Handbook of Fire and Explosion Protection Engineering Principles

for Oil, Gas, Chemical and Related Facilities

Third Edition

Dennis P. Nolan

ELSEVIER

Handbook of

FIRE AND EXPLOSION PROTECTION ENGINEERING PRINCIPLES

EDITION 3

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DEDICATION

Dedicated to:
Kushal, Nicholas, & Zebulon

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ABOUT THE AUTHOR

Dennis P. Nolan has had a long career devoted to fire protection engineering, risk engineering, loss prevention engineering, and system safety engineering. He holds a Doctor of Philosophy Degree in Business Administration from Berne University, Master of Science degree in Systems Management from Florida Institute of Technology. His Bachelor of Science degree is in Fire Protection Engineering from the University of Maryland. He is also a US-registered Fire Protection Engineering, Professional Engineer, in the State of California.

Dr. Nolan is currently associated with the Loss Prevention executive management staff of the Saudi Arabian Oil Company (Saudi Aramco) as a Loss Prevention Consultant/Chief Fire Prevention Engineer. He is located in Dhahran, Saudi Arabia, headquarters for the largest oil and gas operations in the world. The magnitude of the risks, worldwide sensitivity, and foreign location make this one the most highly critical operations in the world. He has also been associated with Boeing, Lockheed, Marathon Oil Company, and Occidental Petroleum Corporation in various fire protection engineering, risk analysis, and safety roles in several locations in the United States and overseas. As part of his career, he has examined oil production, refining, and marketing facilities under severe conditions and in various unique worldwide locations, including Africa, Asia, Europe, the Middle East, Russia, and North and South America. His activity in the aerospace field has included engineering support for the NASA Space Shuttle launch facilities at Kennedy Space Center (and for those undertaken at Vandenburg Air Force Base, California) and "Star Wars" defense systems.

He has received numerous safety awards and is a member of the American Society of Safety Engineers, National Fire Protection Association, Society of Petroleum Engineers, and the Society of Fire Protection Engineers. He was a member of the Fire Protection Working Group of the UK Offshore Operators Association (UKOOA). He is the author of many technical papers and professional articles in various international fire safety publications. He has also written several other books which include, *Application of HAZOP and What-If Safety Reviews to the Petroleum, Petrochemical and Chemical Industries* (1st, 2nd, 3rd, and 4th Editions), *Fire Fighting Pumping Systems at Industrial Facilities, Encyclopedia of Fire Protection* (1st and 2nd Editions) and *Loss Prevention,* and *Safety Control Terms and Definitions*.

Dr. Nolan has also been listed for many years in *Who's Who in California,* has been included in the sixteenth edition of *Who's Who in the World* and listed in "Living Legends" (2004) published by the International Biographical Center, Cambridge, England.

PREFACE

The security and economic stability of many nations and multinational oil and chemical companies is highly dependent on the safe and uninterrupted operation of their oil, gas, and chemical facilities. One of most critical impacts than can occur to these operations is fire and explosion events from an incident.

This publication is intended as a general engineering handbook and reference guideline to those individuals involved with fire and explosion prevention and protection aspects of these critical facilities. The first edition of this book was published when there was not much information available on process safety, the US CSB had not been established and the CCPS was just beginning to publish its guidance books on process safety. At that time there was a considerable void of process safety information that may have lead to some serious incidents that occurred in the industry. The main objective of the 3rd Edition of this book is to update and expand the information to the current practices of process safety management and technical engineering improvements which have occurred since its original publication.

The main objective of this handbook is to provide some background understanding of fire and explosion problems at oil, gas, and chemical facilities and as a general reference material for engineers, designers, and others facing fire protection issues that can be practically applied. It should also serve as a reminder for the identification of unexpected hazards that can exist at a facility.

As stated, much of this book is intended as a guideline. It should not be construed that the material presented herein is the absolute requirement for any facility. Indeed, many organizations have their own policies, standards, and practices for the protection of their facilities. Portions of this book are a synopsis of common practices being employed in the industry and can be referred to where such information is outdated or unavailable. Numerous design guidelines and specifications of major, small, and independent oil companies as well as information from engineering firms and published industry references have been reviewed to assist in its preparation. Some of the latest practices and research into fire and explosion prevention have also been mentioned.

This book is not intended to provide in-depth guidance on basic risk assessment principles nor on fire and explosion protection foundations or design practices. Several other excellent books are available on these subjects and some references to these are provided at the end of each chapter.

The scope of this book is to provide practical knowledge on the guidance in the understanding of prevention and mitigation principals and methodologies from the effects of hydrocarbon fires and explosions.

Explosions and fire protection engineering principles for the hydrocarbon and chemical industries will continually be researched, evolved, and expanded, as is the case with any engineering discipline. This handbook does not profess to contain all the solutions to fire and explosion concerns associated with the industry. It does however, try to shed some insight into the current practices and trends being applied today. From this insight, professional expertise can be obtained to examine detailed design features to resolve concerns of fires and explosions.

Updated technical information is always needed so that industrial processes can be designed to achieve to optimum risk levels from the inherent material hazards but still provide acceptable economical returns.

The field of fire protection encompasses various unrelated industries and organizations, such as the insurance field, research entities, process industries, and educational organizations. Many of these organizations may not realize that their individual terminology may not be understood by individuals or even compatible with the nomenclature used, outside their own sphere of influence. It is therefore prudent to have a basic understanding of these individual terms in order to resolve these concerns.

This book focuses on terminology that is applied and used in fire protection profession. Therefore NFPA standards and interpretations are utilized as the primary guidelines for the definitions and explanations.

This book is based mainly on the terminology used in United States codes, standards, and regulations. It should be noted that some countries may use similar terminology, but the terminology may be interpreted differently.

The term accident often implies that the event was not preventable. From a loss prevention perspective, use of this term is discouraged, since an accident should always be considered preventable and the use of "incident" has been recommended instead. Therefore, the term accident has generally been replaced by incident.

CHAPTER 1

Historical Background, Legal Influences, Management Responsibility, and Safety Culture

Fire, explosions, and environmental pollution are the most serious "unpredictable" life affecting and business loss having an impact on the petroleum, petrochemical, and chemical industries today. The issues have essentially existed since the inception of industrial-scale petroleum and chemical operations during the middle of the last century. These issues to occur with increasing financial impacts, highly visible news reports, with increasing governmental concern. Management involvement in the prevention of these incidents is vital if they are to be avoided. Although in some perspectives "accidents" are thought of as non-preventable, in fact all "accidents," or more correctly referred to as incidents, are preventable. This book is about examining process facilities and measures to prevent such incidents from occurring.

In-depth research and historical analyses have shown that the main causes of incidents or failures can be categorized to the following basic areas:

Ignorance:

- Assumption of responsibility by management without an adequate understanding of risks;
- Supervision or maintenance occurs by personnel without the necessary understanding;
- Incomplete design, construction, or inspection occurs;
- There is a lack of sufficient preliminary information;
- Failure to employ individuals to provide guidance in safety with competent loss prevention knowledge or experience;
- The most prudent and current safety management techniques/ operational excellence (or concerns) are not known or applied; or advised to senior staff.

Economic Considerations:

- Operation, maintenance, or loss prevention costs are reduced to a less than adequate level;
- Initial engineering and construction costs for safety measures appear uneconomical.

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Oversight and Negligence:

- Contractual personnel or company supervisors knowingly assume high risks;
- Failure to conduct comprehensive and timely safety reviews or audits of safety management systems and facilities;
- Unethical or unprofessional behavior occurs;
- Inadequate coordination or involvement of technical, operational, or loss prevention personnel, in engineering designs or management of change reviews;
- Otherwise competent professional engineers and designers commit errors.

Unusual Occurrences:

- Natural Disasters—earthquakes, floods, tsunamis, weather extremes, etc., which are out of the normal design range planned for the installation;
- Political upheaval—terrorist activities;
- Labor unrest, vandalism, sabotage.

These causes are typically referred to as "root causes." Root causes of incidents are typically defined as "the most basic causes that can reasonably be identified which management has control to fix and for which effective recommendations for preventing reoccurrence can be generated." Sometimes it is also referred to as the absence, neglect, or deficiencies of management systems that allow the "causal factors" to occur or exist. The most important key here to remember is that root causes refer to failure of a management system. Therefore if your investigation into an incident has not referred to a management action or system, it might be suspect of not identifying the root cause of it. There are many incident reviews where only the immediate cause, or commonly referred to as the causal factors, is identified. If the incident review only identifies causal factors, then it is very likely the incident has a high probability to occur again as the root cause has not been addressed.

The insurance industry has estimated that 80% of incidents are directly related or attributed to the individuals involved. Most individuals have good intentions to perform a function properly, but it should be remembered that where shortcuts, easier methods, or considerable (short term) economic gain opportunities present themselves, human vulnerability usually succumbs to the temptation. Therefore it is prudent in any organization, especially where high risk facilities are operated, to have a system in place to conduct considerable independent checks, inspections, and safety audits of the operation, maintenance, design, and construction of the installation.

Safety professionals have realized for many decades that safety practices and a good safety culture is good for business profitability.

This book is all about the engineering principles and philosophies to identify and prevent incidents associated with hydrocarbon and chemical facilities. All engineering activities are human endeavors and thus they are subject to errors. Fully approved facility designs and later changes can introduce an aspect from which something can go wrong. Some of these human errors are insignificant and may be never uncovered. However, others may lead to catastrophic incidents. Recent incidents have shown that nay "fully engineered" and operational process plants can experience total destruction. Initial conceptual designs and operational philosophies have to address the possibilities of a major incident occurring and provide measures to prevent or mitigate such events.

1.1. HISTORICAL BACKGROUND

The first commercially successful oil well in the US was drilled in August 1859 in Titusville (Oil Creek), Pennsylvania by Colonel Edwin Drake (1819–1880). Few people realize that Colonel Drake's famous first oil well caught fire and some damage was sustained to the structure shortly after its operation. Later in 1861, another oil well at "Oil Creek," close to Drake's well, caught fire and grew into a local conflagration that burned for 3 days causing 19 fatalities. One of the earliest oil refiners in the area, Acme Oil Company suffered a major fire loss in 1880, from which it never recovered. The state of Pennsylvania passed the first anti-pollution laws for the petroleum industry in 1863. These laws were enacted to prevent the release of oil into waterways next to oil production areas. At another famous and important early US oil field named "Spindletop" (discovered in 1901) located in Beaumont, Texas, an individual smoking set off the first of several catastrophic fires, which raged for a week, only 3 years after the discovery of the reservoir. Major fires occurred at Spindletop almost every year during its initial production. Considerable evidence is available that hydrocarbon fires were a fairly common sight at early oil fields. These fires manifested themselves as either from man-made, natural disasters, or from deliberate and extensive of the then "unmarketable" reservoir gas. Hydrocarbon fires were accepted as part of the early industry and generally little efforts were made to stem their existence. See Figures 1.1 and 1.2.

Offshore drilling began in 1897, just 38 years after Colonel Edwin Drake drilled the first well in 1859. H.L. Williams is credited with drilling a well off a wooden pier in the Santa Barbara Channel in California. He used the pier

Figure 1.1 Spindletop gusher (*photo credit: American Petroleum Institute*).

Figure 1.2 Early petroleum industry fire incident.

to support a land rig next to an existing field. Five years later, there were 150 "offshore" wells in the area. By 1921, steel piers were being used in Rincon and Elwood (California) to support land-type drilling rigs. In 1932, a steel-pier island (60 × 90 ft with a 25-ft air gap) was built one half mile offshore by a small oil company, Indian Petroleum Corporation, to support another onshore-type rig. Although the wells were disappointing and the island was destroyed in 1940 by a storm, it was the forerunner of the steel-jacketed platforms of today.

Offshore ultra deepwater wells are now costing more than $50 million, and some wells have cost more than $100 million. It is very difficult to justify wells that cost this much given the risks involved in drilling the unknown. The challenge to the offshore industry is to drill safely and economically, which means "technology of economics," with safety, environment, security, and personnel health all playing a large role.

The first oil refinery in the world was built in 1851 in Bathgate, Scotland by Scottish chemist James Young (1811–1883) who used oil extracted from locally mined torbanite, shale, and bituminous coal to distill naphtha and lubricating oils that could light lamps or be used to lubricate machinery. Shortly afterwards, Ignacy Łukasiewicz (1822–1882), a pharmacist, opened an "oil distillery," which was the first industrial oil refinery in the world, around 1854–1856, near Jasło, then Galicia in the Austrian Empire, and now Poland. These refineries were initially small as there was no real demand for refined fuel at that time. The plant initially produced mostly artificial asphalt, machine oil, and lubricants. As Łukasiewicz's kerosene lamp gained popularity, the refining industry grew in the area. The refinery was destroyed in a fire in 1859.

The world's first large refinery opened in Ploieşti, Romania, in 1856–1857, with US investment. In the 19th century, refineries in the US processed crude oil primarily to recover the kerosene. There was no market for the more volatile fraction, including gasoline, which was considered waste and was often dumped directly into the nearest river. The invention of the automobile shifted the demand to gasoline and diesel, which remain the primary refined products today.

Ever since the inception of the petroleum industry, the level of incidents for fires, explosions, and environmental pollution that has precipitated from it, has generally paralleled its growth. As the industry has grown, so has the magnitude of the incidents that have occurred. The production, distribution, refining, and retailing of petroleum taken as a whole represents the world's largest industry in terms of dollar value. Relatively recent major high profile incidents such as Flixborough (1974), Seveso (1976), Bhopal (1984), Shell Norco (1988), Piper Alpha (1988), Exxon Valdez (1989), Phillips Pasadena (1989), BP Texas City (2005), Buncefield, UK (2005), Puerto Rico (2009), and Deepwater Horizon/British Petroleum (2010) have all amply demonstrated the loss of life, property damage, extreme financial costs, environmental impact, and the impact to an organization's reputation that these incidents can produce.

After the catastrophic fire that burned ancient Rome in 64 A.D., the emperor Nero rebuilt the city with fire precaution measures that included wide public avenues to prevent fire spread, limitations in building heights to prevent burning embers drifting far distances, provision of fireproof construction to reduce probabilities of major fire events, and improvements to the city water supplies to aid firefighting efforts. Thus, it is evident that basic fire prevention requirements such as limiting fuel supplies, removing available ignition sources (wide avenues and building height limitations), and providing fire control and suppression (water supplies) have essentially been known since civilization began.

Amazingly to us today, "Heron of Alexandria," the technical writer of antiquity (circa 100 A.D.) describes a two cylinder pumping mechanism with a dirigible nozzle for firefighting in his journals. It is very similar to the remains of a Roman water supply pumping mechanism on display in the British Museum in London. Devices akin to these were also used in the 18th and 19th century in Europe and America to provide firefighting water to villages and cities. There is considerable evidence that society has generally tried to prevent or mitigate the effects of fires, admittedly after a major mishap has occurred.

The hydrocarbon and chemical industries have traditionally been reluctant to immediately invest capital where direct return on the investment to the company is not obvious and apparent, as would any business enterprise. Additionally, fire losses in the petroleum and chemical industries were relatively small up to the 1950s. This was due to the small size of the facilities and the relatively low value of oil, gas, and chemicals to the volume of production. Until 1950, a fire or explosion loss of more than $5 million dollars had not occurred in the refining industry in the US. Also in this period, the capital-intensive offshore oil exploration and production industry was only just beginning. The use of gas was limited in the early 1900s. Typically production gas was immediately flared (i.e., disposed of by being burnt off) or the wall was capped and considered an uneconomical reservoir. Since gas development was limited, large vapor cloud explosions were relatively rare and catastrophic destruction from petroleum incidents was essentially unheard of. The outlays for petroleum industry safety features were traditionally the absolute minimum required by governmental regulations. The development of loss prevention philosophies and practices were therefore really not effectively developed within the industry until the major catastrophic and financially significant incidents of the 1980s and 1990s started to occur.

In the beginning of the petroleum industry, usually very limited safety features for fire or explosion protection were provided, as was evident by the many early blowouts and fires. The industry became known as a "risky" operation or venture, not only for economic returns, but also for safety (loss of life and property destruction) and environmental impacts, although this was not well understood at the time.

The expansion of industrial facilities after World War II, construction of large integrated petroleum and petrochemical complexes, increased development and use of gas deposits, coupled with the rise of oil and gas prices of the 1970s have sky-rocketed the value of petroleum products and facilities. It also meant that the industry was awakened to the possibility of large financial loses if a major incident occurred. In fact, fire losses greater than \$50 million dollars were first reported during the years 1974 and 1977 (i.e., Flixbourough, UK, Qatar, and Saudi Arabia). In 1992, the cost just to replace the Piper Alpha platform and resume production was reportedly over \$1 billion dollars. In 2005 the Buncefield incident cost was over \$1,221,000,000 dollars (£750 million UK pounds reported in insurance claims). In some instances, legal settlements have been financially catastrophic, e.g., Exxon Valdez oil spill legal fines and penalties were \$5 billion dollars. In 2009, the Occupational Safety and Health Administration (OSHA) proposed it largest ever fine, \$87 million dollars against British Petroleum (BP) for a lack of compliance with safety regulations and agreed-upon improvements at the Texas City refinery, after the explosion of 2005. It has already paid out more than \$2 billion dollars to settle lawsuits from the incident.

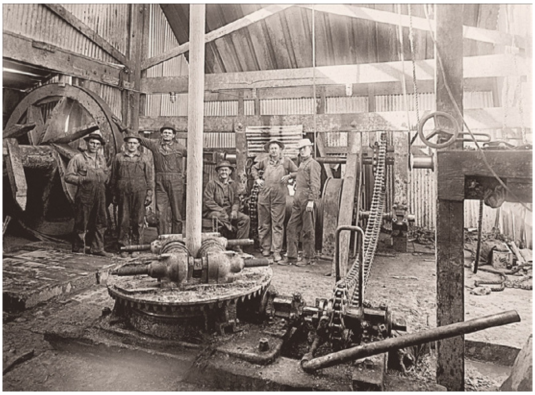
It should also be remembered that a major incident may also force a company to literally withdraw from that portion of the business sector where public indignation, prejudice, or stigma toward the company strongly develops because of the loss of life suffered. The availability of 24 h news transmissions through worldwide satellite networks, cell phone cameras and texting, or via the internet, emails, and its "blogs," virtually guarantees a significant incident in the petroleum or chemical industry will be known worldwide very shortly after it occurs, resulting in immediate public reaction and the thought of lawsuits.

Only in the last several decades has it been well understood and acknowledged by most industries that fire and explosion protection measures may also be operational improvement measures, as well as a means of protecting a facility against destruction. An example of how the principle of good safety practice equates to good operating practice is the installation of an emergency isolation valve at a facility's inlet and outlet pipelines. In an emergency they serve to isolate fuel supplies to an incident and therefore limit damage. They could also serve as an additional isolation means to a facility for maintenance or operational activities when a major facility isolation requirement occurs (e.g., Testing and Inspection (T&Is), Turnarounds, new process/project tie-ins, etc.). It can be qualitatively shown that it is only limitations in practical knowledge by those involved in facility construction and cost implications that have generally restricted practical applications of adequate fire protections measures throughout history.

Nowadays safety features should hopefully promulgate the design and arrangement of all petroleum and chemical facilities. In fact, in highly industrial societies, three features must demonstrate to the regulatory bodies that the facility has been adequately designed for safety before permission is given for their construction. It is thus imperative that these measures are well defined early in the design stage in order to avoid costly project change orders or later incident remedial measures expenses required by regulatory bodies. Industry experience has demonstrated that revising a project design in the conceptual and preliminary stages for safety and fire protection features is more cost effective than performing the reviews after the designs has been completed. The "Cost Influence Curve" for any project acknowledges that 75% of a project cost is defined in the first 25% of design. On average the first 15% of the overall project cost is usually spent on 90% of the engineering design. Retrofit or modification costs are estimated at 10 times the cost after the plant is built and 100 times after an incident occurs. It should be realized that fire protection safety principles and practices are also prudent business measures that contribute to the operational efficiencies of a facility. Where this is not realized by management it contributes to the root cause(s) of an incident eventually occurring. Most of these measures are currently identified and evaluated through a systematic and thorough risk analysis role.

1.2. LEGAL INFLUENCES

Before 1900, US industry and the federal government generally paid little notice to the safety of industrial workers. Only with the passage of the Workmen's Compensation laws in the US between 1908 and 1948 did businesses start to improve the standards for industrial safety. Making the work environmentally safer was found to be less costly than paying compensation for injuries, fatalities, governmental fines, and higher insurance premiums. Labor shortages during World War II focused renewed attention on industrial safety and on the losses incurred by industrial incidents, in order to maintain production output available for the war effort. In the 1950s, 1960s, and 1970s a number of industry specific safety laws were enacted in the US due to increasing social and political pressure to improve safety and health of workers and the realization by the government of the existence of technically outdated standards, poor enforcement, and their obvious ineffectiveness. They included the Coal Mine Health and Safety Act (1952 and 1969), the Metal and Nonmetallic Mine Safety Act (1966), the Construction Safety Act (1969), and the Mine Safety and Health Act (1977). All of this legislation mandated safety and fire protection measures for workers by the companies employing them.



1.2.1 Occupational Safety and Health Administration (OSHA)

A major US policy toward industrial safety measures was established in 1970, when for the first time all industrial workers in businesses affected by interstate commerce were covered by the Occupational Health and Safety Act (1970), 29 CFR Part 1910. Under this act, the National Institute for Occupational Safety and Health (NIOSH) was given responsibility for conducting research on occupational health and safety standards, and the Occupational Safety and Health Administration (OSHA) was charged with setting, promulgating, and enforcing appropriate safety standards in industry.

The Occupational Safety and Health Administration, under the US Department of Labor, publishes safety standards for both general industry as well as specific industries, including the petroleum and chemical industries. OSHA requires accident reporting and investigation for all regulated industries, which includes the petroleum and chemical industries. OSHA also issued the Process Safety Management of Highly Hazardous Chemicals standard (29 CFR 1910.119). Process Safety Management (PSM) is addressed in specific standards for the general and construction industries. OSHA's standard emphasizes the management of hazards associated with highly hazardous chemicals and establishes a comprehensive management program that integrates technologies, procedures, and management practices.

1.2.2 Chemical Safety and Hazard Investigation Board (CSB)

In 1990, the US Clean Air Act authorized the creation of an independent Chemical Safety and Hazard Investigation Board (CSB), but it did not become operational until 1998. Its role, as defined by 40 CFR Part 1600, is to solely investigate chemical incidents to determine the facts, conditions, and circumstances which led up to the event and to identify the cause, probable cause or causes so that similar chemical incidents might be prevented. Its mandate is significantly different than a regulatory enforcement body, as it does not limit the investigation to only determine if there was a violation of an enforceable requirement, but to determine the cause or the causes of an incident. An assumption stated in the overview for the CSB is that it estimated that annually there would be 330 catastrophic incidents and of these, between 10 and 15 would be major catastrophic incidents with life loss. This is an alarming prediction for the industry and clearly indicates some improvement is needed.

It is interesting to note that the CSB does not maintain a comprehensive incident database or compile national statistics on petroleum or chemical industry incidents, nor do they summarize the incident investigations for root causes or trend analysis. At the present time, no such comprehensive statistics or analysis exist within the federal government for the petroleum or chemical industries for serious incidents such as those the CSB investigates. Separately the Environmental Protection Agency (EPA), the Occupational Safety and Health Administration (OSHA), the National Response Center (NRC), the Agency for Toxic Substances and Disease Registry (ATSDR), and other agencies maintain certain incident databases that vary in scope, completeness, and level of detail. Therefore, although the CSB is helpful in individual incident investigations, an examination by it of its overall recommendation root causes or trends in incidents would be of high benefit to industry and the safety profession.

1.2.3 DOT/PIPA Guidelines

In 2010, the Pipelines and Informed Planning Alliance (PIPA) developed a report, "Partnering to Further Enhance Pipeline Safety Through Risk-Informed Land Use Planning," which offers nearly 50 recommended practices for communities, developers, and pipeline operators to use to help reduce safety risks that result from community growth near pipelines. The US DOT said the recommendations explain how land use planning and development decisions can help protect existing pipelines. They also provide recommendations on how communities can gather information about local pipelines; about how local planners, developers, and pipeline operators should communicate during all development phases; and how to minimize pipeline damage from excavation during site preparation and construction.

1.2.4 BSEE, Safety and Environmental Management Systems

Also in 2010, the Bureau of Safety and Environmental Enforcement (BSEE), part of the US Department of Interior, published the Final Rule for 30 CFR Part 250 Subpart S—Safety and Environmental Management Systems (Ref. US Federal Register, 75 FR 63610). The BSEE enforces safety and environmental protection on the 1.7 billion-acre US Outer Continental Shelf (affecting offshore oil and gas development). This Final Rule incorporates by reference, and makes mandatory, the American Petroleum Institute's Recommended Practice for Development of a Safety and Environmental Management Program for Offshore Operations and Facilities (API RP 75), Third Edition, May 2004, reaffirmed May 2008. This recommended practice, including its appendices, constitutes a complete Safety and Environmental Management System (SEMS).

API RP 75 consists of 13 sections, one of which is a "General" section. This relates to the 12 elements identified in the ANPR and states the overall principles for the SEMS and establishes management's general responsibilities for its success. The General element is critical to the successful implementation of the SEMS in API RP 75, and the BSEE is incorporating this standard by reference with some of the BSEE prescriptive requirements. The BSEE believes that adoption of API RP 75 in its entirety is consistent with the direction of the National Technology Transfer and Advancement Act of 1996, which directs agencies, whenever possible, to adopt private standards. The Final Rule became effective on November 15, 2010. The Final Rule applies to all US Outer Continental Shelf (OCS) oil and gas and sulfur operations and the facilities under the BSEE jurisdiction including drilling, production, construction, well workover, well completion, well servicing, and Department of Interior pipeline activities.

1.2.5 National Institute of Occupational Safety and Health (NIOSH)

According to the Centers for Disease Control (CDC), part of the National Institute of Occupational Safety and Health (NIOSH), in a report prepared by the National Occupational Research Agenda (NORA), the US oil and gas extraction industry had during 2003–2008, 648 oil and gas extraction worker fatal injuries on the job, resulting in an occupational fatality rate of 29.1 deaths per 100,000 workers—eight times higher than the rate for all US workers. Two goals set by NORA are to, by the year 2020, reduce the occupational fatality rate by 50% and reduce the rate of non-fatal occupational injuries by 50% for workers in the oil and gas extraction industry.

1.2.6 Security Vulnerability Assessment (SVA) Regulation

In March 2003, the United States implemented Operation Liberty Shield to increase the readiness and security in the United States primarily due to international threats from non-government affiliated self-motivated political and religious groups. One objective of this operation is to implement comprehensive process security management programs into existing OSHA, EPA, and FDA laws to address deliberate acts of threats of terrorism, sabotage, and vandalism. In April 2007, the Department of Homeland Security (DHS) issued the Chemical Facility Anti-Terrorism Standard (CFATS). The purpose of DHS is to identify, access, and ensure effective security at high risk chemical facilities. Included in this responsibility is the requirement for chemical facilities handling chemicals above a threshold amount to submit a SVA for DHS review and approval along with a site security plan (SSP). A potential fine of $25,000/day, an inspection and audit by DHS, or an order to cease operations is stated for noncompliance. The type and amount of chemicals handled which require submission of screening review and SVA submittals are listed on the DHS website. Additionally, internal company security procedures, although confidential, would also require that an adequate security review be undertaken to identify and assess such risks. Since the methodology of conducting process security reviews is similar to existing process hazard analysis reviews, they can be adapted to fit within the parameters of existing procedures established for these analyses. Both API and AIChE have also issued their own guidelines to assist companies undertaking process security reviews. A major process safety consultant recently stated that statistics show that the use of outside security experts for protective services consultations has increased by 200% in the last 5 years. This is due to escalating concerns over workplace and domestic violence, privacy and security practices, and terrorist threats. Process security reviews are not intended to identify minor thefts or mishaps; these are the responsibility of the company's general security requirements that are well established and can be examined with other financial auditing tools.

1.2.7 US Presidential Executive Orders (13605 and 13650)

President Obama issued Executive Order 13605 on April 13, 2012, entitled Supporting Safe and Responsible Development of Unconventional Domestic Natural Gas Resources. It provides a mechanism to formalize and promote ongoing interagency coordination, by establishing a high-level, interagency working group that will facilitate coordinated Administration policy effort to support safe and responsible unconventional domestic natural gas development.

On August 1, 2013, President Obama signed Executive Order 13650, entitled Improving Chemical Facility Safety and Security. It is designed to combine efforts by many federal agencies to improve their effectiveness and efficiency of efforts to prevent and mitigate chemical catastrophes. The overlaps and gaps between the Environmental Protection Agency (EPA) Accidental Release Prevention (ARP) program under the Clean Air Act and the Department of Labor's (DOL) Occupational Safety and Health Administration (OSHA) Chemical Process Safety Management Standard (PSM) have led to some confusion for organizational and facility-level operating and compliance personnel. DHS's more recent Chemical Facility Anti-Terrorism Standards (CFATS) program has added another layer of regulations. The main objectives of this Executive Order are to:

- Establish a Chemical Facility Safety and Security Working Group, co-chaired by DHS, EPA, and DOL, including DOT, Department of Justice (DOJ), and Department of Agriculture, and directed to consult with other security and environmental agencies and the White House.
- The Working Group is to establish a pilot program within DHS, EPA, and DOL to validate best practices and to test innovative methods for federal interagency collaboration regarding chemical facility safety and security.
- The DHS is to assess the feasibility of sharing CFATS information with State Emergency Response Commissions/Tribal Emergency Response Commissions and Local Emergency Planning Committees (SERCs/TERCs and LEPCs).
- The DOJ's Bureau of Alcohol, Tobacco, Firearms and Explosives (ATF) is to assess the feasibility of sharing data related to explosive materials with SERCs/TEPCs and LEPCs.
- The Working Group is to consult with the federal Chemical Safety Board to determine whether any specified interagency memorandum of understanding (MOU) related to post-incident inspections should be revised.
- The Working Group is to analyze ways to improve agency data collection and information sharing.
- The Working Group is to meet with stakeholders and develop options for improvements to agency and facility risk management (including outreach, public and private guidelines, and regulations).
- Respective lead agencies are to review recommend additional chemical listings under ARP, CFATS, and PSM, and DOL to review existing exemptions under PSM.
- The Working Group is to develop regulatory and legislative proposals for improved handling of ammonium nitrate.
- The Working Group is to develop a plan to support state and local regulators and emergency responders, and facilities with chemicals, to improve chemical facility safety and security.
- The Working Group is to propose streamlining and enhancement to agency data collection and information sharing.
- The Working Group is to create comprehensive and integrated standard operating procedures for a unified federal approach for identifying and responding to risks in chemical facilities.

Clearly, the industry will require more safety information and analysis to support these requirements.

1.3. HAZARDS AND THEIR PREVENTION

Petroleum and chemical related hazards can arise from the presence of combustible or toxic liquids, gases, mists, or dusts in the work environment. Common physical hazards include ambient heat, burns, noise, vibration, sudden pressure changes, radiation, and electrical shock. Various external sources such as chemical, biological, or physical hazards can cause work-related injuries or fatalities. Hazards may also result from the interaction between individuals and their work environment. These are primarily associated with ergonomic concerns. If the physical, psychological, or environmental demands on workers exceed their capabilities, an ergonomic hazard exists, which may lead to physiological or psychological stress in individuals. This may lead to further major incidents because the individual cannot perform properly under stress during critical periods of plant operations. Although all of these hazards are of concern, this book primarily concentrates on fire and explosion hazards that can cause catastrophic events. Industrial fire protection and safety engineers recommend methods to eliminate, prevent, mitigate, or reduce the intensity by clearly identifying the hazards, analyzing their risks, and recommending appropriate safeguards for consideration by management. The level of protection is usually dependent on an organizational safety level requirement (i.e., internal company standard), the risk identified, and a cost-benefit analysis for major exposures. Typical safeguard examples include the use of alternative or less combustible materials, changes in the process or procedures, improved spacing or guarding, improved ventilation, spill control, protective clothing, inventory reduction, and fire explosion protection measures—passive and active mechanisms, etc.

1.4. SYSTEMS APPROACH

Today most industrial safety management, incident prevention programs, or safety applications are based on a systems approach, in order to capture and examine all aspects that may contribute to an incident. Because incidents arise from the interaction of workers and their work environment, both must be carefully examined. For example, injuries can result from lack of or poorly written procedures, inadequate facility design, working conditions, use of improperly designed tools and equipment, fatigue, distraction, lack of skill or poor training, and risk taking. The systems approach examines all areas in a systematic fashion to ensure all avenues of incident development have been identified and analyzed.

Typically the following major loss prevention elements are examined from a systems approach:

- Company Safety Polices and Responsibilities
- Communication
- Risk Management
- Standards and Procedures
- Mechanical Integrity
- Operations
- Maintenance and Construction
- Training
- Emergency Response and Incident Investigation
- Safety Reviews and Audits

Incident and near miss investigation is a key element, whereby the history of incidents can be learned from to eliminate patterns that may lead to similar hazards.

The systems approach also acknowledges the capabilities and limitations of the working population. It recognizes large individual differences among people in their physical and physiological capabilities. The job and the worker should therefore be appropriately matched whenever possible.

The safety and risk of facility cannot be assessed solely on the basis of firefighting systems, e.g., *we have a plant fire water system,* or past loss history, e.g., *we never had a fire here for 25 years, so we don't expect any*. The overall risk can only be assessed by thorough risk analysis for the facility and the risk philosophy adopted by senior management for the organization.

Due to the destruction nature of hydrocarbon and chemical forces when handled incorrectly, fire and explosion protection principles should be the prime feature in the risk philosophy mandated by management for a facility. Disregarding the importance of protection features or systems will eventually prove to be costly in both human and economic terms should a catastrophic incident occur without adequate safeguards.

1.5. FIRE PROTECTION ENGINEERING ROLE/DESIGN TEAM

Fire protection engineering is not a standalone discipline that is brought in at an indiscriminate state of a project design or even after the fact design review of a completed project. Fire protection principles should be an integrated aspect of a hydrocarbon or chemical project that reaches into all aspects of how a facility is proposed, located, designed and constructed, and operated and maintained. Initially due to major impacts, they are usually the prime starting and focus points in the initial proposals, layouts, and process arrangements. Once these parameters are set, they are almost impossible to change as the project proceeds and expensive or compromised features will have to be considered to mitigate any high risk concerns.

Fire protection engineering should be integrated with all members of the design team, i.e., structural, civil, electrical, process, HVAC, etc. Although a fire protection or risk engineer can be employed as part of a project team or engineering staff, he should mainly play an advisory role. He can suggest the most prudent and practical methods to employ for fire protection objectives. The fire protection or risk engineer therefore must be knowledgeable in each of the fire protection applications for these disciplines. In addition, he must have expertise in hazard, safety, risk and fire protection principles and practices applied in the petroleum, chemical, or other related industries.

1.5.1 Risk Management and Insurance

It should be realized that the science of risk management provides other avenues of protection besides a technical solution to a risk. The insurance and risk management industry identifies four possible options for risk management:

The four methods, in order of preference, include:

1. Risk avoidance
2. Risk reduction
3. Risk insurance
4. Risk acceptance

This handbook concentrates primarily on risk avoidance and risk reduction techniques. Risk acceptance and risk insurance techniques are monetary measures that are dependent on the financial options available to the organization's management. They are based on an organization's policy and preferences in the utilization of insurance measures and available insurance policies in the market. If used, they rely on financial measures of an organization to provide for financial security in case of an incident. Although these measures accommodate for financial losses, and invariably all organizations typically have a form of insurance, they are ineffective because of reputation and prestige effects from an incident (i.e., negative social reaction). This is one of the reasons which is promoting risk avoidance and risk reduction as a preferred method of solution for a high risk problem within the process industry and industrial community at large.

Risk avoidance involves eliminating the cause of the hazard. This is accomplished by changes in the inherent risk features of a process or facility, e.g., using noncombustible fluid as a heat transfer medium (i.e., hot oil system) instead of a combustible fluid (e.g., diesel oil). Risk reduction concerns the provision of prevention measures or protection features that will lessen the consequences of a particular incident. Some examples include firewalls, firewater sprays, emergency shutdown systems, etc. Most facilities include some aspect of risk reduction measures simply due to prescriptive or even performance based regulatory requirements.

Risk insurance is the method chosen when the possible losses are financially too great to retain by risk acceptance and might be in some cases too expensive to prevent or avoid. However, even the risk insurers, i.e., insurance companies, will want to satisfy themselves that adequate precautions are being taken at the facilities they are underwriting, usually required as part of the policy articles. Thus they will look very carefully at the installations they are underwriting. They will particularly examine risks they feel are above the industry norm or have high loss histories within the industry. Consequentially, insurance engineers have become more sophisticated in their understanding of process faculties and will want to physically tour and inspect locations for adequate risk management practices and estimate loss potentials using incident computer modeling programs, in addition to testing fixed protection measures. The insurance industry itself is also quite adept at informing its members of root causes for major incidents and highlighting this aspect to verify during the next scheduled insurance inspection for a facility.

As a matter of normal practice, insurance evaluations want to verify fire protection systems will perform as intended, critical systems are not bypassed, and previous recommendations have been acted upon. Where deficiencies are noted, the risk is elevated, and the insurance policies are revised as appropriate (e.g., coverages dropped, premiums raised, exclusions noted, etc.).

As industries become ever larger and more expensive, there may be cases where even though an organization desires to obtain insurance, it may not be available in the market. Therefore in this case even more "elaborate" risk reduction measures may have to be relied upon or employed than anticipated to reduce the risk profile that was found acceptable to management as would have otherwise been acceptable with insurance in place.

Most offshore installations, international onshore production sharing contracts, and large petrochemical complexes are owned by several companies or participating national governments. The majority owner or most experienced company is usually the onsite operator and responsible for it. The objective is to share the startup and operating funding and also the financial risk of developing and operating the facility. In the case of petroleum exploration, should the exploration well prove to be "dry," i.e., commercially uneconomical and have to plugged and abandoned, it presents an undue economic impact to the exploration budget for a particular area. However, by having several partners, the loss to each individually is lessened. The same holds true if an incident were to occur; it lessens the financial impact to each member for their percentage of investment in the operation. If a company historically has a poor record in relation to safe operations, other companies may be hesitant to invest funds with it, since they may consider that it represent too high of an overall risk and would seek other investment opportunities. Alternatively, they make ask to undertake management of the facility since they would feel better qualified and the risk to the facility would be lower.

Business interruption losses may also occur at a facility, since most likely a process will have to be shut down because of an incident because it cannot function as intended. Analysis of insurance industry claims data indicates that business interruption losses are generally three times the amount of physical property damage. Although business interruption insurance coverage is available (with provisions and stipulations that might be overlooked), often the justification for a safety improvement may not be the property damage itself but the overall business interruption impacts to operations and loss revenue it produces.

1.6. SENIOR MANAGEMENT'S RESPONSIBILITY AND ACCOUNTABILITY

In the petroleum industry, most of the major oil companies were originally started in the late 1800s and early 1900s as drilling organizations. Additionally, it must also be noted that drilling personnel were traditionally idolized by company management as the individuals who supplied the real resources or profit to the company by successfully drilling and "finding" the oil or gas reservoirs. Since the early days of the petroleum industry, exploration activities have been considered somewhat reckless and hazardous, particularly due to "wildcat" (i.e., highly speculative and risky) drilling operations. They usually are operations entirely separate from major integration petroleum activities. This impression or "inheritance" of drilling personnel used to be traditionally of aloof or above safety features or requirements. Due to dramatic incidents of the occasional well blowout, this impression is still rather difficult to eradicate. This idea also exists within the general public. In some organizations where drilling personnel are idolized, they will usually eventually be promoted to senior management positions. Their independent attitude may still prevail or impressions by subordinate employees will be preconceived as a lack of safety concern due to their background. This is not to say other departments or individual job classifications within an organization may not be just as ill perceived (e.g., construction, project management, etc.).

