CSO valve in the case of closed discharge) to permit isolation for inspection and testing, if permitted by local codes.***

## 5.13. Vacuum

Equipment which can operate under a vacuum, either continuously or intermittently, must be designed to withstand partial or full vacuum conditions or otherwise be protected. In some cases, this may include piping as well as vessels or other equipment. Other equipment which does not operate under vacuum, either continuously or intermittently, may be exposed to vacuum inadvertently, by contingencies such as the following:

***1.*** *Instrumentation malfunctions.*

***2.*** *Drainage of non-volatile liquid from a vessel without atmospheric venting or gas re-pressuring.*

***3.*** *Shutting off steam at the completion of steam purging without admitting a non-condensable vapor (e.g., air at shutdown, fuel gas at startup).*

***4.*** *Maloperation of valves.*

*5. Low ambient temperatures resulting in sub atmospheric vapor pressure of certain materials in pressure storage.*
*6. Loss of heat input to closed process equipment handling low vapor pressure materials, while cooling continues such as by a condenser or through heat loss to the atmosphere.*
*7. Loss of heat input to waste heat boilers with resulting condensation of steam.*
*8. Loss of heat input to closed process equipment where appreciable quantities of steam are generated.*
*9. Overcooling in total condensers.*

any vacuum condition which can be created during process operation such as abnormal cooling, low ambient temperature, loss of heat or blocked suctions on compressors must be considered in the design.

Vacuum relief instrumentation which permit breaking of a vacuum with inert or flammable vapors are not permitted as the sole means of protection on process. For systems where a flammable atmosphere can develop with the influx of air through a vacuum breaker, instrumentation should be employed to break the vacuum with inert gas or hydrocarbon gas at a higher setting than the vacuum breaker in order to reduce the probability of a flammable mixture in the system. However, since instrumentation is not sufficiently reliable, a vacuum breaker must also be provided.

As a rule, steam systems do not require special vacuum protection, since they are normally capable of withstanding vacuum developed if steam generation should fail and residual steam condense. However, low-pressure steam systems should be verified for potential vacuum failures. Generally, equipment need not be designed for vacuum due to blocking in of a vessel after steaming for shut down reasons. Reliance is placed on good operations to ensure that the vessel or equipment is not bottled up.

Cone roof atmospheric storage tanks must be provided with either a pressure-vacuum valve or an open vent, depending upon the flash point of the stored product.

## 5.14. Pressure Relief Valve Chattering

Chattering is the rapidly alternating opening and closing of a PR valve. This vibration may result in misalignment and leakage when the valve returns to its normal closed position. If chattering continues for a sufficient period, chattering may result in mechanical failure of valve internals or associated piping fittings. In addition, the vibration may loosen bolts and result in flange leaks around the PR valve.

Chattering may occur in both liquid and vapor service PR valves. The principal identified causes of PR valve chattering are oversized valve, excessive inlet pressure drop, excessive built-up back pressure incorrect blow-down ring setting, and liquid surge. In addition, a further mechanism of chattering may be introduced in some liquid service PR valve installations if the response characteristics of a control valve in the same system are such that hunting between the two occurs. so, appropriate design features shall be considered to avoid PRV's chattering per international design practices, design standards and PR vendors specifications.

## 6. Discharge Routing

Routing of PR valve discharges to the atmosphere or to a closed system is determined in accordance with the following criteria:

Discharge to a Closed System is required for PR valves in the following categories:

*1. PR valves handling materials which are liquid or partially liquid at the valve inlet. An exception to this is made for certain thermal expansion relief valves as described below.*

*2. PR valves normally in vapor service, but which under any design contingency may discharge flammable, corrosive or hazardous liquids.*

*3. PR valves located in the vapor space of partially liquid-filled vessels when liquid overfill as a cause of overpressure is a design contingency.*

*4. PR valves handling, flammable, toxic or corrosive vapors which condense at ambient conditions, e.g., phenol or flammable vapors with an average molecular weight greater than 100 (since they may condense).*

*5. PR valves in toxic vapor services where discharge to the atmosphere would result in the calculated concentration at any working area (either at grade or an elevated platform) exceeding the Short Term Exposure Limit (STEL).*

*6. Release of flammable vapors which would result after dilution with air in a fuel-air mixture with a concentration above 50% of Lower Flammability Limit (LFL) at grade or any frequently accessed platform or equipment.*

*7. Releases of flammable vapors which, if discharged to the atmosphere, would in the event of inadvertent ignition, result in radiant heat densities in excess of the permissible exposure level (6000 Btu/h $ft^2$ or 19 $kW/m^2$) for personnel at grade or a frequently manned platform. Note that increasing the height of the riser to reduce radiant heat densities is an acceptable alternative to discharge to a closed system.*

Discharge to a Closed System is Desirable for the following:

*1. PR valves discharging vapors which do not fall into the above categories but which would be significant contributors to atmospheric pollution. Such releases should not normally be used to size the closed system but should be tied into the closed system up to the limit of its capacity. The order of preference for tying in is: (1) malodorous vapors, (2) unsaturated hydrocarbons, and (3) saturated hydrocarbons. If local requirements do not permit such atmospheric discharges, it will be necessary to include these releases in sizing the closed system.*

*2. PR valves where atmospheric discharge is permissible, but connection to an adjacent closed header (provided that capacity is available) is less costly than an atmospheric discharge line to an acceptable location.*

Discharge to Atmosphere is permitted only if all of the following conditions are satisfied:

*1. PR valves handling only vapor at the valve inlet.*

*2. For partially liquid-filled vessels, liquid overfill is a remote contingency.*
*3. Discharge to a closed system is not otherwise required.*
*4. Local regulations regarding atmospheric releases are complied with.*

**Discharge Paths for Multiple Valves -** Some equipment operating in two modes, such as reactors which are periodically regenerated, will require separate PR protection for each service. Special precautions are necessary where the PR valve in normal service discharges hydrocarbons and the valve for the regeneration cycle would discharge air. Where both valves discharge to atmosphere, a caution sign should be posted by the PR valves, and appropriate procedures clearly spelled out in the operating instructions. If the PR valve for hydrocarbon service discharges to a closed system, interlocks should be provided so that only one PR system can be in service at a time, and air from the regeneration cycle is kept out of the closed system. In addition appropriate caution signs and proper instructions and training should be provided.

## 7. Isolation Valves for Pressure Relief Systems

Block valves for maintenance isolation purposes (line size for flare header, or flange size for PR valve inlet and outlet) are permissible in pressure relieving systems provided that they are car-sealed open and comply with the requirements of CSO valves defined in this document. The particular locations where such CSO valves are permitted are:

*a. PR valve inlets, where isolation of the PR valve for on-stream maintenance is required, subject to compliance with local codes.*

*b. PR valve outlets which are manifolded to a closed system or combined atmospheric vent, where isolation of the PR valve for on-stream maintenance is required, subject to compliance with local codes.*

*c. A flare header at the battery limit of a unit that shuts down independently of other units tied into the same header.*

# Basic Safety Concepts for Emergency Isolation, Depressuring and Shut Down
# NPC-HSE-S-10

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## 1. Scope

This document covers the minimum safety considerations and requirements for emergency and isolation of compressors, pumps, vessels, combustion devices, vulnerable equipment, and isolation at battery limits to rapidly stop the uncontrolled release of toxics or flammable material that is feeding a fire and shall be considered in design phase. Other design aspects such as process, isolation,trips and shut downs shall be followed as per proper design standards and international practice and are not included in this document.

## 2. References

- *API-RP 553,Refinery control valves*
- *IEC-61508, Electrical/Electronic/Programmable Electronic Safety-related Systems*
- *IEC-61511, Safety Instrumented systems for the Process Industry Sector*
- *The AIHA Emergency Response Planning Guidelines (ERPGs) and Workplace Environmental Exposure Level Guides Handbook.*
- *ANSI/FCI 70-2 1991, Quality Control Standard for Control Valve Seat Leakage.*
- *Exxon-Mobile Engineering standards*

## 3. Definitions

**Battery Limit:** boundaries of the smallest geographical subdivisions of a processing equipment area which are separated by at least 50 ft. (15 m) from each other and from adjacent facilities, and which contain either a complete process or a group of integrated processes which may be shut down together for turnaround.

**Combustible Liquids:** High-flash liquids [flash points 100°F (38°C) or higher] when handled at temperatures more than 15°F (8°C) below their closed cup (Pensky-Martens) flash point.

**Emergency Block Valve (EBV):** Emergency Block Valves (EBVs) permit the control of hazardous situations. These are valves for emergency isolation or vapor blow down and are as Type A, B, C or D.

***Type A Valve:*** *Type A EBV is manually operated and is installed at the equipment or vessel nozzle. Manual operation may be augmented with locally controlled power actuators in cases where valve size, flange classification or ergonomics is a factor.*

***Type B Valve:*** *Type B EBV is installed at least 25 ft. (7.5 m) horizontally from the equipment it is to isolate. It is manually operated, 8 in. (200 mm) size or smaller, no higher than 15 ft. (4.5 m) above grade, and up through flange class 300. Exception: Battery Limit Type B EBV may be any flange class or any height.*

***Type C Valve:*** *Type C EBV is installed at least 25 ft. (7.5 m) horizontally from the equipment it is to isolate. It is power operated with the actuating push button located at the valve. It is located no* *higher than 15 ft. (4.5 m) above grade.*

***Type D Valve:*** *Type D EBV is power operated. Its actuating button is located at least 40 ft. (12 m) horizontally away from the source of potential leak and such that it can be operated from grade. Consideration should also be given to locating the actuating button in the control house.*

**Emergency Response Planning Guideline -** Level 3 (ERPG-3): The ERPG-3 is defined by the American Industrial Hygiene Association (AIHA) as: "the maximum airborne concentration below which it is believed nearly all individuals could be exposed for up to one hour without experiencing or developing life threatening health effects."

**Equipment with High Fire Potential:** Equipment with High Fire Potential shall include:

1. *Pumps with a rated capacity over 200 gpm (45 $m^3$/h) handling flammable liquids.*
2. *Compressors over 200 HP (150 kW) handling flammable gasses.*
3. *Fired heaters handling flammable liquids in tubes.*
4. *Vessels, heat exchangers, and other equipment containing flammable liquids over 600°F (315°C) or above their auto ignition temperature, whichever is less.*
5. *Certain reactors that operate at high pressures or are capable of producing exothermic or runaway reactions.*

**Fire Hazard Area:** A fire hazard area shall generally be considered as the area within a horizontal distance of 20 ft. (6.0 m) from equipment with high fire potential with the following qualifications:

1. *For tanks, spheres and spheroids, containing flammable material, the fire hazard area shall extend to the dike wall or 20 ft. (6.0 m) from the storage vessel, whichever is greater.*
2. *For rotating equipment, the 20 ft. (6.0 m) distance will be taken from the expected source of leakage.*
3. *For marine docks where flammable liquids are handled, the fire hazardous area shall extend 100 ft. (30 m) horizontally from the manifolds or loading connections.*

**Flammable Liquids:** Low-flash liquids [flash point below 100°F (38°C)], and high-flash liquids [flash point 100°F (38°C) or higher] when handled at temperatures above or within 15°F (8°C) of their closed cup (Pensky-Martens) flash points.

**Flammable Materials:** Flammable liquids, hydrocarbon vapors, and other vapors, such as hydrogen and carbon disulfide, that are readily ignitable when released to atmosphere.

**Light Ends:** Light ends are volatile flammable liquids, which are significantly vaporized at normal ambient conditions. This indicates a type of material of greater fire hazard than heavier hydrocarbons because of the large volume of vapor generated by a liquid leak or spill. For the purposes of this document, the definition of light ends is a material having a Reid Vapor Pressure (RVP) of 15 psia (103 kPa) or greater, as determined by the standard ASTM D-323 test. By common usage, this covers the following:

- *Pentane and lighter hydrocarbons (either pure hydrocarbons or mixtures).*
- *Un-stabilized naphtha, which meet the RVP criterion.*
- *Flammable chemicals which meet the RVP criterion.*

When used as a criterion of hazardous properties for safety design purposes, the term is applied to the above materials only when they are in the liquid phase or a combination of liquid and vapor phases. A process unit is considered to be a light ends unit when a significant part of the equipment handles light ends.