There are and probably always will be requirements to achieve petroleum production, refining, or chemical processing for any given project as soon as possible. Therefore the demands on drilling, construction, project management, and operations to obtain an operating facility as soon as possible may be in some cases in direct conflict with prudent safety practices or measures, especially if they have not been planned or provided for before the start of the project. Operations management should not be mistakenly led into believing a facility is ready to operate just because it is "felt" by those constructing it that it is complete, as there may be other financial completion incentives that are given for an early startup, which results in overlooking some features that might be required for safe startup and operation.

However unfortunate, drilling personnel have been historically directly connected with major incidents with in the petroleum industry on numerous occasions, and the impression consciously or unconsciously still remains. On the other hand, it is very rare or nonexistent that a loss prevention professional is promoted to the high ranks of an organization's senior management (as evident by a review of corporate annual statement management biographies), even though they have to be keenly conscientious in maintaining a high economic return to the company by advising how to prevent catastrophic incidents from occurring.

Safety achievement is a team approach. All parties to the operation must participate and contribute. Without team cohesiveness, commitment, and accountability, objectives will not be met. Specifically important is the leadership of a team, which in business operations is senior management. If senior management does not endorse or demonstrate safety it will not be part of the corporate culture.

Senior management responsibility and accountability are the keys to providing effective fire and explosion safety measures at any facility or operation. The real attitude of management toward safety will be demonstrated in the amount of importance placed on achieving qualitative or quantifiable safety results. Providing a permissive attitude of leaving safety to subordinates or to the loss prevention personnel will not be conductive or lead to good results. The effect of indifference or lack of concern to safety measures is always reflected top down in any organizational structure and develops into the company culture. Executive management must express and contribute to an effective safety program in order for satisfactory results to be achieved. All incidents should be thought of as preventable. Incident prevention and elimination should be considered as an ultimate goal of any organization. Setting arbitrary annual incident recordability limits for incidents may be interpreted by some as allowing some incidents to occur. Where a safety culture is "nurtured," continual economic benefits are usually derived. On the other hand, it has been stated that of the 150 largest petroleum and chemical incidents in the last several decades, many have involved breakdowns in the management of process safety and a lack of organization safety culture, which could have prevented these occurrences.

1.6.1 Achieving a World Class Organizational Safety Culture

There are several models that characterize safety culture within an organization. The two most widely known are the Dupont Bradley Curer and the Hudson/Parker HSE Culture Ladder. (See also Chapter 21, Human Attitude.)

The Dupont Bradley Curve (see Figure 1.3) highlights how to achieve world class safety performance through applying a management approach to improving safety culture. In a mature safety culture, safety is realized as sustainable, with injury rates approaching zero. Individuals are empowered to take action as needed to work safely. They support and challenge each other. Decisions are made at the appropriate level and people live by those decisions. The organization as a whole realizes significant business benefits in higher quality, greater productivity, and increased profits.

The four stages are further described below:

Reactive Stage

People do not take responsibility. They believe that safety is more a matter of luck than management, and that "accidents will happen." And over time, they do.

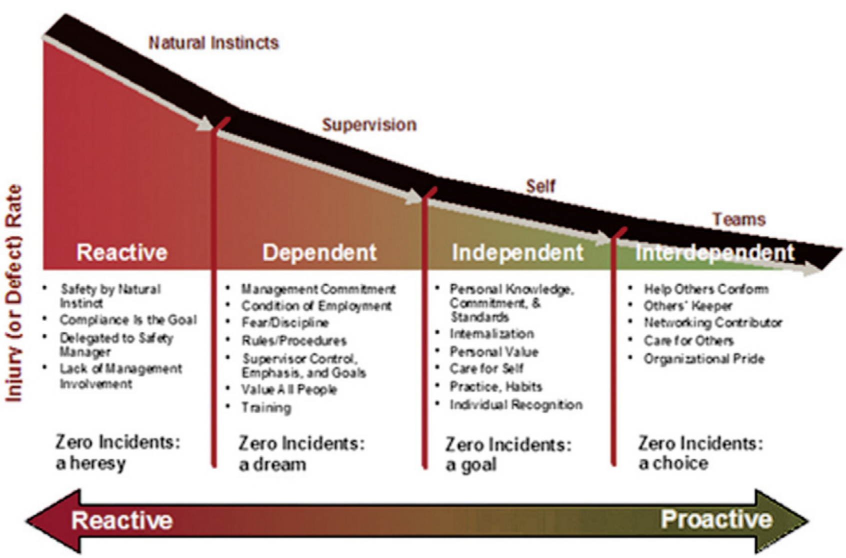


Figure 1.3 Dupont Bradley curve.

Dependent Stage

People see safety as a matter of following rules that someone else makes. Accident rates decrease and management believes that safety could be managed "if only people would follow the rules."

Independent Stage

Individuals take responsibility for themselves. People believe that safety is personal, and that they can make a difference with their own actions. This reduces accidents further.

Interdependent Stage

Teams of employees feel ownership for safety, and take responsibility for themselves and others. People do not accept low standards and risk taking. They actively converse with others to understand their point of view. They believe true improvement can only be achieved as a group, and that zero injuries are an attainable goal.

A similar arrangement is provided by Hudson and Parker in the 5-step "HSE Culture Ladder," which is characterized by the levels indicated in Table 1.1.

At the pathological level an organization displays a failure and lack of willingness to recognize and/or address those issues that may result in poor safety performance. At the highest level, generative, safe working practices are viewed as a necessary and desirable part of any operation of the organization. As the progression from Pathological to Generative is undertaken, employees are increasingly informed and there is increased trust.

1.7. OPERATIONAL EXCELLENCE

Operational Excellence (OE) is an element of organizational leadership that stresses the application of a variety of principles, systems, and tools toward the sustainable improvement of key performance indexes. The process involves focusing on customer needs, keeping employees positive and empowered, and continuous improvement of activities in the workplace. Most major process industries have moved toward the operational excellence concept. In this fashion, safety management systems have had to evolve and integrate with the introduction of operational excellence which most safety management systems had already. The key challenge in integrating or adapting to the operational excellence from safety management (as some of the elements of each overlap) is not to lose focus of the importance of loss prevention as a key objective or goal of the organization. Also OE

Table 1.1 HSE Culture Ladder

Ladder Step Identifier	Characteristics
Generative	• Safety is integral to how business is handled • Continuous improvement to the organization • Safety viewed as providing profit to the company • New safety ideas and suggestions are encouraged
Proactive	• We work on the issues that we still find • Resources are available to correct issues before an incident • Management is concerned but safety statistics are very important • Procedures are owned by the workers
Calculative	• We have systems in place to manage all concerns and hazards • Numerous safety audits • HSE individuals handling most safety statistics
Reactive	• We do a lot every time there is an incident • Safety is important • We are serious, but why don't they do what they are directed to? • Considerable discussion to re-classify incidents • Safety is very critical after an incident
Pathological	• Who cares? as long as we are not found out • Our lawyers said it was acceptable • Of course we have incidents, this business is risky • Fire the idiot who had an incident!

recognizes that leadership is the single largest factor for its success within an organization. Leaders establish the overall vision and set objectives that challenge the organization to achieve world-class results.

1.7.1 Typical OE Elements

OE typically is organized though a set of element processes similar to a safety management system. The elements usually include some aspects of the following:

- *Leadership, Management, and Accountability*—Management establishes policy, strategy, sets expectations, and provides the resources for successful operations. Assurance of operations integrity requires management leadership and commitment visible to the organization and accountability at all levels.

- *Human Resources and Training*—Control of operations depends upon people. Achieving operational excellence requires the appropriate screening, selection, placement, continuous assessment, and training of employees.
- *Asset Management (Design, Construction, Operations, Maintenance, Inspection)*—Inherent safety and security can be achieved, and risk to health and the environment minimized, by using consistent engineering standards, procedures, and management systems for facility design, construction, operation, maintenance, and inspection activities.
- *Management of Change*—Changes in operations, procedures, site standards, facilities, or organizations must be evaluated and managed to ensure that risks arising from these changes remain at an acceptable level.
- *Risk Management*—Risk assessments can reduce safety, health, environmental, and security risks and mitigate the consequences of incidents by providing essential information for decision-making.
- *Reliability and Efficiency*—Identify and resolve facility, business work process, and human reliability and efficiency concerns that may cause significant incidents or performance gaps.
- *Product Stewardship*—Manage potential health, environmental, safety, and integrity risks of the company's products throughout a product's life cycle.
- *Compliance Assurance*—Verify conformance with company policy and government regulations. Ensure that employees and contractors understand their related responsibilities.
- *Emergency Response and Incident Investigation*—Emergency planning and preparedness are essential to ensure that, in the event of an incident, all necessary actions are taken for the protection of the public, the environment, and company personnel and assets. Effective incident investigation, reporting, and follow-up are necessary to provide the opportunity to learn from reported incidents and to use the information to take corrective action and prevent recurrence from the identified root causes.
- *External Services*—Third parties doing work on the organization's behalf impact its operations and its reputation. It is essential that they perform in a manner that is consistent and compatible with the company's policies and business objectives.
- *Social Responsibility*—Work ethically and constructively to influence proposed laws and regulations and debate emerging issues.

- *Continuous Improvement*—Continuously improve operations and accountability to achieve higher levels of safety culture, technology, management, and overall company performance.

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CHAPTER 2

Overview of Oil, Gas, and Petrochemical Facilities

Petroleum and gas deposits occur naturally throughout the world in every continent and ocean. Most of these deposits are several thousand meters deep. The petroleum industry's mission is to find, develop, refine, and market these resources in a fashion that achieves the highest economic return to the owners or investors while adequately protecting the fixed investment in the operations.

Oil and gas operations today almost universally constitute a continuous run operation versus a batch process, which may be used in the chemical industry for some processes. Once fluids and gases are found and developed they are transported from one process to another without delay or interruption. This provides improved economics, but also may increase inventories and thereby the inherent risk in the operation is increased. Additionally, with ever increasing demands for efficiencies and high economic returns, larger facilities are provided, where natural resources are plentiful, to achieve even higher economies of scale and inversely higher risk.

The main facets of the oil and gas industry are exploration, production, refining, transportation, and marketing. A brief description of each of these sectors is provided in this chapter to give the reader some background that will relate to fire or explosion concerns highlighted later in this book. Although some petroleum companies are fully integrated (i.e., have all of the facets mentioned above) with each of these operations, others are segmented and only operate in their particular expertise or highest financial return.

Petrochemical and chemical process facilities primarily receive feedstocks from oil and gas facilities and manipulate these in numerous finished products through a variety of chemical processes and manufacturing techniques.

2.1. EXPLORATION

Exploring for oil and gas reserves consists mainly of geophysical testing and drilling exploratory or "wildcat" wells to verify the existence and economic viability of the reservoir. To find crude oil or natural gas reserves, geologists

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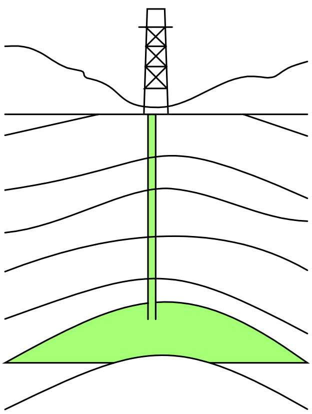
typically search for a sedimentary basin in which shales rich in organic material have been burieds for a sufficiently long time for petroleum to have formed. The petroleum must also have had an opportunity to migrate into porous traps that are capable of holding a large amount of fluid or gas. The occurrence of crude oil or gas is limited both by these conditions, which must be met simultaneously, and by the time span of tens of millions to hundreds of million years. Surface mapping of outcrops of sedimentary beds makes possible the interpretation of subsurface features, which can then be supplemented with information obtained by drilling into the crust and retrieving cores or samples of the rock layers encountered.

Seismic techniques, the reflection and refraction of sound or shock waves propagated throughout the earth, are also used to reveal details of the structure and interrelationships of various layers in the subsurface. The sound or shock waves record densities in the earth's surface that may indicate an oil or gas reservoir. Explosive charges or vibration devices are used to impart the required shock wave.



Ultimately the only way to prove that oil is present underground is to drill an exploratory well. Most of the oil provinces in the world have initially been identified by the presence of surface seeps and most of the actual reservoirs have been discovered by so-called wildcatters who relied perhaps as much on intuition as on science. The term wildcatter comes from west Texas, USA, where in the early 1920s, drilling crews came across many wildcats as they cleared locations for exploratory wells. The hunted wildcats were hung on the oil derricks, and wells became known as wildcat wells. A wildcat well is essentially considered a test boring to verify the existence and commercial quantities of quality oil and gas deposits. Since absolute characteristics of a wildcat well are unknown until actually drilled, a high pressure volatile hydrocarbon reservoir may be easily encountered. As drilling occurs deeper into the earth, the effects of overburden pressure of any fluid in the wellbore increases. If these reservoirs are not adequately controlled during exploratory drilling, by monitoring the pressure and use of drilling mud and fluids as counterweights, they can lead to an uncontrolled release of hydrocarbons up through the drilling system. This is commonly termed as a "blowout," whether it is ignited or not. Blowout preventers

(BOPs), i.e., fast-acting hydraulic shear rams located at the surface where the pipe exits the ground, are provided to control and prevent a blowout event by immediately trapping the pressure in the pipe when activated. Uncontrolled hydrostatic pressure is considered the primary cause of drilling blowouts (while evidently the underlying root cause is human error, due to less than adequate control of the drilling operation). Since well blowouts are considered catastrophic incidents, the location chosen for exploratory wells requires careful planning and risk assessments to ensure fire, explosion, and toxic gas effects from such an event would not impact adjacent land uses (e.g., highly populated areas) or if so, and allowed by local regulatory agencies, suitable additional emergency features (e.g., perimeter gas detection/alarms, contingency plans, and drills) and procedures are in place, as defined by the risk assessment to lower the consequences to an acceptable level.

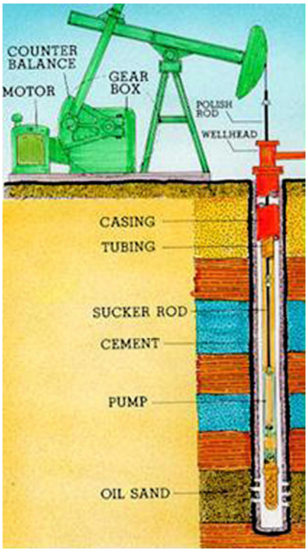
Exploratory wells that may still prove to be uneconomical have to be plugged and abandoned (commonly referred to as P & A). These activities have to carefully completed to avoid leaks or seepages later on. A few wells that were not property plugged from early drilling periods had a separate concern of small children falling into the wellsite borehole. Where these incidents occurred it resulted in dramatic rescues and unfavorable publicity for the industry.

An oil field may comprise more than one reservoir, i.e., more than one single continuous, bounded accumulation of oil. Indeed several reservoirs may exist at various depths, actually stacked one above the other, isolated by intervening shales and impervious rock strata. Such reservoirs may vary in size from a few meters in thickness to several hundred or more. Most of the oil that has been discovered and exploited in the world has been found in a few relatively large reservoirs. In the US, for example, 60 of the approximately 10,000 oil fields have accounted for half of the productive capacity and reserves in the country.

2.2. PRODUCTION

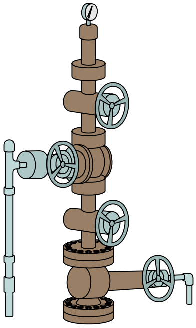
Oil and gas deposits are produced through wells that are drilled to penetrate the oil/gas bearing rock formations or reservoirs. Almost all oil wells in the world are drilled by the rotary method. In rotary drilling, the drill "string," which is a series of connected pipes, is supported by a derrick (a structural support tower) and the associated hoisting hardware at the top. The actual drilling device or drill "bit" at the end of the string is generally designed with three cone-shaped wheels tipped with hardened teeth. Additional lengths of drill pipe are added to the drill string as the bit penetrates deeper into the earth's crust. The force required for cutting into the earth comes from the weight of the drill pipe itself, which is controlled by the hoisting mechanism located at the top of the derrick. Drill cuttings of the formation rock are continually lifted to the surface by a circulating fluid system, which utilizes a "mud" that is usually a composition of bentonite (a type of clay) with some additives. The drilling mud is constantly circulated (i.e., pumped) down through the drill pipe, out through nozzles in the drill bit, and then back up to the surface through the space between the drill pipe and the bore through the earth. The diameter of the bit is somewhat greater than the string of pipes to allow this circulation. By varying the force and momentum on the drill bit, the bore can be angled or directionally drilled to actually penetrate horizontally to the reservoir in any direction from where the derrick is located. This is useful where terrain or other manmade obstructions might restrict the placement of the derrick directly on top of the reservoir or in an offshore location where it would be cost prohibitive to have many offshore drilling structures, but requires a highly skilled drilling personnel for its operation.

Once the well is drilled, the oil is either released under natural pressure or pumped out. Normal crude oil is under pressure; were it not trapped by impermeable rock it would have continued to migrate upward and seeped out ages ago, because of the differential pressure cause by its buoyancy. When a well bore is drilled into a pressure accumulation of oil, the oil expands into the low-pressure sink created by the well bore in communication with the earth's surface. As the well fills up with the fluid, a back pressure is exerted on the reservoir, and the flow of additional fluid into the wellbore would soon stop, were no other conditions involved. Most crude oils, however, contain a significant amount of natural gas in solution. This gas is kept in solution by the high pressure in the reservoir. The gas comes out of solution when the low pressure in the well bore is encountered and the gas, once liberated, immediately begins to expand. This expansion, together with dilution of the column of oil by less dense gas, results in the propulsion of the oil up to the earth's surface. As fluid withdrawal continues from the reservoir, the pressure with in the reservoir gradually decreases, and the amount of gas in solution decreases. As a result, the flow rate of fluid into the well bore decreases, and less gas is liberated.



The fluid may not reach the surface, so that a pump (artificial lift) must be installed in the wellbore to continue produce the crude oil. The reliability of electrical submersible pumps (ESPs) has increased to the point where the submersible electrical pump is now commonly used for the production of liquid hydrocarbons where artificial lift is required for production. Gas reservoirs by their nature are high pressure and can be essentially tapped into to obtain the deposit.

Well production may also start to decrease due to heavier petroleum deposits (tars, waxes, etc.) or other particulates plugging the rock pores, strata collapse, etc., in the area coming to the well. Reservoir engineers evaluate the production concerns and usually recommend a "workover" to revitalize or stimulate the well by various means based on the well characteristics and the problem encountered.



The produced oil or gas is connected to surface flowlines from the wellhead pumping unit or surface regulating valve assembly, typically referred to as a "Christmas tree," due to its arrangement, which in profile appears to be a small tree. The flowlines collect the oil or gas to local tank batteries or to central production facilities for primary oil, water, and gas separation.

Primary separation facilities process the produced fluids and gases into individual streams of gas, oil, and water. These facilities are commonly referred to as Central Processing Facilities or Gas Oil Separation Plants or if located offshore on production-drilling-quarters platforms (PDQs). The offshore platform may either float on the sea or be supported on steel or concrete supports secured to the ocean floor, where it is capable of resisting waves, wind, and in Arctic regions, ice flows. In some instances, surplus oil tankers have been converted into offshore production and storage facilities.

The produced fluids and gases are typically directed into primary separation vessels. Under the influence of gravity, pressure, heat, retention times, and sometimes electric fields, separation of the various phases of gas, oil, and water occurs so that they can be drawn off in separate streams. Suspended solids such as sediment and salt will also be removed. Deadly hydrogen sulfide (H_2S) gas is sometimes encountered, which is extracted simultaneously with the petroleum production. Crude oil containing H_2S can be shipped by pipeline and used as a refinery feedstock, but it is undesirable for tanks or long pipeline transport. The normal commercial concentrations of impurities in crude oil sales are usually less than 0.5% BS & W (Basic Sediment & Water) and 10 Ptb (Pounds of salt per 1000 barrels of oil). Natural gas production may also have various impurities that have to separated, collected, and disposed of, e.g., carbon dioxide (a greenhouse gas). Some of these can be classified as hazardous materials, e.g., mercury, and have to handled and disposed of though hazardous waste mechanisms. The produced liquids and gases are then transported to a gas plant or refinery by truck, railroad car, ship, or pipeline. Large oil and gas production areas commonly have direct connections to common carrier or national pipelines.

2.3. ENHANCED OIL RECOVERY

Most petroleum reserves are developed by numerous production wells. As the initial primary production (recovery) approaches its economic limit, perhaps 25% of the crude oil in place from a particular reservoir has been withdrawn. The petroleum industry has developed unique schemes for supplementing the production of gases and liquid hydrocarbons that can be obtained by taking advantage of the natural reservoir energy and geometry of the underground structures. These supplementary schemes, collectively known as enhanced oil recovery (EOR) technology, can increase the recovery of crude oil, but only at the cost of supplying extraneous energy to the reservoir. In this way, the recovery of crude oil has been increased to an average of 33% of the original "in the ground" oil. As the industry matures and the reservoirs are depleted, the resultant oil price increase will justify more application of EOR applications, and they may eventually become commonplace. This will result in a higher overall recovery rate for the reservoirs.

2.4. SECONDARY RECOVERY

- **Water Injection:** In a completely developed oil or gas field, the wells may be drilled anywhere from 60 to 600 m (200–2000 ft) horizontally from each other, depending on the nature of the reservoir. If water is pumped into alternate wells (i.e., water injection wells) in such a field, the pressure in the reservoir as a whole can be maintained or even increased. In this way, the daily production rate of the crude oil can be increased. In addition, the water physically displaces the oil, thus increasing the recovery efficiency. In some reservoirs with a high degree of uniformity and little clay content, water flooding may increase the recovery efficiency to as much as 60% or more of the original oil in place. Water flooding was first introduce in Pennsylvania oil fields, somewhat accidently, in the late 19th century, and now has been used throughout the world.

- **Steam Injection:** Steam injection is used in reservoirs that contain very vicious oils, i.e., those that are thick and flow slowly. The steam not only provides a source of energy to displace the oil, but it also causes a marked reduction in viscosity (by raising the temperature of the reservoir), so the crude oil flows faster under any given pressure differential.
- **Gas Injection:** Some oil and gas formations contain large quantities of produced natural gas and carbon dioxide (CO_2). This gas is typically produced simultaneously with the liquid hydrocarbon production. The natural gas or CO_2 is recovered, recompressed, and re-injected into the gaseous portion of the reservoir. The re-injected natural gas or CO_2 maintains reservoir pressure and assists with pushing additional liquid hydrocarbons out of the liquid portion of the reservoir.

2.5. TERTIARY RECOVERY

As the production of secondary methods of recovery lose their efficiencies, further techniques have been tested and found to continue to release additional amounts of oil. These methods are considered tertiary methods and are generally associated with gaseous or chemical re-circulatory methods of recovery. Some methods of in-situ thermal recovery have been used but not on a large scale.

- **Chemical Injection:** Proprietary methods have been developed that inject chemicals detergent solutions into the oil reservoirs to increase the viscosity of the remaining oil reservoirs. After the chemical detergent solutions are injected, polymer thickened water is provided behind the chemical detergent to push the oil toward the producing wellbores.
- **Thermal Recovery:** Underground hydrocarbons are ignited, which creates a flame front or heat barrier that pushes the oil toward the well.
- **Re-circulated Gas Drive:** Natural gas or carbon dioxide (CO_2) is re-injected to mix with the underground oil, to free it from the reservoir

rock. The gas is reclaimed and re-circulated back into the reservoir until it is economically non-productive (i.e., the recovery rate is marginal). Some other experimental methods of recovery have been tried and proven technologically feasible, but these are still considered commercially unviable, i.e., in-situ combustion, electromagnetic charging, and similar methods.

2.6. TRANSPORTATION

Transportation is the means by which onshore and offshore oil and gas production is carried to the manufacturing centers and from which refined products are carried to wholesale and retail distribution centers.

Petroleum commodities (gas and oil) are normally transported in pipelines from source points to collection and processing facilities. Pipelines route unprocessed or refined products to centers of manufacturing and sales from areas of extraction, separation, and refining. Where a pipeline system is unavailable, trucking is usually employed.

Shipment from continent to continent is accomplished by large tanker vessels, carriers, or ships, which is the most economical method of shipping. These economies have produced the largest ships in the world, appropriately named supertankers and have two classes—Very Large Crude Carriers (VLCC) of a size range from 160,000 to 320,000 dead weight tons (dwt) and Ultra Large Crude Carriers (ULCC) of size range from 3,200,000 to 550,000 dwt. Refined products are typically shipped in vessels up to 40,000 dwt class rating. LNG or LPG vessels are typically in the range of up to 100,000 cubic meters (838,700 bbls.) capacity. Because of their large size the VLCC and ULCC cannot use normal port facilities and typically have to utilize special loading and unloading facilities that are located in deeper waters. These can be specialized single point moorings (SPMs), offshore platforms, such as the Louisiana Offshore Oil Port (LOOP), or similar structures. The shipment of hydrocarbons in vessels presents various fire and explosion hazards similar to onshore storage facilities.

In order to achieve a complete transportation system a host of other supporting subsystems complement the transportation operations. Loading facilities, pumping and compressor stations, tank farms, and metering and control devices are necessary for a complete transportation system of liquid or gaseous hydrocarbon commodities.

2.7. REFINING

In its natural state, crude oil has no practical uses except for burning as fuel after removal of the more volatile gases that flow with it from the produced well. It therefore is "taken apart" and sorted into the principal components for greater economic return. This is accomplished in a refinery that separates the various fractions into gases, liquefied petroleum gases, aviation and motor gasolines, jet fuels, kerosene, diesel oil, fuel oil, and asphalt. Refinery operations can be generally divided into three basic chemical processes: (1) distillation, (2) molecular structure alteration such as thermal cracking, reforming, catalytic cracking, catalytic reforming, polymerization, alkylation, etc., and (3) purification.

There are numerous refining methods employed to extract the fractions of petroleum liquids and gases. A particular refinery process design is normally dependent on the raw feedstock characteristics (e.g., crude oil and produced gas natural specifications) and the market demands (e.g., aviation or automotive gasolines) that it intends to meet.

Refining is superficially akin to cooking. Raw materials are prepared and processed according to a prescribed set of parameters such as time,

Table 2.1 Largest Petroleum Refineries in the World

Refinery Owner	Location	Capacity (bbls/day)
Reliance Industries Refinery	Jamnagar, Gujarat, India	1,240,000
SK Energy Ltd.	Ulsan, South Korea	1,120,000
PDVSA Refinery Complex	Parguana, Falcon, Venezuela	940,000
GS Caltex Refinery	Yeosu, South Korea	730,000
ExxonMobil	Singapore, Asia	605,000
Motiva Enterprises	Port Arthur, Texas, USA	600,000
ExxonMobil	Baytown, Texas, USA	572,500
Saudi Aramco	Ras Tanura, Saudi Arabia	550,000
Marathon Petroleum	Garyville, LA, USA	522,000
ExxonMobil	Baton Rouge, LA, USA	502,500

temperature, pressure, and ingredients. The following is a summary of the basic processes that are used in refinery processes.

Currently, the world's largest refinery complex is the Jamnagar Refinery Complex, consisting of two refineries side by side operated by Reliance Industries Limited in Jamnagar, India with a combined production capacity of 1,240,000 barrels per day.

The world's largest refineries are shown in Table 2.1.

2.7.1 Basic Distillation

The basic refining tool is the common distillation unit. It is usually the first process in refining crude oils. Crude oil normally begins to vaporize at a temperature somewhat less than that required to boil water. Hydrocarbons with the lowest molecular weight vaporize at the lowest temperatures, whereas successively higher temperatures are applied to separate or distill the larger molecules.

The first liquid material to be distilled from the crude oil is the gasoline fraction, followed in turn by naptha and then by kerosene. The middle and lower distillations then produce diesel, fuel oils, and the heavy fuel oils.

2.7.2 Thermal Cracking

In an effort to increase the yield from distillation, a thermal cracking process was developed. In thermal cracking the heavier portions of the crude oil are heated under pressure at higher temperatures. This results in large hydrocarbon molecules being split into smaller ones, so that the yield of gasoline from a barrel of oil is increased. The efficiency of the process is limited because of the high temperatures and pressures that are used. Typically a large amount of coke (solid, carbon-rich residue) is deposited into the reactors. This in turns requires still higher temperatures and pressures to crack the crude oil. A coking process was developed in which fluids were re-circulated, and the process operates for a much longer time with less buildup of coke.

2.7.3 Alkylation and Catalytic Cracking

Two additional basic processes, alkylation and catalytic cracking, were introduced in the 1930s to further increase the gasoline yield from a barrel of crude oil. In the alkylation process, small molecules produced by thermal cracking are recombined in the presence of a catalyst. This produces branched molecules in gasoline boiling range that have superior properties, e.g., higher antiknock ratings as a fuel for high-powered internal combustion engines that are used today in the automotive industry.

In the catalytic cracking process, crude oil is cracked in the presence of a finely divided catalyst, typically platinum. This permits the refiner to produce many diverse hydrocarbons that can then be recombined by alkylation, isomerization, and catalytic reforming to produce high antiknock engine fuels and specialty chemicals. The production of these chemicals has given birth to the chemical process industry (CPI).

The CPI industry manufactures alcohols, detergents, synthetic rubber, glycerin, fertilizers, sulfur, solvents, and feedstock for the manufacture of drugs, nylon, plastics, paints, polyesters, food additives and supplements, explosives, dyes, and insulating materials. The petrochemical industry uses about 5% of the total supply of oil and gas in the US.

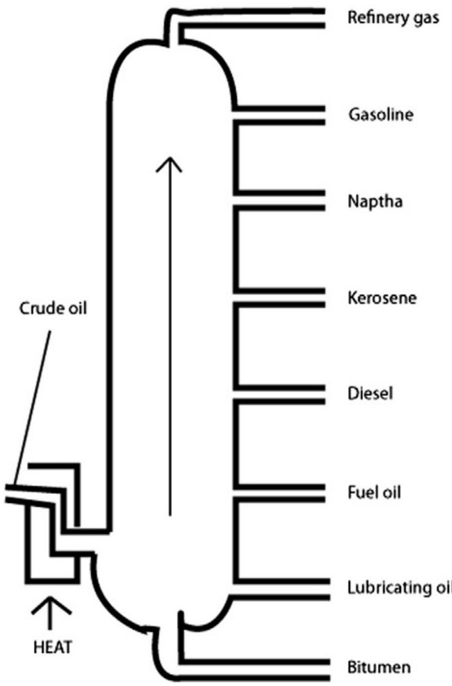
2.7.4 Purification

Purification processes are used to remove impurities such as sulfurs, mercury, gums, and waxes. The processes include absorption (primarily in filter material), stripping, solvent extraction, and thermal diffusion.

2.8. TYPICAL REFINERY PROCESS FLOW

At a refinery all crude oil normally is first directed to a crude distillation unit. The crude is routed in piping inside a furnace at high temperature to cause it to partially vaporize before it flows into a fractionating tower. The high volatile vapors rise up though the tower, cooling and liquefying in a number of "bubble" trays. The cooling and liquefying is assisted by a relatively cold stream of liquid naptha (a term in refining for "rough" gasoline streams from crude oil) being pumped into the top of the tower to flow downward from one bubble tray to another. The liquid on the different bubble trays condenses the heavier part of the vapors and evaporates its own lighter fractions or components.

Liberated gases are drawn off at the top of the tower. The gas is recovered to manufacture refrigerated liquefied petroleum gas (LPG). A condensed naptha stream is split into light naptha for gasoline blending and heavy naptha for further reforming. Kerosene and diesel stream are taken off at separate locations in the tower where the temperature condenses these products. Middle distillates are withdrawn and brought up to specification with separate processes, e.g., hydrodesulfurization. The heavy oil from the bottom of the crude unit can be used for oil blending or can be processed further in vacuum distillation units to recover a light distillate, used in blending diesel oils.



After products are produced by refining they are further enhanced in a blending unit. For gasoline, for example, coloring dyes or special additives may be added in blending tanks to complete its specification. The completed blends are tested and routed to tank farms for storage or shipment.

2.8.1 Production Percentages

The demand for lighter distillation products for gasoline and jet engines has increased the relative hazard levels of refinery facility processes over the years. A comparison of finished products from 1920 to today indicates the dramatic increase in light or more flammable production percentages. See Table 2.2.

By producing higher quantities of "lighter" fuels, the plants themselves have become higher risks just by the nature of the produced percentage than in previous years. The corresponding expansion of these facilities through the decades has also combined with more explosive products to heighten risk levels unless adequate protection measures are provided.

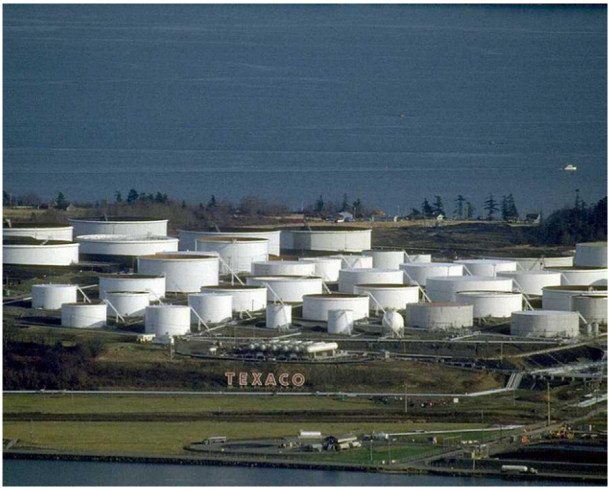
Table 2.2 Comparison of Refinery Fractions 1920/Today

Product	1920s	Today	Percent Change (%)
Gasoline	11	21	+91
Kerosene	5.3	5	−6
Gas oils	20.4	13	−36
Heavy oils	5.3	3	−43

2.9. MARKETING

Bulk plants distribution and marketing terminals store and distribute the finished products from the refineries and gas plants through the transportation systems. Typically these facilities handle gasoline, diesel jet fuels, asphalts, and compressed propane or butane.

These facilities consist of storage tanks or pressure vessels, loading or unloading facilities, by ship, rail, or truck, metering devices, and pumping or compressor stations. Their capacities are relatively smaller compared to refinery storage and are normally dictated by commercial demands in the bulk storage location.



2.10. CHEMICAL PROCESSES

A relatively small number of hydrocarbon feedstocks form the basis of the petrochemical industries. The basic building blocks in the petrochemical industry include the Aromatics (benzene, toluene, and xylene) and Olefins (ethylene and propylene) that are converted into products that are used in consumer products. Chemical plants produce olefins by steam cracking of natural gas liquids like ethane and propane. Aromatics are produced by catalytic reforming of naphtha.

Chemical reactions can convert certain kinds of compounds into other compounds in chemical reactors. Chemical reactors may be packed beds and may have solid heterogeneous catalysts that stay in the reactors as fluids move through. Since the surface of solid heterogeneous catalysts may sometimes become poisoned from deposits such as coke, regeneration of catalysts may be necessary. Fluidized beds may also be used in some cases. There can also be units (or subunits) for mixing (including dissolving), separation, heating, cooling, or some combination of these. For example, chemical reactors often have stirring for mixing and heating or cooling going on in them. Some plants may have units with organism cultures for biochemical processes such as fermentation or enzyme production.

Separation processes include filtration, settling (sedimentation), extraction or leaching, distillation, re-crystallization or precipitation (followed by filtration or settling), reverse osmosis, drying, and adsorption. Heat exchangers are often used for heating or cooling, including boiling or condensation, often in conjunction with other units such as distillation towers. There may also be storage tanks for storing feedstock, intermediate or final products, or waste.

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CHAPTER 3

Philosophy of Protection Principles

There are basically four major areas that influence how a facility will be protected—legal, financial, management accountability, and moral or ethical. Legal concerns meeting regulations and rules that apply to the facility. Financial concerns maintaining a viable and profitable facility even if an incident occurs. Management accountability deals with the responsibility for safety that the senior authority places on the organization and which they are held accountable for. Finally, there are social and moral issues that if an incident occurs, affects the personal integrity of individuals and the prestige of the organization. There are various features of each of these areas and all of these interact together, based on management direction, to form a level of hierarchy for a philosophy of protection that can be identified for a facility.

The risk management techniques of the organization should be defined before any considerations of the philosophy of protection needs for a facility are identified. An organization that is capable of obtaining a high level of insurance coverage at very low expense, even though they may have risks, may opt to have a limited outlay for protection measures since it is not cost effective. In reality this would probably never occur, but serves to demonstrate influences in a corporate approach to protection levels and risk acceptance criteria.

The protection of petroleum facilities follows the same overall philosophy that would be applied to any building or installation. These basic requirements are emergency evacuation, containment, isolation, and suppression. Since these are design features that cannot be immediately

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brought in at the time of an incident, they must be adequately provided as part of the original facility design. What constitutes adequate is the definition fire, risk, and loss professions must be able to advise upon.

3.1. LEGAL OBLIGATIONS

Two federal US agencies (OSHA and EPA) have major legal requirements for the management of process safety. These are identified below.

3.1.1 Occupational Safety and Health Administration (OSHA)

OSHA Process Safety Management (PSM) regulation, 29 CFR 1910.119, requires a comprehensive set of plans, policies, procedures, practices, administrative, engineering, and operating controls designed to ensure that barriers to major incidents are in place, in use, and are effective. Its emphasis is on the prevention of major incidents rather than specific worker health and safety issues. PSM focuses its safety activities on chemical-related systems, such as chemical manufacturing plants, wherein there are large piping systems, storage, blending, and distributing activities.

3.1.2 Environmental Protection Agency (EPA)

Under the authority of section 112(r) of the Clean Air Act, the Chemical Accident Prevention Provisions (40 CFR Part 68) require facilities that produce, handle, process, distribute, or store certain chemicals to develop a Risk Management Program, prepare a Risk Management Plan (RMP), and submit the RMP to the EPA. Covered facilities were initially required to comply with the rule in 1999.

Additionally, the Emergency Planning and Community Right-to-Know Act (EPCRA) of 1986, which defines industrial chemical reporting requirements, dictates that facilities must report the storage, use, and release of certain hazardous chemicals. It was created to help communities plan for emergencies involving hazardous substances. EPCRA has four major provisions: one addresses emergency planning and the other three outline chemical reporting.

3.2. INSURANCE RECOMMENDATIONS

All insurance companies provide property risk engineers or inspectors to evaluate their insured risks for high value properties or operations. So in reality, a basic standard level of protection is probably maintained in the industry. All the major oil companies have high levels of self insurance and usually high deductibles. Their insurance coverages are also typically obtained in several financial layers from different agencies with considerable options, amendments, and exclusions. So hopefully no individual insurer would be in a financial peril from a single major incident.

A general level of loss prevention practices is considered prudent both by insurers and petroleum companies, so overall all facilities are required to meet the corporate protection standard. In fact, the premium of insurance is normally based on the level of risk for the facility after an insurance engineer has "surveyed" its facilities. Isolated cases may appear where less fixed protection systems are provided in place of manual fire fighting capabilities, but the general level of overall loss prevention or risk is maintained. Insurers will also always make recommendations for loss prevention improvements where they feel the protection levels are substandard and the risk high. Where they feel the risk is too high, they may refuse to underwrite certain layers of insurance or charge substantial additional premiums for reinsurance requirements.

3.3. COMPANY AND INDUSTRY STANDARDS

Both the industry and companies have safety standards for the protection of process industries. The industry standards are considered guidelines and are useful for companies to base their own particular standards on. The major industry standards include API Recommended Practices, NFPA Fire Codes, and CCPS guidelines (see Figure 3.1).