**Toxic Materials:** A toxic material is one which has the inherent ability to cause adverse biological effects. Some toxic materials are listed in The AIHA (American Industrial Hygiene Association) 1998 Emergency Response Planning Guidelines (ERPGs).

## 4. Design Features

Location, accessibility, and other design requirements for emergency block valves are summarized in Table 1. The Design Specification shall identify all EBVs and indicate Type A, B, C or D, as appropriate. When unknown layout could affect the type of EBV selected, the option should be specified. Design specification documents shall define these types, and require color coding or signs to identify the EBVs and their actuating push buttons in the field.

Table 1; Location, Size and Operability Requirements for Emergency Block Valves

| Requirement | Applicable Restrictions for Valve Type | | | |
|---|---|---|---|---|
| | A | B | C | D |
| VALVE LOCATION<br>• Horizontal Distance from Source of Potential Leak | At equipment | >25 ft. (7.5m)(1)(4) | >25 ft. (7.5m)(1)(4) | No restrictions |
| • Maximum Elevation above Grade | At equipment | 15 ft. (4.5m)(2) | 15 ft. (4.5m)(2) | No restrictions |
| VALVE SIZE & FLANGE RATINGS<br>• Recommended for | All sizes and classes | ≤ 8 in.(200mm) or class300 and lower(3) | > 8 in.(200mm) or class300(3) | All sizes and classes |
| PUSH BUTTON FOR ACTIVATION<br>• Push - Button Location | Not applicable | Not applicable | At valve | > 40 ft. (40m) from source of leak(4) |
| • Operable from | Not applicable | Not applicable | Grade or platform | Grade |
| • Maximum Elevation above Grade | Not applicable | Not applicable | 15 ft.(4.5m)(2) | At grade |
| ACCESSIBILITY<br>• Valve can be Reached without Passing the Source of Potential Leak Closer than | Not applicable | 25 ft. (7.5m)(4) | 25 ft. (7.5m)(4) | Not applicable |
| • push - button can be operated without passing the source of potential leak closer than | Not applicable | Not applicable | 25 ft. (7.5m)(4) | Not applicable |

***Notes:***

***(1) This distance increases to 40 ft. (12 m) for manually operated block valves in process, fuel and pilot gas lines to fired heaters.***

***(2) If the valve is more than 75 ft. (23 m) horizontally from source of potential leak, or identified as "Battery Limit (BL)" valve, there are no restrictions on elevation or flange class.***

***(3) EBVs located at Battery Limits normally are either Type B or C. Type C EBVs are required at the battery limit only in flammable or toxic services for valves larger than 8 in. (200 mm).***

***(4) For marine pier facilities, this distance is 100 ft. (30 m)***

***(5) For pressurized and refrigerated storage facilities (e.g., LPG) the push-button should be located outside of the dike.***

# 5. Installation Requirements

## 5.1. Location and Operability of EBVs

The distances stated in Table 1 are minimum values based on experiences with average fires. Access to Type B and C valves and to Type D push buttons must be direct and safe during an emergency. In addition to distance, other factors have to be evaluated carefully during detail design. For example, if a Type B or C EBV is located at the proper distance from a potential leak but is positioned near a catch basin that will drain that potential leak, then the valve shall be relocated or designated as a Type D since the intent of the spacing guideline is not met. Also, if the height limitation for Type B and C EBVs is met but access is only possible from platforms elevated above the actual installation, and then the valve should be either relocated or designated as a Type D since easy access is not possible. Hand wheels for Type A and B valves as well as hand wheels for Type C and D actuators must be operable from either grade or a platform. Chain wheels are not permitted on any EBV installation, but flexible remote valve actuators may be considered for certain applications.

## 5.2. Choice of Valve Body

The valve body choice for emergency block valves depends on application and on location. In areas where an EBV might be exposed to fire (such as in process areas) and must remain closed in an emergency, the valve body must be capable of withstanding prolonged fire impingement without leaking. Therefore, EBVs in isolation service should be either a gate valve, a lubricated plug valve, or a high performance ball or butterfly valve. High performance ball or butterfly valves have metal seats without soft seals and are considered inherently fire safe. Soft seated, fire-tested (fire safe) type ball, plug or butterfly valves are only to be used if they are fireproofed. However, such “fire safe” soft seated valves are allowed in areas where there is only a remote chance of fire.

## 5.3. System Failure

Consideration of system failure must be included in the design of EBV, both on a plant-wide and an individual basis. In a “Fail-Safe” design, the valve will move to the position considered safest in an emergency upon loss of the control signal or actuating medium. Such emergency block valves should mechanically lock in the “fail-safe” position regardless of whether the valve was purposely moved or failed to the “fail-safe” position.

## 5.4. Valve Actuators

Valve actuators for Type C and D valves can be energized by electric power, hydraulic oil, instrument air or nitrogen. The reliability of the energy source system at each location may influence the choice. Specific requirements and restrictions for the different types of actuators are as follows:

**1. Electric Motor**

Electric motor actuators in conjunction with gate valves have proven to be highly reliable in many locations and are therefore recommended as a first choice. However, since this system "Fails-Stationary," operation can only be guaranteed as long as it cannot be damaged by fire. Thus, within the presumed fire hazard area, the actuator and cables must be fireproofed. The power supply for the electric motor should be from a secondary selective power system. Motor overload protection, if furnished, shall be deactivated.

**2. Hydraulic Piston**

Hydraulic pistons may be used for emergency isolation valves when a reliable hydraulic system has already been designed for other use (e.g., slide valve actuation on some units).

**3. Air Drivers**

The instrument air system should be used to provide motive energy for driving EBV air pistons. The capacity of the main air surge drum and system line sizes should be evaluated to ensure that there is adequate air available to move the valve, even with an air compressor failure. For retrofit cases, where there is insufficient air holdup capacity, installation of individual air surge drums, pressurized through a check valve, may be justified. Rotary air motors and single acting air piston operators are not recommended in emergency service. Diaphragm operated valves are not acceptable for isolation purposes. If a diaphragm operator is specified in isolation service where it is expected that the valve will remain closed if exposed to fire, the spring, even if fireproofed, could relax its pressure due to overheating. This would lead to reopening of the valve, which cannot be tolerated.

## 5.5. Fireproofing for EBVs

EBVs are intended to operate during the first phase of a contingency when in some cases a fire may already have started. Therefore, from a safety standpoint, the best location for an EBV is outside the presumed fire hazard area. For most fires, this means 25 ft. (7.5 m) away from the equipment where the leak might occur. However, for some isolation situations, where the possibility of greater fire spread exists and where the impact of a fire can be significant, increased spacing for EBVs may be justified. Beyond those distances no fireproofing would be needed.

**1. D Type EBVs (not fail safe)**

If it is not justified to locate an EBV 25 ft. (7.5 m) or more from a potential fire source, a fireproofed Type D EBV may be installed. The installation has to be done in such a way that fire damage does not impair the operation of the valve. Therefore, the preferred cable routing and fireproofing for Type D EBVs are as follows:

- *Underground routing of power and signal cables up to the point vertically below the valve actuator. If power and signal cables cannot be run underground from outside the fire hazard area to the point vertically below the valve actuator, they shall be fireproofed within the fire hazardous area of the protected equipment.*
- *Fireproofing of power and signal cables between grade and the actuator.*
- *Fireproofing of the actuator.*

Fireproofing shall not include the valve body and hand wheel. Fireproofing of power cables, signal cables, and the actuator shall be designed so that the system will function for at least 15 minutes when exposed to a 2000°F (1100°C) fire with an incident heat flux of at least 50,000 Btu/hr-ft$^2$ (160 kW/m$^2$) at the conditions set forth in UL-1709, ASTM E-1529, or equivalent test method. There shall be no uncovered sections at junctions, bends or terminal entries. Fire resistant cable that meets the above temperature, heat flux, and time criteria may be used without additional fireproofing. For actuators, an easily installed or dismantled fireproof enclosure is recommended.

In hot services greater than 700°F (370°C) the functioning of a fireproofed electric motor can be impaired by heat transfer through stem and yoke into the actuator. In such cases, the EBV should either be installed in a location where no fireproofing is needed or the valve should be refitted with a longer stem and yoke to facilitate cooling.

If underground routing of power and signal cables is impractical, conduits should be routed via the shortest distance possible away from the area of the potential leak. Normal cable banks should not be used for convenience if their use results in enlarging the exposed EBV cable length. For dock installations, the system has to be fireproofed within a horizontal distance of 100 ft. (30 m) from the potential leak. Vulnerable parts in LPG storage vessel isolation valve systems have to be fireproofed within and beyond the dike area. For all other installations, the above ground power and control wiring associated with remote actuation has to be fireproofed within a horizontal distance of 25 ft. (7.5 m) of the equipment being protected, or further if the equipment fire hazardous area demands. Depressuring systems and air to oxidation processes (actuators and cables), when not designed to be “Fail-Safe,” have to be fireproofed within battery limits if above ground. This increase in fireproofing is required since this system is counted on to be available assuming the fire can occur anywhere in the unit.

Careful engineering may result in a solution where aboveground power and signal cables are always routed outside other potential fire hazard areas. However, if power and signal cables are routed through areas where they might be endangered by a fire not requiring the use of this EBV, they need not be fireproofed. Furthermore, it is reasonable to assume that one contingency does not necessarily result in another. Only when a hazard analysis reveals that one event leads to another is additional fireproofing justified.

**2. C Type EBVs**

Types C EBVs by definition are installed at a horizontal distance of at least 25 ft. (7.5 m) from the potential leak and therefore do not need fireproofing. This implies that cables serving a Type C EBV are routed outside the presumed fire hazard area associated with this valve. It would not be acceptable if cables for such valves were routed back through the presumed fire hazard area. Even if fireproofed, this would not meet the intent for Type C EBV requirements. As with Type D EBVs, it is preferable to route cables serving Type C EBVs underground.

## 5.6. Actuating Controls

Actuating controls for Type C and D EBVs should consist of push buttons for moving the valve in the opening and closing directions. Valve travel once initiated should continue until the valve has moved to its full travel position in the required direction. For testing purpose, a stop push-button shall be provided allowing the valve travel to be stopped at any intermediate point. All actuating buttons must be provided with a protective guard to prevent inadvertent operation. With Type D EBVs, the actuation push buttons for remote operation should be located 40 ft. (12 m) from the potential leak. Control room activation for Type D EBVs in toxic service shall be considered because the field push button could be in the toxic cloud. Additional push buttons for compressor, fired heater and Depressuring system EBVs must be located in the control house. These push buttons should be placed on the appropriate section of control panel covering the unit involved in a logical process relationship to the layout of the other instrumentation.

All field mounted buttons should be grouped, located at battery limits and should be at least 40 ft. (12 m) away from the nearest potential leak. These unit EBV (D) actuation stations should be clearly marked (to enable personnel to locate during an emergency) and have the emergency action buttons (for example, the close button for a normally open EBV) clearly identified. Valve position indicator shall be provided.

However, if additional push buttons are installed on the control panel, the wiring for an actuating circuit shall be such that remote operation will still function even though a local actuation point is lost. If this cannot be accomplished, the local actuating system has to be fireproofed.

## 5.7. Testing

For testing, the following requirements shall be considered as a minimum:

- The EBV system should be tested periodically by actuating all functions. Where it is not possible to test an EBV at a frequency suitable to ensure availability without impacting operations, facilities should be provided for on-line testing. For normally open, isolation EBVs (C or D) smaller than 8 in. (200 mm), a CSC (car sealed closed) bypass valve shall be provided, for EBVs equal to or greater than 8 in. (200 mm) which are normally open (isolation valves), the EBV can be partially closed for on stream testing, and full closure is carried out periodically. An exception is made for normally open isolation EBVs installed in a furnace outlet. In this case, a CSC bypass valve shall be provided around the EBV for on-stream testing, regardless of its size.

- EBVs, which are normally closed (Depressuring valves), should be provided with a CSO block valve upstream and adjacent to the EBV.
- It is required that the open/close position of an emergency valve can be clearly determined by visual observation of the valve, even when the valve actuator is fireproofed. Extension rods on gate valve stems or indicators on quarter turn valves can serve this purpose.

## 6. Emergency Isolation

Manually or power operated EBVs located at strategic points throughout the equipment (on both geographical and process flow bases), permit an affected section to be isolated from other sections of the plant, so that the inventory of fuel feeding a fire or release is limited. On a larger scale, in the event of a widespread fire, it is necessary to shut in the whole unit by closing valves at battery limits. Mechanical failures of machinery, fired heater tubes, and other vulnerable equipment are recognized as a common cause of major fires, and individual EBVs for this equipment shall be specified. When considering EBVs for equipment such as pumps and compressors, the intent is to provide an isolation capability where there is fire directly associated with that equipment.

### 6.1. Long Lines

Where emergency isolation is needed in long lines, such as those present in marine loading facilities, consideration should be given to the time it takes for the EBV to close fully. The possibility of creating a potentially damaging hydraulic pressure surge should be evaluated and the valve closing time appropriate to the specific situation should be used.

### 6.2. Toxic Materials

Where toxic materials are present and a release to the atmosphere can occur, either due to a failure of a small connection or a flange leak (one half of a flange gasket blows out), and the resulting toxic vapor concentration can exceed the ERPG-3 at the unit B.L., then either a Type D EBV shall be installed or alternative isolation means shall be considered. When a Type D EBV is required for toxic service, control room activation shall be considered because the field push button could be in the toxic cloud.

### 6.3. Compressors

1. Type D EBVs are required in the suction and discharge of any compressor of 200 HP (150 kW) and higher handling flammable or toxic gases. These EBVs shall be equipped with position switches set to trip the compressor when they are less than 50% open, but the EBVs shall not be actuated (automatically closed) by the compressor shut down system. For compressors less than 200 HP (150 kW), no EBV is required.
2. For compressors meeting the above criteria which have multiple suctions or discharges connected to different pressure stages, Type D EBVs are required in all suction and discharge lines that leave the compressor area and are normally open.
3. For compressors meeting the criteria in (1), above, which have interstage circuits (e.g., condensers and K.O. drums), Type D EBVs are required in the suction and discharge lines of each interstage, if that interstage's equipment contains more than 1000 gallons (4 $m^3$) of flammable liquid at normal levels.

## 6.4. Pumps

1. A Type B, C, or D EBV according to size and location shall be installed in the pump suction line when the inventory in a pump suction vessel meets either of the criteria listed below. In the case of towers, inventory is calculated at the top of the working level range, with the addition of tray and reboiler holdup if they are draining into the tower sump.
a. Inventory is over 2,000 gallons (7.5 $m^3$) of flammable liquid.
b. Inventory is over 4,000 gallons (15 $m^3$) of combustible liquid.

2. A Type D EBV shall be installed in the pump suction line if toxic liquid released from a seal failure would result in exceeding the Emergency Response Planning Guideline Level 3 (ERPG-3) at the unit B.L. Quantities resulting in ERPG-3 can be determined by dispersion calculations specific to the plant.
3. Where an EBV is installed in the suction line to a pump, or in the common suction line to two or more pumps, the EBV and all piping components between it and the pump(s) must have a pressure rating at normal operating temperature of not less than 3/4 of the pressure that will exist downstream of the pump when the EBV is shut. This requirement is the short time design basis for piping per ASME 31.3. Should a change of flange rating be required in a pump suction system because of this consideration, it must occur at the upstream side of the EBV.
4. Type A EBV shall be installed in the suction line if the pump is not located in an onsite process area. However, an EBV Type B, C, or D would be required if spacing is substandard per NPC-HSE-S-03, or if pump is located near other equipment which is vulnerable to fire.

## 6.5. Vessels

Vessels containing more than certain inventories of liquid light ends, liquid heavier than light ends but above or within 15°F (8°C) of its closed cup flash point, or toxic liquids shall be provided with EBVs at the vessel nozzles located below the maximum working level. These EBVs are to isolate the vessel contents from possible failures in the associated liquid piping. Small piping is more vulnerable to mechanical damage and should be provided with EBVs in some cases where large lines are not. The volume of liquid is calculated at the top of the working level range with the addition of tray and reboiler holdup in the case of towers and neglecting line inventory, unless the inventory in the line exceeds 250 gal (900 l). Connections between EBVs and the vessel should be avoided. The connection to the closed drain header should be taken off downstream of the isolation valve and the vessel. In determining the type of EBV to install, the worst contingency shall be evaluated. This may not always be the first or largest flange out of the vessel, e.g., a flange leak from an elevated drum under low pressure may have a lower leak rate at the first out flange than a smaller flange at grade, due to liquid head.
The type of EBV shall be as follows:
1. If a toxic liquid release can exceed the ERPG-3 at the unit B.L. when one half of a flange gasket blows out from any normally open line below the maximum working level, then a Type

D EBV is required in the respective line. The liquid inventory required to exceed ERPG-3 can be established by dispersion calculations specific to the plant.

2. If the liquid inventory of any volume in an offsite storage vessel is light ends, then Type D EBVs are required on all normally open lines below the maximum working level and a Type A EBV on all other lines below the maximum working level.

3. If the liquid inventory in a process vessel is more than 10,000 gal (40 $m^3$) light ends and there are any special factors such as substandard spacing, etc., then a Type D EBV is required on all normally open lines below the maximum working level, and a Type A EBV is required on all normally closed lines below the maximum working level. If no special factors apply, then a Type A EBV is required on all lines below the maximum working level.

4. If the liquid inventory is more than 1,000 gal (4 $m^3$) but less than 10,000 gal (40 $m^3$) light ends, then a Type A EBV shall be installed on all lines 2 in. (50 mm) or smaller below the maximum working level.

5. If the liquid inventory in a process vessel is over 10,000 gallons (40 $m^3$) heavier than light ends at a temperature above or within 15°F (8°C) of its closed cup flash point, then a Type A EBV is required on all lines below the maximum working level. This requirement may be applied to smaller inventories when there are special hazard factors associated with the vessel contents, e.g., high corrosion rates, high pressure, or cryogenic conditions.

6. If the liquid inventory is over 1,000 gallons (4 $m^3$) but less than 10,000 gallons (40 $m^3$) heavier than light ends and at a temperature above or within 15°F (8°C) of its closed cup flash point, then a Type A EBV is required on all lines 2 in. (50 mm) or smaller below the maximum working level.

7. Lines between towers and associated reboilers need not have EBVs.

### 6.6. Fired Heaters, Boilers and Other Combustion Devices

**1. Fuel to Firebox**

All fuel streams (including pilot gas, auxiliary fuel, off gas, etc.) to fired heaters, boilers and other combustion devices shall be provided with an accessible Type B EBV located at least 40 ft. (12 m) from the equipment. A battery limit valve or other EBV in the line may be considered to meet the fuel isolation requirement, provided that its closure would not create other hazards or conflict with other actions that might be necessary during a plant emergency. For example, a fuel gas line might be required to be open as a Depressuring route. This fuel isolation requirement is in addition (and is intended as a back-up) to tight shut off valves provided for the emergency shut down system.

**2. Process Feed to Fired Heater**

Means must be provided for stopping the flow of flammable process fluids to fired heater coils. This should consist of an accessible Type B EBV in each stream, located at least 40 ft.

(12 m) from the fired heater. Block valves for feed pumps, compressors, or control valves, which meet the above requirement, are acceptable for this purpose.

Means of emergency isolation in the outlet of a fired heater handling flammable materials is also desirable in cases where backflow of the downstream inventory would have a major effect on the extent and duration of a tube failure fire. However, this objective has to be balanced against the practical problems of coking and inadvertent closure of isolation devices.

Factors associated with the downstream equipment which would favor the installation of fired heater outlet isolation include high pressure, volatile liquids, large inventory and absence of vapor blow downs. Fired heater outlet isolation is not normally provided unless coil outlet pressures exceed 200 psig (1400 kPa).

a. When isolation is required, a check valve is the normal method, provided that reliability can be expected considering coke deposition. The check valve must be of the swing-check type with no external actuation or dampening mechanism. No additional overpressure protection is necessary as a result of the inclusion of this check valve.

b. Although isolation by check valve is recognized to have a degree of unreliability, use of a remote operated valve as an additional means of isolation is not generally recommended, because of the possibility of inadvertent closure and the associated problems of designing an effective safety relief system that will maintain continuity of flow through the coil. However, an exception is made in the case of a process fired heater operating at coil outlet pressures above 1,000 psig (6,900 kPa) where the importance of isolation is considered sufficient to justify the installation of a positive shut off of the Type D EBV in addition to a check valve in the fired heater outlet. Fired heater overpressure protection must be provided in these applications, in accordance with NPC-HSE-S-09 (Overpressure in Specific Equipment Items).

### 6.7. Vulnerable Equipment

Emergency isolation may be required for equipment, which is exceptionally vulnerable to fracture and uncontrolled release as a result of mechanical or thermal shock. In these cases the type of EBV shall be as follows:

1. If the contents include flammable material, Type B, C or D EBVs (depending on the valve's size and location) are required in the equipment inlet and outlet piping.
2. If the contents include toxic materials which if released from a hole 2 times the cross sectional area of a tube would result in a level exceeding the ERPG-3 at the unit B.L., then Type D EBVs are required in the equipment inlet and outlet piping. The volume required to exceed ERPG-3 can be established by dispersion calculations specific to the plant.

The engineering safety specialists should be consulted on these applications.

## 6.8. Battery Limits

Battery limit valve manifolds must be located at the battery limit or if there is an adjacent offsite pipe band, location up to the nearer edge of this pipe band is permissible.

1. Emergency isolation is required in every process or utility line entering or leaving plant battery limits if the line is normally pressurized.
2. A single valve in a line at battery limits may serve for both emergency and turn-around isolation.
3. Battery limit EBVs should be grouped into one or more manifolds provided with line identification.
4. Type B or Type C EBVs must be specified according to size and service and must meet the requirements for these valves defined in Table 1. Type C EBVs are only required in flammable or toxic service where the valve is larger than 8 in. (200 mm).
5. Onsite equipment adjacent to the battery limit valve manifold must be located to provide the 25 ft. (7.5 m) horizontal spacing required between Type B and C isolation valves and the equipment being protected (per Table 1). For battery limit isolation, this is interpreted as 25 ft. (7.5 m) from any onsite equipment except low fire-risk facilities, such as those handling non-flammable materials or combustible liquids, for which 15 ft. (4.5 m) spacing is acceptable.

## 7. Emergency Depressuring

It is possible to reduce the duration and intensity of a fire by providing a means to quickly remove the inventory of flammable material in the affected section of the plant. Generally, this involves Depressuring equipment. Depressuring may be accomplished by the use of normal process disposal mechanisms and routes, and/or by the use of special vapor blow down facilities.

### 7.1. Vapor Blow down

Special emergency Depressuring facilities (vapor blow downs) are provided on certain high-pressure equipment so that vessel stresses, and hence the risk of failure under fire exposure or runaway reactions, may be reduced in an emergency situation.

They also facilitate rapid shut down of a plant in the event of mechanical failure and potential fire. Vapor blow downs are installed as follows:

1. *On equipment operating above 150 psig (1030 kPa) where there is no liquid inventory or the liquid inventory is dispersed in a continuous vapor phase such as in a mixed-phase fixed-bed reactor.*
2. *For other equipment (for example large light ends fractionators or surge drums) operating above 250 psig (1,720 kPa) where the flammable liquid and vapor contents of a vessel or group of vessels (excluding piping and pumps) would exceed 200,000 ft$^3$ (5,600 m$^3$), when flashed and expanded adiabatically from operating conditions to atmospheric pressure.*
3. *To arrest runaway chemical reactions.*

In all cases where emergency Depressuring facilities (vapor blow downs) are provided, facilities should also be provided to stop all feeds to the system.