3.3.1 General Philosophy

In general, the fire and explosion protection engineering philosophy for petroleum, chemical, and related facilities can be defined by the following objectives (listed in order of preference):

1. **Prevent the immediate exposure on individuals to fire and explosion hazards.**
   No facility should be designed such that an employee or member of the public could be immediately harmed if they were exposed to the operation (e.g., heat radiation from flaring should be placed so no effects will occur outside the specified area).
2. **Provide inherently safe facilities.**
   Inherently safe features at a facilities provide for adequate spacing of high risk from other areas, arrangement and segregation of from high

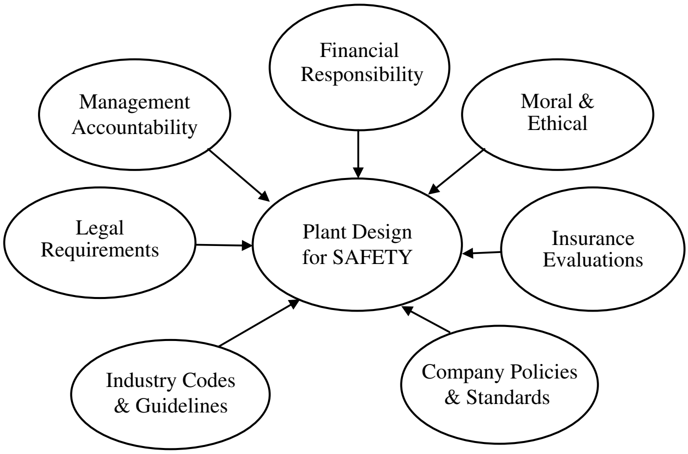

Figure 3.1 Major influences on plant design for safety.

hazard to low hazard risks. The least hazardous process system should be selected and installed for obtaining the desired product or production objectives. Protective systems are provided to minimize the effects that may occur from a catastrophic incident.

3. **Meet the prescriptive and objective requirements of governmental laws and regulations.**
   All international, national, and local laws or regulations are to be complied with, in both prescriptive requirements and underlying objectives. Laws are provided to achieve the minimum safeguards that are required by a society to exist without excessive turmoil. Industry must abide by these laws in order to have a cohesive operation without fear of legal mandates.
4. **Achieve a level of fire and explosion risk that is acceptable to the employees, the general public, the allied industry, local and national government, and the company and its stakeholders.**
   Although a facility could conceivably be designed that would comply with all laws and regulations, if the perception exists that the facility is unsafe, it must be altered or assessed to provide for a facility that is technically judged safe by recognized experts, the industry, and the general public.
5. **Protect the economic interest of the company for both short- and long-term impacts.**
   The prime objective of a business is to provide a positive economic return to the owners. Therefore the economic interest of the owners should be protected for long and short range survival without fear of a potential loss of earnings.

6. **Comply with an organization's policies, standards, and guidelines.**
   An organization's policies, standards, and guidelines are promulgated to provide guidance in the conduction of the specific business in an efficient and cost-effective manner without fear of unexpected incident losses.
7. **Consider the interest of business partners.**
   Where a consortium may exist, the economic interest of the partners must be considered and their management usually requires approval of the risk involved in the venture.
8. **Achieve a cost effective and practical approach.**
   The safety and protection of a facility does not necessarily need to involve highly expensive and elaborate protective systems. All that is required or desired is a simplistic, practical, and economic solution to achieve a level of safety that is commensurate with the level of risk and is acceptable to all interested parties.
9. **Minimize space (and weight if offshore) implications.**
   Usually, the most expensive initial investment of any capital project is the investment in space to provide a facility. For both onshore and offshore facilities, the amount of space a facility occupies typically directly corresponds to increased capital costs, but this consideration should be balanced with the need for adequate separation, segregation, and arrangements of protection design principles.
10. **Respond to the operational needs and desires.**
    To provide effective process safety features, these features should also be effective operational features. Providing safeguards that are counterproductive to safety may cause the exact opposite to occur, since operations may override or bypass the safeguard for ease of operational convenience.
11. **Protect the reputation and prestige of the company.**
    Public perception of a company lowers if it is involved in a major incident that has considerable fatalities or does major harm to the environment. Although in most cases, these incidents can be economically recovered from, the stigma of the incident may linger and affect the sale of company products (especially if a public inquiry or considerable lawsuits occur).
12. **Eliminate or prevent the deliberate opportunities for employee or public-induced damages or terrorist incidents.**
    Negative employee moral may manifest itself in an aspect of direct damage to company equipment as retribution (although unjustified, illegal, and unethical). These effects may be disguised as incidental events in order to avoid persecution by the individuals involved. Other incidents may be perpetrated by outright terrorist activities. Incidental

effects may possibly develop into catastrophic incidents unbeknown even to the saboteur, until it occurs. The design of facilities should account for periods when management and labor relations may not be optimum and opportunities for vandalism could easily avail themselves. Where a terrorist threat is identified, ongoing suitable preventive measures must be instituted i.e., increased security measures, barricades, surveillance systems, etc.

3.4. WORST CASE CONDITION

Normal loss prevention practices are to design protection systems for the worst case fire event that can occur at a facility (within the limits of probabilities). To interpret this literally would mean in some cases that an oil or gas facility is completely on fire or totally destroyed by an explosion. Practical, economic, and historical review considerations indicate this rationale should be redefined as the Worst Case Credible Event (WCCE) or as referenced in the insurance industry, the Probable Maximum Loss (PML), which could occur at the facility.

Much discussion could be presented as the most credible worst case event at the facility. Obviously a multitude of unbelievable events can be postulated (industrial sabotage, insane employees, plane crash impacts, etc.). Only the most realistic and probable events should be considered. In most cases, historical evidence of similar facilities is used as a reference for the worst case events. Alternatively, the effect of the most probable high inventory hydrocarbon release could be postulated. The worst case event should be agreed upon with loss prevention, operational and senior executive management for the facility. The worst case credible event will normally define the highest hazard location(s) for the facility. From these hazards, suitable protection arrangements can be postulated to prevent or mitigate their effects.

Several additional factors are important when considering a worst case credible event.

3.4.1 Ambient Conditions

- Weather—Winds, snow, sandstorms, extremely high or low ambient temperatures, etc. Weather conditions can impede the progress of any activity and interrupt utility services if these become impacted.

- Time of Day—Personnel availability, visibility, etc., plays a key role in the activities of personnel during an incident. Periods of off-duty time for offshore or remote installations, shift changes, and nighttime allow high density of personnel to develop on some occasions, which can be vulnerable to a high fatality risk. Poor visibility affects transportation operations.

3.5. INDEPENDENT LAYERS OF PROTECTION (ILP)

Most facilities are designed around layers of protection commonly referred to as independent layers of protection (ILP). A protection layer or combination of protection layers qualifies as an ILP when one of the following is met:

1. The protection provided reduces the risk of a serious event by 100 times.
2. The protective function is provided with a high degree of availability, i.e., greater than 0.99.
3. It has the following characteristics—specificity, independence, dependability, and auditabilty.

Table 3.1 provides a listing hierarchy of the independent layers of protection commonly found in the process industries.

Most petroleum and chemical facilities rely on inherent safety and control features of the process, inherent design arrangements of the facility, and process safety emergency shutdown (ESD) features as the prime loss prevention measures. These features are immediately utilized at the time of the incident. Passive and active explosion and fire protection measures are applicable after the initiating event has occurred and an adverse effect to the operation has been realized. These features are used until their capability has been exhausted or the incident has been controlled.

3.6. DESIGN PRINCIPLES

To achieve safety objectives and a philosophy of protection through independent layers of protection, a project or organization should define specific guidelines or standards to implement in its designs. Numerous industry standards are available (i.e., API, CCPS, NFPA) that provide options, general recommendations, or specific criteria once a design preference is chosen. It is therefore imperative to have company-specific

Table 3.1 Independent Levels of Protection

Rank	ILP Feature	Typical Periods of Prime Usefulness	General Level of Destruction That May Occur
1	Basic process design (e.g., inventories, commodities, refining processes, etc.)	Continuously during operations and emergencies	None[a]
2	Basic controls, process alarms, and operator supervision (BPCS)	Continuously during operations and emergencies	None[a]
3	Critical alarms, operator supervision, and manual intervention of process control	Continuously during operations and emergencies	None[a]—Minor
4	Emergency shutdown (ESD) intervention—isolation, power down, depressurization, blowdowns, and fail-safe features, etc.	From 0 to 15 min after incident occurrence	Minor—Major
5	Physical process protection measures (e.g., relief valves, process integrity features, etc.)	From 0 to 2 h after incident occurrence	Major
6	Facility passive protective measures (e.g., containment, dikes, spacing, fireproofing, etc.)	From 0 to 4 h after incident occurrence	Major—Severe
7	Facility emergency response measures (e.g., fixed fire suppression systems, medical support, etc.)	From 0 to 6 h after incident occurrence	Severe—Catastrophic
8	Community emergency response measures (e.g., evacuation, mutual aid, etc.)	From 0 to 24 h after incident occurrence	Catastrophic

[a]Lack of these features may contribute to the magnitude of destruction that may occur.

direction in order to comply with management directives for the protection of the facility (see Figure 3.2).

Typically applied generic safety features in the process industries include the following:

- *Evacuation*: Immediate faculty evacuation should be considered a prime safeguard for all personnel from an incident. Exit routes and areas of safe refuge or assembly areas should be identified. All onsite personnel should be fully trained and where required, certified for such an eventuality (e.g., offshore evacuation mechanisms).

Figure 3.2 Design considerations.

- *Process Safety Priority*: Process system emergency safety features, i.e., ESD, depressurization, blowdown, etc., should be considered the prime safeguard for loss prevention over fire protection measures (e.g., fireproofing, firewater systems, manual fire fighting).
- *Regulatory & Company Compliance*: The facility should meet the requirements of local, national, or international regulations and company polices pertaining to safety health and the protection of the environment.
- *Utilization of Industry Standards*: Recognized international codes and standards should be used (e.g., API, ASME, ASTM, CCPS, NACE, NFPA) in the design and in any proposed modification. It should be realized that compliance with a code or a standard is not sufficient in itself to ensure a safe design is provided.
- *Inherent Safety Practices*: Inherent safety practices implement the least risk options for conducting an operation and provide sufficient safety margins. General methods include using inert or high flash point materials over highly volatile low flash point materials, use of lower pressures instead of higher pressures, smaller volumes instead of large volumes, etc.

In general, these design characteristics:

- are intrinsically safe,
- incorporate adequate design margins or safety factors,
- have sufficient reliability,
- have failsafe features,
- incorporate fault detection and alarms, and
- provide protection instrumentation.

Specific inherent safety design features:

- *ESD*—Automatic ESD (shutdown and isolation) activation from confirmed process system instrumentation set points.
- *Inventory Disposal*—Automatic de-inventorying of high volume hydrocarbon processes (gaseous and liquids) for emergency conditions to remote disposal systems.
- *Spacing*—Separation distances are maximized for high risks. Occupied facilities, i.e., control rooms, offices, accommodations, temporary project site offices, etc., should be located as far as practical from high risks and should be evaluated for potential blast impacts. High volume storage is highly spaced from other risks. Safety factors are included in calculated spacing distances, determined by mathematical modeling of probable fire and explosion incidents. Spacing is implemented over passive protective barriers.
- *Inventory Minimization*—The amounts of combustible gases and liquids that may contribute to an incident should be minimized for normal operations and during emergency conditions (limited vessel sizes, isolation provisions, blowdown and depressurization, etc.). The maximum allowable levels for operational and emergency periods should be identified as part of the design process and risk analysis.
- *Automatic Controls*—Automatic control (DCS-BPCS, PLC, etc.) for high risk processes should be used and backed up by human supervision.
- *Control Integrity*—High integrity ESD systems containing failsafe devices should be used where practical. Failure modes are selected for operating devices that isolate fuel supplies (i.e., fail close) and depressure high volume gas supplies (i.e., fail open) upon disruption of utility services during an incident.
- *Staggered Alarms*—Two separate alarm indications (e.g., high/high-high; low/low-low) should be used for critical alarms and controls.
- *Avoidance of Atmospheric Releases*—The release or exposure of combustible vapors or liquids to the operating environment should not be allowed. Relief valve outlets should be connected to a flare or blowdown header, pump seal leakages should be immediately corrected, and vibration stresses on piping components should be avoided.
- *Single Point Failure*—Single point failure locations in the process flow should be eliminated for the prime production process and support systems (e.g., electrical power, heat transfer, cooling water, etc.) that are critical to maintain the production process.

- *Superior Corrosion Prevention Systems*—High performance corrosion protective measures or allowances should be instituted. Corrosion monitoring should be used in all hydrocarbon containing systems.
- *Free Air Circulation*—The facility should be designed with the maximum use of open space for free air ventilation and circulation to avoid the buildup of unexpected vapor releases, especially for offshore installations. Enclosed spaces should be avoided.
- *Control of Ignition Sources*—Exposed ignition sources (e.g., vehicles, smoking, etc.) should be spaced as far as practical from hydrocarbon-containing systems (maximize electrical area classification requirements).
- *Critical Air Supplies*—Air supplies for ventilation of control rooms, prime movers, emergency generators, etc., should be located at the least likely location for the accumulation of combustible vapors or routes of dispersion.
- *Personnel Evacuation*—Two separate on-site evacuation mechanisms should be provided and available.
- *Critical System Preservation*—The integrity of safety systems (e.g., ESD, depressurization, fire detection, fire suppression, evacuation means) should be maximized and preserved from a fire or explosion incident.
- *Drainage*—Surface drainage and safe removal of spilled or accumulated liquids is adequately provided and arranged to prevent exposure to the hazard to the process system or critical facility support systems. Liquids should be immediately removed from an area through surface runoff, drains, area catch basins, sumps, sewers, dikes, curbing, or remote impounding.
- *Use of Low Hazard Commodities*—High flash point, noncombustible, or inert liquids and gases should be utilized whenever possible.
- *Low Pressure Preferences*—Gravity or low pressure systems should be used over high pressure systems (e.g., fuel to prime movers, day tank supplies, etc.).
- *Minimization of Leak Points*—Common vulnerable leakage points should be minimized (e.g., glass level gauges, hose transfer systems, etc.).
- *Piping Protection*—Piping carrying a hazardous material should be minimized where practical and where exposed afforded protection considered necessary by the risk.

- *Personnel Incipient Actions*—Operational personnel should be expected to suppress only very small incipient fires. All other emergencies are to be handled with emergency shutdown (ESD), blowdown, isolation, fire protection systems (active or passive), or exhaustion of the fuel sources by the incident.

- *Employee Unrest*—Opportunities for employee-induced damages are minimized. All activities are made so that they are direct actions and cannot be attributed to purely mechanical failures, e.g., easily broken gauge glasses are protected or removed, drains are capped, field ESD push buttons are provided with protective covers, work permit procedures are enforced, lock-out/tag-out measures are used, etc.
- *Weather/Geological Impacts*—The facility is secured and evacuated if weather or geological event predictions suggest severe conditions may be imminent at the location.
- *Controls Technologically Updated*—The controls are designed and updated with the use of the best available control technology (BACT), e.g., DCS/PLCs, process management systems commensurate to the level of the risk the facility represents.
- *Process Hazard Reviews*—The facility and subsequent changes are subjected to a process hazard analysis commensurate to the level of hazards the facility represents (i.e., Checklist, What-If, PHA, HAZOP, Event Tree, FMEA, LOPA, etc.). The results of these analyses are fully understood and acknowledged by management. Where high risk events are identified as probable, quantifiable risk estimation and effects of mitigation measures should be undertaken and applied if productive.

These are some of the numerous inherent design features that can be incorporated into the design of a process system depending on its characteristics. Not only should a process design achieve economic efficiency but inherent safety of the process should be optimized simultaneously as well.

3.7. ACCOUNTABILITY AND AUDITABILITY

An organization should have a well-thought-out protection design philosophy that is understood and accepted by management. The safety design philosophies should be reflected in the engineering design standards or guidelines used by the organization. The standards or guidelines form the basis from which safety of the facility can be audited against. Organizations that do not provide such information do not have any accountability standards to meet or achieve, and therefore the safety of the facility will suffer accordingly. Additionally, the objectives of design standards and guidelines can be more fully understood if a philosophy of design (protection) is documented (see Figure 3.3).

The argument cannot be made that standards and guidelines restrict innovation or are unduly expensive. Waivers and exceptions to the

Figure 3.3 Management accountability.

requirements can always be allowed when fully justified. Such justification must demonstrate equivalency or superiority in meeting the requirements or safety objective or intent. In this fashion, standards or guidelines can be also improved to account for such acceptable changes or improvements in technology. Although not easily calculated, a firm set of requirements also prevents "re-inventing the wheel" each time a facility is designed. This will also hopefully prevent mistakes made in the past from reoccurring. Thus, they establish a long-term savings to the organization. Additionally, reference to industry standards, e.g., API, NFPA, etc., will not specify the actual protection measures to be provided at a facility. In most cases, they only define the design parameters. A project or facility requires the "local jurisdiction" to determine the protection requirements, which is usually the company itself. Industry codes and guidelines can only provide detailed design guidance that can be used on a particular protection philosophy is specified.

FURTHER READING

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CHAPTER 4

Physical Properties of Hydrocarbons and Petrochemicals

Petroleum or crude oil is a naturally occurring oily, bituminous liquid composed of various organic chemicals. It is found in large quantities below the surface of the earth and is used as a fuel and a raw material (feedstock) in the chemical and related industries. Modern industrial societies primarily use it to achieve a degree of mobility as a fuel for internal combustion and jet engines. In addition, petroleum and its derivatives are used in the manufacture of medicines, fertilizers, foodstuffs, plasticware, building materials, paints, and clothing and to generate electrical power. Gas supplies are becoming increasingly more important as the reserves of liquid hydrocarbons are becoming more difficult to locate and produce and existing reservoirs are being depleted. The relatively clean burning gases are also more acceptable environmentally.

Petroleum is formed under the earth's surface by the decomposition of organic material. The remains of tiny organisms that lived in the sea and to a lesser extent, those of land organisms that were carried down to the sea in rivers, along with plants that grow on the ocean bottoms combined with the fine sands and silts in calm sea basins. These deposits, which are rich in organic materials, became the source rocks for the formation of carbon and hydrogen, i.e., natural gas and crude oil.

This process began many millions of years ago with the development of abundant life and continues to this day. The sediments grow thicker and sink into the sea floor under their own weight. As additional deposits collect and pile on top, the pressure on the ones below increases several thousand times, and the temperature rises by several hundred degrees. The mud and sand harden into shale and sandstone. Carbonate precipitates and skeletal shells harden into limestone. The remains of dead organisms are then transformed into crude oil and natural gas. Usually the underground and formation pressure is sufficient for the natural release of hydrocarbon liquids and gases to the surface of the earth.

Hbk of Fire and Explosion Protection, http://dx.doi.org/10.1016/B978-0-323-31301-8.00004-0

4.1. GENERAL DESCRIPTION OF HYDROCARBONS

The range and complexity of naturally occurring petroleum is extremely large, and the variation in composition from one reservoir to another shows quite a range. Crude oil is graded by a specific viscosity range indicated in degrees API. Higher degrees being lighter (therefore more valuable) and lower degrees being heavier (less valuable). The specific molecules vary in shape and size from C_1 to C_{80} or more. At the simplest, the one carbon compound has four hydrocarbon atoms bonded to the carbon atom to produce the compound CH_4, or methane gas. Liquid hydrocarbons from natural wells may have nitrogen, oxygen, and sulfur in quantities from trace amounts to significant, as well as traces of metals, such as mercury.

Natural petroleum is distilled or fractionated and reformulated to produce a variety of fuels for general use and as a raw feedstock for other industries.

Three broad categories of crude petroleum exist: paraffin types, asphaltic types, and the mixed base types. The paraffin types are composed of molecules in which the number of hydrogen atoms is always two more than twice the number of carbon atoms. The characteristics of the asphaltic types are naphthenes, composed of twice as many hydrogen atoms as carbon atoms. In the mixed based group are both paraffin hydrocarbons and naphthenes.

The saturated open-chain hydrocarbons form a homologous series called the paraffin series or the alkane series. The composition of each of the members of the series corresponds to the formula C_nH_{2n+2}, where n is the number of carbon atoms in the molecule. All the members of the series are unreactive. They do not react readily at ordinary temperatures with reagents such as acids, alkalies, or oxidizers.

The first four carbon molecules, C_1–C_4, with the addition of hydrogen, form hydrocarbon gases: methane, ethane, propane, and butane. Larger molecules C_5–C_7 cover the range of light gasoline liquids, C_8–C_{11} are napthas, C_{12}–C_{19} are kerosene and gas oil, C_{20}–C_{27} are lubricating oils, and above C_{28}, heavy fuels, waxes, asphalts, bitumen, and materials as hard as stone at normal temperatures. Accompanying the gas compounds may be various amounts of nitrogen, carbon dioxide, hydrogen sulfide, and occasionally helium.

4.1.1 Alkene Series

The unsaturated open-chain hydrocarbons include the alkene or olefin series, the diene series, and the alkyne series. The alkene is made up of chain hydrocarbons in which a double bond exists between two carbon atoms. The general formula for the series is C_nH_{2n}, where n is the number of carbon atoms. As in the paraffin series, the lower numbers are gases, intermediate compounds are liquids, and higher members of the series are solids. The alkene series compounds are more active chemically than the saturated compounds. They react easily with substances such as halogens by adding atoms at the double bonds.

They are not found to any extent in natural products, but are produced in the destructive distillation of complex natural substances, such as coal, and formed in large amounts in petroleum refining, particularly in the cracking process. The fire member of the series is ethylene C_2H_4. The dienes contain two double bonds between pairs of carbon atoms in the molecule. They are related to the complex hydrocarbons in natural rubber and are important in the manufacture of synthetic rubber and plastics. The most important members of this series are butadiene, C_4H_6 and isoprene, C_5H_8.

4.1.2 Alkyne Series

The members of the alkyne series contain a triple bond between two carbon atoms in the molecule. They are very active chemically and are not found free in nature. They form a series analogous to the alkene series. The first and most important member of this series is acetylene, C_2H_2.

4.1.3 Cyclic Hydrocarbons

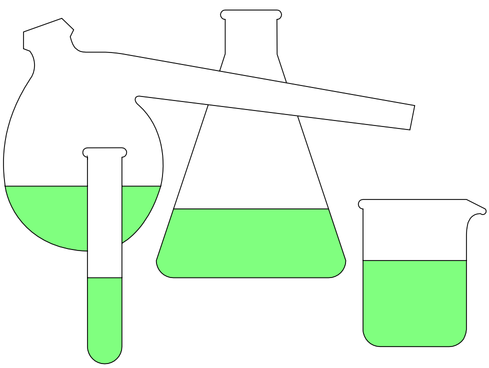
The simplest of the saturated hydrocarbons, or cycloalkanes, is cyclopropane, C_3H_6, the molecules of which are made up of three carbon atoms to each of which two hydrogen atoms are attached. Cyclopropane is somewhat more reactive than the corresponding open-chain alkane propane, C_3H_8. Other cycloalkanes make up a part of ordinary gasoline.

Several unsaturated cyclic hydrocarbons, having the general formula $C_{10}H_{16}$, occur in certain fragrant natural oils that are distilled from plant materials. These hydrocarbons are called terpenes and include pinene (in turpentine) and limonene (in lemon and orange oils).

The most important group of unsaturated cyclic hydrocarbons is the aromatics, which occur in coal tar. All the aromatics sometimes exhibit unsaturation, that is, the addition of other substances, and their principle reactions bring about the replacement of hydrogen atoms by other kinds of atoms or groups of atoms. The aromatic hydrocarbons include benzene, toluene, anthracene, and naphthalene. Aromatics are utilized primarily in the petrochemical industries.

4.2. CHARACTERISTICS OF HYDROCARBONS

Hydrocarbon materials have several different characteristics that can be used to define their level of hazard. Since no one feature can adequately define the level of risk for a particular substance, they should be evaluated as a synergism. Is should also be realized that these characteristics have been tested under strict laboratory conditions and procedures that may alter when applied to industrial environments. The main characteristics of combustible hydrocarbon materials that are of high interest for fire and explosion concerns are described below.



4.2.1 Lower Explosive Limit (LEL) and Upper Explosive Limit (UEL)

This is the range of flammability for a mixture of vapor or gas in air at normal conditions. The terms flammable limits and explosive limits are

Table 4.1 Common Material Flammable Ranges and Spreads

Material	Flammable Range (%)	Range Spread
Hydrogen	4.0–75.6	71.6
Ethane	3.0–12.5	9.5
Methane	5.0–15.0	10.0
Propane	2.37–9.5	7.1
Butane	1.8–8.4	6.6
Pentane	1.4–8.0	6.6
Hexane	1.7–7.4	5.7
Heptane	1.1–6.7	5.6

interchangeable. Where the range between the limits is large, the hydrocarbons may be considered relatively more dangerous, e.g., hydrogen has a range of 4–75%, while gasoline has a range of 1.4–7.6%, when compared to each other, since it has a higher probability of ignition in any particular situation. Flammable limits are not an inherent property of a commodity, but are dependent on the surface-to-volume ratio and the velocity or direction of the air flow under the test.

Some common petroleum commodities and their flammable limits under normal conditions are listed beginning with the widest ranges (see Table 4.1).

4.3. FLASH POINT (FP)

The lowest temperature of a flammable liquid at which it gives off sufficient vapor to form an ignitable mixture with the air near the surface of the liquid or within the vessel used. The flash point has been commonly determined by the open cup or closed cup method (ASTM D 56, Standard Test Method for Flash Point by Tag Closed Cup Tester, ASTM D 92, Standard Test Method for Flash and Fire Points by Cleveland Open Cup Tester, ASTM D 93, Standard Test Method for Flash Point by Pensky-Martens Closed Cup Tester ASTM D 3278, Standard Test Method for Flash Point of Liquids by Small Scale Closed Cup Apparatus, ASTM D 3828, Standard Test Method for Flash Point by Small Scale Closed Cup Tester), but recent research has yielded higher and lower flash points depending on the surface are of the ignition source.

Common petroleum materials with some of the lowest flash points under normal conditions are listed in Table 4.2.

Table 4.2 Common Material Flash Points

Material	**Flash Point °C (°F)**
Hydrogen	Gas
Methane	Gas (−188°C)
Propane	Gas
Ethane	Gas
Butane	−60°C (−76°F)
Pentane	<−40°C (<−40°F)
Hexane	−22°C (−7°F)
Heptane	−4°C (25°F)

4.4. AUTOIGNITION TEMPERATURE (AIT)

The autoignition temperature or the ignition temperature is the minimum temperature at which a substance in air must be heated to initiate or cause self-sustaining combustion independent of the heating source. It is an extrinsic property, i.e., the value is specific to the experimental method that is used to determine it. The most significant factors that influence a measurement of AITs are the volume to surface ratio of the source of ignition (i.e., a hot wire versus a heated cup will yield different results). Ignition temperatures should always be thought of as approximations and not as exact characteristics of the material for this reason.

For straight paraffin hydrocarbons (i.e., methane, ethane, propane, etc.), the commonly accepted autoignition temperatures decrease as the paraffin carbon atoms increase (e.g., ethane 540°C (1004°F) and octane 220°C (428°F).

Some common petroleum material AITs under normal conditions are listed in Table 4.3.

Table 4.3 Common Material Autoignition Temperatures

Material	**Autoignition Temperature °C (°F)**
Heptane	204°C (399°F)
Hexane	225°C (437°F)
Pentane	260°C (500°F)
Butane	287°C (550°F)
Propane	450°C (842°F)
Ethane	472°C (882°F)
Hydrogen	500°C (932°F)
Methane	537°C (999°F)

A mathematical method for obtaining a general approximation of the hydrocarbon ignition temperature based on the molecular weight of the vapor is given in the NFPA Fire Protection Handbook. It states that the autoignition temperature of a paraffinic hydrocarbon series decreases as the molecular weight of the substance increases. A figure is provided by which if the "average carbon chain length" is known, the minimum ignition temperature can be theoretically approximated.

For hydrocarbon mixtures containing only paraffinic components, an approximation of the ignition temperature can be made using the average molecular weight of the substance. It can be estimated by multiplying the molecular weight of each pure vapor by its concentration (i.e., measured percentage), in the mixture, to arrive at an average mixture molecular weight (average carbon chain length 0). Once this is known, it can be compared to the ignition temperature of a known substance with an equal weight or reference can be made to the figure in the NFPA Fire Protection Handbook. Actual laboratory sampling of several paraffinic mixtures and their tested AITs against this mathematical method has confirmed it is a viable calculating tool that provides a conservative estimate. Figure 4.1 provides an example of this calculation method. Where major decisions are required on the basis of autoignition temperatures, it is always best to obtain a laboratory test to determine the autoignition temperature.

By general inspection, where a large percentage of high ignition temperature paraffinic gas coexists in a mixture with a low percentage of ignition temperature paraffinic gas, it can be conferred that the mixture will have a higher ignition temperature than that of the low ignition gas (e.g., 90% propane, 10% hexane).

This can be substantiated by the fact that where high molecular weight hydrocarbon molecule is converted by combustion, it takes less energy to sustain the reaction than it would for a lower molecular weight (less energy) containing molecule. This is because more energy is being used for release in the high molecular weight hydrocarbon substance.

This principle is only applied to straight chain hydrocarbons and is inappropriate if other types of substances are involved (e.g., hydrogen).

Autoignition temperatures are vitally important for process designs as it is the temperature to prevent or eliminate readily available ignition sources, which is specified for some plant equipment, e.g., operating temperatures of electrical equipment, lighting fixtures, etc.

Example: NGL Column Bottoms Liquid Percentage Concentration (from a sample analysis).

Name	Symbol	Molecular Weight	Autoignition Temperature	Percentage
Methane	C1	16	540°C	2.3%
Ethane	C2	30	515°C	0.2%
Propane	C3	44	450°C	30.0%
Butane	C4	58	405°C	25.0%
Pentane	C5	72	260°C	15.5%
Hexane	C6	86	225°C	23.0%

MW_{ave} = (16 x 0.023) + (30 x 0.002) + (44 x 0.30) + (58 x 0.25) + (72 x 0.155) + (86x 0.23)

= 58.2 or equivalent to Butane, C4

The NGL column bottoms has an average molecular weight equivalent to normal butane and therefore has an approximate autoignition temperature of 405°C (761°F).

As a practical application, say two types of light fixtures are available to install in the subject process unit. One that operates at 200°C (392°F) and costs $1,000/each (Case 1), and one that operates at 375°C (707°F) and costs $500/each (Case 2). Let's assume the 200 light fixtures are required for the unit.

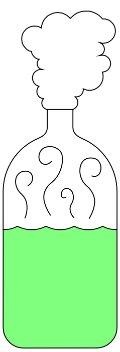
Case1 200 x $1,000 = $200,000

Case 2 200 x $500 = $100,000

Therefore in this example (to meet area electrical classification requirements), if the lowest autoignition temperature (i.e., 225°C) were chosen for the commodities in the composition, $200,000 would have to be expended for the light fixtures, but if it was accepted that a mixture of commodities will be constant in the process and a higher autoignition temperature (i.e., 405°C) is acceptable for the composition as demonstrated by the calculation (and possibly collaborated by a laboratory sample test), a $100,000 savings could be realized with the utilization of the higher temperature light fixtures (i.e., 375°C).

Figure 4.1 Autoignition temperature approximation method example.

4.5. VAPOR DENSITY RATIO



Vapor density ratio is the measure of the relative density of the pure vapor or gas when compared to air for the purposes of fire protection applications. Technically it is the weight of the vapor per unit volume at any given temperature and pressure. Vapors with a vapor density ratio of greater than 1.0 are heavier than air and will follow the surface of the ground and may accumulate until they are dissipated by some means and are generally considered more of a hazard. Vapors with a vapor density less than 1.0 will rise into the atmosphere, the lower the density the faster they will rise, and are considered relatively less hazardous since they may dissipate and disperse more quickly, but could also travel further distances to reach an ignition source. Vapor density ratios are reported at conditions of equal temperatures and atmospheric pressure. Unequal or changing conditions will appropriately affect the density of a particular vapor.

Common petroleum materials with some of the highest vapor densities under normal conditions are listed below:

Material	Vapor Density Ratio
Hydrogen (H)	0.069
Methane (CH_4)	0.554
Ethane (C_2H_6)	1.035
Propane (C_3H_8)	1.56
Butane (C_4H_{10})	2.01
Pentane (C_5H_{12})	2.48
Hexane (C_6H_{14})	2.97
Heptane (C_7H_{16})	3.45

The density of air at sea level is 1.2kg/m^3.

4.6. VAPOR PRESSURE

This is the property of a substance to vaporize. Liquids are usually classified by the Reid vapor pressure (ASTM D 323, Standard Test Method for Vapor Pressure of Petroleum Products), which is calculated on the basis of a specific oil at a temperature of 37.8°C (100°F).

4.7. SPECIFIC GRAVITY

The specific gravity is the ratio of weight of equal volumes of a substance to that of another substance; for fire protection purposes, this is usually water. For petroleum products it is customary to measure the ratio at 15.6°C (60°F). A liquid with a specific gravity less than one will float on water and therefore it is important in the application of firefighting foams to suppress vapors or in fire extinguishing operations.

4.8. FLAMMABLE

Generically flammable means capable of being easily set on fire, combustible. It is a synonym of inflammable. Inflammable is considered an obsolete term in the US because of the connotation of the negative prefix that incorrectly suggests the material is nonflammable. Liquids are classified either flammable or combustible based on their flash point by NFPA 30, Combustible, and Flammable Liquids Code, i.e., a flammable liquid (Class I liquid) is any liquid that has a closed cup flash point below 37.8°C (100°F), as determined by the test procedures and apparatus set forth in ASTM D 323, Standard Test Method for Vapor Pressure of Petroleum Products (Reid Method) and a Reid vapor pressure that does not exceed an absolute pressure of 276kPa (40psi) at 37.8°C (100°F). Flammable liquids are further subclassified into the following three basic classes:

- *Class IA Liquid*—Any liquid that has a flash point below 22.8°C (73°F) and a boiling point below 37.8°C (100°F).
- *Class IB Liquid*—Any liquid that has a flash point below 22.8°C (73°F) and a boiling point at or above 37.8°C (100°F).
- *Class IC Liquid*—Any liquid that has a flash point at or above 22.8°C (73°F), but below 37.8°C (100°F).

4.9. COMBUSTIBLE

In a general sense any material that can ignite is considered combustible. This implies a lower degree of flammability, although there is no precise distinction between a material that is flammable and one that is combustible. NFPA 30, Combustible and Flammable Liquids Code, defines the difference between flammable liquids and combustible liquids based on flash point and vapor pressure. Under this code Class II and Class III liquids are defined as combustible as follows:

- *Class II Liquid*—Any liquid that has a flash point at or above 37.8°C (100°F) and below 60°C (140°F).
- *Class III Liquid*—Any liquid that has a flash point at or above 60°C (140°F).

Additionally, a Class III combustible liquid is further subdivided as follows:

- *Class IIIA Liquid*—Any liquid that has a flash point at or above 60°C (140°F), but below 93°C (200°F).
- *Class IIIB Liquid*—Any liquid that has a flash point at or above 93°C (200°F).

4.10. HEAT OF COMBUSTION

The heat of combustion of a fuel is defined as the amount of heat released when a unit quantity is oxidized completely to yield stable products.

4.10.1 Description of Some Common Hydrocarbons

4.10.1.1 Natural Gas

Naturally occurring mixtures of hydrocarbon gases and vapors, the more important of which are methane, ethane, propane, butane, pentane, and hexane. Natural gas is lighter than air, non-toxic, and contains no poisonous ingredients. Breathing natural gas is harmful when there is not an adequate supply of oxygen in the atmosphere.

4.10.1.2 Crude Oil

Crude oils consist primarily of hydrocarbons and compounds containing sulfur, nitrogen, oxygen, and trace metals as minor constituents. The physical and chemical characteristics of crude oil varies widely, depending on the percentages of the various compounds that are present. Its specific gravities cover a wide range, but most crude oils are between 0.80 and 0.98g/ml or gravity between 45° and 15° API. There is also a wide variation in viscosities, but most crude oils are in the range of 2.3–23 centistokes.

All crudes are a variation of the hydrocarbon base CH_2. The ultimate composition generally shows 84–86% carbon, 10–14% hydrogen, and small percentages of sulfur (0.06–2%), nitrogen (2%), and oxygen (01.–2%). The sulfur content is usually below 1.0% but may be as high as 5%. Physically crude oil may be water-white, clear yellowish, green, brown, or black, heavy and thick like tar or asphalt.

Because of the variations in the quality of crude oils, the flash point of any crude oil must be tested; however, because most crude oils contain a quantity of light vapors, they are considered in a low flash point classification, i.e., a flammable liquid. In atmospheric burning, heavy smoke production normally occurs.

4.10.1.3 Methane

Methane, also referred to as marsh gas, is composed of carbon and hydrogen with a chemical formula of CH_4. It is the simplest member of the paraffin or alkane series of hydrocarbons. It is lighter than air, colorless, odorless, tasteless, and is flammable. It occurs in natural gas and as a by-product of petroleum refining. In atmospheric burning no smoke production normally occurs. In air methane burns with a pale faintly luminous flame. With excess air carbon dioxide and water vapor is formed during combustion, with an air deficiency carbon monoxide and water is formed. It forms an explosive mixture with air over a moderate range. It is primarily used as a fuel and raw feedstock for petrochemical products.

Methane melts at −182.5°C (−296.5°F) and boils at −161.5°C (−258.7°F). Its fuel value is 995Btu per cubic ft.

4.10.1.4 LNG, Liquefied Natural Gas

Commercial liquefied natural gas (LNG) is composed of at least 99% methane (CH_4), that has been cooled to approximately −160°C (−256°F), at atmospheric pressure. At the temperature it occupies only 1/600 of its original volume. LNG is less than half as dense as water, is colorless, odorless, non-toxic, and sulfur free. It is vaporized as needed for use as a high-quality fuel. In atmospheric burning, no smoke production normally occurs.

4.10.1.5 Ethane

A gaseous paraffinic hydrocarbon with a chemical formula of CH_3, CH_3. It is colorless and odorless and normally is found in natural gas, usually in small proportions. It is slightly heavier than air and practically insoluble in water. When ignited in atmospheric burning, it produces a pale faintly luminous flame, with little or no smoke production. With excess air during combustion, it produces carbon dioxide and water. With limited air supplies, the combustion process will produce carbon monoxide and water. It forms an explosive mixture with air over a moderate range.

Ethane has a boiling point of −88°C (−126°F). The fuel value of ethane is 1730Btu per cubic ft.

4.10.1.6 Propane

Propane is a colorless, odorless gas of the alkane series of hydrocarbons with a chemical formula of C_3H_8. It occurs in crude oil, natural gas, and as a by-product of refinery cracking gas during petroleum refining. Propane does not react strongly at room temperature. It does react, however, with chlorine at room temperature if the mixture is exposed to light. At higher temperatures, propane burns in air, producing carbon dioxide and water as final products, and is valuable as a fuel. In atmospheric burning smoke production usually occurs.

About half of the propane produced annually in the US is used as a domestic and industrial fuel. When it is used as a fuel, propane is not separated from the related compounds of butane, ethane, and propylene. Butane with a boiling point of −0.5°C (31.1°F), however, reduces somewhat the rate of evaporation of the liquid mixture. Propane forms a solid hydrate at low temperatures, and this causes great concern and inconvenience when a blockage occurs in a natural gas line. Propane is also used as a so-called bottled gas, as a motor fuel, as a refrigerant, as a low-temperature solvent, and as a propylene and ethylene.

Propane melts at −189.9°C (−309.8°F) and boils at −42.1°C (−43.8°F).

4.10.1.7 Butane

Butane is ne of two saturated hydrocarbons, or alkanes, with the chemical formula C_4H_{10} of the paraffin series. In both compounds, the carbon atoms are joined in an open chain. In n-butane (normal), the chain is continuous and unbranched, whereas in i-butane (iso) the carbon atoms forms a side branch. This difference in structure results in small but distinct differences in properties. Thus, n-butane melts at −138.3°C (−216.9°F) and boils at −0.5°C (31.1°F), and i-butane melts at −145°C (−229°F) and boils at −10.2°C (13.6°F).

4.10.1.8 LPG, Liquefied Petroleum Gas

Commercial liquefied petroleum gas (LPG) is a mixture of the liquefied gases of propane and butane. It is obtained from natural gas or petroleum. LPG is liquefied for transport and then vaporized for use as heating fuel, engine fuel, or as a feedstock in the petrochemical or chemical industries. One volume of LPG liquid may vary from 2300 to 13,500 times the volume of gas in air. LPG vapor is an anesthetic and asphyxiant in high concentrations. LPGs are colorless, odorless, non-corrosive, and non-toxic. It has a low viscosity and therefore more likely to find a leakage path than other petroleum products. In the case of a leakage, it tends to spread on the surface accompanied by a visible fog of condensed water vapor, but the ignitable vapor mixture extends beyond the visible area.

4.10.1.9 Gasoline

Gasoline is a mixture of the lighter liquid hydrocarbons that distills within the range from 38 to 204°C (100–400°F). Commercial gasolines are a mixture of straight-run, cracked, reformed, and natural gasoline. It is produced by the factional distillation of petroleum, by condensation or adsorption from natural gas, by thermal or catalytic decomposition of petroleum or its fractions, the hydrogenation of producer gas, or by the polymerization of hydrocarbons of lower molecular weight.

Gasoline produced by the direct distillation of crude petroleum is known as straight-run gasoline. It is usually distilled continuously in a bubble tower that separates gasoline from the other fractions of the oil having higher boiling points, such as kerosene, fuel oil, lubricating oils, and grease. The range of temperatures in which gasoline boils and distills off is roughly between 38 and 205°C (100 and 400°F). The yield of gasoline from this process varies from 1 to 50%, depending on characteristics of the supplied crude oil. Straight-run gasoline now makes up only a small portion of gasoline production because of the superior merits of the various cracking processes. The flash point of gasoline is below −17.8°C (0°F), and at atmospheric burning smoke production normally occurs.

In some instances natural gas contains a percentage of natural gasoline that may be recovered by condensation of adsorption. The most common process for the extraction of natural gasoline includes passing the gas as it comes from the well through a series of towers containing light oil cased straw oil. The oil absorbs the gasoline, which is then distilled off. Other processes involve absorption of the gasoline on activated alumina, activated carbon, or silica gel.

High-grade gasoline can be produced by a process known as hydrofining, i.e., hydrogenation of refined petroleum oils under high pressure in the presence of a catalyst such as molybdenum oxide. Hydrofining not only converts oil of low value into gasoline of higher value but also at the same time purifies the gasoline chemically by removing undesirable elements such as sulfur. Producer gas, coal tar, and coal-tar distillates can also be hydrogenated to form gasoline.

4.10.1.10 Condensate

Condensate is normally considered the entrapped liquids in process or production gas streams due to temperature or pressure. They are typically in the range of C3, C4, C5, or heavier hydrocarbon liquids. It is also known as natural gasoline C5 plus and pentanes plus, and as a liquid at normal temperatures and pressure. It is normally condensed (i.e., by expansion and cooling of the gas) out of the process stream in primary separation processes where it is then sent to other refinery processes to further separate the condensate into its primary fractions, i.e., propane, butane, and liquid constituents.

The flash point of condensate is generally taken as that of hexane, where precise measurements have not been taken. Hexane has the lowest flash point of any material in the constitution of the condensate. In atmospheric burning smoke production normally occurs.

4.10.1.11 Gas and Fuel Oils

Gas oil and fuel oil is a generic term applied to petroleum distillates boiling between kerosene and lubricating oils. The name gas oil was originally derived from its initial use for making illuminating gas, but is now used as a burner fuel, diesel engine fuel, and catalytic cracker charge stock. Gas oils contain fuel oils such as kerosene, diesel fuels, gas turbine fuels, etc. In atmospheric burning smoke production normally occurs.

4.10.1.12 Kerosene

Kerosene, sometimes referred to as Fuel Oil #1, is a refined petroleum distillate. Kerosences usually have flash points within the range of 37.8 to 54.4°C (100–130°F). Therefore, unless heated, kerosene will usually not produce an ignitable mixture over its surface. In atmospheric burning smoke production normally occurs. It is commonly used as fuel and sometimes as a solvent. In some applications it is treated with sulfuric acid to reduce the content of aromatics, which burn with a smoky flame.

4.10.1.13 Diesel

Diesel is sometimes referred to as Fuel Oil #2 and is the fraction of petroleum that distills after kerosene, which is in the family of gas oils. Several grades of diesel are produced depending on the intended service. The combustion characteristics of diesel fuels are expressed in terms of a cetane number, which is a measure of ignition delay. A short ignition delay, i.e., the time between injection and ignition is desirable for a smooth running engine. Diesel fuel is typically assigned a flash point of between 38 and 71°C (100–160°F). In atmospheric burning smoke production normally occurs.

4.10.1.14 Fuel Oils #4, 5, and 6

These are fuels for low and medium speed engines or as a feedstock for catalytic cracking in the refinery process.

4.10.1.15 Lubricating Oils and Greases

Vacuum distillates or residual fraction of vacuum distillates are the main source of lubricating oils from the petroleum industry. Although they account for only 1% of the volume of petroleum fuel sales they are a high value unit. Besides lubrication they are used as heat transfer mediums, hydraulic fluids, corrosion protection, etc., in both industry and society.

Grease is a thick, oily, lubricating material that typically has a smooth, spongy, or buttery feel. Lubricating greases are made by thickening lubricating oils with soaps, clays, silica gel, or other thickening agents. Greases range from soft semi-fluids to hard solids, the hardness increasing as the content of the thickening agent increases. Greases are classified according to the type of thickener used, e.g., lithium, calcium, organic, etc., and their consistency.

4.10.1.16 Asphalt

Asphalt is a bituminous substance that is found in natural deposits or as the residual of petroleum or coal tar refining processes. It has a black or brownish-black color and pitchy luster. It is cement-like in nature, varying in consistency at room temperature from solid to semi-solid depending on the amount of light hydrocarbon fractions that have been removed. It can be poured when heated to the temperature of boiling water. The quality of asphalt is affected by the nature of the crude oil and the refining process. It is used in surfacing roads, in water retaining structures, such as reservoirs and swimming pools, and in roofing materials and floor tiles. Asphalt should not be confused with tar. Tar is a black fluid substance derived from coal. About 75% of US production of petroleum asphalt is used for paving while 15% is used for roofing. The remaining is utilized in more than 200 other applications.

There are two main hazards associated with asphalt: Fire and explosion hazards and health hazards associated with skin contact, eye contact, and/or inhalation of fumes and vapors. Most of the fire and explosion hazards associated with asphalt come from the vapors of the solvent mixed into the asphalt, not the asphalt itself. The hazard is determined by the flammable or explosive nature of the solvent used and how fast it evaporates. The flash point (FP) of the asphalt and solvent mix will be higher than the FP of the solvent alone. Asphalt is combustible, typically with a FP of 204–288°C (400–550°F). The flash point—and therefore, the fire or explosion hazard—can be determined, in part, by the type of asphalt used. There are three types of "cut" asphalts. Rapid-curing asphalt (RC) is blended asphalt that has been "cut" with a "low-flash" (highly flammable) petroleum solvent. This low-flash solvent quickly evaporates, allowing the "RC" mixture to rapidly set and harden. Examples of solvents commonly used in "RC" mixtures include: Benzene (FP=−11°C (12°F)), Dioxin (FP=27–32°C (81–90°F)), Naphtha (FP=42°C (107°F)), Toluene (FP=4°C (40°F)), and Xylene (FP=27–32°C (80–90°F)). Medium-curing asphalt (MC) is blended asphalt that has been "cut" with a solvent with a flash point over 170°F. Slow-curing asphalt (SC) is blended asphalt that has been "cut" with a low-flash oil having a flash point of over 121°C (250°F).

There are three other concerns that must be considered when handling asphalt:

- *Storage Temperature*—Asphalt should be stored sufficiently below its ignition temperature. This provides a safe margin for deviations of any measuring devices. Asphalt should be stored at least 30°C (86°F) under its flash point.

- *Self-Ignition in Insulation*—There is a risk of self-ignition if asphalt has leaked into insulation. Heating that leads to self-ignition on the surface of porous or fibrous material that has been impregnated with asphalt, or by condensed asphalt fumes, can occur at temperatures below 100°C (212°F).
- *Pyrophoric Concerns*—Carbon deposits, which can be pyrophoric, may develop on walls and roofs of asphalt storage tanks. In the presence of oxygen, these might develop a risk of self-ignition.

Asphalt fires must be extinguished by smothering, so that the continued supply of oxygen can be prevented. Small fires can be put out with a blanket of foam, dry powder, or carbon dioxide extinguishers. Large fires are extinguished preferably by using foam or dry powder extinguishers but there is a danger of fires flaring up again. Foam and powder do not provide a lasting oxygen-free atmosphere in bitumen fires. Fires in tank or pipe insulation can be put out using steam from a spray unit or a dry-powder extinguisher. A fire may restart again when oxygen gets access, unless the temperature is well below 100°C (212°F).

4.10.1.17 Wax

The word "wax" usually refers to a variety of organic substances that are solid at ambient temperature but become free-flowing liquids at slightly higher temperatures. The chemical composition of waxes is complex, but normal alkanes are always present in high proportion and molecular weight profiles tend to be wide. Paraffin wax is a mixture of saturated hydrocarbons of higher molecular mass, produced during the refining of petroleum. The main commercial source of wax is crude oil but not all crude oil refiners produce wax. Natural petroleum waxes may occur during the production of some hydrocarbon reservoirs containing heavy oils. It consists of a mixture of hydrocarbon molecules containing between 20 and 40 carbon atoms. "Mineral" wax can also be produced from lignite. Plants, animals, and even insects produce materials sold in commerce as "wax."

Wax is typically a soft impressionable semi-solid material having a dull luster and somewhat soapy or greasy texture. It softens gradually upon heating, going through a soft malleable state before ultimately forming a liquid. It is solid at room temperature and begins to melt above approximately 37°C (99°F); its boiling point is >370°C (698°F). It may burn, but will not ignite readily. Chlorinated paraffin waxes have come into considerable use because of their fire resistant properties.

4.10.2 Description of Common Petrochemicals Used in the Petrochemical Industry

4.10.2.1 Aromatics

A basic chemical hydrocarbon based on a single or multiple benzene rings (C_6H_6). Some of the more common aromatics include benzene, toluene, xylene, and phenol. They exhibit a somewhat sweet, yet sickly odor. The term "aromatic" was assigned before the physical mechanism determining aromaticity was discovered, and was derived from the fact that many of the compounds have a sweet scent. They will burn with a sooty yellow flame because of the high carbon-hydrogen ratio.

4.10.2.2 Olefins/Alkenes

A basic chemical hydrocarbon such as ethylene, containing one or more pairs of carbon atoms linked by a double bond. Olefins, which might be considered an archaic synonym that is widely used in the petrochemical industry, are also referred to as alkenes. The two most important alkenes/olefins are ethylene and propylene, as they form the backbone of the petrochemicals market. The highly reactive double bond makes the olefin molecule ideal for conversion to many useful end products. The majority of olefins' capacity is consumed in the production of polymers used for plastics (i.e., polyethylene and polypropylene). Ethylene dichloride, ethylene oxide, propylene oxide, oxo alcohol, polystyrene, and acrylonitrile are other important olefins-based petrochemicals.

Today, the majority of ethylene is produced by thermal cracking of hydrocarbon feedstocks ranging from ethane to heavy vacuum gas oils. Over 60% of the world's propylene is produced as a by-product of thermal cracking, with the balance being supplied from refinery sources and others. Raw materials are mostly natural gas condensate components (principally ethane and propane) in the US and Mideast and naphtha in Europe and Asia. Alkanes/olefins are broken apart at high temperatures, often in the presence of a zeolite catalyst, to produce a mixture of primarily aliphatic alkenes and lower molecular weight alkanes. The mixture is feedstock and temperature dependent and separated by fractional distillation.

Related to this is catalytic dehydrogenation, where an alkane loses hydrogen at high temperatures to produce a corresponding alkene. This is the reverse of the catalytic hydrogenation of alkenes. This process is also known as reforming. Both processes are endothermic and are driven toward the alkene at high temperatures by entropy. Catalytic synthesis of higher α-alkenes (of the type $RCH{=}CH_2$) can also be achieved by a reaction of ethylene with the organometallic compound triethylaluminium in the presence of nickel, cobalt, or platinum (see Table 4.4).

4.10.2.3 Chemical Compound Concerns

Essentially all materials are unstable above certain temperatures and will thermally decompose. Thermal decompositions may be exothermic or endothermic. Exothermic decompositions are usually irreversible and frequently explosive. Organic compounds that are known to decompose before melting include azides, diazo compounds, nitramines, oxygen-containing salts, and metal styphnates.

Decomposition characteristics of energetic materials can be significantly different from those of the same chemical when combined with a solvent, and different solvents may have different effects on the decomposition temperature and rate. Solids that decompose without melting usually generate gaseous products. Particle size and aging affect the decomposition rate. Age may result in crystallization of the solid surface.

Endothermic decompositions are usually reversible and are typified by hydrate, hydroxide, and carbonate decompositions. For example, a substance may have several hydrates depending on the partial pressure of water vapor. Ferric chloride, FeCl2, combines with 4, 5, 7, or 12 molecules of water. The dehydration activation energy is nearly the same as the reaction enthalpy.

Oxygen balance is an analytic tool based on the difference between the oxygen content of the chemical compound and that required to fully oxidize the elements of the compound. Materials and processes approaching zero oxygen balance have the greatest heat release potential and are the most energetic. Oxygen balance calculations may be used for organic nitrates and nitro compounds. There is no correlation between oxygen balance and general self-reactivity. Improper application of the oxygen balance criterion can result in incorrect hazard classifications.

A current analytic tool used to determine the maximum enthalpy of decomposition is the ASTM Computer Program for Chemical Thermodynamics and Energy Release Evaluation (CHETAH). It is based on molecular structure-reactivity relationships. Currently it can only predict the reactivity of organic compounds only, not inorganic compounds.

A substance should be considered energetic and potentially hazardous if any of the theoretical methods indicate hazardous thermal properties or if the experimental enthalpy of decomposition in the absence of oxygen is over 50–70cal/g (~200–300J/g). Note that this range is highly dependent

Table 4.4 Characteristics of Selected Common Hydrocarbons

Substance	Formula	Boiling Point (°C)	Vapor Density Ratio	Specific Gravity	Flash Point (°C)	LEL (%)	UEL (%)	AIT (°C)
Alkanes								
Methane	CH_4	−162	0.6	–	Gas	5.3	15.0	537
Ethane	C_2H_6	−89	1.0	–	Gas	3.0	12.5	472
Propane	C_3H_8	−42	1.6	–	Gas	3.7	9.5	450
n-Butane	C_4H_{10}	−1	2.0	0.6	−60	1.9	8.4	287
i-Butane	C_4H_{10}	−12	2.0	0.6	Gas	1.8	8.4	462
n-Pentane	C_5H_{12}	36	2.5	0.9	−40	1.4	7.8	260
i-Pentane	C_5H_{10}	36	2.5	0.6	−51	1.4	7.6	420
n-Hexane	C_6H_{14}	69	3.0	0.7	−22	1.2	7.4	225
i-Hexane	C_6H_{14}	57–61	3.0	0.7	−29	1.0	7.0	–
n-Heptane	C_7H_{16}	98	3.5	0.7	−4	1.2	6.7	204
i-Heptane	C_7H_{16}	90	3.5	0.7	−18	1.0	6.0	–
n-Octane	C_8H_{18}	126	3.9	0.7	13	0.8	3.2	206
n-Nonane	C_8H_{20}	151	4.4	0.7	31	0.7	2.9	205
n-Decane	$C_{10}H_{22}$	174	4.9	0.7	46	0.6	5.4	201
n-Undecane	$C_{11}H_{24}$	196	5.4	0.7	65	0.7	6.5	240
n-Dodecane	$C_{12}H_{26}$	216	5.9	0.8	74	0.6	12.3	203
Kerosene	$C_{14}H_{30}$	151	4.5	0.8	49	0.6	5.6	260
Alkenes								
Ethylene	C_2H_4	−104	1.0	–	Gas	2.7	28.6	450
Propylene	C_3H_6	−47	1.5	–	Gas	2.1	11.1	455
i-Butene	C_4H_8	−6	1.9	–	Gas	1.6	9.9	385

i-Pentene	C_5H_{10}	30	2.4	0.7	−18	1.5	8.7	275
Hexene	C_6H_{12}	63	3.0	0.7	−9	1.2	6.9	253
Cycloparaffins								
Cyclopropane	C_3H_6	−34	1.5	–	Gas	2.4	10.4	498
Cyclobutane	C_4H_8	13	1.9	–	Gas	1.1	–	210
Cyclopentane	C_5H_{10}	49	2.4	0.7	−7	1.1	9.4	361
Cyclohexane	C_6H_{12}	82	2.9	0.7	−20	1.3	7.8	245
Cycloheptane	C_7H_{14}	119	3.4	0.8	6	1.2	–	–
Aromatics								
Benzene	C_6H_6	80	2.8	0.9	−11	1.2	7.1	498
Toluene	C_7H_8	111	3.1	0.9	4	1.3	6.8	480
m-Xylene	$C_6H_4(CH_3)_2$	139	3.7	0.9	27	1.1	7.0	528
o-Xylene	$C_6H_4(CH_3)_2$	144	3.7	0.9	32	1.0	6.0	464
p-Xylene	$C_6H_4(CH_3)_2$	138	3.7	0.9	27	1.1	7.0	529
Biphenyl	$(C_6H_5)_2$	254	5.3	1.0	113	0.6	5.8	540
Napthalene	$C_{10}H_8$	218	4.4	1.1	79	0.9	5.9	526
Athracene	$C_{13}H_{10}$	340	6.2	1.2	121	0.6	–	540
Ethylbenzene	C_8H_{10}	136	3.7	0.9	21	1.0	–	432
Buthybezene	$C_{10}H_{14}$	180	4.6	0.9	71	0.8	5.9	410

on the process conditions and does not pertain to substances that produce significant quantities of gas.

A substance should be considered as having deflagration potential if the experimental enthalpy of decomposition in the absence of oxygen is greater than 250cal/g (~1000J/g). A substance should be considered as having detonation potential if the experimental enthalpy of decomposition in the absence of oxygen is greater than 700cal/g (2900–3000J/g).

The calculated adiabatic reaction temperature (CART) also provides some indication of a compound's potential hazard. Known explosive compounds have CART values higher than 1500K.

Enthalpy of Decomposition, CART values, and Relative Hazard Rankings for Selected Chemical Compounds are provided in Table 4.5.

Table 4.5 Enthalpy of Decomposition, CART Values, and Relative Hazard Rankings for Selected Chemical Compounds

Compound	Formula	ΔHr (kJ/g)	CART (K)	Hazard Index*
Acetone	C_3H_6O	−1.72	706	N
Acetylene	C_2H_2	−10.13	2824	E
Acrylic acid	$C_3H_4O_2$	−2.18	789	N
Ammonia	NH_3	2.72	–	N
Benzoyl peroxide	$C_{14}H_{10}O_4$	−0.70	972	E
Dinitrotoluene	$C_7H_6N_2O_4$	−5.27	1511	E
Di-t-butyl peroxide	$C_8H_{18}O_2$	−0.65	847	E
Ethyl ether	$C_4H_{10}O$	−1.92	723	N
Ethyl hydroperoxide	$C_2H_5O_2$	−1.38	1058	E
Ethylene	C_2H_4	−4.18	1253	N
Ethylene oxide	C_2H_4O	−2.59	1009	N
Furan	C_4H_4O	−3.60	995	N
Maleic anhydride	$C_4H_2O_3$	−2.43	901	N
Mercury fulminate	$Hg(ONC)_2$	−2.09	5300	E
Methane	CH_4	0.00	298	N
Mononitrotoluene	$C_7H_7NO_2$	−4.23	104	N
Nitrogen trichloride	NCL_3	−1.92	1930	E
Nitroguanidine	$CH_4N_4O_2$	−3.77	1840	E
Octane	C_8H_{18}	−1.13	552	N
Phthalic anhydride	$C_8H_4O_3$	−1.80	933	N
RDX	$C_3H_6N_6O_6$	−6.78	2935	E
Silver azide	AgN_3	−2.05	>4000	E
Trinitrotoluene	$C_7H_5N_3O_6$	−5.73	2066	E
Toluene	C_7H_8	−2.18	810	N

Hazard Index (*Note:* See Ref. [8] of this chapter):
N-No known unconfined explosion hazard.
E-Unconfined explosion hazard.

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CHAPTER 5

Characteristics of Hazardous Material Releases, Fires, and Explosions

Petroleum (oil and gas) is a highly dangerous commodity that should be recognized for its hazards and handled with the proper precautions. The ignition of combustible gas clouds or vapors can produce highly damaging explosions with high temperature fires. These events can completely destroy an entire installation within few minutes if allowed to develop or left uncontrolled. Ordinary wood and combustibles burn with a relatively gradual increase in temperature to a relatively moderate level, while hydrocarbon fires immediately reach a high temperature within minutes and continue at this level, until exhausted or suppressed. By comparison to ordinary combustible fires, hydrocarbon fires are a magnitude greater in intensity. Fire barriers or suppression mechanisms adequate for ordinary fires are quite easily overtaxed when a high intensity hydrocarbon fire is prevalent.

The most destructive incidents in the petroleum and related industries are usually initiated by an explosive blast that can damage and destroy unprotected facilities. These blasts have been commonly equated with the force of a TNT explosion and are quite literally like a "bomb." The protection of hydrocarbon and chemical industries is in a rather unique discipline by itself, which requires specialized techniques of mitigation and protection in a systems based approach. The first step in this process is to understand the characteristic of hydrocarbon releases, fires, and explosions.

There is a great degree of variation in the degree of intensity that can be experienced in hydrocarbon fires. This is due to the variation in the properties of the hydrocarbon materials involved in the industry.

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Open fires of any kind generally involve flame and combustion products that flow upwards. Where less volatile materials (i.e., liquids) are involved, they may tend to accumulate at the ground in "pools" of liquid. The more volatile the material becomes from heat effects, uncontained pressure releases, or other factors, the more the fire will burn with flames rising to higher elevations, with less tendency to burn at the point of origin. They may be localized effects that determine the shape and configuration of the upward flames and products of combustion.

Localized failures of pressurized piping, process pumps, compressors, vessels, or other parts of the process containing combustible materials under pressure will cause a "torch" or "jet" fire. These fires may project flames in any direction, for a considerable distance, depending on the contained pressures and volumes at the source. Any facility that retains large amounts of high pressure combustible liquids or gases can produce jet flames for extended periods if adequate isolation and depressurization capability is not available. The worst offenders, most known by the public, are typically wellheads, high pressure gas pipelines, and storage facilities.

5.1. HAZARDOUS MATERIAL RELEASES

Hazardous material releases in the process industries are either gaseous, mists, or liquids and are either atmospheric releases or from contained pressurized process systems. Gas and mist releases are considered more significant since if combustible, they are readily ignitable since they are in the gas state and due to the generation of vapor clouds, which if ignited, are instantly destructive in a widespread nature. This is in contrast to liquid fires that may be less prone to ignition, generally localized, and relatively controllable.

The cause of a release can be external or internal corrosion, internal erosion, equipment wear, metallurgical defects, operator errors, third-party damages, or in some cases may have been for operational requirements.

Generally the physical release openings can be categorized as follows:

- **Catastrophic Failure**—A vessel or tank opens completely immediately releasing its contents. The amount of release is dependent on the size of the container (e.g., a long tank welded seam split).
- **Long Rupture**—A section of pipe is removed leading to two sources of material release. Each section being an opening whose cross-sectional areas are equal to the cross-sectional area of the pipe (e.g., pipeline external impact and a section is removed).

- **Open Pipe**—The end of a pipe is fully opened, exposing the cross-sectional area of the pipe (e.g., a drilling blow-out).
- **Short Rupture**—A split occurs on the side of a pipe or hose. The cross-sectional area of the opening will typically be about equal to the cross-sectional area of the pipe or hose (e.g., pipe seam split from "hydrogen induced cracking" effect).
- **Leak**—Leaks are typically developed from valve or pump seal packing failures, localized corrosion or erosion effects, and are typically "small" to "pin-hole" sized (e.g., corrosion or erosion).
- **Vents, Drains, Gauge, or Sample Port Failures**—Small diameter piping or valves may be opened or fail which releases vapors or liquids to the environment unexpectedly (e.g., level gauge sight glass breaks).
- **Normal Operational Releases**—Process storage or sewer vents, relief valve outlets, tank seals, flare, and burn pit disposal systems, which are considered normal and accepted releases to the atmosphere.

5.2. GASEOUS RELEASES

There are a number of factors that determine the release rate and initial geometry of a hydrocarbon gas release. The most significant is whether the gas is under pressure or released at atmospheric conditions. Depending on the release source the escaping gas can last from several minutes, hours, or days, until the supply is isolated, depleted, or fully depressurized, and routed for safe disposal. Common long duration sources are underground reservoirs (e.g., blow-outs), long pipelines without intermediate isolation capabilities, large volume process vessels, and process systems that contain large inventories without segmented isolation capabilities.

If released under atmospheric conditions, the gas will either rise or fall depending on its vapor density and will be carried into the path of the prevailing wind (if existent at the time). The vapor density for most common petroleum and chemical materials is greater than 1 and therefore they will not readily rise and dissipate. In the absence of wind, heavier gases will collect in low points in the terrain or will not dissipate from congested areas. These atmospheric releases, if ignited, will burn relatively close to the source point, normally in a vertical position with flames of short length. For the lighter gases, the height of a gas plume will mostly be limited by atmospheric conditions, such as ambient wind speed. If gases are ignited, the height of the plume will rise due to the increased buoyancy of the high temperature gases from the combustion process.

For gas releases under pressure, there are a number of determining factors that influence the release rates and initial geometry of the escaping gases. The pressurized gas is released as a gas jet and depending on the nature of the failure, may be directed in any direction. For piping systems, the release is usually perpendicular to the pipe. All or part of the gas may be deflected by surrounding structures or equipment.

If adequate isolation capabilities are available and employed in a timely fashion, the initial release will be characterized by high flow and momentum that decreases as isolation is applied or supplies are exhausted. Within a few pipe diameters from the release point, the released gas, pressure decreases. Escaping gases are normally very turbulent and air will immediately be drawn into the mixture. The mixing of air will also reduce the velocity of the escaping gas jet. Obstacles such as overhead platforms, pipe racks, structures, etc., will disrupt momentum forces of any pressurized release. These releases if not ignited will then generally form a vapor cloud that would naturally disperse in the atmosphere or if later then ignited, cause an explosive blast if the cloud is in a relatively confined area. Where turbulent dispersion processes are prevalent (e.g., high pressure flow, winds, congestion, etc.) the gas will spread in both horizontal and vertical dimensions while continually mixing with available oxygen in the air. Initially, escaping gases are above the UEL, but with dispersion and turbulence effects, they will rapidly pass into the flammable limits. If not ignited and given an adequate distance for dilution by the environment, they will eventually disperse below the LEL. Various computer software programs are currently available that can calculate the turbulent gaseous jet dispersion, downwind explosive atmospheric locations, and volumes for any given flammable commodity, release rates, and atmospheric date input (i.e., wind direction and speed).

5.2.1 Mists or Spray Releases

Spray or mists releases generally behave like a gas or vapor release. The fuel is highly atomized and mixed with air. Sprays or mists can be easily ignited, even below their flash point temperature of the material involved since mixing of the small particles of fuel with the air is occurring.

5.2.2 Liquid Releases

Liquid releases can be characterized by being contained, allowed to runoff, or spread to a lower surface elevation. If they are highly volatile, dissipation by vaporization may occur when the vaporization rate equals the spread rate. Depending on the viscosity of non-volatile liquids, they will spread out immediately and form into a "pool" of liquid that is somewhat localized to the immediate area. The higher the viscosity, the longer time it will take to spread. As a general estimate, 3.81 (1 gallon) of an unconfined liquid on a level surface will cover approximately 1.8 square meters (20 sq.ft.), regardless of viscosity. A pool on calm water will spread under the influence of gravity until limited by surface tension, typically giving a minimum oil slick thickness of 10 mm (0.04 in.) on the water. A pool on the water will also drift in the direction of the wind and current. If no ignition occurs, the lighter ends will evaporate and eventually the residual oil will be broken up by wave action and bacteriological digestion. During the evaporation of the lighter fractions, combustible vapors may form immediately above the oil spill for a short distance.

Liquids under pressure (pipeline leaks, pump seal failures, vessel ruptures, etc.) will be thrown some distance from the point source, while atmospheric leakages will emit at the point of release. The other characteristic of liquid releases is their flash points. High point liquids, not contained above their flash point temperatures, are inherently safer than low flash point liquids. Most liquid fires are relatively easy to contain and suppress, while gas fires are prone to explosion possibilities if extinguished and source points are not isolated.

Liquid releases are characterized by the following features:

- **Leaks and Drips**—Leaks and drips are characterized by small diameter releases of high frequencies. They are typically caused by corrosion and erosion failures of piping, mechanical and maintenance failures of gaskets and valves.
- **Streams**—Medium sized releases of moderate to low frequencies. Typically small diameter pipe openings that have not been adequately closed, e.g., sample or drain lines.
- **Sprays or Mists**—Medium sized releases of moderate frequencies that are mixed immediately into the air upon release. Typically pipe gasket, pump seal, and valve stem packing failures under high pressure. On occasion release from flare stacks.
- **Ruptures**—Large releases of very low frequencies. Typically vessel, tank, pipeline, or hose failures from internal, external, or third-party sources and fire conditions (i.e., BLEVE conditions).
- **Unintentional Operations Release**—Human error actions by operators that occur with low frequencies. Unusual releases that typically occur during non-routine activities.

5.3. NATURE AND CHEMISTRY OF HYDROCARBON COMBUSTION

Simple hydrocarbon fires combine with oxygen to produce carbon and water through a combustion process. Combustion is a chemical process of rapid oxidation or burning of a fuel with simultaneous evolution of radiation energy, usually heat and light. In the case of common fuels, the process is one of chemical combination with atmospheric oxygen to produce as the principle products carbon dioxide, carbon monoxide, and water. Hydrocarbons are freely burning and generally easily ignitable in open air situations.

The energy released by the combustion causes a rise in temperature of the products of combustion. The temperature attained depends on the rate of release, dissipations of the energy, and quantity of combustion products. As air is the most convenient source of oxygen, and because air is three-quarters nitrogen by weight, nitrogen becomes a major constituent of the products of combustion, and the rise in temperature is substantially less than if pure oxygen is used. Theoretically, in any combustion, a minimum ratio of air to fuel is required for complete combustion. The combustion, however, can be made more readily complete, and the energy released maximized, by increasing the amount of air. An excess of air, however, reduces the ultimate temperature of the products and the amount of released energy. Therefore, an optimum air-to-fuel ratio can usually be determined, depending on the rate and extent of combustion and final temperature desired. Air with enriched oxygen content or pure oxygen, as in the case of an oxyacetylene torch, will produce a high temperature. The rate of combustion may be increased by finely dividing the fuel to increase the surface area and hence its rate of reaction and by mixing it with the air to provide the necessary amount of oxygen to the fuel.

Hydrocarbon materials must be first in a vapor condition before combustion processes can occur. For any gaseous material this is an inherent property. Liquids, however, must have significant vapor emissions in order for flammable concentrations to be present for combustion processes to occur. Therefore, hydrocarbon liquid releases are relatively less dangerous than gaseous releases.

Gases by their nature are immediately ignitable (versus liquids that must be vaporized to support combustion) and can produce a fast burning flame front that generates into an explosive force in confined areas. If pressurized gas leak fires are extinguished, but the leakage is not stopped, the vapors can again be re-ignited and produce an explosive blast.

When an ignition source is brought into contact with a flammable gas or a mixture of gases, a combustion chemical reaction will occur at the point of introduction, provided an oxidizer is present, normally oxygen. The combustion components are commonly graphically referred to as a simple fire triangle, fire tetrahedron, or fire square.

Combustion will occur that travels from the point of origin throughout the body of the gas and air mixture. Combustion continues until the fuel is exhausted if sufficient air (i.e., oxygen) is available or until a suppression mechanism interrupts the process.

The basic equation for the chemical reaction of hydrocarbon molecules in ideal combustion is provided by the following:

$$CH_4 + 2O_2 = CO_2 + 2(H_2O)$$

In ideal combustion, 0.45 kg (1 lb.) of air combines with 1.8 kg (4 lbs.) of oxygen to produce 1.2 kg (2.75 kg) of carbon dioxide and 1.02 kg of (2.25 lbs.) of water vapor. Carbon monoxide, carbon dioxide, nitrogen, and water vapor are the typical exhaust gases of ordinary combustion processes. If other materials are present they will also contribute to the exhaust gases forming other compounds, which in some cases can be highly toxic. Imperfect combustion will occur during accidental fires and explosion incidents. This is mainly due to turbulence, lack of adequate oxidizer supplies, and other factors that produce free carbon (i.e., smoke) particles, carbon monoxide, etc.

The combustion process is accompanied by the evolution of radiation—heat and light. A typical liquid hydrocarbon combustion process produces approximately 15 kg (33 lbs.) of combustion products per kilogram (2.2 lbs.) of hydrocarbon consumed. Because of the high proportion of nitrogen in the atmosphere (approximately 78% by weight), nitrogen tends to dominate in combustion exhaust products (it is mixed in during the free air combustion process). Because of this, it is sometimes used as the main constituent in fire mass release dispersion modeling. The mass flow rate is normally taken as 15 times the burning rate of the hydrocarbon material. A typical fuel burning rate for liquid hydrocarbon is 0.08 kg/sq.m/s (0.0164 lbs./sq.ft./s).

Depending on the fuel involved, a specific amount of heat (i.e., calories or Btu) is released. Ordinary combustibles produce a moderate level of heat release, but hydrocarbon molecules have a very high level of heat release. In ideal combustion of 0.45 kg (1 lb.) of methane, approximately 25,157 kJ

(23,850 Btu) are released. The temperature of the combustion products is normally taken to be 1200°C (2192°F), which is a typical hydrocarbon fire temperature. Steel often melts at around 1370°C (2500°F), but loses its strength capability much earlier, which is why hydrocarbon fires are so destructive to industrial processes.

A heat flux rate is commonly specified during consequent modeling of hydrocarbon fires. Heat flux is considered the more appropriate measure by which to examine the radiation effects from a fire. A radiant heat flux of 4.7 kw/m$_2$ (1469 Btu/ft.$_2$) will cause pain on exposed skin, a flux density of 12.6 kw/m$_2$ (3938 Btu/ft.$_2$), or more may cause secondary fires and a flux density of 37.8 kw/m$_2$ (11,813 Btu/ft.$_2$) will cause major damage to a process plant and storage tanks.

Under atmospheric conditions flame travel in an unconfined vapor cloud precedes as a definite flame front at a determinable velocity. For example, where the ignition point is located in the middle of a volume of gas, the flame front tends to generally proceed as an expanding sphere from the point of origin. Flame propagation results from the conduction transfer of energy from the flame front to the layer of gases in front of it. These gases are in turn ignited, which continues the process. In mixtures that contain the fuel and oxidizer in proportions outside the LEL/UEL, insufficient heat energy is released by combustion heat to the adjacent layers of gases to produce sustained combustion. When the combustion is within the LEL/UEL limits, flame propagation appears most rapid in an upward direction, which is chiefly due to convection flames carried upwards, while burning in the horizontal direction is relatively slower.

In normal atmospheric conditions, fire is initiated by a combustible material coming into contact with a heat source. The spread of fire occurs due to direct flame impingement of the transfer of heat to the surrounding combustible materials. Heat transfer occurs by three principle mechanisms—conduction, convection, and radiation. Conduction is the movement of heat through a stationary medium, such as solids, liquids, or gases. Steel is a good conductor of heat as is aluminum, therefore they can pass the heat of fire if left unprotected.

Convection signifies the transfer of heat from one location to another by a carrier medium moving between them, such as when a gas is heated at one point and travels to another point at which it gives up its heat. Convection currents of heated hot air and gases normally amount for 75–85% of the heat generated from a fire. Large masses of heat air by flame convection currents will quickly raise the temperature of all combustible materials in their path to the required ignition temperature. Where prevented from rising due to structural barriers such as ceilings, decks, etc., the fire will spread out laterally and form a heat layer with increasing depth and intensity as the fire progresses. Within enclosed spaces the ambient conditions soon are raised to temperatures above the ignition point and combustion occurs simultaneously everywhere, which is known as a flashover.

Radiation is the transfer of energy by electromagnetic waves and can be compared to the transmission of light through the atmosphere. When radiation waves meet an object, their energy is absorbed by that object at its surface. The rate of heat transfer by conduction is proportional to the temperature difference between the point giving up the heat and receiving the heat. In convection, the rate of heat transfer is dependent upon the rate of movement of the carrier medium. The movement may be caused by differences in density of the material or due to mechanical pumping (e.g., hot air blowing system). In the radiation of heat, the transfer rate is approximately proportional to the fourth power of the temperature difference between the radiating source and the receiver. Thus the radiant heat transmission from fires is a high factor to consider for any fire incident. This is why high importance is placed on cooling exposed surfaces of processes, storage tanks and vessels, and preservation of structural support by fireproofing materials.

If a hydrocarbon release is ignited, various possible fire and explosion events may result. The events are primarily dependent on the type of material, the rate of release, the item at which it is ignited, and the nature of the surrounding environment.

5.3.1 Hydrocarbon Fires

Typical process industry hydrocarbon fire events can be categorized as follows.

5.3.1.1 Jet Fire

Most fires involving gas in the oil and gas industry will be associated with a high pressure and labeled as "jet" fires. A jet fire is a pressurized stream of combustible gas or atomized liquid (such as a high pressure release from a gas pipe or wellhead blow-out event) that is burning. If such a release is ignited soon after it occurs, the result is an intense jet flame. This jet fire stabilizes to a point that is close to the source of the release, until the release is stopped. A jet fire is usually much localized, but very destructive to anything close to it. This is partly because as well as producing thermal radiation, the jet fire causes considerable convective heating in the region beyond the tip of the flame. The high velocity of the escaping gas entrains air into the gas "jet" causing more efficient combustion to occur than in pool fires. Consequentially, a much higher heat transfer rate occurs to any object immersed in the flame, i.e., over 200 kw/sq.m (62,500 Btu/sq.ft.) for a jet fire than a pool fire flame. Typically the first 10% of a jet fire length is conservatively considered un-ignited gas as a result of the exit velocity causing the flame to lift off the gas point of release. This effect has been measured on hydrocarbon facility flares at 20% of the jet length, but a value of 10% is used to account for the extra turbulence around the edges of a real release point as compared to the smooth gas release from a flare tip. Jet flames have a relatively cool core near the source. The greatest heat flux usually occurs at impingement distances beyond 40% of the flame length, from its source. The greatest heat flux is not necessarily on the directly impinged side. The most likely location for jet fires to occur in a plant are at flanges on large-sized pipe headers containing high pressure combustible gas. The number of these flanges should be minimized and kept distant from process equipment. The most likely area in the plant to experience a jet fire is the pipeline scraper receiver/launcher areas.