#### 7.1.1. Design of Vapor Blow down Connections

1. Two or more vessels may be grouped for emergency Depressuring purposes and fitted with a single blow down connection, provided that the interconnecting piping and any control valves in this piping have adequate capacity to meet the Depressuring time requirement defined below, and are designed to avoid plugging. In addition, control valves must move towards the open position as a result of both actuating medium failure and normal control response to the Depressuring operation.
2. The connection shall have a restriction orifice (RO) and a Type D EBV actuated from the control room and shall discharge to the flare system. Where two or more vapor blow down connections is installed in a process unit, separate actuation of the EBVs shall be provided. A tight-shut off, Fail-Open control valve may be used as an alternative to the EBV/RO system. The control valve seat leakage rate should meet the Class VI specification, per ANSI/CFI 70-2,

unless the material temperature would exclude its use.

3. A blow down connection is typically sized to reduce the pressure in the equipment from its operating pressure to 50% of its design pressure in 15 minutes for fire emergency. Higher rates may be required to contain runaway reactions. For grouped vessels, the pressure of each vessel must be reduced to a pressure no higher than this requirement. Over sizing blow down connections should be avoided since this can result in an excessive large flare system and, for some reactors, the possible lifting of the catalyst bed.

### 7.1.2. Design of Vapor Blow down Release Systems

1. When actuated, the vapor blow down release system needs to lock open until Depressuring is complete.

2. Blow down connections shall discharge into a flare header or other closed release system.

3. For header sizing, the contingency considered is a fire in a single fire hazard area, with all vapor blow downs in that area releasing simultaneously, along with all safety relief devices in the same fire hazard area which meet all of the following criteria:

*a. They are on equipment not provided with vapor blow downs.*
*b. They are tied into the same header as the vapor blow downs.*
*c. They discharge as a result of fire exposure on equipment.*

Each fire hazard area is examined on this basis, and the header is sized such that during the largest single contingency release, back pressure on all safety relief devices tied into the header does not exceed the limitations applying to the design of normal closed release headers.

4. Vapor blow downs may be discharged to the atmosphere if all the criteria applying to the atmospheric discharge of pressure relief valves are satisfied (including pollution considerations), and provided that the material released can only be vapor under any foreseeable emergency conditions.

## 7.2. Low-Temperature Impact Strength

Vessels containing volatile liquids, with vapor blow down piping, must be designed to withstand the low temperatures resulting from auto refrigeration during emergency Depressuring, in accordance with the requirements of proper standards.

## 7.3. Contingency other than Fire

If Depressuring facilities are required for the control of exothermic or runaway process reactions, these conditions must be considered separately. If blow down facilities are required for both fire and process Depressuring, the larger requirement must govern.

## 7.4. Normal Disposal Routes, Uses and Controls

For process plant equipment which does not meet the criteria for installation of special vapor blow down facilities as described above, it is assumed that in a fire situation some of the normal disposal mechanisms and routes are still functional and accessible to the operators, so that they can remove as much as possible of the flammable inventory. These may include:

- *Depressuring by releasing vapors to the fuel gas header or associated plants.*
- *Pumping or pressurizing liquids from vessels by normal routes out of the plant to tankage, to other units, or to slop.*

These functions can often be carried out using the valve, manifolding, and process controllers provided for normal, startup and shut down operations. Note this type of flammable inventory reduction is not quick. Valves which are critical for these functions (e.g., product diversion to slop), should be located in a low fire-risk area, such as at the battery limit piping manifold. Emergency conditions must be analyzed to avoid dangerous situations in tankage or equipment receiving disposal materials.

## 7.5. Instrument Failure Considerations

Considerations of instrumentation failure must be included in the design of emergency systems, both on plant-wide and individual bases. Overpressure protection considerations for instrument failures are covered in NPC-HSE-S-09.

## 8. Emergency Shut-Down Systems

### 8.1. General safety concepts design features

Emergency shut down systems enable the operators to perform the quick shut down of a plant in an emergency situation by remotely carrying out functions such as shutting down major machinery, stopping heat input to fired heater and reboilers, and shutting off air to oxidation processes. They also serve as a means by which machinery may be remotely shut down in the event of mechanical malfunctions when there is a possibility of catastrophic failure.

Shut down controls must be provided with suitable guards to prevent accidental operation. They should be designed for the maximum possible extent of on stream testing without actually shutting down the equipment. Shut down signal systems to machinery drivers should normally be de-energized while the protected equipment is in operation. All other shut down instrument systems must be normally energized.

Emergency shut downs are required for the following systems as minimum requirement:

- **Drivers**

1. On all compressors over 200 HP (150 kW). (Actuation from the control house)
2. On steam driven pumps and compressors that handle combustible liquid or flammable materials. (Actuated remotely)
3. on other machinery where there are particular factors which increase the potential for mechanical failure and major release of flammable materials, e.g., large multistage pumps.

- **Fired Heaters, Boilers and Other Combustion Equipment (Fuel to Fire Box)**

The ability to close from the control house the main fuel shut down valves and pilot gas valves to combustion equipment is required. These valves should be tight shut off, dedicated only to safe shut down of the equipment. An additional EBV (Type B) in all fuel lines (including pilot gas) shall be provided as discussed under Emergency Isolation.

- **Air Injection / Oxidizer Streams to Process**

A shut down valve actuated from the control house is required for an air injection or oxidizer stream to process where immediate shut off is a stage in the emergency shut down procedure, which is essential to making the unit safe. Besides a tight shut off valve, the installation should include a check valve and a vent valve to depressurize the air/oxidizer stream.

- **Refrigerated Liquid / Gas Facilities**

The required Type D EBVs shall be tied into an emergency shut down system so that refrigerated liquid tanks, pumps, compressors, loading facilities and processing units can be segregated from each other.

## 8.2. Exothermic Reactors

Exothermic reactors with the potential for temperature runaways must be protected from excessively high metal temperatures, which can result in vessel, line, or equipment failure. This applies to all processes in which there is the possibility of exceeding the reactor vessel design temperature as a result of uncontrolled exothermic reactions caused by process upsets, mal-distribution, decomposition, or other reaction mechanisms. Protection of such reactors is usually achieved by high temperature cut-outs that automatically depressure the reactor system when the reactor temperature reaches a pre-determined level. The reactor temperature is normally monitored with multiple thermocouples within the reactor bed and occasionally with reactor skin thermocouples or maximum temperature monitoring bands connected to a Controller based protective system. There may be other initiators in addition to high reactor temperature tied into the system. In addition to Depressuring the reactor system, there may be other responses that depend on the configuration of the individual unit. Such responses may include shutting-off the flow of reactants, tripping feed and/or treat gas heaters and others.

## 8.3. Special Cases

Further application of remote shut downs may be justified in special cases, to enable other process functions or equipment to be stopped, thus accelerating the shut down procedure. Factors, which should be taken into account in such cases, include plant size, complexity and operator manning levels.

## TABLE 2: AMERICAN INDUSTRIAL HYGIENE ASSOCIATION (AIHA) ERPG-3's 1998

| CHEMICAL | ERPG-3 |
|---|---|
| Acetaldehyde | 1000 ppm |
| Acrolein | 3 ppm |
| Acrylic acid | 750 ppm |
| Acrylonitrile | 75 ppm |
| Allyl Chloride | 300 ppm |
| Ammonia | 1000 ppm |
| Benzene | 1000 ppm |
| Benzyl Chloride | 25 ppm |
| Beryllium | 100 μg/m$^3$ |
| Bromine | 5 ppm |
| 1,3-Butadiene | 5000 ppm |
| n-Butyl Acrylate | 250 ppm |
| n-Butyl Isocyanate | 1 ppm |
| Carbon Disulfide | 500 ppm |
| Carbon Tetrachloride | 750 ppm |
| Chlorine | 20 ppm |
| Chlorine Trifluoride | 10 ppm |
| Chloroacetyl Chloride | 10 ppm |
| Chloropicrin | 3 ppm |
| Chlorosulfonic acid | 30 mg/m$^3$ |
| Chlorotrifluoroethylene | 300 ppm |
| Crotonaldehyde | 50 ppm |
| Cyanogen chloride | 4 ppm |
| Diborane | 3 ppm |
| Diketene | 50 ppm |
| Dimethylamine | 500 ppm |
| Dimethyldischlorosilane | 25 ppm |
| Dimethyl Disulfide | 250 ppm |
| Dimethylformamide | 200 ppm |
| Dimethyl Sulfide | 2000 ppm |
| Diphenylmethane Diisocyanate | 25 mg/m$^3$ |
| Epichlorohydrin | 100 ppm |
| Ethylene Oxide | 500 ppm |
| Fluorine | 20 ppm |
| Formaldehyde | 25 ppm |
| Furfural | 100 ppm |
| Hexachlorobutadiene | 30 ppm |
| Hexafluoracetone | 50 ppm |
| Hezafluoropropylene | 500 ppm |
| | |

| CHEMICAL | ERPG-3 |
|---|---|
| Hydrogen Chloride | 150 ppm |
| Hydrogen Cyanide | 25 ppm |
| Hydrogen Fluoride | 50 ppm |
| Hydrogen Peroxide | 100 ppm |
| Hydrogen Sulfide | 100 ppm |
| Iodine | 5 ppm |
| Isobuthyronitrile | 200 ppm |
| 2-Isocyanatoethyl Methacrylate | 1 ppm |
| Lithium Hydride | 500 μg/m$^3$ |
| Methanol | 5000 ppm |
| Methyl Bromide | 200 ppm |
| Methyl Chloride | 1000 ppm |
| Methyl Iodide | 125 ppm |
| Methyl Isocyanate | 5 ppm |
| Methyl Mercaptan | 100 ppm |
| Methylene Chloride | 4000 ppm |
| Methyltrichlorosilane | 15 ppm |
| Monomethylamine | 500 ppm |
| Perchloroethylene | 1000 ppm |
| Perfluoroisobuthylene | 0.3 ppm |
| Phenol | 200 ppm |
| Phosgene | 1 ppm |
| Phosphorous pentoxide | 100 mg/m$^3$ |
| Propylene oxide | 750 ppm |
| Styrene | 1000 ppm |
| Sulfur dioxide | 15 ppm |
| Sulfuric acid (Oleum, Sulfur Trioxide, and Sulfuric acid) | 30 mg/m$^3$ |
| Tetrafluoroethylene | 10000 ppm |
| Tetramethoxysilane | 20 ppm |
| Titanium Tetrachloride | 100 mg/m$^3$ |
| Toluene | 1000 ppm |
| 1,1,1- Trichloroethane | 3500 ppm |
| Trichloroethylene | 5000 ppm |
| Trichlorosilane | 25 ppm |
| Trimethoxysilane | 5 ppm |
| Trimethylamine | 500 ppm |
| Uranium Hexafluoride | 30 ppm |
| Vinyl Acatate | 500 ppm |
| | |

***Note:***

***(1) For other chemicals which may be potentially toxic, or for updated values of the chemicals listed above, refer to the latest AIHA Emergency Response Planning Guidelines (ERPGs) and Workplace Environmental Exposure Level Guides Handbook (the list is Updated periodically).***

# Basic Safety Concepts for Flare
# NPC-HSE-S-11

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## CONTENTS

**Page**

## 1. Scope

This document describes minimum safety requirements for selecting, designing and spacing elevated and multi-jet flares design criteria as point of safety view. Other design aspects such as process, Mechanical, Electrical, Instrument and calculations…shall be followed as per proper design standards and international practices.