5.3.1.2 Pool Fire

Pool fires have some of the characteristics of vertical jet fires, but their convective heating is much less. Heat transfer to objects impinged or engulfed by pool fires is both by convection and radiation. Once a pool of liquid is ignited, gas evaporates rapidly from the pool as it is heated by the radiation and convective heat of the flame. This heating mechanism creates a feedback loop whereby more gas is vaporized from the surface of the liquid pool. The surface fire area increases in size rapidly in a continuing process of radiation and convective heating to the surrounding area until essentially the entire surface of the combustible liquid is on fire. The consequences of a pool fire are represented numerically by a flame zone surrounded by envelopes of different thermal radiation levels. Heat transfer rates to any equipment or structure in the flame will be in the range of 30–50 kw/sq/m (9375–15,625 Btu/sq.ft.).

5.3.1.3 Flash Fire

If a combustible gas release is not ignited immediately, a vapor plume will form. This will drift and be dispersed by the ambient winds or natural ventilation. If the gas is ignited at this point, but does not explode (because of lack of confinement), it will result in a flash fire, in which the entire gas cloud burns very rapidly. It is generally unlikely to cause any immediate fatalities, but will damage structures. If the gas release has not been isolated during this time, the flash fire will burn back to a jet fire at the point of release. A flash fire is represented by its limiting envelope, since no damage is caused beyond it. This envelope is usually taken as the LEL of the gas cloud.

The process plant and pipework have a much broader spectrum of response to fires than structures. The performance ranges from simple sagging of a dry pipe to possible catastrophic explosion of a pressure vessel or a hydrocarbon-transporting pipe. The resistance of pipework to fire loadings is extremely variable.

The main considerations are:

- *Insulation*—If a process line is partially or completely insulated for process reasons, it may perform well under fire loads, but some lagging materials are unlikely to be effective in a fire.
- The size of the pipework.
- *Material of construction*—The prime material types are carbon steel, lined carbon steel, stainless steel, and Kunifer. These materials have different elevated temperature characteristics, and will behave differently under fire loading conditions. The material properties will be linked to a function of the pipe itself and so evaluation should be carried out on a system-by-system basis.
- *Contents and Flow Rate*—The normal contents of the pipe will need to be considered. The internal pipe fluid will be able to remove local heating at a rate which will be determined by the properties of the fluid itself and the fluid flow rate. Gases will have little cooling effect, while water will give considerable assistance.

The main acceptance criteria for piping systems may be categorized under three broad categories, also used for structural components: strength limit, strain limit, and deformation limit, maintenance of structure, and insulation integrity.

Mathematical estimates are available that can calculate the flame and heat effects (i.e., size, rate, and duration) of pool, jet, and flash hydrocarbon fires. These estimates are based on the "assumed" parameters or estimates of the material's release rate from a potential incident. The ambient wind speed also has a varying influence on the size of the vapor release coverage that will occur. Some modeling prepares estimates for small, medium, and large releases for comparative analysis with varying wind conditions (i.e., direction and speed). The latest innovation is to utilize these computer applications (i.e., vapor cloud release impacts) in real-time at an emergency control center, during an incident, to assist in management emergency response activities. The estimated result is calculated with real-time weather input and displayed on a large wall video display, from point of release on a plot plan of the facility, to realize actual impacts to all involved in the emergency management activities.

All hydrocarbon fire mechanisms and estimates will be affected to some extent by flame stability features such as varying fuel composition as lighter constituents are consumed, available ambient oxygen supplies, ventilation parameters, and wind effects. Studies and experimental tests are ongoing by some research institutes and industries to provide more precise modeling techniques into the release of gas, its dispersion, fire, and explosion effects.

5.3.1.4 Nature of Hydrocarbon Explosions

A combustible vapor explodes under a very specific set of conditions. There are two explosive mechanisms that need to be considered when evaluating combustible vapor incidents—detonations and deflagrations. A detonation is a shock reaction where the flames travel at supersonic speeds (i.e., faster than sound). Deflagrations are where the flames are traveling at subsonic speeds.

During the 1970s considerable progress was made in the understanding of supersonic explosions, i.e., detonations. It was shown that the conditions needed to initiate a detonation—whether by shock, flame jet ignition, or flame acceleration—are too extreme to occur in everyday operations for all non-pressurized natural gas and air systems. However, they can still occur in pressurized gas and air systems (i.e., process vessels and piping systems). It is generally recognized that vapor cloud explosions have flames that travel at subsonic speeds and are therefore technically classified as deflagrations but are still commonly referred to as explosions.

5.3.1.5 Process System Explosions (Detonations)

Detonations can occur in solids (e.g., dusts) and liquids but are particularly frequent in petroleum facilities in mixtures of hydrocarbon vapors with air or oxygen. Detonations will develop more rapidly at initial pressures above ambient atmospheric pressure. If the initial pressure is high, the detonation pressure will be more severe and destructive.

Detonations can produce higher pressures than what would be considered ordinary explosions. In most cases a process vessel or piping system will be unable to contain detonation pressure. The only safe procedure to avoid process system detonations is preventing the formation of flammable vapor and air mixtures within vessels and piping systems. While the flame speed of explosions is relatively slow detonations traveling at supersonic speeds will be more destructive.

5.3.1.6 Vapor Cloud Explosions

An unconfined vapor cloud explosion (UVCE) is a popular term that concisely explains the ignition of a combustible gas or vapor release in the "open" atmosphere. In fact, a considerable amount of published literature states that "open" air explosions will only occur if there is sufficient congestion or in some cases, turbulence of the air is occurring. Gas or vapor clouds ignited under certain conditions produce an explosion. Research into the mechanism of vapor cloud explosions indicates the flames are high speed, but have subsonic combustion, resulting in a deflagration not a detonation. Experiments have also demonstrated that such flames traveling through unenclosed gas or air clouds produce negligible overpressures. When objects such as pipes and vessels are near or in the presence of an ignited gas cloud they generate turbulence, producing damaging overpressures ahead of the flame front.

In order for a vapor cloud explosion to occur in a hydrocarbon facility, four conditions have to be achieved:

1. There has to be significant release of a flammable material.
2. The flammable material has to be sufficiently concentrated to the surrounding are a in order to achieve a composition between the LEL and UEL for the material.
3. There has to be an ignition source.
4. There has to be sufficient confinement, congestion, or turbulence in the released area.

The amount of explosive overpressure is determined by the flame speed of the explosion. Flame speed is a function of the turbulence created within the vapor cloud that is released and the level of fuel mixture within the combustible limits. Maximum flame velocities in test conditions are usually obtained in mixtures that contain slightly more fuel than is required for stoichiometric combustion. Turbulence is created by the confinement and congestion within the particular area. Modern open air explosion theories suggest that all onshore process plants have enough congestion and confinement to produce vapor cloud explosions. Certainly, confinement and congestion are available on most offshore production platforms to some degree.

Two types of open air explosions, representing two different mechanisms for pressure buildup, have been identified.

- **Semi-Confined Vapor Cloud Explosion**
  These require some degree of confinement, usually inside a building or module. The mechanism of pressure buildup is the expansion of hot gas as it burns, exceeding the vent capacity of the enclosure. No significant shock wave is created, because in general the space is too small or there is insufficient gas for the flame front to accelerate the necessary speed. The explosions can occur with small amounts of gas.
- **Vapor Cloud Explosion**
  These explosions may occur in unconfined areas, although some degree of congestion is still required. The overpressure is created by rapid and accelerating combustion of the gas and air mixture. The speed of the flame front can reach over 2000 meters per second (6000 ft./s), creating a shock wave as it pushes the air ahead of it. Vapor cloud explosions can only occur in relatively large gas clouds.

Once the explosion occurs it creates a blast wave that has a very steep pressure rise at the wave front and a blast wind that is a transient flow from behind the blast wave. The impact of the blast wave on the structures near the explosion is known as blast loading. The two important aspects of the blast loading concern is the prediction of the magnitude of the blast and the pressure loading on the local structures. Pressure loading predictions as a result of a blast resemble a pulse of trapezoidal or triangular shape. They normally have durations of between approximately 40 ms and 400 ms. The time to maximum pressure is typically 20 ms.

Primary damage from a hydrocarbon explosion may result from several events:

- **Overpressure**—The pressure developed between the expanding gas and its surrounding atmosphere.
- **Pulse**—The differential pressure across a plant as a pressure wave passes that might cause collapse or movement, both positive and negative.

- **Projectiles, Missiles, and Shrapnel**—These are whole or partial items that are thrown by the blast of expanding gases that might cause damage or event escalation. These items are generally small in nature (e.g., hard hats, nuts, bolts, etc.), since the expanding gases do not typically have enough energy to lift heavy items such as vessels, valves, etc. This is in direct contrast to a rupture in which the rupture or internal vessel explosion causes portions of the vessel or container to be thrown far distances. In general, these "missiles" from atmospheric vapor cloud explosions cause minor impacts to process equipment since insufficient energy is available to lift heavy objects and cause major impacts. Small projectile objects are still a hazard to personnel and may cause injuries and fatalities. Impacts from rupture incidents may produce catastrophic results (i.e., puncturing other vessels, impacts to personnel, etc.), hence the tremendous reliance on pressure relief systems (overpressure safety valves, depressuring capability, etc.) by hydrocarbon, chemical, and related facilities.

In process facilities these effects can be generally related to flame velocity, and where this velocity is 100 m/s (300 ft./s), damage is considered unlikely. The size of the vapor cloud or plume in which such velocities can occur have been experimentally investigated at the Christian Michelsen Institute (CMI, Norway). Experiments there demonstrated that flames need a "run-up" distance of approximately 5.5 m (18 ft.) to reach damaging speeds. Therefore, vapor clouds with a dimension less than this may not cause substantial damage. This is an over-simplification of the factors and variables involved, but does assume the WCCE of congestion, confinement, and gas concentrations.

5.3.1.7 Deliberate Terrorist Explosions

However unfortunate, the petroleum industry has to consider terrorist activities. Terrorists typically use solid type explosives in their attacks on facilities. The blast effects from such incidents emit from single point location versus a hydrocarbon vapor which typically is inside immediate process areas and covers a larger area. Therefore, it is more likely that terrorist detonations will be in less confined circumstances. The effect or damage from such explosions have been observed and are usually from the various shrapnel pieces thrown out from the vehicle as it disintegrates, which is utilized for the transport of the device. Where large amounts of explosives are used, they highly fragment the light construction components of the vehicle and cause little impact, since industrial facilities are composed of robust materials, i.e., high strength steels and concrete masonry structures that have relatively high impact resistance to light fragments. The heavy components, engine, transmission, drive line, etc., which do not easily disintegrate, may be the objects that inflict the most amount of damage, similar to a vessel rupture. Also, the heavier objects tend to be thrown horizontally from the event, as the explosive device is usually at the same elevation or higher than these components. A bomb "crater" is usually created at the location. This fact also reduces the probability of serious impacts from these events, as vessels, pipe racks, fin fans, etc., tend to be at higher elevations and underground process piping (except for sewers) is not normally provided in such installations. The highest impact may be to individuals in the area at the time of the event. The orientation, distance, and explosive type influence the degree of impact from these events.

5.3.1.8 Semi-Confined Explosion Overpressures

The overpressure developed in semi-confined explosions depends on the following key parameters:

- **The Volume of the Area**—Large confined areas experience the largest overpressures.
- **Ventilation Area**—The degree of confinement is of vital importance. The existence of openings, whether permanent vents or covered by light claddings, greatly reduces the predicted overpressure.
- **Obstacles, Process Equipment, and Piping**—Structural steel and other obstacles create turbulence in the burning cloud, which increases the overpressure. The profile, size, and location of obstacles will all influence the amount of overpressure developed.
- **Ignition Point**—Ignition points long distances from the vent areas increase the overpressure.
- **Gas Mixture**—Most studies have been conducted on methane and air mixtures, but propane and air mixtures are known to be slightly more reactive and create higher overpressures. Increasing the content of the higher hydrocarbon gases is therefore expected to have a similar effect. The initial temperature of the mixture may also influence the overpressure outcomes.
- **Gas Mixing**—Combustible gases must be mixed with air to achieve the explosive range limits for the particular gas. A worst case mixture, slightly richer in fuel than stoichiometric, corresponding to the fastest burning mixture is normally used in calculation estimates providing a conservative approach.

Some consulting companies and risk engineering departments of insurance agencies have software available to perform estimates of overpressures for semi-confined explosions, taking into account these particular parameters. These proprietary software models are generally based on empirical formulas, with validation against 1:5 scale experimental testing and studies against actual historical incidents, i.e., Flixborough, Piper Alpha, and others. Insurance agencies tend to take a conservative approach in their estimates.

5.3.1.9 Vapor Cloud Overpressures

Previous studies of vapor cloud explosions (VCE) have used a correlation between the mass of a gas in the cloud and the equivalent mass of TNT to predict explosion overpressures. This was thought to have conservative results, but past research evidence indicates this approach was not accurate to natural gas in air mixtures. The TNT models did not correlate well in the areas near the point of ignition, and generally overestimated the level of overpressure in the near field. Experiments on methane explosions in "unconfined" areas have indicated a maximum overpressure of 0.2 bar (3.0 psio). This overpressure then decays with distance. Current propriety computer modeling programs have been improved to simulate real gas and air explosions from both historical and experimental evidence.

The criteria selected for an overpressure hazard is normally taken as 0.2 bar (3.0 psio). Although fatalities due to direct effects of an explosion may require up to 2.0 bar (29.0 psio) or higher, significantly lower levels result in damages to structures and buildings that would likely cause a fatality to occur. An overpressure of 0.2–28 bar (3.0–4.0 psio) would destroy a frameless steel panel building, 0.35 (5.0 psio) would snap wooden utility poles and severely damage facility structures, and 0.35–0.5 bar (5.0–7.0 psio) would cause complete destruction of houses. Commonly accepted blast overpressure levels for damage to occur are shown in Table 5.1.

Historically, all reported vapor cloud explosions have involved the release of at least 100 kg (220 lbs.) of combustible gas, with a quantity of 998–9979 kg (2200–22,000 lbs.) being the most common. In the US, Occupational Safety and Health (OSHA) regulations (Ref. 29 CFR 1910.119 (a) (1) (ii) and 1926.64 (a) (1) (ii)) require only processes containing 4536 kg (10,000 lbs.) of material or more to be examined for the possibility of an explosion. Additionally, the possibilities associated with vapor clouds exploding that are 4536 kg (10,000 lbs.) or less are considered very low. Most major catastrophic incidents in the process industries have occurred when the level of material released has been large. Generally for vapor cloud explosions that

Table 5.1 Blast Damage to Equipment, Structures, and Infrastructure

Damage	Overpressure kPa (psi)
Storage tank roof collapses	7 (1.0)
Round storage tank supporting structure collapses	100 (14.5)
Empty storage tanks cracking	20–30 (2.9–4.4)
Cylindrical storage tank displacement, pipe connection failures	50–100 (7.3–14.5)
Fractionating column damage	35–80 (5.1–11.6)
Pipe bridge slight deformation	20–30 (2.9–4.4)
Pipe bridge displacement, pipe failures	35–40 (5.1–5.8)
Pipe bridge collapse	40–55 (5.8–8.0)
Automotive vehicle plating presses inward	35 (5.1)
Wooden telephone pole break	35 (5.1)
Loaded train cars overturn	50 (7.3)
Large trees falling	20–40 (2.9–5.8)

are less than 4536 kg (10,000 lbs.), less damage occurs than at greater volumes (i.e., greater than 4536 kg (10,000 lbs.).

A natural gas and air mixture is only likely to explode if all the following conditions are met:

- A degree of congestion from obstacles creates turbulence.
- A relatively large area, allowing the flame front to accelerate to high velocities.
- A minimum flammable mass of 100 kg (220 lbs.) is generally required for flame front acceleration.

It could be argued that vapor cloud explosions for hydrocarbon facilities need only be calculated for those facilities that contain large volumes of volatile hydrocarbon gases that can be inadvertently released where some degree of confinement or congestion exists. The most probable amount is taken as 4536 kg (10,000 lbs.), but incidents have been recorded where only 907 kg (2000 lbs.) has been released. Additionally, an actual calculation of the worst case releases to produce 2.0 bar (3 psio) at say 46 m (150 ft.) indicates a minimum of 907 kg (2000 lbs.) of material is needed to develop that amount of overpressure. A low amount, say 907 kg (2000 lbs.), release of hydrocarbon vapor is considered a prudent and conservative approach for the minimum volumes that need examination.

5.3.1.10 Boiling Liquid Expanding Vapor Explosions (BLEVES)

BLEVES arise from the reduction in yield stress of a vessel or pipe wall to the point that it cannot contain the imposed stresses by the design and construction of the container are also influenced by the relief valve set point. This results in sudden catastrophic failure of the containment causing a violent discharge of the contents and producing a large intense fireball.

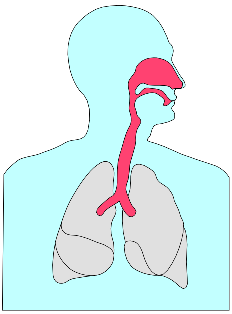
Typically a BLEVE occurs after a metal container has been overheated to above 538°C (1000°F). The metal may not be able to withstand the internal stress and therefore failure occurs. The contained liquid space of the vessel normally acts as a heat absorber, so the wetted portions of the vessel are not at high risk, only the surface portion of the internal vapor spaces. Most BLEVEs occur when vessels are less than 1/2 to 1/3 full of a liquid (which is not uncommon for some process vessels). The liquid vaporization expansion energy is such that vessel pieces have been thrown as far as 0.8 km (1/2 mile) from the rupture and fatalities from such incidents have occurred up to 224 m (800 ft.) away. Fireballs may occur at the time of rupture, that are several meters (ft) in diameter, resulting in intense heat exposure to personnel nearby. Fatalities from such incidents have occurred as much as 76 m (250 ft.) away from the point of rupture.

A study of BLEVE occurrences in LPG storage vessels ranging from 3.8 to 113 cubic meters (32–847 bbls) showed a time range to rupture of 8–30 min with approximately 58% occurring within 15 min or less.

5.3.1.11 Smoke and Combustion Gases

Smoke is a by-product of most fires caused by the incomplete oxidation of the fuel supply during the chemical process of combustion. It accounts for a large majority of fatalities from fire incidents at both onshore and offshore petroleum facilities. In the Piper Alpha incident of 1988, probably the worst petroleum industry loss of life incident, the majority of deaths were not from burns, drowning, or explosion impacts, but from smoke and gas inhalation. The report on the incident concluded that, of the bodies recovered from the incident, 83% were as a result of inhalation of smoke and gas. Most of these victims were assembled in the platform accommodation awaiting a possible evacuation direction or as they may have thought—a possible rescue.

Smoke from hydrocarbon fires consists of liquid or solid particles of usually less than one micron in size, suspended in the combustion gases, which are primarily nitrogen, carbon monoxide, and carbon dioxide, existing at elevated temperatures. At normal temperatures, carbon is characterized by low reactivity. At high combustion temperatures, carbon reacts directly with oxygen to form carbon monoxide (CO) and carbon dioxide (CO_2).



The main dangers of smoke are the presence of narcotic gases, oxygen depletion, and irritants. The narcotic gases are principally carbon monoxide (CO), hydrogen cyanide (HCN), and carbon dioxide (CO_2). Inhaling narcotic gases often leads to hyperventilation and therefore increased inhalation of gases as the breathing rate increases. Narcotic gases also cause incapacitation by an attack on the central nervous system. The asphyxiating effects of an oxygen depleting atmosphere, due to the combustion process, severely affects human respiration capabilities. Irritants to the respiratory system include inorganic acids (halogen acids and oxides of sulfur) and inorganic irritants (acrolein, formaldehyde, ammonia, and chlorine). There also may be complex or exotic molecules such as polycyclic aromatic hydrocarbons, some of which are mutagens and carcinogens and dioxins that could affect the reproductive system. Overall, the severity depends on the chemical concentration, exposure, duration, and solubility.

A low level of oxygen in the brain leads to psychological disorders that cause impairments to judgment and concentration. These effects may confuse, panic, or incapacitate personnel. Carbon monoxide poisoning causes suffocation by blocking transport of oxygen in the blood. Incapacity occurs in less than 10 min with 0.2% concentration of carbon monoxide if heavy activities are being performed. Carbon monoxide kills because it combines with the hemoglobin of the blood preventing oxygen to bind with hemoglobin, which is necessary to sustain life. Carbon monoxide has an affinity for hemoglobin 300 times that of oxygen. The degree of poisoning depends on the time of exposure and concentration of the gas. If the percentage of carbon monoxide in the blood rises to 70–80%, death is likely to ensue.

The precise technical name of HCN is Hydrocyanic Acid. The cyanides are true protoplasmic poisons, combining in the human tissues with enzymes associated with cellular oxidation. They thereby render the oxygen unavailable to the tissues and cause death through asphyxia.

Inhaling concentrations of more than 180 ppm of HCN will lead to unconsciousness in a matter of minutes, but the fatal effects would normally be caused by carbon monoxide poisoning after HCN has made the victim unconscious. Exposure to HCN concentrations of 100–200 ppm for periods of 30–60 min can also cause death.

Inhaling hot (fire) gases into the lungs will also cause tissue damage to the extent that fatal effects could result in 6–24 h after the exposure.

Psychologically, the sight and smell of smoke may induce panic, disorientation, and despair. When this occurs, movement of personnel to achieve evacuation objectives may be severely inhibited or disrupted. This is especially critical where personnel are unfamiliar with the facility. Smoke will also hinder firefighting and rescue efforts.

Smoke travel is affected by the combustible particle's rise, spread, rate of burn, coagulation, and ambient air movements. Combustion products, due to heating by the fire, tend to gradually rise because they are lighter in weight than the surrounding air. They will spread out when encountering objects such as a ceiling or structural components. The smoke particulates inside an enclosure will readily penetrate every available opening, such as a ceiling, cracks, crevices, staircases, etc. Rate of burn is the amount of material consumed by combustion in any given time period. Particle coagulation is the rate at which combustion particles gather in groups large enough to precipitate out of the air. Coagulation occurs continuously because of the mutual attraction of the combustion particles. Air movement will direct smoke particles in a particular pattern or direction.

There are mathematical models for the dispersion of smoke plumes (e.g., CHEMET). Ambient atmospheric conditions at the time of an

Table 5.2 General Hazards of Common Petroleum Commodities (under typical process operations and conditions)

Commodity	Explosion	Pool Fire	Jet Fire	Smoke
Methane	X		X	
LNG	X	X	X	
Ethane	X		X	
Propane	X		X	
Butane	X		X	
LPG	X	X	X	X
Crude oil	X	X		X
Gasoline	X	X		X
Diesel		X		X
Kerosene		X		X

incident will greatly influence the dissipation or collection of smoke particulates, i.e., wind speed, direction, and atmospheric stability.

Smoke is expected to pose the most concern for public health as it may not be immediately recognized that the general population is at risk though exposure to organic irritants, complex molecules, and particulate matter. Scenarios of incomplete combustion are expected to form the greatest quantities of hazardous combustion products. People at most risk are generally those with respiratory conditions (e.g., asthma), the elderly, pregnant women, newborn infants, and children. For interior locations, smoke generation from fires generally fills the entire enclosure, unless there is an easy path for it to escape to the outside, i.e., window, door, or other similar openings.

Whenever the dangerous effects of smoke will affect personnel, adequate respiratory protection must be provided, such as adequate measures to evacuate from its effects, smoke resistant barriers/shelter-in-place program, alternative fixed fresh air supplies, or portable self-contained breathing equipment (see Table 5.2).

5.3.1.12 Petrochemical and Chemical Process Hazards

All the pertinent physical and chemical properties of chemical materials should be evaluated in relation to the hazards of fire, explosion, toxicity, and corrosion. These properties should include thermal stability, shock sensitivity, vapor pressure, flash point, boiling point, ignition temperature, flammability range, solubility, and reactivity characteristics (e.g., water reactivity and oxidizing potential).

Petrochemical and chemical processes may contain additional processes that need to be evaluated as applicable on raw materials, catalysts, intermediates, products, by-products, unintended products, solvents, inhibitors, quenchers, decomposition products, and cleaning products, such as:

(a) Pyrophoric properties
(b) Water reactivity
(c) Oxidizing properties
(d) Solid (dust), liquid, and/or vapor flammability or ignitability properties
(e) Common contaminant reactivity (e.g., rust, heat transfer fluid, scrubber solutions)
(f) Mechanical sensitivity (mechanical impact and friction)
(g) Thermal sensitivity
(h) Self-reactivity

The results of the hazardous chemical evaluation are used to determine to what extent detailed thermal stability, runaway reaction, and gas evolution testing is needed. The evaluation may include reaction calorimetry, adiabatic calorimetry, and temperature ramp screening using accelerating rate calorimetry, a reactive system screening tool, isoperibolic calorimetry, isothermal storage tests, and adiabatic storage tests.

There are a variety of measures to inhibit uncontrolled chemical reactions. Common measures include adding an inhibitor, neutralization, quenching with water or another diluent, or dumping the contents into another vessel that contains a quench liquid. The inhibitor or quench material must be selected carefully through an understanding of the inhibition reaction. The concentration and rate of addition of the inhibitors must be included in operating procedures for the process.

It is most optimum to avoid the use of unstable raw materials or intermediates if at all possible. Where unavoidable, unstable raw material feeds have to be carefully controlled so that concentrations are kept low and the material is consumed as rapidly as it is added. The process should not allow unstable intermediates to accumulate or be isolated. Special attention has to be given to the handling of rework material (see Table 5.3).

5.3.1.13 Mathematical Consequence Modeling

The use of computer modeling for rapidly and easily estimating the effects from explosions, fires, and gas releases is almost commonplace in risk evaluations for the hydrocarbon industry. Specialized risk consultants and even insurance risk offices can now offer a variety of software products or services to conduct mathematical consequence modeling of most hydrocarbon adverse events. Even major petroleum companies have bought

Table 5.3 Common Chemical Process Reactions and Critical Processing Parameters

Chemical Reaction	Energy Type	Potentially Critical Processing Parameters[a]	Remarks
Alkylation	Moderately to Highly Exothermic	1, 2, 6	Excess reagent may be needed
Amination	Endothermic to Highly Exothermic	1, 2, 3, 4, 5 12 (diazo)	
Aromatization	Endothermic to Moderately Exothermic	1, 2, 3, 4	Dumping/suppressant may be needed
Calcination	Endothermic	1, 6 (offgas)	
Condensation	Moderately Exothermic	1, 2, 3, 4, 5	
Double decomposition	Endothermic to Mildly Exothermic	6, 7, 8	NH3 decomposition potential
Electrolysis	Endothermic	5, 6, 7, 9	pH, electrical variables
Esterification (organic acids)	Mildly Exothermic	1, 2, 5	Moisture, contaminants
Fermentation	Mildly Exothermic	1	
Halogenation	Endothermic to Highly Exothermic	5, 8, 11 (some), 12 (some)	
Hydration	Mildly Exothermic	1, 2	Excluding acetylene production
Hydrogenation	Moderately Exothermic	1, 2, 3, 5, 6, 7	
Hydrolysis	Mildly Exothermic	1, 2	Includes enzymes
Isomerization	Mildly Exothermic	1, 2, 3	
Neutralization	Mildly Exothermic	1, 2	
Nitration	Highly Exothermic	1–6, 8, 12	Contamination, dumping may be needed, detonation potential
Organometallic	Highly Exothermic	1–5, 8, 10, 12	
Oxidation	Endothermic to Moderately Exothermic	1, 3, 4, 5, 11 (some)	
Polymerization	Mildly to Moderately Exothermic	1–7, 12 (some)	Viscosity concerns
Pyrolysis and cracking	Endothermic	1, 2, 8	

Table 5.3 Continued

Chemical Reaction	Energy Type	Potentially Critical Processing Parameters[a]	Remarks
Reduction	Endothermic to Mildly Exothermic	1, 2, 10 (some)	
Reforming	Endothermic to Moderately Exothermic	1, 3, 4, 5	
Substitution	Endothermic to Mildly Exothermic	1, 2	
Sulfonation	Mildly Exothermic	1, 2, 5	

[a]Processing parameters: (1) Temperature, (2) Pressure, (3) Agitation, (4) Cooling/Heating, (5) Addition rate, (6) Concentration, (7) Flammable gases (LEL detection), (8) Inerting, (9) Liquid level, (10) Water reactive, (11) Reactive metals, (12) Critical that adequate and reliable process control be provided.

licensed copies of these programs in order to conduct studies "in-house." The primary advantage of these tools is that some estimate can be provided on the possible effects of an explosion or fire incident where previously these effects were rough guesses or unavailable. Although these models are effective in providing estimates, they should still be used with some caution and consideration of other physical features that may alter the real incident outcome.

The mathematical models require some "assumed" data on the source of release for a material. These assumptions form the input data, which is then easily placed into a mathematical equation. The assumed data is usually the size of the mass released, wind direction, wind speed, etc. They cannot take into all the variables that might exist at the time of an incident. The models are becoming more accurate at predicting events that match the assumed input data, but research and experimentation is continuing with various institutions to improve their accuracy.

The best avenue when undertaking these estimates for risk analysis is to use data that would be considered the WCCE (worse case credible event) for the incident under evaluation. One should then question if the output data provided is realistic or corresponds to historical records of similar incidents for the industry and location. In other cases, where additional analysis is needed, several release scenarios, small, medium, and large, can be examined and probabilities assigned to each outcome. This would then essentially be an event tree exercise, normally conducted during a quantitative risk analysis. Certain releases may also be considered so rare an event they may be outside the realm of accepted industry practical protective requirements.

Some readily available commercial consequence models include the following:

- Gas discharge from an orifice
- Gas discharge from a pipe
- Liquid discharge from an orifice
- Liquid discharge from a pipe
- Two-phase discharge from an orifice
- Two-phase discharge from a pipe
- Adiabatic expansion
- Liquid "pool" spill and vaporization
- Vapor plume rise
- Smoke plume
- Chemical release
- Jet dispersion
- Dense cloud dispersion
- Neutrally buoyant dispersion
- Liquid "pool" fire
- Jet flame
- Fireball/BLEVE
- Vapor cloud Explosion blast pressures
- Indoor gas build

From the estimates of fire or explosion exposures, the effectiveness of various fire protection systems can be examined or compared, e.g., heat absorption of deluge water sprays at various densities, fireproofing at various thicknesses or types of material, etc. Some cases of theoretical fire modeling have proven very cost effective by demonstrating, for example, that fireproofing was not beneficial to the subject application since the heat transmission to the subject area was not high enough to weaken the steel to its unacceptable failure point. For offshore structures this is vitally important, not only for cost savings but also for topside weight savings obtained by decreased amounts of fireproofing installation requirements.

5.4. METHODS OF FLAME EXTINGUISHMENT

If any one of the principle elements of the combustion process can be removed from a fire, it will be extinguished. The principle methods of extinguishment are discussed below.

5.4.1 Cooling (Water Spray, Water Injection, Water Flooding, Etc.)

Removing heat from or cooling a fire absorbs the propagating energy of the combustion process. When the fuel temperature is lowered below its ignition temperature it results in extinguishment of the fire. For liquid hydrocarbon fires it also slows and eventually stops the rate of release of combustible vapors and gases. Cooling by water also produces steam, which may partially dilute the ambient oxygen concentration local to the fire point. Because heat is continually being released by the fire in the form of radiation, convection, and conduction it is only necessary that a relatively small amount of a heat absorbing commodity be applied to the fire in order for it to be extinguished by cooling means.

5.4.2 Oxygen Deprivation (Steam Smothering, Inerting, Foam Sealing, CO_2 Application, etc.)

The combustion process requires oxygen to support its reaction. Without oxygen the combustion process will cease. The normal oxygen level in the atmosphere is 21% (approximately 20.9% oxygen, 78.1% nitrogen, 1% argon, carbon dioxide, and other gases). Combustion of stable hydrocarbon gases and vapors will usually not occur when the ambient oxygen level is lowered to below 15%. Acetylene, which is an unstable hydrocarbon, requires the oxygen level to be below 4% for flame extinguishment. For ordinary combustibles (wood, paper, cotton, etc.) the oxygen concentration levels must be lowered to 4% or 5% for total fire extinguishment. If sufficient amounts of diluents are added until the oxygen is displaced, the combustion process will be terminated. For some suppression methods, oxygen is not removed from a fire but merely separated from it.

5.4.3 Fuel Removal (Foam Sealing, Isolation, Pump-out, etc.)

If the fuel is removed or consumed by the subject combustion process, no more fuel supplies will be available for the combustion process to continue and it will cease. In some cases, a fuel is not literally removed from a fire, but it is separated from the oxidization agent. Foam suppression methods are good examples of where a barrier is introduced to remove the fuel from the air, i.e., oxidizer. Storage tanks and pipeline fires can use pump-out methods (e.g., pump tank contents to another storage tank) and inventory isolation (e.g., emergency isolation valves), respectively, as methods of fuel removal.

5.4.4 Chemical Reaction Inhibition (Clean Agent Total Flooding, Dry Chemical Application, etc.)

The chemical chain reaction is the mechanism by which the fuel and oxidizing agents produce fire. If sufficient amounts of a combustion-inhibiting agent (e.g., dry chemical agents or clean agent total flooding applications, etc.) are introduced the combustion process will stop. Chemical flame inhibition interrupts the chemical process of combustion by inhibiting the chain reaction.

5.4.5 Flame Blow-Out (Explosives, Jet Engines)

Flame extinguishment for relative point sources can be accomplished dynamically through the combined action of oxygen dilution and flame blow-out or application of rapid ambient air velocity such as when a candle is blown out. It is achieved when the ambient air velocity exceeds the flame velocity. Techniques such as these are primarily applied during specialized well blow-out control operations. The detonation of high explosives results in a pressure wave that "blows-out" the wellhead fire by separating the flame from the available combustion gas. Some specialized apparatus is also available that uses jet engines to literary "blow-out" wellhead fires. These jet engine devices (jet engines mounted on a tank chassis) have been used to control blow-outs in the Russian oil industry and many wellhead fires in the aftermath of the Gulf War.

5.5. INCIDENT SCENARIO DEVELOPMENT

As part of Process Safety Management (PSM) requirements by both OSHA and the EPA, both risk analysis and emergency response management require the determination (i.e., identification and evaluation) of incident scenarios that are likely to develop at an installation. Risk analyses techniques such as PHA, What-If, HAZOP, etc., will systematically review a process to determine possible deviations from the intended processes that may result in events such as fire and explosions. Additionally, emergency response preparedness plans usually develop "creditable" scenarios that may develop and the generic responses that are required. These PSM techniques aid in the understanding of the type of fire and explosion events that are likely to occur, how they would progress, and a determination of the control and suppression methods that are likely to be employed.

5.6. TERMINOLOGY OF HYDROCARBON EXPLOSIONS AND FIRES

The following terminology is used in the description of various fires and explosions that can occur at a hydrocarbon facility:

Blast—The transient change in gas density, pressure, and velocity of the air surrounding an explosion point.

Blow-out—A blow-out is a high pressure release of hydrocarbons, which may or may not ignite, that occurs when a high pressure oil or gas accumulation is unexpectedly encountered while drilling a well and the mud column fails to contain the formation fluid, which is then expelled through the wellhead bore.

Boiling Liquid Expanding Vapor Explosion (BLEVE)—Is the nearly instantaneous vaporization and corresponding release of energy of a liquid upon its sudden release from a containment under greater than atmospheric pressure and at a temperature above its atmospheric boiling point.

Deflagration—Is the propagating chemical reaction of a substance in which the reaction front advances into the unreacted substance rapidly, but at less than sonic velocity in the unreacted material.

Detonation—Is a propagating chemical reaction of a substance in which the reaction front advances into the unreacted substance at greater than sonic velocity in the unreacted material.

Explosion—Is a release of energy that causes a blast.

Fireball—Is a rapid turbulent combustion of a fuel-air cloud whose energy is emitted primarily in the form of radiant heat, usually rising as a ball of flame.

Flash Fires—Is a fire resulting from the ignition of a cloud of flammable vapor, gas, or mist in which the flame speed does not accelerate to sufficiently high velocities to produce an overpressure, because there is not sufficient congestion or confinement present to produce high velocity flame speed.

Implosion—Is an inward rupture normally caused by inadvertent vacuum conditions in a vessel or tank.

Jet or Spray Fires—Are turbulent diffusion flames resulting from the combustion of a liquid or gas continuously released under pressure in a particular direction.

Overpressure—Is any pressure relative to ambient pressure caused by a blast, both positive or negative.

Running Fire—Is a fire from a burning fuel that flows by gravity to a lower elevation. The fire characteristics are similar to pool fires except a running fire is moving or draining to a lower level.

Ruptures of Internal Vessel Explosions—A catastrophic opening of a container (i.e., tank, vessel, or pipe), commonly from overpressure or metallurgical failure, resulting in the immediate release of its contents.

Smoke—The gas products of the burning of carbonaceous materials made visible by the presence of small particles of carbon, and the small particles, which are liquid or solid consistency, are produced as a by-product of insufficient air supplies to a combustion process.

Spill or Pool Fire—Is the release of a flammable liquid and\or condensed gas that accumulates on a surface forming a pool, where flammable vapors burn above the liquid surface of the accumulated liquid.

Vapor Cloud Explosion (VCE)—Is an explosion resulting from the ignition of a cloud of flammable vapor, gas, or mist in which the flame speed accelerates to produce an overpressure.

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CHAPTER 6

Historical Survey of Major Fires and Explosions in the Process Industries

Historical records show that there were many fires during the inception of the petroleum industry, which unfortunately continue today. The general trend is of an ever increasing financial impact for major incidents. Figure 6.1 graphically illustrates the amount of losses for a single major loss for the past several decades. As can be readily seen the losses have risen dramatically and can be financially disastrous in real economic terms.

There are great benefits from reviewing incident data, since we can learn from past mishaps and make design improvements and change undesirable behaviors or operating procedures. However, when analyzing incident data, only the most recent data available (statistics and descriptions) should be used. Technological improvements and management controls are continuously improving so the comparisons to data of say 15–25 years ago may be of little technical value. Although the general categories of loss mechanisms might be useful to review from such outdated data, overall the data cannot be compared directly to today's environment.

Hbk of Fire and Explosion Protection, http://dx.doi.org/10.1016/B978-0-323-31301-8.00006-4

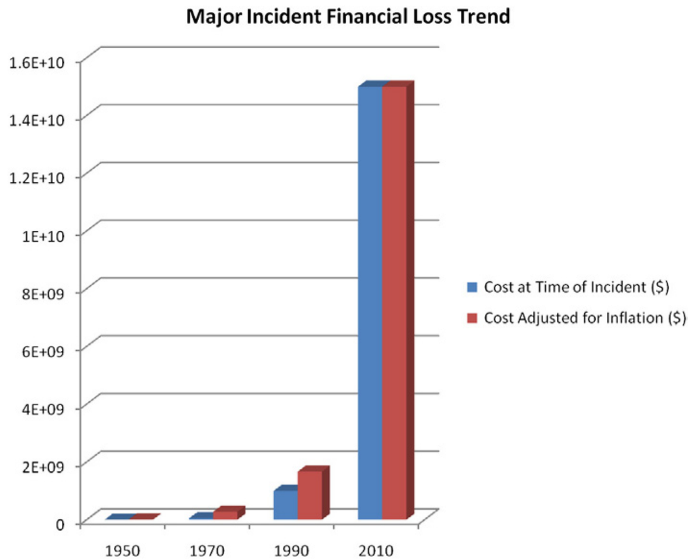


Figure 6.1 Historical financial losses for major incidents.

6.1. LACK OF PROCESS INDUSTRY INCIDENT DATABASE AND ANALYSIS

At the present time, no comprehensive database or statistics exist within the US federal government that encapsulate all of the process industry incidents, nor were such information available, would it be analyzed for trends, root causes, etc.

The US Chemical Safety and Hazard Investigation Board (CSB) investigates major process industry incidents, but, US governmental bodies such as the CSB do not maintain comprehensive incident databases or compile national statistics on chemical incidents. The Occupational Safety and Health Administration (OSHA), the National Response Center (NRC), the Agency for Toxic Substances and Disease Registry (ATSDR), the Environmental Protection Agency (EPA), and other agencies do maintain certain incident databases that vary in scope, completeness, and level of detail. The Mineral Management Service maintains an incident database solely for offshore operations; however, this is segregated by region. The National Transportation Safety Board (NTSB) investigates major incidents associated with transportation incidents, i.e., pipelines, ships, and railroads in the US.

OSHA collects data on injuries and fatalities and does some inspections, but generally undertakes no analysis of the causes of fires and explosions in the process industries. It rather determines if federal laws were violated and issues a fine. The Bureau of Safety and Environmental Enforcement (BSEE) undertakes similar functions for US OCS petroleum operations. In fact, there is no national or international governmental data bank available where fire and explosion incidents from the entire petroleum, chemical, or related industries are logged and analyzed.

6.2. INSURANCE INDUSTRY PERSPECTIVE

The most readily available public listing of process industry incidents is from insurance agencies who periodically publish historical listings of process industry incidents for use by both the insurance and process industries in an effort to improve their operations and prevent such occurrences.

The insurance industry as a whole has a substantial self-interest in analyzing incidents, sponsoring research, and issuing publications on the methods to prevent incidents or mitigate their effects. Hence, their data is the most useful and readily available. Because of their own self-interest, their recommendations are sometimes viewed by the industry as too conservative.

6.3. PROCESS INDUSTRY PERSPECTIVE

The process industry has organized their own requirements, which are typically contained in AIChE and API publications. Public insistence on having governmental review and analysis of process industry incidents is essentially non-existent. This is probably due to the generally low level of fatalities and the perceived low level of public exposure to process incidents. Since petroleum and chemical industries generally do not threaten the public, governmental oversight has generally not been necessary. However, where such circumstances do not prevail, public oversight may be mandated, as environmental regulations have amply demonstrated and the ever increasing magnitude of catastrophic incidents indicates.

The Center for Chemical Process Safety (CCPS) of the American Institute of Chemical Engineers (AIChE) has developed a Process Safety Incident Database (PSID), (http://www.psidnet.com), adapted from that of a major oil company, circa 1995. The database system is used to collect data from high learning value process safety incidents from participating process industry companies to consolidate it in a confidential database, and to allow these same participating companies to analyze the resulting data and information for trends and lessons learned.

Nowadays all operating companies have considerable legal restraints concerning divulging information publically when injuries and property damage are or could be under litigation. Hence, much of the prevalent information (except for the major incidents during legal proceedings is not circulated or generally released by operating companies. They also have a self-interest to portray their operations as safe in order to achieve lower insurance premiums and achieve greater public acceptance of process industry operations. As anyone in the petroleum industry will confidentially tell you, not all incidents that occur at field installations are reported and it is probably facetious to think otherwise. This is due to the business and social pressures that exist to achieve a high production rate, safe man-hour awards, promotions, peer pressures, fear of reprimand, etc. In real life, very little incentive exists to report incidents in a company other than it may be difficult to deny if physical damage or personal injuries result. The system basically relies on the honor system. In other cases, where incidents are reported, they may be described in such a fashion that the risks are not fully identified.

6.4. MAJOR INCIDENTS AFFECTING PROCESS INDUSTRY SAFETY MANAGEMENT

Tables 6.1 and 6.2 list pertinent major incidents in the process industry that have had a dramatic effect on the management and regulation of the industry. As a result of the catastrophic impact these incidents had on industry, government, and environment, their subsequent investigations revealed that significant changes were required in the safety management of facilities in order to address major safety deficiencies.

6.5. RELEVANCY OF INCIDENT DATA

In reviewing incident histories, remember that technology and operating practices have changed tremendously and are likely to continue to Control technology continuously improves operating practices and may also lower manpower requirements. In practice only the last 10–15 years or so of loss histories are generally examined for relevancy to the current operating environments of most process facilities.

Table 6.1 The 20 Largest Industry Losses Since 1988

Date	Industry Segment	Incident	Location	Property Loss*
04.20.10	Production	Blow-out, explosion, fire, & pollution, vessel destruction	Gulf of Mexico, USA	>15,000
07.07.88	Production	Explosion & fire, platform destruction	North Sea, UK	1600
10.23.89	Petrochemical	Vapor cloud explosion & fire	Pasadena, Texas, USA	1300
03.19.89	Production	Explosion & fire	Gulf of Mexico, USA	750
09.12.08	Refining	Hurricane	Texas, USA	750
06.04.09	Production	Collision	North Sea, Norway	750
08.23.91	Production	Structural failure, sinking, destruction of platform hull	Sleipner North Sea, Norway	720
05.15.01	Production	Explosion, fire and vessel sinking	Campos Basin, Brazil	710
09.28.98	Gas processing	Vapor cloud explosion	Victoria, Australia	680
04.15.03	Production	Riot	Escravos, Nigeria	650
04.28.88	Production	Fire	Campos Basin, Brazil	640
09.21.01	Petrochemical	Explosion	Toulouse, France	610
06.25.00	Gas processing	Vapor cloud explosion	Mina Al-Ahmadi, Kuwait	600
05.04.88	Petrochemical	Explosion	Nevada, USA	580
01.19.04	Gas processing	Explosion & fire	Skikda, Algeria	580
05.05.88	Refining	Vapor cloud explosion	Louisiana, USA	560
11.01.92	Production	Mechanical damage	Northwest Shelf, Australia	470
11.14.97	Petrochemical	Vapor cloud explosion	Texas, USA	430
12.25.97	Gas processing	Explosion & fire	Sarawak, Malaysia	430
07.27.05	Production	Explosion & fire	Mumbai High, India	430

*US Dollars (MM), adjusted for inflation.

Table 6.2 Key Incident Drivers in the Process Industry

Incident	Event	Long-Term Impact
Flixborough, UK (1974)	Poor modification practices led to a 40-ton release of cyclohexane from a temporary connection and a vapor cloud explosion that resulted in 28 operator fatalities, mostly in the control room.	Led the industry to recognize that safety management and performance standard approach is superior to a prescriptive approach for safety. The HAZOP technique started to gain prominence as a hazard identification tool.
Seveso, Italy (1976)	A pesticide reactor, left in a suspended state, went exothermic and discharged it contents, including 2 kg of dioxin by-product. Emergency response by the company and authorities was poor. Many animal deaths and environmental impacts resulted.	This event and Flixborough led the EU to pass a directive in 1986 on the control of major industrial hazards. This embodied a performance standard and safety report concept. This was updated in 1999 as the Seveso 2 Directive embodying risk assessment ideas and adding environmental impacts.
Texas City, TX, USA (1987)	A crane accident in a Marathon Refinery resulted in a dropped object on a hydrofluoric reactor vessel and a large release of toxic vapor. The impact was limited.	The US EPA developed a Risk Management Plan extension to the OSHA PSM regulations addressing offsite safety (1996).
Piper Alpha, North Sea, UK (1988)	A controllable pool fire on an Occidental offshore production platform caused by failure in the control of work, escalated due to poor emergency response into a total loss of the facility and 167 fatalities. Economic impact estimated at $1.2 billion to Occidental.	Based on recommendations of the investigation (Cullen Report) the UK introduced a Safety Case approach for offshore facilities that is being progressively adopted in the world as best practices. Occidental withdrew from North Sea oil production circa 1990.
Bhopal, India (1989)	A Union Carbide (joint venture) pesticide plant experienced an exothermic reaction leading to a massive release of methyl-isocyanate and over 2500 fatalities. Local management had allowed nine relevant safeguards to be out of service due to poor economic conditions.	The US process industry established the Center for Chemical Process Safety (CCPS) with the aim to place in the public domain all the best safety practices. Company dramatically changed and value lowered.

Pasadena, TX, USA (1989)	A Phillips high-density polyethylene (HDPE) plant suffered a maintenance error that led to total loss of reactor inventory, causing a vapor cloud explosion resulting in 23 fatalities and 130 injuries. Loss estimated at $1.4 billion. See Figure 6.2.	API developed its RP 750 PSM guide and OSHA used this and the CCPS Guide as a basis for the OSHA 1910 Process Safety Management Regulations (1992). These were performance based and focused on worker safety.
Valdez, Alaska, USA (1989)	An Exxon crude oil tanker ran aground and discharged 11 million gallons of crude oil. Human error was the main cause of this event. Huge public and governmental pressure was applied to Exxon.	Exxon developed the prototype for an industry leading safety management system (OIMS), which it applied to all its businesses worldwide. Other leading oil companies developed similar or derivative systems about this time. The US passed the Oil Pollution Act of 1990, which requires tankers to be double hulled by 2015.
Texas City, TX, USA (2005)	A BP refinery overfilled an Isomerization process vessel that subsequently released flammable vapors and liquids from a vent stack that caused a major vapor cloud explosion, resulting in 15 fatalities and 170 injured.	The CSB requested an independent panel investigate safety culture and management at BP North America. The Baker panel report found a lack of process safety management at company. BP CEO resigned in 2007. BP sold refinery in 2011.
Buncefield Oil Depot, Hertfordshire, UK (2005)	Vapor cloud explosion and tank farm fire that lasted for 5 days from overfilling a gasoline tank due to failure of level indicators. Forty injuries and 20 tanks destroyed. Potential $1 billion in claims.	The types of managerial failings revealed during the Buncefield investigation were often found at other major incidents. UK HSE report and findings on incident issued. Major examination of petroleum tank farm arrangements and operations within the petroleum industry.
Deepwater Horizon, Gulf of Mexico, USA (2010)	A semi-submersible exploration vessel leased to BP experienced an incident during a well cementing operation resulting in a fire/explosion that caused 11 fatalities, sinking of the vessel, and a massive oil spill in the Gulf of Mexico. Economic impact estimated at $15–30 billion to BP.	Reported as one of the worst incidents in the petroleum industry due to widespread environmental impact. Increased regulatory safety requirements for offshore drilling in the USA, with emphasis on blow-out prevention measures. Company stock quickly lost over 30% of its value. Company had to sell assets to cover cost impact. BP CEO was later replaced.

Figure 6.2 Pasadena, Texas incident aftermath.

Similarly, only loss histories that can be directly related to the facility under review should be studied. Not only should the type of facility be examined for applicability (e.g., refinery versus refinery), but also the ambient conditions under which the facility exists should be considered. For example, an oil production facility in Northern Siberia should not be thought of as having a similar operating environment as the jungle of Peru, either due to the environmental conditions, technology availability, or political influences. The Gulf of Mexico cannot be applied to the North Sea but it could have similarities with the Arabian Gulf or the South China Sea. Ideally, the best loss history is from the facility itself, since every location has its own characteristics and operating practices. For entirely new facilities, the closest comparison has to be chosen (see Figure 6.2).

6.6. INCIDENT DATA

The following is a brief selective list of major worldwide fire and explosion incidents within the petroleum and chemical industries during the last 18 years, i.e., 1995 to 2013 (the first edition of this book contains major incidents from 1960 to 1994 both onshore and offshore, greater than $100,000,000 in direct property loss. Numerous smaller incidents have been recorded that are not listed here but may be studied in other references. Financial losses are mostly direct property losses and may not include business interruption, legal, environmental cleanup, and company stock value impacts.

2013

11.28.13

Western Missouri, USA, Natural Gas Pipeline, Explosion and Fire

Nearby residents were evacuated and seven buildings on a nearby farm caught fire and were destroyed. Reports indicate the pipeline company experienced a similar explosion in 2008 about 20 miles away. That incident resulted in approximately $1 million in damage.

$ Property loss and business interruption unknown.

11.22.13

Qingdao, China, Crude Oil Pipeline Rupture, Explosion and Fire

Twenty-seven-year-old pipeline failure incident located in municipal area. Oil leaking from the pipeline ignited resulting in an explosion and fire that also produced an oil spillage into an adjacent seaport that spread across 3000 square meters of seawater surface. The director of the State Administration of Work Safety cited an unreasonable oil-pipeline layout, negligent pipeline supervision, and "unprofessional handling of oil leakage before the blasts." Afterward, China's President ordered safety checks on the country's oil and gas pipeline network. Urban encroachment onto the pipeline route also was a factor.

55 fatalities, 160 injured, $ Property loss and business interruption unknown.

11.19.13

Antwerp, Belgium, Continuous Catalytic Reforming (CCR) Unit, Refinery, Steam Explosion

An explosion occurred in a steam system of a gas-producing unit during maintenance operations due to failure of the studs on a bonnet-to-body flange of a motor operated valve.

2 fatalities, $ Property loss and business interruption unknown.

11.14.13

Milford, Texas, USA, LPG Pipeline, Fire

Drilling crew drilled inadvertently into 10-inch interstate LPG pipeline, resulting fire lasted 2 days and required 1.5-mile evacuation zone for 24 h and an adjacent 14-inch LPG to be shut down. The drilling rig was completely engulfed in flames.

$ Property loss and business interruption unknown.

08.17.13

Caspian Sea, Well Blow-out

Exploration well No. 90 in the Bulla Deniz gas field suffered a blow-out as it neared a depth of 6000m and subsequently caught fire. Required 2 months to extinguish blaze.

$ Loss unknown.

08.06.13

Horlivka, Ukraine, Chemical Facility, Fire, and Ammonia Leak

During the overhaul of plant, a fire and rupture of ammonia pipeline occurred.

5 fatalities, 23 injured.

07.23.13

Gulf of Mexico, USA, Drilling Rig, Gas Blow-out, and Fire

Caused a collapse of the drill floor and derrick.

$ Loss unknown (see Figure 6.3).

06.13.13

Geismar, LA, USA, Olefins Plant, Explosion and Fire

Chemical manufacturing—fire and explosion.

Fire resulted from a rupture in an off-line reboiler (which is a specific type of heat exchanger) that was in standby mode and located in the propylene fractionator area of the plant, adjacent to the in-service reboiler. The heat input system of the in-service reboiler was undergoing regular evaluation and analysis work at the time of the incident. Investigation ongoing.

2 fatalities, loss estimated $500,000,000.

Figure 6.3 Gulf of Mexico drilling rig incident in 2013.

01.05.13
Hajira, Surat, India, Oil Terminal, Fire

21 h fire in petroleum storage tanks.

3 fatalities, loss estimated at $8,000,000.

6.6.2 2012

11.16.12
Gulf of Mexico, USA, Offshore Platform, Explosion and Fire

A blast occurred at an offshore platform located at the West Delta Block 32, Platform E, about 17 miles off Grand Isle, LA. The US Bureau of Safety and Environmental Enforcement (BSEE) issued 41 incidents of noncompliance (INC) resulting from its investigation into the incident.

3 Fatalities, $ loss unknown.

09.19.12
Reynosa, Tamaulipas Mexico, Gas Plant, Explosion and Fire

Authorities evacuated residents within a 5 km radius of the plant.

26 fatalities, 27 injured, $ loss unknown (see Figure 6.4).

08.09.12
Punto Fijo, Venezuela, Refinery, Explosion and Fire

A gas cloud exploded and provoked fires in at least two tanks of the refinery and in the surrounding areas. The explosion damaged the infrastructure of the refinery and nearby houses.

Figure 6.4 Reynosa, Tamaulipas Mexico, gas plant explosion and fire.

41 fatalities, 80 injured, $ loss unknown.

08.06.12
Richmond, California, USA, Refinery Fire

A fire occurred at the refinery crude unit, flames and a column of smoke were visible in the air, which affected nearby residents. Corrosion in a 40-year-old pipe caused a leak that initiated the fire. Reportedly 15,000 nearby residents sought treatment after breathing emissions from the fire. Company received 25 citations from Cal/OSHA.

$ Property loss and business interruption unknown, approximately $2 million in fines (see Figure 6.5).

08.02.12
Tulsa, Oklahoma, USA, Refinery, Explosion and Fire

Incident occurred in diesel hydrotreater.

$ Property loss and business interruption unknown.

07.29.12
Oil Tanker, Fire and Explosion

Figure 6.5 Richmond, California refinery incident, 2012.

Rancha-Rancha industrial zone, Pulau Enoe, Labuan, Malaysia.

A 38,000 deadweight-ton tanker was loading six tons of methanol when a small fire broke out during a thunderstorm. The fire caused at least three major explosions.

5 fatalities, $ loss unknown.

05.11.12

Gas Processing Plant Explosion and Fire, Kerth, Malaysia

Fire occurred as contractor was servicing the pretreatment unit during a scheduled maintenance shutdown.

1 fatality, 23 injured, $ loss unknown.

04.17.13

West, Texas, USA, Fertilizer Distribution Plant, Explosion and Fire

Ammonium nitrate was the trigger for the explosion, but the cause of the initial fire is as yet unknown.

15 fatalities, more than 160 were injured and more than 150 buildings were damaged or destroyed, $ loss unknown.

03.31.12

Marl, Germany, Petrochemical Plant, Explosion and Fire

Plant produces cyclododecatriene (CDT), an intermediate used to make flame retardants, flavors, and fragrances. The blast occurred in a tank in the CDT plant, which was caused by an overdosage of a catalyst used to make CDT.

Loss $105,000,000, 2 fatalities, loss of production impacting auto industry as CDT is used in the production of a nylon resin, used in the production of the fuel and brake lines in vehicles.

6.6.3 2011

03.21.11

Louisville, Kentucky, USA, Chemical Manufacturing Plant, Explosion and Fire

A large explosion at a chemical plant killed two workers and injured two others, resulted from a failure by the company to investigate similar but smaller explosive incidents over many years while deferring crucial maintenance of the large electric arc furnace that exploded.

2 fatalities, $ loss unknown.

03.11.11

Ichihara, Chiba Prefecture, Japan, Earthquake, Refinery Fire

An offshore earthquake of magnitude 8.8 and subsequent tsunami caused major fires to occur at the 220,000-barrel per-day oil refinery. It was extinguished after 10 days, injuring six people, and destroying storage tanks.

Loss estimate $590,000,000.

01.06.11

Fort McMurray, Alberta, Canada, Oilsands Plant, Explosion and Fire

Explosion and fire at primary oilsands upgrader unit (upgraders convert bitumen stripped from the oilsands into refinery-ready synthetic crude).

4 injured, loss $1,007,000,000 (see Figure 6.6).

Figure 6.6 Earthquake impact, refinery fire, Canada 2011.

6.6.4 2010

04.20.10

Gulf of Mexico, USA, Offshore Oil Production, Explosion and Fire

Offshore semi-submersible experienced a well blow-out during cementing operations, resulting in total destruction and sinking of vessel and massive environmental impact (200 million gallons of crude oil spilled into the Gulf of Mexico).

11 fatalities, Loss $>1,500,000,000 (see Figure 6.7).

04.02.10

Anacortes, Washington, USA, Refinery, Explosion and Fire

Naptha hydrotreater unit was undergoing maintenance. The fire resulted from equipment failure for the unit producing naphtha at the plant.

7 fatalities, $ loss unknown.

6.6.5 2009

10.29.09

Jaipur, India, Oil Terminal, Fire

Fire in storage tanks that continued for 11 days.

11 fatalities, loss estimated at $45,000,000.

Figure 6.7 Semi-submersible blow-out and fire, Gulf of Mexico, 2010.

Figure 6.8 Storage tanks burning as pool fires, Puerto Rico, 2009 *(Photo Credit CSB)*.

10.23.09

Bayoman, San Juan, Puerto Rico, USA, Refinery, Explosion and Fire

15 storage tanks destroyed in tank farm, blast affected surrounding buildings.

$6,000,000 Loss (estimate) (see Figure 6.8).

08.21.09

Montara Oil Field, Timor Sea, Australia Offshore Oil Production, Explosion and Fire

Oil and gas blow-out incident on offshore platform. Considered one of Australia's worst oil disasters. Well continued leaking until 3 November 2009, in total 74 days.

Loss $300,000,000 (see Figure 6.9).

2009

Angola, Drilling/Exploration Explosion and Fire

Well blow-out.

Loss $140,000,000.

6.6.6 2008

02.18.08

Big Springs, Texas, USA, Refinery, Explosion and Fire

Apparent pump failure during startup of propylene unit, fire destroyed unit and damaged catalytic cracker and three storage tanks.

Loss $756,000,000.

Figure 6.9 Montara oil field, Australia, offshore oil production, explosion and fire.

6.6.7 2007

08.16.07

Pascagoula, Mississippi, USA, Refinery, Explosion and Fire

Fire occurred in one of two crude units.

Loss $230,000,000.

03.2.07

Niigata, Japan, Petrochemical Plant, Explosion and Fire

Static electricity ignited methylcellulose powders resulting in dust explosion.

Loss $240,000,000.

6.6.8 2006

10.12.06

Mazeikiu, Lithuania, Refinery, Explosion and Fire

Leak on piping of incorrect material to vacuum distillation column.

Loss $140,000,000.

04.26.06
Texas, USA, Petrochemical Plant, Explosion and Fire

Incident in propylene refrigeration unit.

Loss $200,000,000.

6.6.9 2005

12.11.05
Hemel Hempstead, Hertfordshire, UK, Buncefield Oil Storage Depot, Explosion and Fire

Vapor cloud explosion and tank farm fire that lasted for 5 days from overfilling a gasoline tank due to failure of level indicators. Forty injuries and 20 tanks destroyed.

Loss claimants whose properties were damaged or destroyed were asking for up to £1 billion in damages. The terminal owners and operators were fined a total of £8.6 million by the Health and Safety Executive and the Environment Agency (see Figure 6.10).

12.10.05
Muchsmunter, Germany, Petrochemical Plant, Explosion

Figure 6.10 Buncefield oil depot incident.

Release of hexane vapor resulting in vapor cloud explosion.

Loss $200,000,000.

07.25.05

Mumbai High, Indian Ocean, Production, Explosion and Fire

A support vessel collided with offshore platform, rupturing a riser and causing a major fire that destroyed the platform.

22 fatalities, loss $195,000,000 (see Figure 6.11).

03.23.05

Texas City, Texas, USA, Refinery, Explosion and Fire

Unexpected release of material from isomerization unit vent stack during maintenance.

15 fatalities, 180 injured, loss $200,000,000.

01.04.05

Fort McMurray, Alberta, Canada, Refinery, Explosion and Fire

Ruptured oil cycle line in oil sands refinery upgrader. Ice damage from fire fighting also contributed to loss.

Loss $1,467,000,000 (production output impacted to 50% for 8 months).

Figure 6.11 Offshore platform fire incident, Indian Ocean, 2005.

6.6.10 2004

08.10.04
Mediterranean Sea, Egypt, Offshore Oil Production, Explosion and Fire

Fire during well control incident (blow-out) on production platform spread to nearby jack-up rig.

Loss $190,000,000.

07.10.04
Mediterranean Sea, Egypt, Offshore Oil Production, Explosion and Fire

Blow-out on jack-up rig, fire incident spread to adjacent production platform.

Loss $190,000,000.

04.23.04
Illiopolis, Illinois, USA Chemical Plant, Explosion and Fire

Human error caused the release of vinyl chloride vapors during maintenance activities that exploded and caused plant fires.

5 Fatalities, Loss $150,000,000.

01.20.04
Gresik, East Java, Indonesia, Petrochemical Plant, Fire

Machine overheated fire spread to compound.

2 fatalities, $100,000,000.

01.19.04
Skikda, Algeria, Gas Processing Plant (LNG), Explosion and Fire

Incident released a large amount of hydrocarbons, which was ignited by nearby boiler.

27 fatalities, loss $470,000,000.

6.6.11 2003

07.28.03
Karachi, Pakistan, Tanker Operations, Oil Spillage

Tanker ran aground near the Karachi port and cracked into two pieces. 28,000 tons of crude oil spilled into the sea.

Loss unknown.

07.08.03
Harare, Zimbabwe, Terminal, Explosion and Fire

During offloading of a tanker it caught fire and exploded, allegedly from nearby smoking.

Loss $160,000,000.

01.06.03
Fort McMurray, Alberta, Canada, Oil Sand Oil Production Facility, Explosion and Fire
Hydrocarbon leak from piping.
Loss $120,000,000.

6.6.12 2002

11.22.02
Port of Mohammedia, Morocco, Refinery, Explosion and Fire
Waste oil contacted hot equipment.
2 fatalities, loss $130,000,000.

01.31.02
Raudhatain, Kuwait, Oil and Gas Gathering/Booster Station, Explosion and Fire
Leak from pipeline was ignited from nearby power substation.
4 fatalities, loss $150,000,000.

6.6.13 2001

09.21.01
Toulouse, France, Petrochemical Plant, Explosion
Off-spec ammonium nitrate storage exploded in warehouse, destroying plant.
30 fatalities, $430,000,000 loss.

08.14.01
Lemont, Illinois, USA, Refinery, Fire
Fire in crude distillation unit.
Loss $574,000,000.

05.15.01
Roncador Field, Campos Basin, Brazil, Production Explosion and Fire, Drilling Rig Sunk.
Improper tank drainage operations during maintenance.
11 fatalities, loss $500,000,000.

04.21.01
Carson City, California, USA, Refinery, Fire
Pipe leak resulted in fire in coker unit.
Loss $120,000,000.

04.09.01

Wickland, Aruba, Dutch Antilles, Refinery, Explosion and Fire

Valve failure during maintenance on pump strainer in Visbreaker caused oil spill that auto-ignited.

Loss $160,000,000.

6.6.14 2000

06.25.00

Mina Al-Almadi, Kuwait, Refinery, Explosion and Fire

Failure on condensate piping during leak repair, 3 crude units damages, and 2 reformer units destroyed.

5 fatalities, loss $506,000,000.

6.6.15 1999

12.12.99

French Atlantic Coast, Tanker, Oil Spillage

Tanker broke apart and sank spilling 3 million gallons of heavy oil into the sea.

Loss unknown.

03.25.99

Richmond, California, USA, Refinery, Explosion and Fire

Failure of valve bonnet on hydrocracker vessel released gas with vapor cloud explosion and fire.

Loss $110,000,000.

6.6.16 1998

12.03.98

Gulf of Mexico, USA, Offshore Oil Production, Explosion

Topside module dropped during installation, fell on barge causing explosion.

Loss $110,000,000.

09.25.98

Longford, Victoria, Australia, Gas Processing Plant

Hot oil pump shutdown caused vessel cool-down when hot oil reintroduced it caused brittle fracture in a heat exchanger that ruptured.

Loss $633,000,000.

6.6.17 1997

12.25.97

Bintulu, Sarawak, Malaysia, Gas Processing Plant, Explosion and Fire

Combustion event in an air separation unit by explosive burning of aluminum heat exchanger elements in the presence of liquid oxygen, such that the elements ruptured explosively.

Loss $275,000,000, 2 years' business interruption for plant rebuilding.

06.22.97

Deer Park, Texas, USA, Petrochemical Plant, Explosion and Fire

Check valve failure in pipeline to compressor causing rupture.

$140,000,000 loss.

6.6.18 1996

07.26.96

Catus, Reforma, Mexico, Gas Processing Plant, Explosion and Fire

Gas release during maintenance of pumps due to faulty isolation, which caused a vapor cloud explosion.

Loss $140,000,000.

6.6.19 1995

None reported greater than $100,000,000.

6.6.19.1 Summary of Recent US Outer Continental Shelf Incidents

Table 6.3 provides a summary of incidents from the US OCS, i.e., Gulf of Mexico (GOM) and offshore the Pacific Coast (PAC), from 2007 to mid-2013 (08.16.13) from the BSEE database. The trend for the number of fire and explosion incidents during this period appears to be very slightly decreasing (see Table 6.4).

6.7. SUMMARY

According to the worldwide petroleum and chemical insurance market estimates for the period 1993–2013 there have been about 1100 major insurance claims (i.e., major incidents) amounting to approximately $32 billion (for property damage and business interruption). Their analysis estimates that the worldwide risk has been constant over this period, i.e., the average frequency and cost impact has been a constant trend, neither increasing nor decreasing. This equates on average to 110 losses totaling $2–3 billion per year.

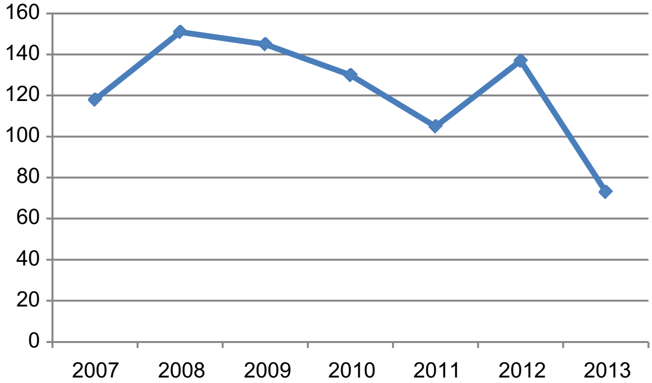
Table 6.3 US OCS Incidents by Category, 2007–2013

Type	2007		2008		2009		2010		2011		2012		2013 ytd	
	GOM	PAC	GOM	PAC	GOM	PAC	GOM	PAC	GOM	PAC	GOM	PAC	GOM	PAC
Fatalities	5	0	11	0	4	0	12	0	3	0	4	0	1	0
Injuries*	423	17	318	14	285	16	273	12	213	18	2	34	122	10
Loss of well control*	7	0	8	0	6	0	4	0	3	0	4	0	7	0
Fire/explosion	110	8	139	12	133	12	126	4	103	2	131	6	48	4
Collisions*	20	1	22	0	29	0	8	0	14	0	9	1	15	0
Spills $\geq$ 50 bbls	4	0	33	0	11	0	5	0	3	0	8	0	^	^
Other*	268	27	278	36	308	28	155	17	186	15	236	41	142	21
Incident total for the year	837	53	809	62	776	56	583	33	524	35	648	82	335	35
Combined total for the year	890		871		832		616		559		730		370	

*Effective July 17, 2006, BOEMRE revised the regulations for incident reporting. Related to this chart, changes were made to the reporting criteria for Injuries, Loss of Well Control incidents, Collisions, and Other Incidents. Thus the number of incidents shown in these categories for 2006 and beyond may be affected by this change when compared to previous years.

Note: Incidents may be counted in more than one category. For example, a fire resulting in an injury would be counted in both the fire and injury category.

Table 6.4 Number of Fire and Explosion Incidents in US OCS from 2007 to 2013 (Number of incidents for 2013 prorated for year from mid-year data)



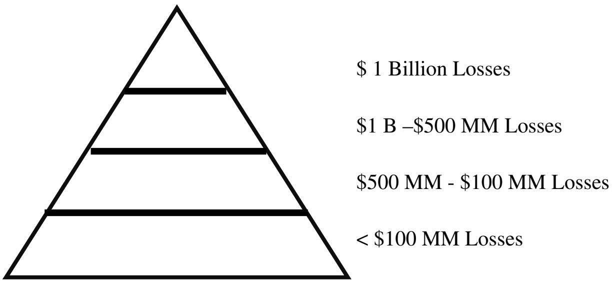


Figure 6.12 Loss triangle.

Additionally, these losses would fit a traditional loss incident ratio triangle with ever increasing number of losses as the magnitudes of the losses decreases (i.e., as the steps in the triangle widen) (see Figure 6.12).

New projects are now (circa 2010) in the region of $50 billion, which equates to the Deepwater Horizon incident loss, and the potential for even larger losses from a single incident is still a possibility. The industry must do more to prevent these incidents and improve so the loss trend decreases.

Most of the incidents appear to occur during periods of non-typical operations, i.e., maintenance activities, startup or shutdown, drilling activities, etc. During these periods more attention, knowledge, and experience are required from personnel to safely manage the facility. This therefore implies that the facility can also be enhanced by technical hazard identification and engineering to account for and eliminate these concerns in addition to other process safety management techniques.

Any high concentration of personnel activities may suffer a corresponding high fatality incident. Concentrated areas of personnel such as offshore installations, drilling activities, offices, or living quarters near process high risks or transportation means are all potential candidates where a minor incident may result in considerable life loss. Where equipment involved in these tasks is complex the risk of an incident becomes greater. The majority of incidents occur due to lack of system integrity—leaks and mechanical failures. Ignition sources generally tend to be due to local hot surfaces. Large process incidents are the direct result of the inability to isolate fuel supplies from the incipient event. Where large volumes of hazardous materials are processed, handled, or stored, such as pipelines, wellhead, or process arrangements, any escalation in the incident may result in higher levels of injuries or damages that may not have otherwise occurred.

FURTHER READING

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CHAPTER 7

Risk Analysis

Everyone in the engineering profession is familiar with Murphy's Law. "If anything can go wrong, it will." I also prefer to remember the corollary, which states, "If a series of events can go wrong, it will do so in the worst possible sequence." Risk analysis is a sort of Murphy's Law review in which events are analyzed to determine the destructive nature they might produce.

Risk analysis is a term that is applied to a number of analytical techniques used to evaluate the level of hazardous occurrences. Technically, risk analysis is a tool by which the probability and consequences of incidents are evaluated for hazard implications. These techniques can be either qualitative or quantitative, depending on the level of examination required.

Risk analysis can be defined by four main steps:

1. Identify incident occurrences or scenarios.
2. Estimate the frequency of the occurrences.
3. Determine the consequences of each occurrence.
4. Develop risk estimates associated with frequency and consequence.

7.1. RISK IDENTIFICATION AND EVALUATION

The basic methodology adopted for the formal risk evaluation in the petroleum and related industries both for existing facilities and new projects, typically contains the following steps:

1. **Definition of the Facility**—A general description of the facility is identified. Inputs and outputs to the facility are noted, production, manning levels, basic process control system (BPCS), emergency shutdown (ESD) arrangements, fire protection philosophy, assumptions, hazardous material compositions, etc.
2. **Identification of Hazards**—A list of the processes and storage of combustible materials and the process chemistry that can precipitate an incident.

Hbk of Fire and Explosion Protection, http://dx.doi.org/10.1016/B978-0-323-31301-8.00007-6

3. **Development of Incident Events**—Identified scenarios that can cause an incident to occur.
4. **Frequency Analysis**—An examination of the probabilities or likelihoods of an incident to occur.
5. **Consequence Modeling**—A description of the possible incidents that can occur; the level of detail depends on the nature of the risk that has been identified.
6. **Impact Assessment**—The development of the potential severity of the incident in terms of injuries, damage, business interruption, environmental impact, and public reaction.
7. **Summation of Risk**—The combination of severity and probability estimates for an incident to occur.
8. **Effects of Safety Measures**—An evaluation of the mitigation effects of layers of protective systems of different integrities on the effects or prevention of an incident.
9. **Review Against Risk Acceptance Criteria**—The comparison of an incident risk that is supplemented by the selected safety measures to achieve the requirements for company risk management levels.

During the process hazard identification and definition phase of project design, a basic process control system (BPCS) strategy is normally developed in conjunction with heat and material balances for the process.

Both qualitative and quantitative evaluation techniques may be used to consider the risk associated with a facility. The level and magnitude of these reviews should commensurate with the level of risk that the facility represents. High value, critical facilities, or employee vulnerability may warrant high review levels. While unmanned, "off-the-shelf," low hazard facilities may suffice with only a checklist review. Specialized studies are performed when in-depth analysis is needed to determine the cost-benefit analysis of a safety feature or to fully demonstrate that the intended safety feature has the capability to fully meet prescribed safety requirements.

Generally major process plants and offshore facilities represent considerable capital investment and have a high number of severe hazards associated with them (vessel upsets, pipe failures, blow-outs, ship collisions, etc.). They cannot be prudently evaluated with only a checklist type of review. Some level of quantifiable evaluation reviews are usually prepared to demonstrate that that the risk of these facilities is within public, national, industry, and corporate expectations.

These studies may also point out locations or items of equipment that are critical or single point failures for the entire facility. Where such points are identified, special emphasis should be undertaken so that events leading up to such circumstances are prevented or eliminated.

The following is a brief description of the typical risk analyses that are undertaken in the process industries.

7.2. QUALITATIVE REVIEWS

Qualitative reviews are team studies based on the generic experience of knowledgeable personnel and do not involve mathematical estimations. Overall these reviews are essentially checklist reviews in which questions or process parameters are used to prompt discussions of the process design and operations that would develop into an incident scenario of interest due to an identified risk.

- **Checklist or Worksheet**—A standard listing that identifies common protection features required for typical facilities, which is compared against facility design and operation. Risks are expressed by the omission of safety systems or system features.
- **Preliminary Hazard Analysis (PHA)**—A qualitative investigative safety review technique that involves a disciplined analysis of the event sequences that could transform a potential hazard into an incident. In this technique, the possible undesirable events are identified first and then analyzed separately. For each undesirable event or hazard, possible improvements or preventive measures are then formulated. The results of this methodology provide a basis for determining which categories of hazards should be looked into more closely and which analysis methods are most suitable. Such an analysis also proves valuable in the working environment for which activities lacking safety measures can be readily identified. With the aid of a frequency and consequence diagram, the identified hazards can then be ranked according to risk, allowing measures to be prioritized to prevent accidents.
- **Safety Flowchart**—A general flowchart that identifies events that may occur at a facility during an incident. The flowchart can identify possible avenues the event may lead to and the protection measures available to mitigate and protect the facility. It will also highlight deficiencies. The use of a flowchart helps the understanding of events by

personnel unfamiliar with industry risks and safety measures. It portrays a step-by-step scenario that is easy to follow and explain. In-depth risk probability analysis can also use the flowchart as a basis of an event tree or failure mode and effects analysis.