## 2. References

*1. API RP 521, Guide for Pressure Relief and Depressuring Systems, (3rd Edition, 1990).*
*2. Exxon-mobile engineering standards*

## 3. Flare types and Application

Three types of flare are available: the elevated flare, the ground flare, and the burning-pit flare. Although the three basic designs differ considerably in required capital and operating costs, selection is based primarily on pollution/public relations considerations; i.e., smoke, luminosity, air pollution, noise and spacing factors.

- **Elevated Flares**

The elevated flare is the most commonly used type of flare used in refineries and chemical plants. The elevated flare, by the use of steam injection and effective tip design, can be made smokeless and of reasonably low luminosity. Steam injection introduces a source of noise, and a compromise between smoke elimination and noise is usually necessary. If adequately elevated, this type of flare has the best dispersion characteristics for malodorous and toxic combustion products, but visual and noise pollution can present public relations problems. Elevated flare is the general choice either for total flare loads, or for handling over-capacity releases in conjunction with a multi-jet ground flare. For most applications, the elevated type is the only acceptable means of flaring “dirty gases,” i.e., gases high in unsaturated or hydrogen sulfide or which have highly toxic combustion products. Three types of stack for elevated flares are used:

  - ***Guyed Stack:*** *The guy wires result in restrictions on the use of adjacent land, in addition to normal spacing restrictions.*
  - ***Derrick Type Stack:*** *This type of unit is well-suited for tall structures subject to strong winds.*
  - ***Self-Supporting Stack:*** *This type of unit is designed so that the flare riser pipe has no lateral structural support.*

- **Ground Flares**

Various designs of ground flare are available. The type, which has been used almost exclusively, is the multi-jet flare. Smokeless operation can generally be achieved, with essentially no noise or luminosity problems, provided that the design gas rate to the flare is not exceeded. However, since the flame is near ground level, dispersion of stack releases is poor and this may result in severe air pollution or hazard if the combustion products are toxic or in the event of flame-out.

The multi jet flare is suitable for "clean burning" gases (i.e., where toxic or malodorous concentrations are unlikely to be released through incomplete combustion or as combustion products) when noise and visual pollution factors are critical. It should not be used in locations upwind of adjacent residential areas. Generally, it is not practical to install multi-jet flares large enough to burn the maximum release load, and the usual arrangement is a combination with an elevated over-capacity flare.

- **Burning-Pit Flares**

The burning pit can handle liquid as well as vapor hydrocarbons. Its use is usually limited by spacing requirements and smoke formation, and it is applied only in remote locations where there are essentially no pollution restrictions. ***Anyway use of this flare type is not recommended in petrochemical plants.***

## 4. Basic Design Consideration

### 4.1. Flare Spacing, Location and Height

Spacing, location and height of flares shall be determined by consideration of the appropriate standards and following factors:

**Radiant Heat -** Acceptable levels of radiant heat density for equipment and in areas where personnel may be present.

**Burning Liquid Fall out -** The possibility of burning liquid fall-out from an elevated flare, if liquid hydrocarbons should be entrained into it.

**Pollution Limitations** (i.e., smoke formation, malodorous or toxic combustion products, noise) - May be based on statutory and/or public relations requirements.

### 4.2. Flare Capacity and Sizing

Flare systems shall be designed to handle the largest vapor release from pressure relief valves, vapor blow downs and other emergency systems, which results from the design contingency. Flare sizing shall include pressure relief valve and flare headers, blow down drums and seal drums.

### 4.3. Flash-Back Seals

Flare systems are subject to potential flashback and internal explosion since flammable vapor/air mixtures may be formed in the stack or inlet piping by the entry of air, and the pilot constitutes a continuous ignition source. Flares shall therefore always be provided with flashback protection.

### 4.4. Flare Gas Metering

Metering flare gas is mandatory for plant environmental control, loss accounting and for control of steam injection. A special requirement for flare gas meters is low-pressure drop and the ability to continue functioning in fouling conditions.

### 4.5. Protection against Low Ambient or Flare Gas Temperatures

Flare systems must be protected against any possibility of partial or complete blockage by ice, hydrates, solidification, etc. The following design requirements should be included:

- *The requirements of **International Practices** applying to pressure relieving systems, seal legs, bottom of flare stacks and seal drums, must be met.*
- ***Steam Injection** - Seal Drums requiring winterizing shall be provided with temperature-controlled steam injection to maintain the seal water temperature at 40 to 50°F (4 to 10°C), as described above under. This limits the quantity of water vapor entering the flare stack.*
- ***Steam Tracing** - When winterizing is required, the steam tracing and insulation should*

*include the first 25 ft. (7.5 m) of the flare stack above the vapor inlet; and also in the case of a drum seal, the vapor line from the seal drum to the flare. Where severe ambient conditions are encountered (such as where temperatures lower than -40°F (-40°C) have been encountered) then it is recommended that the entire seal drum and flare be insulated in addition to steam tracing and open steam injection at base of flare.*

• ***Cold Gas Releases*** *- Requirements for handling cold flare gas releases, such as by steam injection to the seal drum or by inline heaters, shall be considered per international practices and design standards.*

## 5. Design Procedure

### 5.1. Elevated Flares

#### 5.1.1. Sizing

Sizing of flare systems is a function of maximum allowable back pressure on pressure relief valves and other sources of release into the emergency systems.

Flare stack sizing and pressure drop is included with considerations of pressure drop through the pressure relief valve headers, blow down drums, flare headers, seal drum, etc. Elevated flare tips incorporating various steam injection nozzle configurations are normally sized for a velocity of 400 ft. /s (120 m/s) at maximum flow, as limited by excessive noise and the ability of manufacturers to design tips which will ensure flame stability. This velocity is based on the inclusion of steam flow if injected internally, but the steam is not included if added through jets external to the main tip. Flared gas streams containing hydrogen can generally be flared at higher exit velocities. In these cases flare tip manufacturers should be consulted on higher velocity limitations.

Pressure drops for proprietary tips are obtainable from manufacturer's charts. Available pressure drop may in some cases dictate acceptance of a lower maximum velocity, but at least 250 ft. /s (75 m/s) is recommended to ensure good dispersion. Flare tips consisting of a simple open-ended pipe with a single pilot are subject to flame lift-off and noise problems at high velocities, and should therefore be designed for a maximum velocity of 160 ft. /s (50 m/s).

#### 5.1.2. Location, Spacing and Height

Location, spacing and height of elevated flares are a function of permissible radiant heat densities, possible burning liquid fall-out, and pollution considerations. Design requirements are as follows:

*1. Flares shall be at least as high as any platform or building within 500 ft. (150 m) horizontally, and in no case less than 50 ft. (15 m) high.*

*2. Any source of ignitable hydrocarbons, such as separators or floating roof tanks, shall be at least 300 ft. (100 m) from the base of the flare stack, assuming the potential for liquid fall-out from the flare is minimal. Burning liquid fall-out from a flare can present extremely hazardous situations should ignitable hydrocarbons lie within the fall-out area.*

*3. Flares shall be located to limit the maximum ground level heat density to 1.6 kW/m$^2$ at any property line. The minimum distance from the base of the flare stack to the property line shall be 200 ft. (60 m).*

*4. Flare elevation and spacing must be such that permissible radiant heat densities for personnel at grade and on elevated structural platforms are not exceeded under conditions of maximum heat release. In some special cases, flare elevation and spacing may be governed by radiant heat*

*exposure of certain vulnerable items of equipment, rather than personnel.*
*5. Flare location and height must be such as to meet all applicable regulatory standards of noise level and atmospheric pollution by combustion products.*

### 5.1.3. Tip Types and Steam Injection

Flare tips incorporating steam injection are used where smoke emission and luminosity must be minimized. Generally, tip selection and steam injection capacity shall be designed to give smokeless operation at flare gas rates up to about 20% of design, since this will cover a large proportion of releases in a typical plant.

Significantly higher or lower steam ratios may be required for different tip designs and gas composition. Therefore, definitive steam ratios should be obtained on a case by case basis from flare tip vendors. In some cases steam control consists of a flow ratio controller with adjustable ratio set point, related to flare gas flow. The ratio adjustment, located in the control house, provides for the higher steam ratios necessary at low flaring rates. Manual smoke control shall also be provided using TV monitors in the operating control room.

If necessary, continuously vented surplus low-pressure steam may be used for smoke control at low flaring rates, with high-pressure steam cutting in through the flow ratio controller for larger releases. Injection of steam introduces an additional source of noise, and an effective flare tip is one which achieves a good balance of smoke and luminosity reduction without exceeding acceptable noise levels. Low-frequency noise is encountered at relatively high steam to hydrocarbon ratios. A flare performance chart, if available for the hydrocarbon being flared, may provide additional guidelines for flare tip design.

A maintenance platform shall be provided at the bottom of the flare tip (at the flange), with access by means of a caged ladder with intermediate platforms.

### 5.1.4. Pilots and Igniters

Proprietary flare tips are normally provided with the manufacturer's recommended igniter and pilot system. Typically, one to four pilots are used depending on flare tip type and diameter. The forced air supply type of igniter system is preferred. It is recommended that controls be located at a distance from the base of the flare such that pilot ignition can be readily observed, subject to a minimum of 25 ft. (7.5 m). Since pilot nozzles are small, strainers are needed to prevent plugging.

## 5.2. Multi-Jet Flares

### 5.2.1. Capacity

Multi jet flare is designed to handle a proportion of the maximum flow, so that releases up to this level will be relatively smokeless and no luminous. To further reduce smoking, steam injection at rates of 0.3 lb. steam/lb. gas (0.3 kg steam/kg gas) may be provided.

This will cover a large proportion of releases in a typical plant, but variations on this sizing basis may be dictated by considerations of the number and type of upstream process units, type and probability of major release contingencies and atmospheric pollution restrictions.

An over-capacity line to an elevated flare shall be provided to handle the excess flow when the flaring rate exceeds the capacity of the multi jet flare. The over-capacity line and flare is normally designed to handle the entire maximum flow so that it can spare the multi jet flare when the latter is shut down for maintenance.

**5.2.2. Spacing**

minimum spacing for heat releases between 300 x 106 and 1 x 109 Btu/hr. (90-300 MW) are given below. For heat releases outside this range, a special study must be made.

*1. Clearance from property lines: 200 ft. (60 m).*

*2. Clearance from structures higher than the flare stack: 200 ft. (60 m). In addition, no structure where personnel access may be required while the multi jet flare is in operation shall exceed in height a projected diagonal line from the base of the flare stack to the top of the stack wall diametrically opposite.*

*3. Clearance from structures lower than the flare stack: 150 ft. (45 m).*

*4. Clearance from plant roads and pipe bands: 75 ft. (22.5 m).*

*5. Clearance from the elevated over-capacity flare must comply with radiant heat spacing requirements for elevated flares, considering personnel exposure when maintenance work is being performed on the multi jet flare and the over-capacity flare is taking full design load. Clearance shall be sufficient to allow personnel to evacuate promptly to a safe location. This clearance should not, however, be less than 100 ft. (30 m).*

**5.2.3. Stack Design and Dimensions**

**Dimensions -** The inside diameter of the stack is based on the rate of heat release at design capacity. The bottom of the stack is elevated to allow air for combustion to enter. The minimum clearance between the bottom of the stack and grade is either 6 ft. (1.8 m) or 0.3 D, whichever is greater.

**Insulation -** The steel shell of the stack is lined for its entire length with monolithic type castable refractory.

**Windbreaker -** A windbreaker is necessary to prevent the wind from extinguishing the flames. It serves also to hide the flames. The area below the stack and windbreaker is paved with concrete, surrounded by a 8 in. (200 mm) curb, and graded to a central drain point from which a drain line is routed to a manhole in a vented section of the oily water sewer. The water inlet should be sealed and the manhole should be located at least 50 ft.(15m) from the windbreaker.

### 5.2.4. Burner Design and Back Pressure

The "burner" consists of a large number of small burner jets, arranged in a grid pattern inside the stack, near the bottom. To increase the rangeability of the burners, a two-stage piping system is provided, such that one set of burners handles low flows and the second set cuts in as the gas flow rate increases.