- **What-If Analysis/Review (WIA)**—A safety review method by which "what-if" investigative questions (i.e., brainstorming and/or checklist approach) are asked by an experienced and knowledgeable team of the system or component under review where there are concerns about possible undesired events. Recommendations for the mitigation of identified hazards are provided.
- **Bow-Tie Analysis**—A type of qualitative PHA. The Bow-Tie PHA methodology is an adaptation of three conventional system safety techniques: Fault Tree Analysis, Causal Factors Charting, and Event Tree Analysis. Existing safeguards (barriers) are identified and evaluated for adequacy. Additional protections are then determined and recommended where appropriate. Typical cause scenarios are identified and depicted on the pre-event side (left side) of the Bow-Tie diagram. Credible consequences and scenario outcomes are depicted on the post-event side (right side) of the diagram, and associated barrier safeguards are included. One attribute of the Bow-Tie method is that in its visual form, it depicts the risks in ways that are readily understandable to all levels of operations and management. Bow-Tie reviews are most commonly used where there is a requirement to demonstrate that hazards are being controlled, and particularly where there is a need to illustrate the direct link between the controls and elements of the management system.
- **HAZOP**—HAZOP is an acronym for Hazard and Operability Study. It is a formal qualitative investigative safety review technique. It is undertaken to perform a systematic critical examination of a process and engineering plans of new or existing facilities. Its main objective is to assess the hazard potential that arises from potential deviation in design specifications and the consequential effects on the facilities as a whole. This technique is usually facilitated by an experienced leader who guides a qualified team using a set of prompting deviation guidewords: i.e., More/No/Reverse Flow; High/Low Pressure, High/Low Temperature, etc., to identify concerns from the intended design (see Figure 7.1) for a specific process under examination. From these guidewords the team can identify the most probable scenarios

	GUIDE WORD DESIGN PARAMETER	MORE	LESS	NONE	REVERSE	PART OF	AS WELL AS	OTHER THAN
*	FLOW	HIGH FLOW	LOW FLOW	NO FLOW	BACK FLOW			LOSS OF CONTAINMENT
*	PRESSURE	HIGH PRESSURE	LOW PRESS.	VACUUM		PARTIAL PRESSURE		
*	TEMPERATURE	HIGH TEMP	LOW TEMP				CRYOGENIC	
*	LEVEL	HIGH LEVEL	LOW LEVEL	NO LEVEL				LOSS OF CONTAINMENT
* & **	COMPOSITION OR STATE	ADDITIONAL PHASE	LOSS OF PHASE		CHANGE OF STATE	WRONG CONCENTRATION	CONTAMINANTS	WRONG MATERIAL
* & **	REACTION	HIGH RXN RATE	LOW RXN RATE	NO REACTION	REVERSE REACTION	INCOMPLETE REACTION	SIDE REACTION	WRONG REACTION
**	TIME	TOO LONG	TOO SHORT					WRONG TIME
**	SEQUENCE	STEP TOO LATE	STEP TO EARLY	STEP LEFT OUT	STEP BACKWARDS	PART OF STEP LEFT OUT	EXTRA REACTION INCLUDED	WRONG ACTION TAKEN

* CONTINOUS OPERATION
** BATCH OPERATION

Common Other Parameters: Common : Corrosion, Utility Failure, Vapor Pressure, pH, Heat Capacity, Mixing, Flash Point, Viscosity, Static charge buildup, Startup-Shutdown

Common Chemical Process Other Parameters: Mischarge of Reactants: overcharge of monomer, undercharge of limiting reagent, excess catalyst, wrong catalyst, incorrect sequence of addition or inadvertent addition. Mass Load Upset/Composition & Concentration: accumulation of unreacted materials, non-uniform distribution of gas, settling of solids, phase separation, foaming, or use of re-work. Contamination of raw materials or equipment: water, rust, chemical residue, leaking heat transfer fluid, or cleaning products

Figure 7.1 HAZOP deviation matrix.

that deviate from the design intention and may result in a hazard or an operational problem to the process, which may not have been previously addressed or identified. The process protection safeguards (e.g., instrumentation, alarms, spacing, etc.) are also evaluated, during the identified deviation scenarios, to determine their adequacy. The consequences of the hazard and measures to reduce the frequency with which the hazard will occur are then discussed to determine the risk to the facility. If the risk is determined not acceptable, the team will then suggest improvements, i.e., recommendations are made that would remove or mitigate the hazard to an acceptable level. HAZOP safety reviews have gained wide acceptance in process industries (i.e., oil, gas, chemical processing) as an effective tool for plant safety and operability improvements. HAZOPs are also used in a wide range of other industries, and there is extensive support in the form of published literature and software packages.

- **Chemical Hazard Analysis (CHA)**—A CHA is derived from HAZOP methodologies and can be considered a precursor to a PHA. It is applicable to analyzing petrochemical or chemical processing hazards. The same seven basic HAZOP guidewords are used: no, more, less, part of, reverse, as well as, and other. While CHA assumes the proposed chemical reaction is basically safe when conducted as specified (should be confirmed) and focuses on the consequence of operating outside of the specifications. The consequences are then considered and potential hazards documented for reference. There may be unknown consequences that require further research and/or experimentation. The CHA is used for reference during future PHAs.

- **Interaction Matrix**—The interaction matrix is a tool for understanding potential reactions between materials that is sometimes used in petro-chemical or chemical process reviews. A typical matrix will list all the chemical raw materials, catalysts, solvents, potential contaminants, materials of construction, process utilities, human factors, and any other pertinent factors on the axis. Process utilities are generally listed on only one axis, as utility interactions are outside the scope of process development (these are usually addressed later on during process HAZOPs). Interaction of three or more components is generally handled by listing combinations as separate entries. Each interaction is then considered and the answer documented. Documentation should include notes on the anticipated interactions, specific references, and previous incidents. An interaction matrix is best prepared by a chemist or chemical engineer, then circulated to others to fill in open blocks, make modifications, and review. There may be interactions with unknown consequences that require further research and/or experimentation.
- **Layers of Protection Analysis (LOPA)**—A method of analyzing the likelihood (frequency) of a harmful outcome event based on an initiating event frequency and on the probability of failure of a series of independent layers of protection capable of preventing the harmful outcome. LOPA is a recognized technique for selecting the appropriate safety integrity level (SIL) of a safety instrumented system (SIS) per the requirements of ANSI/ISA-84.00.01 or IEC 61508. Independent protection layers (IPL) are only those protection systems that meet the following criteria:

i) *Risk Reduction*: The protection provided reduces the identified risk by a large amount, i.e., a minimum of 10^{-1}.

ii) *Specificity*: An IPL is designed solely to prevent or to mitigate the consequences of one potentially hazardous event (for example, a runaway reaction, release of toxic material, a loss of containment, or a fire). Multiple causes may lead to the same hazardous event and, therefore, multiple event scenarios may initiate action of the IPL.

iii) *Independence*: An IPL is independent of other protection layers associated with the identified danger.

iv) *Dependability*: It can be counted on to do what it was designed to do, and that both random and systematic failures are addressed in the design.

- **Fishbone Diagram**—A cause and effect investigative technique. The diagram is used to identify all of the contributing root causes likely to be causing a problem. Fishbone diagrams organize potential causes into a graphical format that facilitates an organized approach to problem solving. They are also known as Cause and Effect Diagrams, Fishbone Diagrams, Ishikawa Diagrams, Herringbone Diagrams, and Fishikawa Diagrams. They are called fishbone because they resemble the bones of a fish. There are usually many contributors to a problem, so an effective Fishbone Diagram will have many potential causes listed in categories and sub-categories. The detailed sub-categories can be generated from either or both of two sources: Brainstorming by group/team members based on prior experienceso data collected from check lists or other sources. A closely related Cause & Effect analytical tool called the "5-Why" approach (the "5" in the name derives from an empirical observation on the number of iterations typically required to resolve the problem) can be helpful in constructing the fishbone diagram to drill down to the root causes. See Figure 7.2.
- **Relative Ranking Techniques (DOW and Mond Hazard Indices)**—This method assigns relative penalties and awards points for hazards and protection measures, respectively, in a checklist accounting form. The penalties and award points are combined into an index that is an indication of the relative ranking of the plant risk.
- **Security Vulnerability Analysis (SVA)**—In April 2007, the US Department of Homeland Security (DHS) issued the Chemical Facility

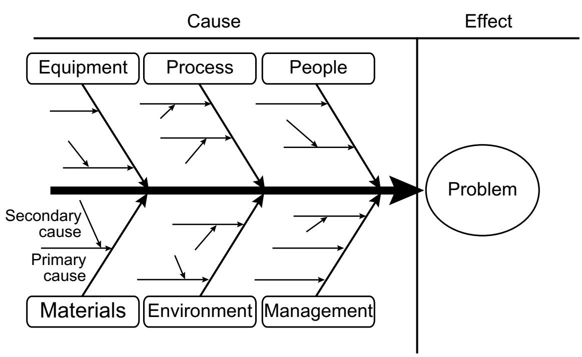

Figure 7.2 Fishbone diagram.

Anti-Terrorism Standard (CFATS). The purpose of the DHS is to identify, assess, and ensure effective security at high risk chemical facilities. Included in this standard is the requirement for facilities handling chemicals above a threshold amount to submit a SVA for DHS review and approval along with a site security plan (SSP). A SVA evaluates risk from deliberate acts that could result in major incidents. It is performed in a systematic and methodical manner to analyze potential threats and evaluates these threats against plant vulnerabilities. From this analysis, it determines possible consequences and whether safeguards to prevent or mitigate their occurrence are recommended.

7.3. QUANTITATIVE REVIEWS

Quantitative reviews are mathematical estimations that rely on historical evidence or estimates of failures to predict the occurrence of an event or incident. These reviews are commonly referred to as Quantitative Risk Assessments (QRAs).

- **Event Tree**—A logic model that mathematically and graphically portrays the combination of failures of events and circumstances in an incident sequence, expressed in an annual estimation.
- **Fault Tree Analysis (FTA)**—A deductive technique that focuses on one particular incident, often called a top event, and then constructs a logic diagram of all conceivable event sequences (both mechanical and human) that could lead to that incident. It is usually a logic model that mathematically and graphically portrays various combinations of equipment faults, failures, and human errors that could result in an incident of interest, expressed in an annual estimation.
- **Failure Mode and Effects Analysis (FEMA)**—FEMA is a tabulation of facility equipment items, their potential failure modes, and the effects of these failures on the equipment or facility. Failure mode is simply a description of what caused the equipment to fail. The effect is the incident, consequence, or system response to the failure. It is usually depicted in tabular format and expresses failures in an annual estimation. A FEMA is not useful for identifying combinations of failures that can lead to incidents. It may be used in conjunction with other hazard identification techniques such as HAZOP for special investigations such as critical or complex instrumentation systems. There is also a Failure Modes, Effects, and Criticality Analysis (FMECA), which is a variation of FMEA that includes a quantitative estimate of the significance of the consequence of a failure mode.

PHA, What-If, Bow-Tie, and HAZOP reviews are the most common industry qualitative methods used to conduct process hazard analyses, while SVAs are typically applied for process security analyses requirements. It is qualitatively estimated that up to 80% of a company's hazard identification and process safety analyses may consist of PHA, What-If, Bow-Tie, and HAZOP reviews, with the remaining 20% from Checklist, Fault Tree Analysis, Event Tree, Failure Mode, and Effects Analysis, etc.

7.4. SPECIALIZED SUPPLEMENTAL STUDIES

Specialized studies are investigations that verify the ability of a facility to perform effectively during an emergency, generally by mathematical estimates. They are used extensively to justify the necessity or deletion of a safety system. The most common studies are listed below, but every facility is unique and may require its own investigative requirements, (e.g., for offshore environments—ship collisions). For simple unmanned wellhead platforms located in warm shallow waters (i.e., Gulf of Mexico), these analyses are relatively simple to accomplish, but for manned integrated production, separation, and accommodation platforms located in deep cold waters (e.g., North Sea), these analyses are typically extensive. These special analyses are prepared from a quantifiable risk analysis and a total risk scenario is then presented that depicts the estimated incident effects.

- **Leak Estimation**—A mathematical model of the probability and amount of potential hydrocarbon release that may occur from selected processes or locations. Usually, the most likely high risk inventory (i.e., highly toxic or combustible gas) is chosen for risk estimates.
- **Depressurization and Blowdown Capabilities**—A mathematical calculation of the system sizing and amount of time required to obtain gas depressurization or liquid blowdown according to the company's philosophy of plant protection and industry standards (i.e., API RP 521).
- **Combustible Vapor Dispersion (CVD)**—A mathematical estimation of the probability, location, and distance of a release of combustible vapors that will exist until dilution naturally reduces the concentration to below the lower explosive limit (LEL), or will no longer be considered ignitable (typically defined as 50% of the LEL). For basic studies, the normal expected wind direction is utilized (based on historical wind rose data). Real-time modeling is sometimes used during incident occurrence to depict area of vapor coverage on plant maps for visual understanding of the affected areas based on wind speeds and direction.

- **Explosion Overpressure**—A mathematical estimation of the amount of explosive overpressure force that may be expected from an incident based on combustible vapor release. It is portrayed as an overpressure radii from the point of initiation until the overpressure magnitudes are of no concern, i.e., typically less than 0.02 bar (3.0 psia). Evaluations performed for enclosed areas will also estimate the amount of overpressure venting capability available.
- **Survivability of Safety Systems**—An estimation of the ability for safety systems to maintain integrity from the effects of explosions and fires. Safety systems may include Emergency Shutdown System (ESD), depressurization, fire protection—active and passive, communication, emergency power, evacuation mechanisms, etc.
- **Firewater Reliability**—A mathematical model of the ability of the firewater system to provide firewater upon demand by the design of the system without a component failure, e.g., a Mean Time Between Failure (MTBF) analysis.
- **Fire and Smoke Models**—A mathematical estimation model depicting the duration and extent of heat, flame, and smoke that may be generated from the ignition of a release of material that may produce combustion. The results of these estimates are compared against protective mechanisms (e.g., firewater, fireproofing, etc.) afforded to the subject area to determine adequacy.
- **Emergency Evacuation Modeling**—A study of the mechanisms, locations, and time estimates to complete an effective removal of all personnel from an immediately endangered location or facility.
- **Fatality Accident Rates (FAR) or Potential Loss of Life (PLL)**—A mathematical estimation of the level of fatalities that may occur at a location or facility due to the nature of work being performed and protection measures provided. It may be calculated at an annual rate or for the life of the project.
- **Human Reliability Analysis (HRA) or Human Error Analysis**—An evaluation method to determine the probability of a system-required human action, task, or job that needs to be completed successfully within the required time period and that no extraneous human actions detrimental to system performance will need to be performed. It provides quantitative estimates of human error potential due to work environment, human-machine interfaces, and required operational tasks. Such an evaluation can identify weaknesses in operator interfaces with

a system, demonstrate quantitatively improvements in human interfaces, improve system evaluations by including human elements, and can demonstrate quantitative prediction of human behavior.

- **Cost-Benefit Analysis**—A review that is a determination of the total value of an investment's inputs and outputs. It is used to evaluate the justification of safety improvements.
- **CHAZOP**—A Computer Hazard and Operability Study. A structured qualitative study of control and safety systems to assess and minimize the effect of failures of subsystems impacting the plant or affecting the ability of an operator to take corrective action. It is based on HAZOP methodology, but specialized for control and safety systems, and uses the appropriate guidewords and parameters applicable to such systems, such as—no signal, out of signal range, no power, no communication, I/O card failure, etc. The scope typically includes the entire safety instrumented loops, from the field instrumentation to the relays, PLCs (DCSSCADA, PSD/ESD, F&G), IO cards, circuit breakers, actuators, local control panels, power supply, etc.
- **EHAZOP**—An Electrical Hazard and Operability Study. A structured qualitative study of electrical power systems to assess and minimize potential hazards present due to incapability or failure of electrical apparatus. It is based on HAZOP methodology, but specialized for electrical systems, including appropriate guidewords and parameters applicable to systems such as power surges, 24 VDC supply failure, UPS availability, battery charging failure, lack of maintenance, etc. The scope typically includes power generation, transformation, transmission and distribution, load shedding philosophy, UPS, etc.

7.4.1 Offshore Specialized Studies

Additional specialized studies are sometimes specified for offshore facilities. These may include the following depending on the facility under review:

- Helicopter, ship, and underwater vessel collisions
- Possibility of falling objects (from platform crane(s) or drilling operations).
- Extreme weather conditions
- Reliability or vulnerability of stability, buoyancy, and propulsion systems (for floating installations or vessels). See Figure 7.3.
- Survivability of a Temporary Safe Refuge (TSR)

Figure 7.3 Lack of adequate buoyancy for semi-submersible platform.

7.5. RISK ACCEPTANCE CRITERIA

A numerical level of risk acceptance is specified where quantitative evaluation of the probabilities and consequences of an incident have been performed. The documentation may also be used by senior management for budgetary decisions or for additional cost-benefit analyses. The values of risk for many industries and daily personnel activities have been published and are readily available for comparison. These comparisons have generally formed the basis of risk acceptance levels that have been applied in the process industries in various projects.

Usually the process industry level of risk for a particular facility is based on one of two parameters. The average risk to the individual i.e., Fatality Accident Rate (FAR) or Potential Loss of Life (PLL) or the risk of a catastrophic event at the facility, a Quantified Risk Analysis (QRA). The risk criteria can be expressed in two manners. Risk per year (annual) or facility risk (lifetime). For purposes of consistency and familiarity, all quantifiable risks are normally specified as annually. Where value analysis is applied for cost comparisons of protection options, a lifetime risk figure is normally used to calculate the cost-benefit value.

It has been commonly acknowledged in the petroleum and chemical industries that the average risk to an individual at a facility should not generally exceed a value in the order of 1×10^{-3} per year. The facility risk is

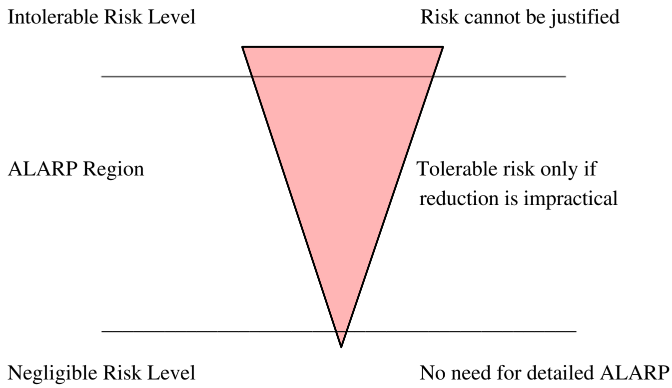

Figure 7.4 ALARP principal.

the total frequency of an event for each main type of incident. Similarly, for most petroleum and chemical facilities, the facility risk should not generally exceed a value in the order of 1×10^{-4} per year.

Where risks are higher than normally acceptable and all reasonable mitigation measures have been examined to find out value and practicality, the principle of risk as low as reasonably practical applies. Where the available risk protection measures have been exhausted and the level of risk is still higher than an accepted numerical value, the risk would be considered "As Low As Reasonably Practical" (ALARP). See Figure 7.4.

7.6. RELEVANT AND ACCURATE DATA RESOURCES

Risk evaluation methods should use data that is relevant to the facility that is under examination. For example, leakage rates for a refinery in Texas may not be highly relevant, comparable, and pertinent to oil production operations in Wyoming. Both the environment and operations are different. Where other data is used an explanation should be provided to substantiate its use; otherwise, inaccurate assumptions will prevail in the analysis that may lead to misleading conclusions. Where highly accurate data is available, the findings of a quantitative risk evaluation will generally only be within an order of magnitude of 10 of the actual risk levels, since some uncertainty of the data to the actual application will always exist.

All quantifiable evaluation documentation should be prepared so that it conforms to the nature of the company's risk evaluation procedures or policies (i.e., compatible with other risk evaluations for comparative purposes and utilization of data resources), and since it may be required for submittal to governmental agencies.

Cost estimates can be prepared to perform any portion or all the risk evaluations for a particular facility or installation based on the manpower necessary for each portion of the analysis (field surveys, data collection, data evaluation and verification, analysis and conclusions) and the size and complexity of the facility.

7.7. INSURANCE RISK EVALUATIONS

In the petroleum and chemical industries, insurance industry surveyors as part of their evaluations typically independently estimate the probable maximum loss (PML) a facility may suffer by performing a calculation of the most harmful catastrophic event that may occur at the installation. A potential vapor cloud explosion at the facility (where this is applicable) is usually the event that is considered. By examining such high loss potentials, i.e., the PMLs, the maximum risk level can be determined and therefore the insurance coverages that are necessary can be defined, based on this evaluation. As an example, the largest isolatable volatile hydrocarbon inventory for a process unit is identified, the vapor cloud potential is estimated, and by determining the explosive overpressures and resultant damage, a loss estimate for the replacement value of equipment is determined, and therefore the insurance rate for this exposure can be determined.

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CHAPTER 8

Segregation, Separation, and Arrangement

The most inherent safety feature that can be provided in an industrial process facility is the segregation, separation, and arrangement of equipment and processes. Some publications emphasize that separation is the prime safety feature that can be employed at any facility. This is true from the viewpoint of preventing exposure to personnel or facilities outside the area of concern. However, this becomes somewhat impractical for large process plants and offshore production platforms that are designed and constructed today. Undoubtedly, manned (both permanent and temporary) locations at process facilities should be located as remotely as possible from high risk locations. Duplicate process trains, a high number of process vessels, multiple storage tanks, and numerous incoming and outgoing pipelines limit the possibilities of remotely locating every single high hazard process risk from each other. Additionally, operational efficiencies would be affected and construction costs would increase. The more practical approach is to combine the features of segregation, separation, and arrangement in a fashion that leads to a more organized and operationally acceptable process facility. This represents the lowest practical risk but still avoids crowding.

Potential future expansion should be addressed and space provided for known and unknown vessel needs. Logical and orderly expansion can only be made if provision is undertaken at the time of original facility installation.

Hbk of Fire and Explosion Protection, http://dx.doi.org/10.1016/B978-0-323-31301-8.00008-8

The master plan should be frozen and only altered if a risk analysis of the changes is acceptable.

Surface runoff has to be considered with equipment layout. If surface runoff from one area goes directly to another area, the feature of separation is then not accomplished.

8.1. SEGREGATION

Segregation is the grouping of similar processes into the same major area. This allows an economical approach to achieve the maximum protection to all the high risk units while a less protection is given to low risk equipment. The segregated high hazard areas can then also be further separated as far as necessary from other areas of the facility and the general public. Some offshore facilities that do not have the luxury of large amounts of space generally have to use segregation as the prime means of protection supplemented with fire and explosion resistant barriers for most areas.

The major facility segregation categories are process, storage, loading/unloading, flaring, utilities, and administration. Each of these categories can be further subdivided into smaller risks, such as individual units for the process areas or tank farms subdivided into product types. The major segregation areas would be provided with maximum spacing distances while the subdivided areas are provided with not as much, depending on the protection afforded the area and individual risk of the units. Most petroleum and chemical processes are arranged in a systematic fashion from reception of raw materials, to manufacturing, to storage, and output of

finished products. This arrangement is complementary to the needs of segregation for the purposes of loss prevention, as high risk processes are grouped together and low risk but critical utilities and offices are grouped remotely from these exposures. Layout cost controls for continuous flow operations also require that the distance products move is minimized. The exact technical process selected for a hydrocarbon or chemical process will also ultimately influence the general layout (see Figure 8.1).

Some designs for offshore platforms have segregated the process (i.e., separation, gas compression, etc.), facilities furthest from accommodation and utility support. Drilling modules are sited between process and utility support modules based on the level of relatively lower risk drilling in a defined reservoir may represent versus possible process incidents.

Each safety system should be diversified as much as possible to avoid the possibility of a single point failure event. A prime example is the firewater supply should be pumped into a facility at several separate and remote locations.

Tank farms are usually segregated based on the service and type of tank for economic reasons, besides segregating by the level of risk. See Figure 8.2.

Flare	Inlets	Process	Storage	Loading	Utility	Offices

Figure 8.1 Simplified process plant segregation arrangements.

Figure 8.2 Tank farm segregation.

8.2. SEPARATION

Process facilities have been traditionally separated by the use of "spacing tables" (i.e., specified distances required between certain plant occupancies) which each organization prepares based on their individual evaluations. Insurance spacing tables (i.e., OIL, OIA, IRI, etc.) are also commonly used in most industries. It appears these may have been formulated based on a few selective historical incidents and do not appear to be scientifically based on the current method of determining explosive or fire damage possible. They cannot account for all the possible design quantities of production process. They may provide too much or too little spacing in some instances for the risks involved. Second, some facilities were constructed before tables were widely applied or were modified without much consideration of a spacing table. Therefore, any relocation of facilities using a spacing table would be very costly to retroactively apply or enforce. Some petroleum companies even considered the insurance spacing requirements as too conservative (see Table 8.1). A survey of "proprietary" industry spacing charts indicates they are all not similar. Some have many spacing differences for some occupancies, and a consolidated industry spacing chart based on an operating company's charts would not include particulars from all, although "typical" spacing tables are now being publically published, i.e., CCPS guidelines. An obvious disparity also exists between operating company spacing charts and the insurance industry spacing recommendations. Also, the mandate for any facility project engineer is to save space and materials to achieve a less costly and easily built facility. He will therefore always

Table 8.1 Comparison of Industry and Insurance Spacing Tables

Spacing Requirement	Insurance Industry Requirement* (ft.)	Petroleum Industry Average** (ft.)	Difference from Insurance Requirement (ft.)	Average Distance for All (ft.)
Control room to compressor	100	93	−7	90
Switchgear to compressor	100	65	−35	68
Process vessel to compressor	100	61	−39	65
Fired equip. to compressor	200	98	−102	111
Storage tank to compressor	250	126	−124	155
Storage tank to flare	300	158	−142	178
Storage tank to vessel	250	100	−150	150
Storage tank to fired equip.	350	125	−225	150
Pressure vessel to fired equip.	300	108	−198	131
Control room to fired equip.	50	78	+28	70
Control room to storage tank	250	145	−105	168

*Industrial Risk Insurers (IRI)—(circa 1990s).
**Average of six integrated petroleum operating companies—(circa 1990s).

desire to congest or compress the area for shorter piping runs, fewer pipe racks, etc., and would be theoretically at odds with the requirements of loss prevention.

Since most of the current facilities in operation today were built prior to the late 1990s, the spacing chart specification was probably utilized to initially plan the entire layout of facilities we see today. Only where a completely new facility has been recently or currently designed and built or upgrades to the facility may have been undertaken, could improvements in the analysis for necessary spacing have been undertaken.

Currently, there is much more guidance available to undertake plant spacing based on risk assessments. This guidance is especially prevalent for locating manned facilities, both permanent and temporary buildings, primarily due to recent incidents in which such facilities were placed too close to operating process units. Both industry standards (e.g., API) and insurance organizations guidelines (e.g., FM Global) now provide information for locating control rooms, temporary office trailers, etc., from fire and explosion process hazards.

For the application of a risk-based approach to spacing the following factors need to be considered:

- Fire, explosion, and toxic health effect hazards of the materials contained in the processed being accessed.
- The volume of the material in the process and how it is isolated or removed during an emergency.
- The strength of a process vessel to maintain integrity during exposure to a hydrocarbon fire.
- The manning and location of employees and contractors in a facility and the proximity to occupied facilities outside the plant.

- The concentration and value of equipment in a particular area.
- The criticality of the equipment to continued business operations.
- Possible fire and explosion exposures to the facility from adjacent hazards.
- The effectiveness of fire and explosion protective measures, both active and passive.
- The possibility of the flare to release liquids or un-ignited combustible vapors.

To achieve these principles the following features are usually adopted:

- Individual process units should be spaced so that incident in one will have minimal impact on the other.
- Utilities such as steam, electricity, and firewater should be separated and protected by the effects of an incident so that they may be continuously be maintained. Where large facilities or critical installations are present, the supply of these services from two or more remote locations should be considered.
- The most critical equipment for continued plant operation or highest valued unit should be afforded the maximum protection by way of location and spacing.
- Unusually hazardous locations should be located as far away as practical from other areas of the facility.
- Consideration should be given to the use of the general prevailing environmental conditions such as wind and terrain elevation to for the best advantage for spill and vapor removal. Facility equipment should not be located where they would be highly vulnerable to a major spill or vapor release.
- Consideration should be given to avoiding the adjacent exposures or other utilities that may transverse the site, i.e., pipelines, railroads, highways, power lines, aircraft, shipping routes (if offshore), etc.
- Adequate arrangements for emergency service access to all portions of the facility for firefighting, rescue, and evacuation means.
- Flare placement where the possibility of material release affecting the plant or outside exposures is minimized.

8.3. MANNED FACILITIES AND LOCATIONS

A primary design consideration for any oil, gas, or related facility should be the protection of employees, contractors, and the general public from the effects of an explosion, fire, or toxic gas release. In all cases, highly populated occupancies (e.g., control rooms) should be located as far as practical in the prevailing upwind direction from the process or storage areas where they would not be affected by incident in these locations. This is in direct contrast to the ideal technical location for a manned control building where it would be best to locate it in the middle of the plant where costs to connect it to controls and instrumentation would be less and it would be more convenient for field operations personnel to interface with the control room staff. Where a control cannot be practically located remote from a process area to avoid direct effects from an incident as identified by a risk analysis it should be provided with fire resistant, blast resistance, and protection against toxic vapor entry commensurate with the exposure.

All buildings have some degree of resistance to blast effects. Various industry references are available to provide guidance in determining the response of existing buildings and new building designs to an anticipated blast effect. A software program available to the industry identified by the acronym, Building Evaluation and Screening Tool—BEAST, developed by the Petroleum & Chemical Processing Industry Technology Cooperative (PIPITC), screens the response of conventional buildings to blast effects. Building damage levels specific to an organization that are higher than a set level predicted by BEAST may then be considered unacceptable and additional analysis or mitigation measures are required.

The siting of manned locations should be considered the highest safety priority in the layout of a process facility. The primary locations where the highest levels of personnel may be accumulated relatively close to hazards in process facilities are usually control rooms and offshore accommodations. Consequentially, an adequate risk analysis for both of these locations should be undertaken as part of any facility design scope. There are really no overwhelming reasons why both need to be near operating processes other than cost impacts and convenience to operating personnel. Historical evidence has dramatically shown that control rooms, and in the case of offshore platforms, accommodations, can be highly vulnerable to the effects of explosions, fires, and smoke if not adequately protected.

The following features should be considered for building arrangements:

- The short side of the building should face any potential explosion source.
- Buildings housing personnel not essential to the operation should be sited as far away as practical.
- Buildings should be sited away from congestion and confined areas that have the potential to build up explosive forces from a blast.
- Buildings should not be sited at lower elevations from sources of heavier than air commodities.
- Buildings should not be located downwind from potential hazardous release sources.
- Buildings should not be sited in a drainage path or low elevations where liquid releases would collect.

The ideal solution for an offshore facility is to locate the accommodation on a separate installation platform, linked by an interconnecting walkway bridge, spaced to avoid the effects of an incident from the production processes and the platform oil and gas risers. Inclusion of the facility control room can also be conveniently provided in the accommodation structure, increasing personnel safety and providing a cost benefit.

The latest designs for onshore plants cater to a centralized control room, well distanced from the operating facility with sub-control areas as part of a distributed control system (DCS). The sub-control areas are closer to the operating processes. Both contain fewer or no personnel and fewer process operating systems so the overall risk level for the facility from a major incident is lowered due to the dispersion of the control capability. The outlying control buildings, sometimes referred to as process interface buildings (PIBs) or satellite interface houses (SIHs), will still need to be sited or protected against impacts from explosions or fires.

8.4. PROCESS UNITS

Process units are the heart of any process facility and the location of the highest risk due to the possibility of a high volume material release that

may form a vapor cloud explosion, cause a major fire incident, or result in a toxic gas exposure. Both company risk assessments and insurance evaluations will therefore focus on these areas for the prediction of the highest plant damage or offsite effects from incident scenarios. Therefore, there is increased emphasis on the use of risk assessment in locating and arranging these process areas rather than strict reliance on a standard spacing table specification.

As process facilities are typically arranged for continuous flow production, the process units are arranged next to a central pipe rack to conveniently route incoming and outgoing pipelines. This pipe rack delineates one side of the process unit and restricts and may somewhat enclose the area. The process itself also usually contains large horizontal vessels, tall columns, collection drums, pumps, compressors, and specialized supporting equipment called "skids." These all may contribute to a congested area that increases the overall risk for the area. The main criteria used for intra-area process unit spacing is typically for maintenance access for cranes and work vehicles, but where high congestion is possible, additional consideration should be given to the need for area free air ventilation to easily dissipate vapors from an incident release and to provide access for emergency response activities (e.g., manual firefighting efforts). An arrangement that takes advantage of natural wind patterns may be advantageous for vapor dispersion purposes.

Process units also operate at high pressures, at high or low temperatures, having a large inventory of possibly flammable liquids above their atmospheric boiling point or toxic materials and therefore are more dangerous than other areas of process facilities.

8.5. STORAGE FACILITIES—TANKS

Tank farm areas require additional consideration for spacing not only between process hazards but from other storage tanks. Minimum tank, i.e., shell to shell, spacing is well defined and is usually in accordance with NFPA 30, Flammable and Combustible Liquids Code. It also includes spacing requirements from buildings and property lines.

The provisions are based on the commodity stored, pressure, temperature, spill management provisions, and fire protection measures afforded to the tank. Each parameter adjusts the minimum requirements. The spacings are intended to prevent a fire in one tank from affecting an adjacent tank. For large storage tanks and those containing crude oil, heated oil, slop oil, or emulsion breaking tanks, additional spacing should be considered since these contain a higher than normal risk.

These include the following:

- Where tanks exceed 45.7 m (150 ft.) in diameter, the spacing between tanks should be a minimum of half the diameter of the largest tank.
- For tanks 45.7 m (150 ft.) in diameter, which contain crude oil, they should be arranged such that the tanks are a minimum of one diameter apart.
- Hot oil tanks heated above 65.6°C (150°F), excluding flash asphalt, slop oil, and emulsion breaking tanks, should be spaced apart by the diameter of the largest tank in the group.

A major factor in the location of storage tanks within a tank farm is the topography of the tank farm area. The slope of the natural topography can be used to assist in drainage requirements for a diked area and minimize the accumulation of spilled liquids near a storage tank. Diversion dikes or curbing can be used to divert spillage so it is removed to a remote safe location.

The prevailing wind condition should also be used to the best extent. Where rows of tanks are designed, they should be arranged so they are perpendicular to the wind instead of parallel. This allows smoke and heat from a fire to dissipate with respect to impact to other storage tanks.

The location of storage tanks to adjoining property or exposures should be treated the same as would be the case with exposure from a process, and the added consideration of public exposure should not be overlooked.

8.6. FLARES AND BURN PITS

The general principles for the location of flares or burn pits should be governed by the following:

- The placement has to account for heat radiant effects on individuals and plant equipment to prevent injury and deterioration aspects.
- They should be as close as practical to the process units being served. This allows for the shortest and most direct route for the disposal gas header and will also avoid passage through other risk areas.
- The flare or burn pit should be located remote from the facility and property line due to their inherent hazardous features. They should be well away from high hazard areas or public occupied areas. A location perpendicular to the prevailing wind direction, remote from the major sources of vapor releases and process or storage facilities, is preferred. A crosswind location is preferred since a downwind location may allow vapors to flow back to the plant during times when the wind direction is reversed, while a crosswind location has less possibility of this. See Figure 8.3.

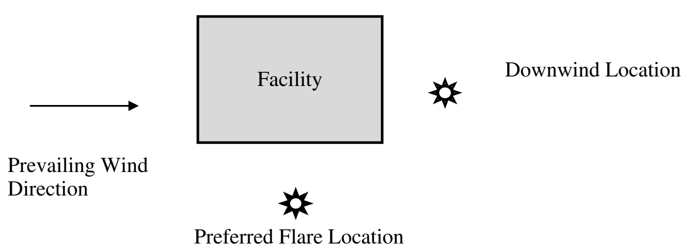

Figure 8.3 Preferred flare location.

- The chosen location should not allow liquids that may be ejected from the flare system to be exposed to the facility. This principle should apply even if a liquid knock-out (i.e., collection vessel or drum) feature is incorporated.
- Where more than one flare is provided, the location of each should be mainly influenced by operational requirements, but the need for maintenance and independent operation should also be considered.

8.7. CRITICAL UTILITIES AND SUPPORT SYSTEMS

During a fire or explosion incident, the primary utilities may be affected if they are not adequately protected. These utilities may provide critical service and support to emergency systems that should be preserved during an incident. The most common services include

- **Firewater Pumps:** Several catastrophic fire incidents in the petroleum industry have been the result of the facility firewater pumps being directed affected by the initial incident effects. The cause of these impacts has been mainly due to locating fire pumps in vulnerable locations without adequate protection measures from probable incidents and the unavailability or provision of other backup water sources. A single point failure analysis of the firewater distribution network is an effective analysis that can be performed to identify where design deficiencies may exists. For all high risk locations, firewater supplies should be available from several remotely located sources that are totally independent of each other (see Figure 8.4) and utility systems that are required for support.
- **Power Supplies:** Power is necessary to operate all emergency control devices. Where facility power sources or distribution networks are unreliable or vulnerable, self-contained power sources (e.g., emergency

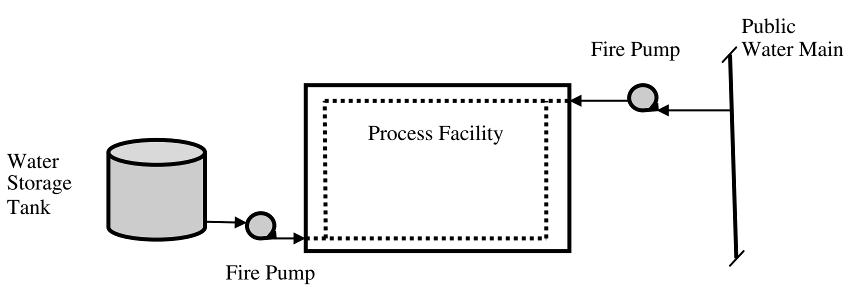

Figure 8.4 Simple diagram of firewater feeds to a process facility.

generators, UPS batteries) should be provided to emergency systems and equipment. Unless protected, power, control, and instrumentation cabling will be the first items destroyed in a fire. The most practical solution is the provision of diesel-driven fire pumps, storage battery support for control and emergency systems, etc. Where field ESD components are located in high risk areas, they are usually also provided with self-contained activation systems such as spring return emergency isolation valves or local compressed air reservoirs to activate pneumatic operators. The selection of back-up systems and their arrangement should be based on the Worst Case Credible Event (WCCE) for the location.

- **Communication Facilities:** Communication plays a vital role in alerting and notifying both in-facility personnel and outside emergency agencies once a major incident has occurred. Communication systems should not be arranged so a single point failure can occur. Of primary concern is the provision of a backup source of power and a remote backup and signaling post. Additionally, most major facilities have designated emergency operations center (EOC) where management can assemble and assist in the incident management and coordination with outside agencies. The EOC has be arranged so the links to the plant processes can be monitored, outside communications are available, the EOC will not be affected by the incident, and personnel can easily access the facility during an emergency.
- **Buoyancy and Propulsion Capability:** Floating vessels for offshore operations offer reduced operating costs but also present additional vulnerability factors. All floating structures must ensure buoyancy integrity, otherwise the vessel may sink with catastrophic results. Similarly, propulsion systems are provided at some installations to provide position stability. All major vessels are required by insurance requirements and most marine regulations to maintain buoyancy systems, while loss of stability will impact ongoing operations. Both of these systems can therefore be considered critical support systems and must be evaluated for risk and loss control measures, either through duplication and protection features or a combination of both.

- **Air Intakes:** Air intakes to occupied building heating and ventilation systems, air compressors for process, instrumentation, and breathing air, and to prime movers for gas compressors, power generation, and pumps should be located as far as practical (both horizontally or vertically) from contamination from dusts, toxic and flammable materials' release sources. They should not be located in electrically classified areas. If close to possible vapor releases (as confirmed by dispersion analyses), they should be fitted with toxic or combustible gas detection devices to warn of possible air intake hazards and shutdown fans or isolate (through re-circulation) the incoming air.

8.8. ARRANGEMENT

Arrangement means the orientation, position, and assemblage of the equipment in a facility. By far the highest concern is the arrangement of vessels, columns, tanks, pumps/compressors, and process trains containing combustible materials of large capacities, especially at high pressures or temperatures. To meet the needs of loss control but still maintain efficient operations, high risk plots are arranged so they are never completely enclosed by other processes or risks. A fire break, usually a road and sometimes pipe racks or open drainage systems (drainage swales), is provided for economic process pipe routings, access convenience, and as a useful method of separation arrangement of related processes or storage areas. The possible loss of common pipe racks (piping and structural steel) are minimal compared to long procurement times for replacement vessels, pumps, or compressors that have high technology process control and instrumentation.

Storage tanks should be grouped so that no more than two rows are tanks provided within diked areas, separated by roads to ensure fire-fighting access is available from different locations depending on wind direction due to obscuration from smoke produced from a fire. Large tanks within a common diked area should be provided with intermediate spill dikes or drainage channels between the tanks, as an intermediate level of protection against spill spread. When a small number of small tanks are located together the level of major impacts is less and therefore the financial risk is lower. In these cases, it is acceptable not to provide full or intermediate dikes between the tanks.

A high pressure process or storage vessel should never be arranged so that it "points" at manned or critical facilities or high inventory systems for concerns of a BLEVE of the container with the ends of the vessel rocketing toward the vulnerable location and escalating the incident. As a further inherent safety enhancement, spheroid separation vessels may be used in some instances instead of horizontal pressure vessel "bullets." This reduces the possibility of BLEVE incident directed toward other exposures.