A simple sequential water seal system with two seal drums is used to control the distribution of flare gas to the two stages and to provide flashback protection. The seal in the over-capacity line is designed to start releasing when the pressure in the second stage burner header reaches a value corresponding to maximum design flow to the multi-jet flare. Design of the seal drums, loop seals, disposal of effluent seal water, etc., follows the procedure described below for elevated flares under **Flash-Back Protection for Flare Systems, with the following exceptions:**

***a.*** *Vapor inlet dip leg submergence is selected to control progressive operation of the stages.*

***b.*** *The second stage seal drums should be vertical, to minimize its size, provided that the required slope up to the burners can be achieved.*

A butterfly valve in the line to the first stage seal drum limits the maximum flow to the first stage burner. The valve is set by observing the burners while flaring at design capacity. Once adjusted, the valve should be locked in position.Pressure indicators are specified to aid in making adjustments and in evaluating burner performance.

First and second stage piping and headers, as well as the burner lines themselves, shall be sized to minimize pressure drop and velocity effects. Thus, mal-distribution of flow to the burners shall be minimized. First and second stage headers must be sloped so that any condensate will drain back to the seal drums. However, the burner lines must be accurately installed in a horizontal plane.

The jet nozzles discharge vertically from the horizontal burner lines, which run across the bottom of the stack. The jet nozzles are not insulated. The number of jets is based on gas velocity. For 1 in. (25 mm) standard pipe, the recommended maximum velocity permits a flow rate of 2550 SCFH. (72.2 $Sm^3/h$) of gas per jet.

The capacity of a multi-jet flare to induce air flow must be calculated, to make sure that it is adequate to meet the maximum air flow requirement for smokeless combustion.

Flame holders are necessary to prevent the flame from "riding" up to the top of the stack. They provide a surface at which burning can take place and also promote better mixing of air and gas by the additional turbulence which they cause above the jets. The position of the flame holders and burner lines relative to the bottom of the stack is critical for efficient operation.

The burner lines should be insulated with at least 1 in. (25 mm) layer of castable insulation. Duplicate continuous gas pilots are required at each side of the flare, corresponding to the split burner grid layout. Selection of pilot and igniter systems follows the guidelines described under

**Flare Pilots and Igniters** and the controls shall be located 50 to 100 ft. (15 to 30 m) from the windbreaker.

Because of the potential hazard of release of un-ignited hydrocarbons at ground level, a flame detection system, e.g. scanner, flame rod, TI / TLA, with alarm in the control house shall be included for each pilot. If an ultra violet detector is used, the flame scanner must be located so that interference of ultra violet rays from the main flame or other sources does not cause false readings. Mount ultra violet detectors looking straight down through the pilots toward the ground. Provide strainers in each gas or oil line to pilots.

Steam injection at a rate of about 0.3 kg of steam/kg of gas will provide additional reduction in smoke for most gases. Steam should be injected into the flare gas either upstream or downstream of the burner nozzles, according to the burner design.

In selection of materials for burner grid, stack lining, and piping inside the windbreaker, temperature rise due to heat radiation from the flame should be evaluated. A flare tip refractory lining should be provided.

## 6. Flare Pilots and Igniters (All Flares)

All flares must be provided with continuous pilots to ensure combustion of any releases discharged to them, and to prevent flame-out. In addition, an ignition system is required for igniting the pilots when a flare is commissioned. The ignition chamber and igniter tube Venturi must be placed close to the flare, i.e., at the base of an elevated flare or adjacent to the windbreaker of a multi-jet flare. Remote operation of the ignition controls may however be achieved by locating the spark ignition push button and the igniter gas and pilot gas valves at any required distance from the flare.

An alternative design uses a compressed air supply (from the instrument air header) for the ignition chamber, the gas/air mixture being controlled by restriction orifices. The flame front passes through an igniter tube as for the inspirating type, but there are no limitations on horizontal distance from the flare, and the igniter assembly may therefore be located remotely. The forced air supply type of igniter system is preferred for all flare applications.

When pilot and igniter systems for flares are being selected available proprietary systems may be considered but the choice should be based upon proven satisfactory operating experience.

Flares, which depend only on PHA and PLA alarms in the pilot gas supply to indicate the pilots are lit, should be Priority 1 alarms which have dedicated alarms in the control room. For flares using thermo-couples to verify pilot flame, such as used on a $H_2S$ flare, the use of PHA and PLA instrumentation in the pilot fuel gas supply is not required. However, the thermo-couples should be equipped with Priority 2 alarms.

Testing of the pilots prior to installation is strongly recommended since the primary air setting may not be valid if site location is different from factory location. Pilot tip temperature must be above the ignition temperature of the fuel and testing will confirm that the desired tip temperature of 1500°F (816°C) is achieved. Use of 80 scfh pilots appears to be adequate to ensure flame stability, and is recommended.

Gas pilots must be provided with a reliable source of gas, which will remain available under any single contingency such as power or air failure. Pilots should be designed for the anticipated gas composition, which should be reasonably constant.

## 7. Flash-Back Protection for Flare Systems

All flares must be provided with flashback protection to prevent a flame front from traveling back to the upstream piping and equipment. A number of different flashback seal designs are available, of which the seal drum is used in nearly all applications. Details are as follows:

**Seal Drum -** a continuous flow of water to the seal drum shall be provided so that loss of level downstream of the baffle is not possible. Condensed hydrocarbon may accumulate downstream of the baffle and skimming connections should be provided.

A baffle maintains the normal water level, and the vapor inlet is submerged. Drum dimensions are designed such that a 10 ft. (3 m) slug of water is pressured back into the vertical inlet piping in the event of flashback, thus preventing the explosion from propagating further upstream.

The inlet piping or dip-legs shall have sufficient wall thickness to withstand an internal explosion and should be good for 50 psig (345 kPa), or consistent with the drum internal design pressure.

The vapor space is sized to avoid water entrainment into the flare gas. The vapor residence time in the drum should allow larger liquid droplets to fall to the liquid surface. The method used follows API 521. The vapor space velocity as measured through the vertical cross-sectional area above the baffle level determines the residence time.

Seal water shall be taken from a reliable source. Salt water should not be used where flare gas components would cause deposition of solids. Winterizing should be provided if required. At some locations, which experience extremely cold weather, a recirculation glycol system is used.

The vertical down flow section of the water outlet line from the drum is sized for a maximum velocity of 0.4 ft./s (0.12 m/s), to allow entrained gases to disengage. The seal loop should be sized for the design water flow. The make-up water rate must be sufficient to compensate for drum purge and evaporation.

The maximum make-up rate assumes that the drum is empty after a blow and shall be high enough to re-establish the seal within a reasonable time after each flaring incident. However, the seal must be re-established before the ingress of air reaches the seal drum. Air ingress occurs as the system cools down after a pressure release. Where higher water rates are considered necessary then facilities for manually increasing the makeup should be provided. The seal depth is equivalent to 175% of the maximum drum operating pressure, subject to a minimum of 10 ft. (3 m). A seal depth of 110% of the maximum operating pressure is permitted when applying the “1.5 times design pressure” rule to remote contingencies. The drum is normally gunite-lined for corrosion control and must be designed to meet all the following combinations of extreme temperature and pressure requirements:

*1. A design pressure of 50 psig (345 kPa) at the highest possible operating temperature of the entering vapors resulting from a single contingency. For those hydrocarbons typically encountered in plant operations, this design pressure should adequately protect the drum against an internal explosion. This design pressure must also be applied to the flare stack and the water outlet seal loop. However, for those locations which may flare streams containing more than 75% by volume ethylene, a design pressure of 150 psig (1035 kPa) should be used.*

*2. A design pressure of 50 psig (345 kPa) at the lowest possible operating temperature of the entering vapors resulting from a single contingency.*

A flare seal drum may also serve as a sour water disengaging drum. In such cases, special care is needed to ensure the drum is adequately sized to simultaneously meet all design features required for both functions. Also a separate source of make up water must still be provided to ensure continuity of the seal.

The drum is provided with steam injection if required for winterizing or cold releases. If winterizing is called for, then the steam should be temperature-controlled to maintain the seal water temperature at 40 to 50°F (4 to 10°C). Oil skimming connections should be provided to remove accumulated oil, carried over from the blow down drum, to the seal drum. The seal drum should be located a minimum practical distance from the flare.

**Dry Seals -** Various proprietary dry seals are available; they may be used in conjunction with a gas purge system when the purge gas is lighter than air. The molecular dry seal functions by trapping a volume of the light gas in the internal inverted compartment, thus preventing air from displacing light gas in the flare stack by buoyancy effects. The fluidic dry seal utilizes the kinetic properties of the gases to prevent movement of air down the flare. The continuous purge flow requirements for these dry seals may be 30-60% of the open stack purge rates as determined from appropriate standards. The vendor should be contacted to determine their specific recommendation for each proposed installation. This reduced purge requirement is the only incentive for installing a dry seal.

Unlike a water seal, a dry seal cannot prevent a flashback from traveling upstream if a combustible mixture has been formed by the entry of air into the pressure relief valve or flare headers. It only protects against internal burning flashback, which might result from air backing down from the flare tip at zero or low flaring rates. Dry seals are therefore not normally specified for new designs.

**Disposal of Seal Water -** Effluent water from water seals must be routed to safe means of disposal, considering possible hazards arising from liquid or vapor hydrocarbons or toxic materials that may be entrained or dissolved in the water. Seal water should be discharged as follows:

*1. if $H_2S$ is never present in the flare gas, seal water effluent should be routed through an open* *funnel (to permit checking of seal water flow) to a manhole in a vented section of the oily water sewer. The water inlet to the manhole must be sealed.*

*2. if $H_2S$ in any concentration is intermittently present in the flare gas, seal water effluent should be routed through a closed connection (incorporating a sight glass for checking flow) to a manhole in a vented section of the oily water sewer. The water inlet to the manhole must be sealed. In addition, the seal drum should include a baffle to preferentially route the make up water to the sewer, while confining $H_2S$-saturated water to the drum. However, pollution considerations may make the routing of seal water to the sewer unacceptable, in which case disposal must follow method (3) below.*

*3. If $H_2S$ is continuously present in the flare gas, or if the flare seal drum also functions as a sour water disengaging drum then the effluent seal water must be routed to a sour water stripper, de-Salter, or other safe means of disposal. Withdrawal from the drum is by pump in place of the normal loop seal arrangement. Seal drum level shall be controlled by LIC with high and low alarm lights plus an independent high level alarm.*

*4. Disposal of effluent water from multi-jet ground flare seal drums should comply with paragraphs (1), (2), and (3) above, except that:*

- *In (1), closed piping with a sight glass should be used rather than an open funnel.*
- *In (1) and (2), the manhole receiving effluent seal water should be located at least 50 ft. (15 m) from the windbreaker.*

***Note: Flame arresters are not permitted as a means of flashback protection in flare systems.***

## 8. Flare Pulsing and Noise Reduction

A major cause of pulsing in flare systems is flow surging in the water seal drum. This can be eliminated by providing a gas distributor in the seal drum. One of several reasons why it is important to eliminate pulsing is to reduce flare noise. Combustion flare noise increases as the steam rate increases. Since the amount of steam required to suppress smoke in a flare is set by the flaring rate, flow surges will require a higher steam rate than for a steady flow. At much higher steam rates than required to suppress smoke, flares occasionally exhibit another type of noise problem, a low frequency rumble that can be sensed in the surrounding community as vibrations. The over steaming of the flare produces pockets of un-combusted gases which then ignite sporadically. By reducing the steam requirement of a flare through eliminating flow surges, there is a greater operating margin between smokeless flaring and high steam rate associated rumble. The likelihood of over steaming a flare and causing noise problems can be reduced by providing automatic smoke control.

Flow surges in the seal drum are generated by the cyclic formation of large bubbles as the flare gas is discharged into the drum. These pulsations can be virtually eliminated by the use of a horizontal sparger incorporating many small diameter holes arranged specifically to allow the open area to increase as flow increases. These holes must be spaced sufficiently far apart to avoid interference between bubbles. Hole density is low at the top of the pipe and is increased lower on the pipe. The maximum open area density of about 10% assures reasonable bubble formation. The average velocity out of the top row of holes starts at about 130 ft. (40 m/s) and increases as the pressure rises and total flow increases. Total areas of holes plus bottom slot should be equal to at least two times the cross sectional area of the inlet pipe.

## 9. Flaring of $H_2S$ Streams

Continuous releases of concentrated $H_2S$ streams must be segregated in a separate flare system. $H_2S$ flare system should consist of a segregated header and separate line routed up the side of a conventional elevated flare stack, sharing the same structure, but having separate pilots and igniters. Flare elevation must be sufficient to meet atmospheric pollution and ground level concentration requirements for the sulfur dioxide produced. Incomplete or no combustion of flared hydrogen sulfide can lead to extremely dangerous situations because of the relatively low lethal concentration of hydrogen sulfide. The following design features shall be considered for design of concentrated streams of hydrogen sulfide flare:

- *It is absolutely essential that flare pilots be lit at all times. The flare pilots shall be provided with a reliable source of fuel gas, a reliable forced air type igniter system and a means of automatic pilot flame verification such as thermocouples situated inside a thermo-well which is located at the base of the pilot flame. Auto relight based on pilot verification is to be considered where manning may limit operator attention. The fuel gas used for the pilots should be clean and free of any appreciable quantities of condensable and should be provided with a pressure controller and high and low pressure alarms. If appreciable quantities of condensable in the fuel gas are likely, then a knock-out drum with a high level alarm should be provided. Piping should be self-draining back to the drum. At least three pilots should be provided. For very small flares [less than 8 in. (200 mm) diameter], at least two pilots and igniter assemblies should be provided. For large flares [greater than 42 in. (1067 mm) diameter], at least 4 pilots should be provided. Each pilot burner should be rated for a minimum heat release of 80000 Btu/hr (23.4 kW). Individual pilot gas lines to the flare tip with isolation capability at grade should be provided to enable isolation of a burnt out pilot. A burnt out pilot may tend to preferentially take gas from the undamaged pilots, which could ultimately lead to their extinguishment.*
- *The combustion characteristics of the flared gas must be high enough to ensure flame stability. If UFL is below 30 vol. %, it is recommended that assist fuel gas be added until the UFL is increased to 30 vol. % or the heating value increased to 500 Btu/SCF (5.2 kJ/Sm$^3$). Supplemental fuel gas, when required, should be automatically introduced (at the upstream end of the flare header for mixing and purging) via ratio control of the fuel gas stream to the measured flare header acid gas rate. Ratio control of fuel gas/acid gas should be a safety critical instrument.*
- *To avoid flame "blow off," acid gas flare exit velocity, including any supplemental fuel gas, should be limited to 150 ft./sec (45 m/s).*
- *Steam should not be added to acid gas while flaring because of the quenching effect it will have on the flame temperature. This can result in incomplete or no combustion. Hydrogen*

*sulfide burns smokeless as will any supplemental fuel gas (unless the fuel gas contains a very high level of unsaturated compounds). Thus, steam addition for smokeless flaring is normally not required.*

- *The flare stack should be high enough that dangerous concentrations of uncombusted hydrogen sulfide are unlikely to accumulate at grade should the flare become extinguished or flaring efficiency drop off. For a given set of conditions, there will be a certain wind velocity and downwind distance from the stack that produce the highest ground level concentration, referred to as the critical ground level concentration. As a design guideline, the flare elevation should be such that the critical ground level concentration of hydrogen sulfide does not exceed 10 vppm over a one hour averaging time assuming none of the hydrogen sulfide entering the flare is converted to sulfur dioxide. In addition to meeting the critical ground level concentration criterion, the stack should be high enough that radiant heat levels at grade do not exceed 3,000 Btu/hr ft$^2$ (9.45 kW/m$^2$) at maximum release rate.*
- *Mechanical reliability of the flare tip assembly should be maximized by providing features such as wind shields to protect the outside of the flare tip against damage from flame lick and internal refractory lining to protect against burning inside the flare tip at low flaring rates.*
- *A potential problem with flaring acid gas is the deposition of ammonium bi-sulfide ($NH_3$+ $H_2S$) and ammonium bicarbonate ($NH_3$ + $CO_2$ + $H_2O$) in the flare header and even at the base of the flare stack. The potential for such deposits depends on the temperature of the gas and the partial pressures of $NH_3$, $H_2S$, $CO_2$ and $H_2O$. Any lines, including the flare header and flare stack, which are susceptible to the formation of such deposits shall be heat traced and insulated to maintain stream temperatures at least 25°F (14°C) higher than the deposition temperature. As a minimum, the line temperature should be maintained above 120°F (49°C). An alternative to heat tracing and insulating the flare stack would be to provide water wash connections into the flare stack approximately 30 ft. (9 m) above the acid gas header inlet. If protection of the stack via water wash is provided, it is imperative that routine washing be carried out.*
- *Flashback protection is required for $H_2S$ flaring systems, either by water seal or continuous gas purge. If a water seal is used, special requirements apply to the disposal of the effluent seal water.*

## Appendix 1: Exposure Limits to Heat Radiation from Flares

- **Personnel Exposure to Heat Radiation**

In most cases, heat radiation is the controlling factor in determining the spacing of flares, considering personnel exposures at grade under maximum heat release conditions. Maximum permissible flare radiation levels for personnel exposure are:

| MAXIMUM PERMISSIBLE K, Btu/hr/ft.$^2$ (kW/m$^2$) | CONDITIONS |
|---|---|
| 3000 (9.45) | Maximum value of K at design flare release at any location where personnel have access, e.g., at grade below the flare, or on a platform or nearby equipment. Exposure must be limited to a few (approx. six) seconds, sufficient for escape only. On towers or other elevated structures, ladders must be provided on the side away from the flare, so that the tower or structure can provide some degree of shielding. |
| 2000 (6.3) | Areas where emergency actions lasting up to 1 minute may be required by personnel without shielding. |
| 1500 (4.75) | Areas where emergency actions lasting several minutes may be required by personnel without shielding, e.g., at the battery limits of a process unit. |
| 500 (1.6) | Maximum value of K at design flare release for continuous exposure of personnel and maximum value of K at property line. [By comparison, solar radiation in a hot climate may be as high as 300 Btu/hr/ft.$^2$ (1 kW/m$^2$).] |

- **Equipment Exposure to Heat Radiation**

In most cases, equipment can safely tolerate higher degrees of heat density than those defined for personnel. However, if anything vulnerable to overheating problems is involved, such as low melting point construction materials (e.g., aluminum or plastic), heat-sensitive streams, flammable vapor spaces, or electrical equipment, then the effect of radiant heat on them may need to be evaluated. When this evaluation is required, the necessary heat balance is performed to determine the resulting surface temperature, for comparison with acceptable temperatures for the equipment, e.g., up to 176°F (80°C) is permitted for electronic instrument transmitters.

- **Ignition of Pressure Relief Valve Releases and Start-up Vents**

The following personnel exposure limits should be used to protect personnel against exposure to high radiant heat resulting from inadvertent ignition of atmospheric vents such as pressure relief valve releases and start-up vents:

| TYPE VENT | PERSONNEL EXPOSURE LIMIT |
|---|---|
| Pressure Relief Valve Release to Atmosphere | 6,000 Btu/hr ft.$^2$ (18.9 kW/m$^2$) maximum at grade or at frequently used operating platforms. Because of the higher exit velocities and additional air entrainment associated with PR valve discharges, the heat release is less than for a low velocity flare. The following factors (fraction of heat release radiated) should be used: |
| Start-up Vent to Atmosphere | 3,000 Btu/hr ft.$^2$ (9.45 kW/m$^2$) maximum at grade or at frequently-used Operating platforms. Note that the higher F factors in this section for flares should be used for start-up vents. |

| | **F for PR Valve Discharges** |
|---|---|
| **Hydrogen, Methane** | **0.1** |
| **$C_2$ and Heavier Hydrocarbons** | **0.25** |

## Appendix 2: Limits of Flammability of Gases and Vapors, Percent in Air

| GAS OR VAPOR | LOWER | UPPER |
|---|---|---|
| Hydrogen | 4.00 | 75.00 |
| Carbon monoxide | 12.50 | 74.00 |
| Ammonia | 15.00 | 28.00 |
| Hydrogen sulfide | 4.00 | 44.00 |
| Carbon disulfide | 1.25 | 50.00 |
| Methane | 5.00 | 15.00 |
| Ethane | 3.00 | 12.50 |
| Propane | 2.10 | 9.50 |
| Butane | 1.90 | 8.50 |
| Iso-butane | 1.80 | 8.40 |
| Pentane | 1.50 | 7.80 |
| Iso-pentane | 1.40 | 7.60 |
| Hexane | 1.10 | 7.50 |
| Heptane | 1.05 | 6.70 |
| Octane | 1.00 | 6.50 |
| Nonane | 0.83 | 2.90 |
| Decane | 0.80 | 5.40 |
| Dodecane | 0.60 | — |
| Tetradecane | 0.50 | — |
| Ethylene | 2.70 | 36.00 |
| Propylene | 2.00 | 11.10 |
| Butadiene | 2.00 | 12.00 |
| Butylene (1-Butene) | 1.60 | 10.00 |
| Amylene (1-Pentene) | 1.50 | 8.70 |
| Acetylene | 2.50 | 100.00 |
| Allylene (Propadiene) | 1.74 | — |
| Benzene | 1.20 | 7.80 |
| Toluene | 1.10 | 7.10 |
| Styrene | 0.90 | 6.80 |
| o-Xylene | 0.90 | 6.70 |
| Naphthalene | 0.90 | 5.90 |
| Anthracene | 0.63 | — |
| Cyclo-propane | 2.40 | 10.40 |
| Cyclo-hexene | 1.22 | 4.81 |
| Cyclo-hexane | 1.30 | 8.00 |
| Methyl cyclo-hexane | 1.20 | 6.70 |
| Gasoline-regular | 1.40 | 7.50 |
| Gasoline-73 octane | 1.50 | 7.40 |
| Gasoline-92 octane | 1.50 | 7.60 |
| Gasoline-100 octane | 1.45 | 7.50 |
| Naphtha | 1.10 | 6.00 |
| Jet fuel JP-4 | 1.80 | 8.00 |
| Kerosene | 0.70 | 5.00 |
| Gas oil | 0.50 | 5.00 |

# Basic Safety Concepts for Light Ends Loading & Storage Facilities
# NPC-HSE-S-12

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## CONTENTS

## 1. Scope

This document covers safety aspects of the design of tank truck and rail loading and unloading facilities, and storage of Liquefied Petroleum Gas (LPG) and similar materials. Other design aspects such as process, Mechanical, Electrical, Instrument and calculations shall be followed as per proper design standards and international practices.

## 2. References

*1. API RP 500, Classification of Locations for Electrical Installations at Petroleum Facilities*
*2. API RP 1004, Bottom Loading and Vapor Recovery for MC-306 Tank Motor Vehicles*
*3. API RP 2003, Protection against Ignitions Arising Out of Static, Lightning, and Stray Currents*
*4. API Std. 2510, Design and Construction of Liquefied Petroleum Gas (LPG) Installations.*
*5. API Pub.2510A, Fire Protection Considerations for the Design and Operation of LPG Storage Facilities.*

## 3. Definitions

**Liquefied Petroleum Gas (LPG) -**Light hydrocarbon material, gaseous at atmospheric temperature and pressure, held in the liquid state by pressure to facilitate storage, transport and handling. Commercial liquefied gas consists essentially of $C_3$'s and $C_4$'s.

## 4. Tank Truck and Rail Loading/ Unloading

Loading and unloading racks present a potential fire risk because of the possibility of hose or loading arm failure, overfilling, venting to atmosphere during loading, and vehicular traffic close to piping and equipment. Designs must therefore minimize uncontrolled releases and ignition sources and provide adequate fire protection. The following safety features shall be considered in the design of truck and rail loading and unloading facilities:

### 4.1. Loading / Unloading Connections for Low and High Flash Fuels

1.Bottom and top loading are equally acceptable if properly designed to recognized codes. For top loading, maximum distance between loading arm's tail pipe and bottom of the loading tank shall not exceed 6"(15cm) so that the liquid free drop shall be prohibited.

***Note 1: for a wide range of hydrocarbons, liquid free drop can lead to generating static electricity and increase fire/explosion risk.***

2. Bottom loading requires compatible dry-break connections for the vehicle and loading arm or hose. The connections should comply with API RP 1004, which also accommodates vapor recovery, or a comparable code. Metal loading arms are recommended; properly specified hose is also acceptable.
3. All-metal loading arms are required for top loading through an open hatch. Vapor recovery with top loading requires special fittings and connections.

## 4.2. Loading / Unloading Connections for LPG

1. Liquid loading and spray loading for LPG are equally acceptable if properly designed to recognized codes with the respect to note 1(above mentioned)
2. Liquid loading and spray loading for LPG shall be accomplished by using hard (all-metal) arms. Existing facilities may continue to load through hoses if risk assessment indicates that the risk from a potential hose failure is acceptably low. It is suggested to use dry break couplings in order to minimize LPG release during uncoupling. Hose connections for bulk transfer should be designed such that they can be emptied of liquid after loading. They may be left in the vapor phase. Hard arms may be left under liquid; however, they need thermal expansion protection.
3. A vapor return will facilitate the loading process in making it shorter. Vapor connections may be through hard arm or hose. The combination liquid as hard arm and vapor as hose is also allowable.
4. Spray loading of LPG or other volatile product into pressurized tank trucks and rail cars is allowed provided the vehicle tank is designed for this operation. Typically the vehicle tank would have a spray header inside the top of the vessel which is directly connected to the liquid filling line. It is important that the tank be free of air (and thus non-condensable) before the loading process begins due to the strong electrostatic charges created by this type of loading.
5. For loading and unloading refrigerated liquefied gases the installation of a vapor return line to compressor and tankage is recommended.
6. Either a pump or a compressor can be used to transfer LPG if a vapor return line is provided.

## 4.3. Overfill Protection

Primary and secondary means of protection against overfilling shall be provided, as follows:

| Product | Loading Method | Primary Protection | Secondary Protection* |
|---|---|---|---|
| Low or high flash | Open top loading | Preset meter | High level cut-off or "deadman"valve on loading arm |
| Low or high flash | Closed top or bottom loading | Preset meter | High level cut-off for each compartment |
| LPG and other liquefied gases | Closed loading | Preset meter or scale preferred; if not available,vehicle level gauge | Vehicle level gauge; weigh scale at gate |

***Note: Internal probes made of conductive materials, such as protrusions extending downward from the roof into the tank, shall be avoided to minimize the chances of electrostatic ignition. Level markers and overflow detectors in tank trucks and tank cars are such internal probes. Explosive atmospheres should also be avoided.***

***Facilities shall be provided to unload overfilled trucks and rail cars.***

## 4.4. Control of Vapor Emissions

Vapors displaced during loading can be captured in a vapor handling system. Depending on local regulations, the vapors can be burned in an incinerator or sent to a recovery unit. In addition to primary and secondary overfill protection, necessary safety features include:

1. Provision for liquid entrained or carried over with the vapor, generally a drop-out tank vented to the vapor handling system.
2. Flashback protection between the loading rack and incinerator or recovery unit.

## 4.5. Emergency Isolation

1. Each loading and unloading line must have an EBV installed between 50 and 100 ft. (15 and 30m) from the loading rack to provide for a rapid shut down in an emergency. Block valves provided for operational reasons at pumps or manifolds will serve this purpose if they are readily accessible from a platform or grade and within the above distance. Chain wheel operators are not acceptable, but flexible remote valve actuators may be considered for certain applications. A check valve shall be installed in each unloading line.

2. Power operated EBVs with local and remote actuation are recommended for installations with large lines or multiple loading bays, and for LPG operations. Remote pump shut down at the rack is recommended if it cannot otherwise be rapidly achieved in an emergency.

3. Provision shall be made to prevent the movement of trucks using brake or electrical interlocks

on the trucks while loading lines are connected. If this cannot be done, excess flow check valves or breakaway couplings should be used to protect against broken loading lines.

### 4.6. Weight Scales

1. Scales, which automatically shut off supply when a pre-set quantity has been loaded, must have an independent overfill alarm and shut down.
2. Scales with below-grade pits in electrically classified areas must have either: (a) continuous forced ventilation of the pit, with an alarm upon ventilation failure, or (b) a continuous combustible gas detector sampling the bottom of the pit, actuating an alarm with provision to purge or ventilate the pit when necessary.

### 4.7. Roofing and Platforms

1. Roofing is recommended: (a) where loading through open hatches, (b) where necessary to minimize the amount of contaminated run off, and (c) where operators require weather protection.
2. Fixed or draw-bridge platforms are required for safe working access when loading or gauging on top of the rail car or truck. Platforms must accommodate the varying sizes and configurations of the vehicles that will be handled. Handrails shall be provided.

### 4.8. Control of Ignition Sources

1. When loading flammable products, the requirements of API RP 2003 and NPC-HSE-S-08 must be followed to avoid static electricity as a source of ignition. Particular attention should be paid to the following:
   - *a. Length of fill pipe, control of filling velocities, avoidance of splash filling, relaxation time downstream of filters, and electrical bonding. Interlocks that prevent loading if the vehicle is not properly grounded are recommended.*
   - *b. Segregation of pumps, lines, meters and filters for different products, to avoid cross-contamination which could alter the classification of the materials handled.*
2. Electrical area classification shall be based on API RP 500, if the rack is in an open area with unrestricted ventilation, and leakage and spills are limited to the loading area. To avoid inadvertent replacement with components of the wrong classification, it is preferable for all electrical equipment at the loading rack to meet at least Division 2 requirements.
3. Tracks of railroad spurs may connect with electrified main lines, cross electric railway tracks, or be connected with rail circuit signaling systems. In all such circumstances, insulated couplings should be placed in rail joints of the spur track so it will be completely insulated from the source of any return currents, per API RP 2003.

### 4.9. Fire & Gas Detection

Fire and gas detection systems including hydrocarbon fixed gas detectors shall be provided in loading area as an effective tool for early leak detection. The technical aspects of F& G system shall meet NPC-HSE-S-06.

## 5. Layout and Spacing

NPC-HSE-S-03 covers requirements for location, layout and spacing of loading and unloading racks, including vehicle access and area paving.

## 6. Firefighting Facilities

Refer to NPC-HSE-S-07.

## 7. Special Requirements for Chemicals

If the chemical is toxic or corrosive, the design must include appropriate features to prevent hazardous exposures to personnel and equipment.

## 8. Storage of LPG and Similar Materials

This section covers pressurized and refrigerated storage of flammable liquids having an RVP of 15psia or higher, such as LPG, ethylene, butadiene, butenes, isoprene, methyl chloride, ammonia, and liquefied natural gas.

Storage of flammable liquefied gases is among the most severe hazards in chemical plant. Auto-refrigeration of most of these materials introduces potential embrittlement and freeze-up problems. Spillage produces large volumes of vapor; heavier-than-air vapors tend to flow along the ground, and may reach an ignition source some distance from the point of leakage. An unconfined vapor cloud explosion (UVCE) can result if a large amount of the vapor cloud is in the flammable range. An unprotected pressure storage tank, if exposed to fire, is vulnerable to a boiling liquid-expanding vapor explosion (BLEVE).

***Safe storage of these materials must provide for elimination of potential sources of uncontrolled releases; spacing; overpressure protection; and adequate fire protection by means of fireproofing and firewater coverage.*** General guidelines are provided in API 2510 and in API 2510A. Also, the following safety features shall be considered in the design of storage for LPG and similar materials:

1. To minimize risks of brittle fracture, the piping and equipment Critical Exposure Temperature (**CET**) shall be in compliance with the design standards and practices.
2. Horizontal storage drums must have special consideration because they have a

tendency to become projectiles if they fail under fire exposure. To the extent possible, horizontal vessels should be oriented so their longitudinal axes do not point toward other tanks, process equipment, control rooms, or loading/unloading facilities in the vicinity. In addition, to minimize fire exposure, piping connections should be avoided between vessel supports, and located at the same end of grouped vessels.

3. Plants handling different grades (e.g., propane and butane) shall have dedicated piping for each product, to avoid excessively low temperature or high pressure as a result of cross-contamination.
4. Overfill is a particular concern with liquefied gas tanks because the consequences can be severe; and the liquid level is determined only by instruments, and cannot be observed directly. There shall be two level indicators, of different types, plus an independent high level alarm, all of which are repairable in service. In addition, an automatic high-high level cut-off of incoming liquid flow shall be provided for all pressurized storage and refrigerated tanks.
5. Gas detectors shall be considered to provide early detection of leaks and spills.
6. Appropriate connections must be provided for commissioning storage vessels and taking them out of service. Refrigerated tanks normally require nitrogen purge injection and vent connections. Pressure tanks are usually purged by water filling, with vent connection to remove air displaced as the water rises. A vapor connection to an adjacent tank in the same service, where available, allows vapor to be drawn in when the water is drained. The same connection can be used for taking the tank out of service: water is injected, displacing the residual liquid and vapor over the top into the adjacent vessel.
7. Purging the annulus of double-walled refrigerated tanks - The insulated annulus, if not contiguous with the vapor space, must be provided with connections for nitrogen pressurization, and for sampling to detect leakage of the inner vessel.
8. Foundations for refrigerated tanks - Foundations and supports for refrigerated storage vessels must be able to withstand the effects of a spill of cold liquid up to the full height of the dike without risk of mechanical failure. Heated foundations should have instrumentation for monitoring temperatures. The heaters should be designed for removal and replacement while the tank is in service.
9. Protection against rollover in refrigerated storage. Adequate mixing of feed and tank heel during filling. The preferred method is to bottom fill tanks through jet mixer nozzles. If this is not feasible, alternative mixing methods (such as spargers for mixed phase feed) should be considered.
10. Layout of an LPG storage area is an important factor in determining fire water and drainage requirements for a plant, as well as in minimizing risk to nearby facilities. Enough firewater must be available to provide the recommended rate for any tank involved in a fire, plus coverage of adjacent tanks.

11. Because of the nature of LPG, remote emergency isolation of the storage facilities should be included. For this reason use of Excess Flow valves is recommended in tank discharge line close to tank flange.
12. Provision of dewatering facilities under LPG storage tanks should prohibit as possible. In case of process necessity (provision shall be made for double valving system with suitable anti-freezing and EBV facilities.
13. Tanks supports shall be fireproofed according to proper standards in order to prepare suitable passive fire protection.
14. Dike area shall be considered for Storage Tanks as per NFPA 30 and API 2510 requirements.
15. Storage facilities should also comply with the Design standards and Inten tional Practices and other guidelines to cover the following aspects of design:

| **Instrumentation: Pressure Gauges, Alarms, Cut-outs,** | **Layout, Spacing, Dikes, Drainage:** |
|---|---|
| Design Temperature, Pressure, | Isolation Valves, EBVs |
| Piping Connections: | Sample Point Double Valving |
| Water Flood Connections | Water Draw-off |
| Fireproofing: | Vessel Supports |
| Firefighting Facilities | Pressure Storage Spheres and Drums |
| Access for Operation and Maintenance | Pressure Storage |
| Temperature Indicator, Dual Level Measurement, | Refrigerated Storage |
| Prohibition of Gauge Glasses | Mounding |
| Overpressure Protection | |

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ISBN:978-600-6682-43-3
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