8.9. PLANT ROADS—TRUCK ROUTES, CRANE ACCESS, AND EMERGENCY RESPONSE

The main access and egress to a facility should preferably be from the upwind side, with secondary points at crosswind locations. These locations should be at relatively higher elevations than the process areas so that spillages or vapor releases have less of an opportunity to affect emergency aid measures. Two access points should be provided as a minimum to each facility.

Routine truck traffic within the facility should be routed on perimeter roads as much as possible instead of directly through a plant. This avoids truck incidents that may affect plant processes, lessens the possibility of trucks striking pipe bridges or other equipment, and regulates their presence to specific areas.

Crane access is usually required for most process areas to support periodic maintenance activities, replace worn equipment, and support possible upgrades and expansions. The step up and use of cranes requires large areas for their utilization, therefore it is incumbent during a plant design to account for such use where this is expected to occur. The lifting of objects over operating plants should be avoided as the load could be dropped, which has occurred in the past and led to a major hydrocarbon incident (i.e., dropped crane load on a vessel in refinery, 1987, Texas City, Texas).

FURTHER READING

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CHAPTER 9

Grading, Containment, and Drainage Systems

Drainage and surface liquid containment systems are usually thought of as a supplemental process system that has little input to the risk analysis of a facility. Without adequate drainage capabilities, spilled hydrocarbon or chemical liquids have no avenue of dissipation except to be consumed by any potential fire or explosion. Liquid disposal systems are also a potential source of hazards because of the possibilities of the formation and distribution of explosive gas-air mixtures. Liquid drainage systems therefore play a key role in the avoidance, reduction, and prevention of hydrocarbon materials that may result in fire and explosion incidents. Drainage philosophies and design features should be examined at the beginning of a facility design.

There are several drainage mechanisms employed at process facilities—surface runoff or grading, spill containment (diking), gravity sewers (oily water, special, sanitary), and pressurized sewer mains and lift station collection sumps.

9.1. DRAINAGE SYSTEMS

The topography, climate conditions, and arrangements for effective treatment will influence the design of drainage systems for the control of spills resulting from the failure of equipment, overflows, or operating errors. Additionally, the amount, spacing, and arrangement of process equipment will also influence the features of a drainage system.

An adequate drainage system should be provided for all locations where a large amount of liquid has the possibility of release and may accumulate according to the terms of the risk analysis frequency levels. Normal practice is to ensure adequate drainage capability exists at all pumps, tanks, vessels, columns, etc., supplemented by area surface runoff or general area catch basins. Sewer systems are normally gravity flow for either sanitary requirements or oily water surface disposal. Where insufficient elevation is available for the main header, sump collection pits are provided, fitted with

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lift pumps that transfer the collected liquids into an outlet once the sump pits reach a certain fill level. This header is routed then to a disposal system or treatment station.

9.2. PROCESS AND AREA DRAINAGE

In the process unit areas, drainage arrangements should ensure that spills will not accumulate or pass under vessels, piping, or cable trays. Primary drainage should be provided by area catch basins that are connected to an underground oily water sewer (OWS) system. An oily water sewer system normally consists of surface runoff that is sloped to area catch basins or collection troughs process drain receptacles that are connected to local area underground headers sized for the expected process and firewater flows. The system is composed of an underground pipe network of branch lines connected to a main header through water trap seals of catch basins and manholes. Fluids from the main header are routed to a central collection point, from which they are typically routed to an oil and water separation process to reclaim liquids.

A prime safeguard of the OWS is that it is designed (or should be designed) to prevent the transmission of combustible vapors or liquids from one area to another, thereby preventing unexpected consequences in another process environment. Since fires and even explosive flame fronts can spread inside sewer piping by flaming hydrocarbon vapors on top of fire-water or surface runoff, sewer systems should be designed with water trap seals to avoid carrying burning liquids from one area to another. The sealing liquid should always be water; otherwise, combustible vapors are likely to be released both to the atmosphere and in the drainage line from the hydrocarbon sealing liquid. Once a drainage receptacle has been used for hydrocarbon disposal, either from surface drainage or process activities, it should be thoroughly flushed with water to re-establish the water seal (see Figure 9.1).

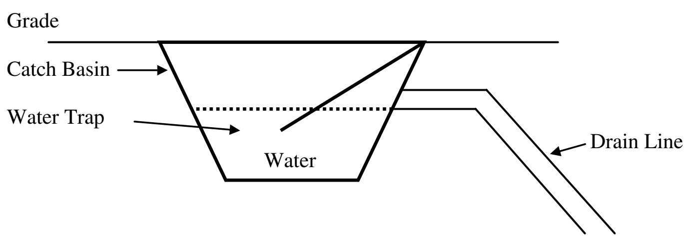

Figure 9.1 General drainage catch basin design (side view).

Line segments that are sealed should be provided with a vent to allow any trapped gases to be relieved; otherwise, hydrostatic vapor lock may occur, which will prevent incoming liquids from draining into the system. Such vents should be located on the high end of the line segment so all the vapors will be released. Vent outlets should be located where they do not pose a hazard to the process units or utility equipment. Manhole cover plates in process areas should be sealed. If the manhole has any openings it may allow gas to escape out of it instead of the sewer vent for dissipation. Over the sewer grade should be away from process areas, shops, manned areas to reduce the possibility of combustible vapors or liquids emitting from sewer openings in other non-classified areas. There have been instances where sump pit pump failure has resulted in the pit overflowing and also backflow through other incoming sewer lines, which can then spread a fluid from one area to another unexpected area back up through the area catch basins.

Sanitary sewer systems should be entirely segregated from oily water sewer systems. Similarly, process venting or blowdown systems should not be connected to the sewer system.

Common practice and a general guide is to prevent combustible vapors from transmitting from one process area to another process area, generally 15 m or (50 ft) or more away. Usually unsealed drainage receptacles, such as drain funnels, tundishes, and drain boxes, are routed to the nearest local water sealed catch basin and then directly into the oily water sewer system collection header. The unsealed receptacles are only allowed in the same process equipment area where if vapors were to be released, it would be considered immaterial due to the proximity to where the liquid is being drained, as the drainage process would emit these vapors anyways.

In some cases a closed drainage system (CDS) can be used that drains process components directly into the oily water sewer. The CDS has the advantage of avoiding releases of vapors in any instance, but assurance must be obtained that back pressure from one drainage location will not back-feed liquids into another drainage point when two valves are open simultaneously or other drainage valves that contain any backpressure on them from other drainage sources.

9.3. SURFACE DRAINAGE

Provision should be made to eliminate the chance of liquid spreading to other processes or offsite locations, even if failure of the underground gravity drainage network occurs. The design philosophy employed should be to direct combustible liquid spills away from critical or high value equipment. They should be collected for disposal at locations as practically remote from the process equipment as possible. These provisions usually consist of surface grading to perimeter runoff collection points, impounding areas, or oily water separation ponds supplemented by directional curbing or diking. The typical surface runoff gradient employed is approximately 1%.

Process areas are normally provided with hard wearing surfaces such as concrete or asphalt, which provides for surface runoff provided a suitable directional grade is established. The surface runoff should be arranged so that flow from broken lines or equipment is directed away from the facility processes or critical facilities. Surface drainage can be enhanced with low elevation diversion diking and drainage channels. Although these enhancements are used to assist in diverting surface liquids to a remote impounding area, sloped paving is the preferred method for spill collection. Paving is preferred to untreated ground or crushed stone since combustible liquids may drain into permeable ground cover and accumulate on the surface of the ground water table. During fire incidents, these liquids may seep back to the exposed ground surface, allowing additional fire hazards to develop. Permeable ground cover will also allow ground water pollution to occur if process liquids can reach it.

Drainage areas can be defined by the process fire area, which has been established by the spacing, segregation, and arrangement provisions of the facility. Open drainage channels should be used where they will not interfere with the use of the area, i.e., crane access, maintenance activities, emergency response needs, etc. They should be designed to minimize erosion, and if excessive velocities are encountered, they should be paved. No more than 5 m/s (15 ft/s) velocity should be allowed in paved surface runoff channels or troughs.

Rainfall, firewater flows, and process spillage should be all analyzed when designing drainage systems. Process spillage should be the most credible maximum vessel leakage or rupture. A rule of thumb in estimating the spread of spills can be made by using the approximation that an unconfined and level spill, 3.81 (1 gal) of even a vicious liquid will cover approximately 1.86 m^2 (20 ft^2). In most cases, firewater flowrates dominate the design capacity of drainage arrangements.

For small facilities (e.g., production separation vessels), the normal practice in the design of surface runoff is to provide a centerline slope from the process area (e.g., from a central pipe rack). This would also include provisions to segregate vessels and pumps from the impact of spills. The runoff is collected into catch basins or collected at the edge of the facility in a collection channel. For larger facilities (refineries, gas plants, etc.), the areas are graded to run off to a central collection point or location, which also serves as a means to separate one fire risk from another. Catch basins should be located away from equipment and critical structural supports since they may produce pools of liquids during spillage incidents. Drainage trenches should not be located under pipe racks or other sources of high liquid holdups, as if they were ignited they would produce a line of fire under critical equipment. The number of catch basins provided to any process areas should be limited, to prevent the number of "collection pools." A typical approach is to limit the drainage areas to a maximum of $232.2\,m^2$ ($2500\,ft^2$) and size the catch basins (i.e., their connection drainage lines) in the area for a maximum flow based on process spillages and firewater flows. All catch basins should be properly water sealed to prevent the spread of combustible vapors to other areas that are not involved in the incident. Underground piping should be buried where it can be excavated in the future should concerns that later develop need to be investigated. Generally, such piping is not routed under a monolithic or slab concrete foundation.

Surface drainage should be adequate to drain the total volume of water that can be used during firefighting activities or storm water, whichever is greater.

9.4. OPEN CHANNELS AND TRENCHES

Underground or enclosed drains are preferred over open trenches since enclosed drains provide a method of removing spilled liquids from the area without exposing equipment to burning liquids. Further, trenches can act as collection points for heavier than air vapors. If used, trenches should be routed in a way that will not carry fire protection water and burning liquids through another fire area. If unavoidable, fire stops (weirs) should be provided in the trench system between the fire areas. Additionally, fire codes normally prohibit enclosed drainage channels for LNG areas except where they are used to rapidly conduct spilled LNG away from critical areas. They are sized for the anticipated liquid flow and vapor formation rates.

Where other means are not available, surface runoff can be routed to a perimeter or intermediate collection channel or trench that routes the liquids to remote impounding areas. Such surface drainage channels, routes, trenches, troughs, or collections areas should not pass under or be located near cable trays, pipe racks, vessels, tanks, or process equipment or even close to firewater lines where, if ignited, it would impact such locations and possibly release further materials that could contribute to the incident. Open channels should not be used in process areas. Instead, an underground oily water sewer with surface catch basins should be provided. Historical evidence indicates many process fires have spread when surface channels were available. Where drainage channels feed into pipes or culverts, provisions should be made for preferential overflow direction in the case of plugging or flooding of the pipe. Typical practice is also to locate open channels or trenches away from process areas containing heavy vapors, so they cannot collect and spread to other areas.

9.5. SPILL CONTAINMENT

Where surface drainage cannot be employed for safe removal of liquids, diking may be utilized to prevent the endangering of property or equipment. Dikes are primarily used to contain tank pump-overs, bottom leakages, piping failures, and limit the spread of liquids during a fire incident—both for hazardous liquids and firewater runoff. Accumulation of spilled liquids can be limited in quantity or removed from retention areas that may overflow through drainage lines with control valves located outside the diked area. Experience has shown that, under normal conditions, it is unlikely that the capacity of the entire dike volume will be fully used or needed. Consequently, a dike area drainage mechanism should be normally kept closed until an incident warrants its opening. Should a

leakage occur while the location is unattended, the diked area contains it before it enters a drain, which may not be ideal at the time.

Dikes should be arranged so liquids will flow (with minimum exposure to pipeways) to a low point within the diked enclosure, remote from the equipment producing the leakage. Accumulated liquid can be easily removed by drainage or pumping out though a liquid removal system (e.g., sump pump, mobile vacuum truck).

Process unit pumping units are usually enclosed with curbing (6 in. (150 mm) toe walls) to contain small leakages in which a catch basin is provided at the remote corner of the curbing enclosure. The grade within this enclosure is directed away from the process pumping unit and toward the sewer drainage connection. As an added safety feature, an overflow from the curbed area is sometimes provided that connects to remote drainage channels to divert large spillage away from equipment. One hundred and fifty millimeter (6″) toe walls are usually provided at hydrocarbon pump bases. Curbing is also usually provided for oil-filled transformers, at furnaces burning liquid fuels and at furnaces with flammable liquid in the tubes.

Drainage slopes within tank diked areas should ensure that any spills are directed away from the tank, manifolds, or piping. Small fires that can occur in gutters or drains around tanks weaken connections to the storage tank and may release its contents. Any gutter encircling a tank should be located a safe distance from the tank. Drain basins should not be located under tank mixers, major valves, or manway entrances to tanks. The diked area should be provided with an impervious surface that will direct liquids toward drainage collection points.

Dike walls should not hinder firefighting efforts or generally impede the dispersion of vapors from spilled liquids. Most industry standards require containment dikes to have an average height of 1.8 m (6 ft) or less. Where additional allowances have been made for emergency access and egress from the diked area, allowance to this requirement can be made. It should be noted that an oil wave may occur in a diked area if the tank fails catastrophically during a boilover or slopover event. This wave could surge over the height of a typical dike wall.

When several tanks are located within a single diked area the provision of a mini-dike or diversion dike, i.e., 305 mm (12 in.) to 457 mm (18 in.) high, between tanks minimizes the possibility of minor leakages endangering all the tanks (see Tables 9.1 and 9.2).

Table 9.1 Comparison of Dike Design Requirements

Standard	Dike Capacity	Drainage Slope	Dike Height Limits
AIChE Guideline for Eng. Design Safety	Refers to NFPA 30	Refers to NFPA 30	No mention
API 12R1	Volume of largest tank plus 10% for rainfall	Sloped away from tank	No mention
API Bulletin D16	Volume of largest tank plus sufficient allowance for precipitation	No mention	No mention
API RP 2001	Consistent with NFPA 30	Consistent with NFPA 30	Consistent with NFPA 30
API RP 2610	Largest tank, allowance for precipitation and consideration for remote impoundment (refers to NFPA 30)	1% for 15 m (50 ft) from tank or to dike base, whichever is less	Average not more than 2 m (6 ft) above the interior grade
EPA Title 40	Volume of largest tank plus sufficient allowance for precipitation	No mention	No mention
NFPA 15	Refers to NFPA 30	Refers to NFPA 30 (1% from critical equipment)	Refers to NFPA 30
NFPA 30	Largest amount of liquid that can be released plus volume of other tanks in diked area below the height of the dike	1% slope away from tank for 15 m (50 ft) or to dike base, whichever is less	No mention
NFPA 58	Volume of largest tank plus sufficient allowance snow accumulation, other containers or equipment	Sufficient to move spilled liquid to dike system and as far away as possible	No mention

NFPA 59A	For dikes holding one container of LNG: One of the following options: • 110% of the maximum liquid capacity of the container • 100% where the impoundment is designed to withstand the dynamic surge in the event of catastrophic failure of the container • 100% where the height of the impoundment is equal to or greater than the container maximum liquid level For multiple LNG containers one of the following: • 100% of the maximum liquid capacity of all containers in the impoundment area • 110% of the maximum liquid capacity of the largest container in the impoundment area, where provisions are made to prevent leakage from any container due to exposure to a fire, low temperature, or both from causing subsequent leakage from any other container	Refers to NFPA 30	Height based on dike wall distance from tank and maximum liquid level in tank for containers operating at 100 kPa (15 psi) or less

Table 9.2 Drainage Requirements and Capacity Analysis

Fire Risk Area	Firewater Flowrate (GPM)	Maximum Liquid Spillage* (BBLs)	Sewer Capacity Flowrate (GPM)	Containment Provisions (BBLs)	Runoff Requirements
Process area	3000	500 GPM	3500	25**	0
Tank storage	2000	50,000	2000	50,000	0
Truck loading	1500	100	1000	0	100 BBLs + 500 GPM
Pump station	1000	20	1000	20**	0

*Tank/Vessel rupture or WCCE estimated leakage rate (may require rainfall provisions).**Provided for incidental spillages.

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CHAPTER 10

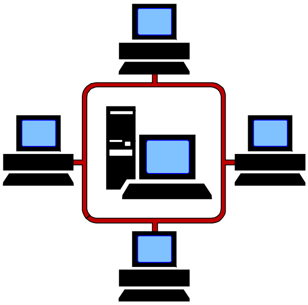
Process Controls

Process controls play an important role in how a plant process upset can be controlled and subsequent emergency actions executed. Without adequate and reliable process controls, an unexpected process occurrence cannot be monitored, controlled, and eliminated. Process controls can range from simple manual actions to computer logic controllers, remote from the required action point, with supplemental instrumentation feedback systems. These systems should be designed such as to minimize the need to activate secondary safety devices. The process principles, margins allowed, reliability, and the means of process control are mechanisms of inherent safety that will influence the risk level at a facility.

10.1. HUMAN OBSERVATION

The most utilized and reliable process control in the process industry is human observation and surveillance. Local plant pressure, temperature, and level gauges along with control room instrumentation are provided so human observation and actions can occur to maintain the proper process conditions. First, stage process alarms are provided to alert operations to conditions that they may not have already noticed. Typically, when secondary alarm stages are reached, computer control systems are employed to automatically implement remedial actions to the process.

10.2. ELECTRONIC PROCESS CONTROL



The state of technology in control for process facilities is computer microprocessors, or commonly referred to as PLCs, programmable logic controllers. It typically consists of a distributed digital instrumentation that is fed into a segmented control system as part of an overall process management system design. Programmable electronic systems are commonly used for most control systems, safety

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functions, and supervisory and control systems (SCADA). These systems may consist of a distributed control system (DCS), programmable logic controllers (PLCs), personal computers, remote terminals, or a combination of these arrangements over a communications network.

The DCS caters to a centralized control but allows sectionalized local control centers with a clearly defined hierarchy. Operator interaction is provided in real-time with video display panels instead of traditional metering instruments and status lights, which are now used only on local equipment panels. The DCS functionally and physically segregates the process controls for systems or areas at separate locations or areas within a building. This segregation prevents damages or downtime to a portion of a system affecting the entire facility or operation, just as the physical components are isolated and segregated for risk protection measures. Typically, segregated DCS controls are provided with their own shelters, commonly referred to as Process Interface Buildings (PIBs) or Satellite Instrumentation Houses (SIHs). Protection and location of these installations should be chosen carefully and risk analyses undertaken, since these facilities are critical and could be vulnerable to impacts the same similar to a process area or main control room.

When the electronic control is specified the following features should be critically examined:

- Availability of the system to function upon demand
- Selection of compatible components
- Failure modes of the components in the system and impact on system control
- Design and reliability of utility supplies

- Control and integrity of software commands
- Capabilities for remote input, monitoring, and control (as backup utilization)

10.3. INSTRUMENTATION, AUTOMATION, AND ALARM MANAGEMENT

Automation and control of processing equipment by highly sophisticated computer control systems is the standard at process facilities. Automatic control provides for closer control of the preprocess conditions and therefore increased efficiencies. Increased efficiencies allow higher production outputs. Automation is also thought to reduce operator manpower requirements. However, other personnel are still needed to inspect and maintain the automatic controlling system. All process control systems should be monitored by operators and have the capability for backup control or override by human operators.

Suggested control and instrumentation systems for the management of process equipment and components are described and outlined in API RP 14C, which is still relatively the arrangement utilized in the process industries. All process control systems are usually reviewed by a Process Hazard Analysis, which will deem if the provided mechanisms are adequate to prevent an incident from developing.

For high risk processes, dual-level alarm-level instrumentation (i.e., high/high-high, low/low-low, etc.) and automatic process control (PLC, DCS, etc.) and shutdown, which are backed up by human intervention, should always be considered. Where alarm indications are used, they should be provided such that an acknowledgment by an operator is required, typically undertaken by "touch" screens today.

Changes in display status should signify changes in functional status, rather than simply indicate a control has been activated. For example, a light for a valve "closed" indicator should signify that the valve is actually closed and not that the valve closed control has been activated.

Whatever method is used, there should be a clear philosophy for the basic process control system (BPCS) employed at a facility that is consistent throughout each process and throughout the facility. Consistency in application will avoid human errors by operators. The philosophy should cover measurements, displays, alarms, control loops, protective systems, interlocks, special valves (e.g., PSV, check valves, EIVs, etc.), failure modes, and controller mechanisms (i.e., PLCs).

The alarm system should have a philosophy that relates the input data—number, types, degree of alarms, and displays and priorities. The information load on the operator has to be taken into consideration, i.e., distinction between alarms and status signals versus operator actions that need to be initiated (see Table 10.1).

Alarm indications should be arranged by their hierarchy of information and alarm status so the operator does not become inundated with a multitude of alarm indications. If such an arrangement exists, he may not be able to immediately discriminate critical alarms from non-critical alarms. Operators sometimes have to make decisions under highly stressful situations with conflicting or incomplete information. It is therefore imperative to keep major alarms for catastrophic incidents as simple and direct as possible.

It is also worth mentioning that the Engineering Equipment & Materials Users' Association (EEMUA) issued its Publication 191 "Alarm Systems—A Guide to Design, Management and Procurement," which recommends a certain alarm frequency for various plant scenarios (process upsets, routine operation, etc.). In particular, it recommends a peak alarm rate for a major plant incident of not more than ten alarms in the first 10 min (Plant Upset Alarm Rate <10 per 10 min) and an average alarm rate of 5 per hour (Average Process Alarm Rate = 5 per hour) for normal operations. This has been prompted by the higher realization of the part human error play in incidents, in particular, alarm overload, poor communication of alarm conditions, poor operator training to cope with abnormal conditions, and bypassed safety measures.

Table 10.1 Typical Plant Control Console Alarm Response Operation

Plant Operation	Operator Action	Alarm Information
Operating as designed	No actions	None
Normal operational variances	Monitoring DCS actions	Informational variance
Process upset	Operator intervention	Operating alarms
Incident	Emergency shutdown actions	Critical safety indications and alarms

10.4. SYSTEM RELIABILITY

The reliability of the process control system should be specified. If a process feature demonstrates that a major consequence has the possibility of occurring (as identified by the risk analysis, i.e., HAZOP, What-If Analysis, etc.), additional independent layers of protection (ILPs) such as instrumentation and control systems should be provided. These features should be of high integrity, so that the safety integrity level (SIL) of the control system is consistent with the level of integrity specified for the facility. Safety integrity levels are a quantitative target for measuring the level of performance needed for a safety function to achieve a tolerable risk for a process hazard. It is a measure of safety system performance, in terms of the probability of failure on demand. There are four discreet integrity levels, SIL 1, 2, 3, and 4. The higher the SIL level, the higher the associated safety level and the lower the probability that a system will fail to perform properly. Defining a target SIL level for a process should be based on the assessment of the likelihood that an incident will occur and the consequences of the incident. The following shows SILs for different modes of operation based upon the probability of failure on demand (PFD_{avg}):

Low Demand Mode SIL

SIL PFD_{avg} RRF

$4 \geq 10^{-5}$ to $<10^{-4} > 10{,}000$ to $\leq 100{,}000$

$3 \geq 10^{-4}$ to $<10^{-3} > 1000$ to $\leq 10{,}000$

$2 \geq 10^{-3}$ to $<10^{-2} > 100$ to ≤ 1000

$1 \geq 10^{-2}$ to $<10^{-1} > 10$ to ≤ 100

High Demand or Continuous Mode SIL

SIL PFD_{avg} per hour

$4 \geq 10^{-9}$ to $<10^{-8}$

$3 \geq 10^{-8}$ to $<10^{-7}$

$2 \geq 10^{-7}$ to $<10^{-6}$

$1 \geq 10^{-6}$ to $<10^{-5}$

The level of overall availability for a system component calculated as 1 minus the sum of the average probability of dangerous failure on demand. SIL-1: availability of 90–99%, SIL-2: availability of 99–99.9%, SIL-3: availability of 99.9–99.99%, SIL-4: availability 99.999–99.9999%. Some common methods of achieving high SIL levels in the process industries are the employment of high integrity protective systems

Table 10.2 Safety Integrity Levels (ISA-84.01 and IEC 61511)

SIL	RRF (Risk Reduction Factor)	PFD_{avg} (Probability of Failure on Demand (1/RRF)	Safety Availability ($1-PFD_{avg}$)/%
0		**Process control**	
1	10–100	1/10–1/100	90–99
2	100–1000	1/100–1/1000	99–99.9
3	1000–10,000	1/1000–1/10,000	99.9–99.99
4	10,000–100,000	1/10,000–1/100,000	99.99–99.999

(HIPS) or triple modular redundant (TMR) arrangements. The numbers are summarized in Table 10.2.

Most published literature cites the mean time between failure (MTBF) for a PLC central processor between 10,000 and 20,000 h (i.e., 1.2–2.4 years), the MTBF of input and output (I/O) interfaces between 30,000 and 50,000 h, and the MTBF of input and output (I/O) hardware between 70,000 and 150,000 h. Therefore the worst case MTBF for the control system may be the PLC-CPU at 1.2 years. This represents an availability of 99.76%, assuming a mean time to repair of 24 h. If a dual CPU-PLC configuration is provided with the CPU operating in backup mode, using single I/Os, the MTBF would be almost doubled, but the overall system availability improves to only 99.88%. Completely dual PLCs with dual I/O and CPUs in a 1oo2 or 2oo2 voting arrangement are seldom used for normal process controls systems but are instead used for certain safety systems where availability, failsafe, and fault tolerant attributes are desired. Complete dual PLCs tend to be more complex and maintenance intensive.

Control loops should have a fail safe logic as much as practical limits will allow.

Most electronic technology systems also use digital electronics in conjunction with microprocessor technology to allow the instrumentation to calibrate and troubleshoot the instrumentation from either local or remote locations. This capability is commonly referred to as "smart" electronic technology.

Critical safety-related control functions also have to be protected from impairment from an incident that would render the devices unable to fulfill their functions.

10.5. HIGH INTEGRITY PROTECTIVE SYSTEMS (HIPS)

HIPS are critical safety systems, essentially replacing pressure relief and/or flare systems. These systems are used to provide overpressure protection and/or flare load mitigation for process equipment, pipelines, wellhead flowlines, gas manifolds, or other special purpose applications. Technically HIPS is a safety instrumented function that consists of a set of components, such as sensors, logic solvers, and final control elements (e.g., valves), arranged for the purpose of taking the process to a safe state when predetermined conditions are violated. The HIPS shall operate independently and be completely separate from the basic process control system (BPCS).

Safety instrumented systems are sometimes used in lieu of mechanical protection, such as safety relief valves, in the following instances:

- Reducing the total design load of a relief/flare system.
- Where a relief device or system is unsuitable, ineffective, or not allowed.
- Where flaring is prohibited, e.g., in environmentally sensitive and populated areas.
- At onshore wellhead piping networks where well shutoff protection is standard industry practice (i.e., where it is impractical to use full mechanical protection for piping and/or relief).
- At offshore wellhead piping where well shutoff protection is standard industry practice (i.e., where it is impractical to use full mechanical protection for piping and/or relief).

A typical HIPS system design includes:

- An independent safety system (e.g., ESD)
- A validated SIL 3 loop, i.e., 99.99% safety availability
- Two safety layers
- Stringent proof/full testing and verification tracking of testing frequencies
- Approval of a system is usually based on safety first principle, i.e., a quantitative risk assessment (QRA) and also the cost effectiveness (cost-benefit analysis)

A basic HIPS design usually consists of the devices shown in Figure 10.1, input sensors (pressure indicators), logic controller, and output devices (valves).

The safety integrity level (SIL 3 in this case) is allocated based on a process hazard and risk assessment. It forms the basis for the risk reduction target for the safety instrumented system/SIL (HIPS in this case). For "on-demand" systems such as a HIPS, the SIL defines the probability of

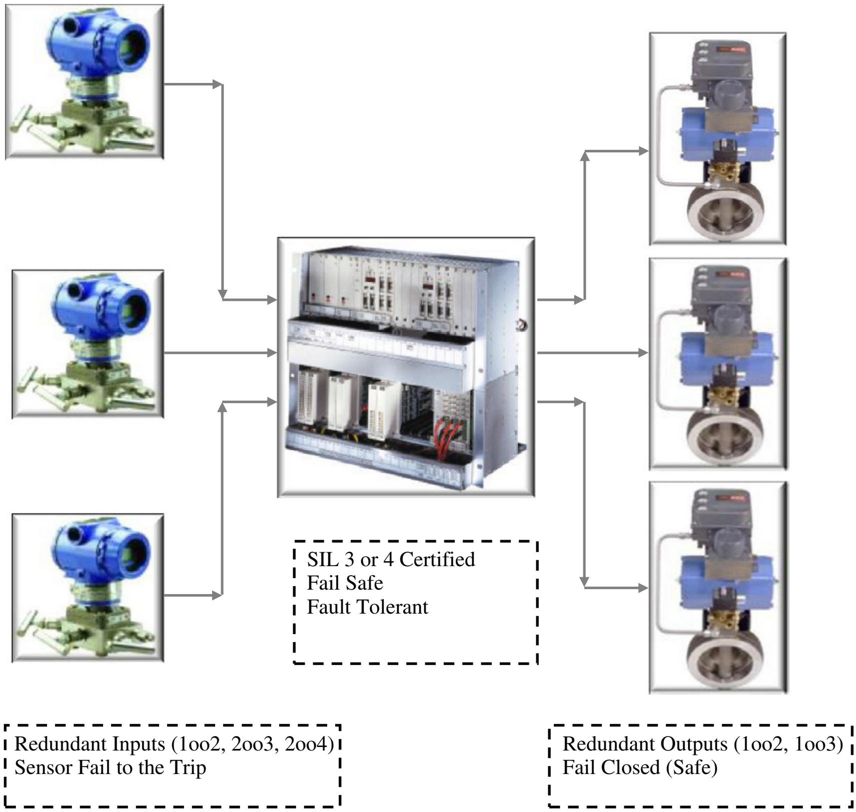


Figure 10.1 Typical HIPS arrangement.

failure demand average (PFD_{avg}) target for the safety instrumented system (SIS). Once the SIS is designed (overall architecture defined, test intervals established, and components selected), a check is made to ensure that the proposed SIS's probability of failure to perform the safety instrumented function meets the SIL defined by the process (SIL 3 in this case).

HIPS are generally considered when, as the result of a major process change or modification, substantial economic gain can be obtained either by continuing to use an existing process or piping network or an existing relief/flare system rather than build a new one or upgrade one to comply with current design or operating requirements.

The steps to evaluate the feasibility of a HIPS usually include conducting a hazard analysis, identifying existing safety layers and operator

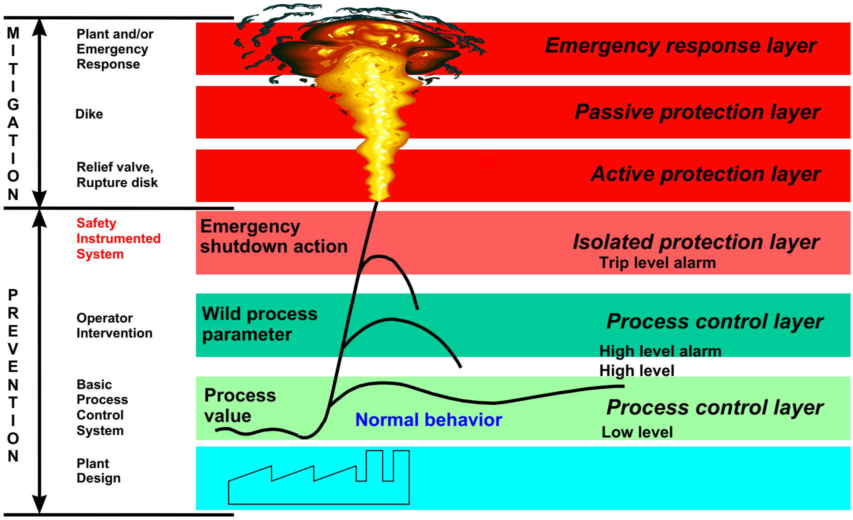
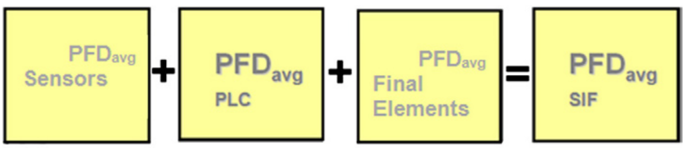


Figure 10.2 HIPS and safety layers of protection.



Voting	(PFDavg)	Architecture
1oo1	$\lambda_{du} * T/2$	1oo1
1oo2	$\frac{(\lambda_{du})^2 * T^2}{3}$	1oo2
2oo2	$\lambda_{du} * T$	2oo2
2oo3	$(\lambda_{du})^2 * T^2$	2oo3

Figure 10.3 SIL PFD.

intervention steps, identifying non-HIPS alternatives, and determining if a conventional relief system will work.

HIPS is considered at just above the emergency shutdown level on the Layers of Protection Analysis (see Figures 10.2 and 10.3).

10.6. TRANSFER AND STORAGE CONTROLS

The highest process concerns for storage and transfer operations are the possibility of a tank or vessel rupture, implosion, and overflow/overfill. These usually occur when dynamics operations are ongoing.

All tanks should be furnished with level gauging instrumentation. Preferably the optimum design is one that provides an alarm before high overflow levels are reached and also shut off fill lines when the optimum fill level is reached to prevent overflow/overfill or rupture.

Although not 100% reliable, check valves are usually installed in most piping systems to prevent backflow in the event of line rupture or segment depressurizing. Storage vessels or tanks receiving products from pipelines or automatic transfer systems are normally required to be fitted with high level alarms that may trip shutoff devices.

10.7. BURNER MANAGEMENT SYSTEMS (BMS)

Fixed heaters are extensively used in the oil and gas industry to process raw materials into unstable product in a variety of processes. Fuel gas is normally used to fire the units that heat process fluids. Control of the burner system is critical in order to avoid firebox explosions and uncontrolled heater fires due to malfunctions and deterioration of the heat transfer tubes. Microprocessor computers are used to manage and control the burner systems. Principle functions of the burner management system are provided with programmed ignition of igniters and burners at lightoff, flame monitoring during boiler operation, and proper furnace shutdown.

The function of the programmed ignition system is to minimize the boiler furnace firebox explosion hazard, which generally occurs during burner ignition. During normal operation a flameout may occur triggering an explosion. The programmed system allows a quick return to service, which would avoid mistakes by an operator during an emergency.

The flame monitoring detector provides an on/off signal to indicate the presence or absence of flame within a designated space. The detector typically provides a signal relative to the intensity and distance between the flame and sensor. In the absence of the flame the detector will operate to shut down the boiler.

The boiler shutdown is accomplished through the burner management system by shutting off all fuel to the burners and simultaneously initiating a post-firing purge.

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CHAPTER 11

Emergency Shutdown

Emergency shutdown capability has to be provided at all process facilities, be it manual, remotely operated, or automatic. Inherent safety practices rely on emergency shutdown capability as a prime facet in achieving a low risk facility. Without adequate shutdown capabilities a facility cannot be controlled during a major incident.

11.1. DEFINITION AND OBJECTIVE

An emergency shutdown (ESD) system is a method to rapidly cease the operation of a process and isolate it from incoming and outgoing connections or flows to reduce the likelihood of an unwanted event from occurring, continuing, or escalating. The aim of the ESD system is to protect personnel, afford protection to the facility, and prevent the occurrence of an environmental impact from a process event.

11.2. DESIGN PHILOSOPHY

The ESD system is distinguished from other facility safety systems in that it responds to a hazard situation that may affect the overall safety of the entire facility. It is therefore considered one of the primary safety systems for any facility. Without an ESD system, an incident at a process facility may be

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provided with "unlimited" fuel supplies that can destroy an entire facility. Such situations are amply demonstrated by well blow-outs that can be fed from underground reservoirs or pipeline connections, where further isolation capability is unavailable or destroyed by the initial incident, e.g., Piper Alpha.

An ESD system should have, as a minimum, the following design features:

- Shutdown reverts the process to a safe state.
- Prevents subsequent process operation until the cause of the shutdown has been corrected
- Prevents unintended process startup until correction of the shutdown

Facilities that do not have the capability to immediately provide an emergency shutdown should be considered high risks. Similarly, if the reliability of an ESD system is very poor the facility might be considered with adequate protection and be therefore judged as a high risk.

11.3. ACTIVATION MECHANISMS

Most ESD systems are designed so that several mechanisms can initiate a facility shutdown. These mechanisms are provided by both manual and automatic means. Typically these include the following:

- Manual activation from a main facility control panel
- Manual activation from a strategically located initiation station(s) within the facility
- Automatic activation from confirmed fire and gas detection system alarms
- Automatic activation from process instrumentation set points (e.g., "high-high" vibration)

11.4. LEVELS OF SHUTDOWN

The activation logic for an ESD system should be kept as simple as possible. Typically most facilities specify plateaus or levels of ESD activation. These levels activate emergency measures for increasing amounts or areas of the facility as the incident or the degree of hazard from the initial event increases. Low hazards or small area involvement would only require a shutdown of individual equipment while major incidents would require a facility shutdown. The isolation of one portion of a facility should not present a hazard to another portion of the facility; otherwise, both should be

Table 11.1 Typical ESD Levels

ESD Level	Action	Criticality
1	Total facility shutdown	Catastrophic
2	Unit or plant shutdown	Severe
3	Unit or equipment shutdown	Major
4	Equipment protective system	Slight
5	Routine (non-ESD) alarms	Routine

shut down. Typical ESD levels utilized in process industries are described below and highlighted in Table 11.1.

Total Plant Shutdown: A total plant ESD effectively shuts down the total plant or facility under emergency conditions. Isolation valves are closed to stop the flow of combustible, flammable, or potentially toxic fluids and to stop heat input to process heaters or reboilers, and rotating equipment. Activation of a total plant ESD should not stop or impede the operation of fire protection or suppression systems, deluge systems, sump pumps, or critical utilities such as instrument or process air.

Unit Shutdown and Depressurization: This shutdown layer isolates an entire process unit, process train, or process area involved in a fire or other emergency, thus limiting the supply of fuel. This includes pumps, vessels, compressors, etc., which comprise an entire process unit up to and including plot limit boundaries. Associated emergency depressurization systems for process vessels and equipment should be applied when it is necessary to reduce the potential of a boiling liquid expanding vapor explosion (BLEVE), or to reduce inventories of hazardous materials.

Equipment Shutdown: A system of equipment stoppage and emergency isolation valves that are used to isolate individual equipment within a process unit and prevent the release of potentially toxic material in the event of a fire, rupture, or loss of containment.

Equipment Protective System Shutdown: Systems that are usually provided for the protection of centrifugal pumps, rotating and reciprocating gas compressors, gas expansion and combustion gas turbines (CGTs), electric motors, generators, and forced or induced draft air fans.

Although it would be easy to institute a total plant shutdown for every incident, it would not be cost effective, as many small incidents occur relative to large incidents, which do not warrant the shutdown of the entire facility and would reduce the economic return on the investment.

11.5. RELIABILITY AND FAIL SAFE LOGIC

The design of an ESD system has traditionally been based on independent and fail safe component utilization. Independence implies they are segregated from other regulatory control and monitoring systems. Independence is typically obtained by physical separation, using separate process locations, impulse lines, controllers, input and output (I/O) instruments, logic devices, and wiring than that of the Basic Process Control System (BPCS). This avoids common failures in the system. Fail safe features are obtained by ensuring that selected components in an ESD system are such that during a failure of a component, the process reverts to a condition considered "safe." Safe implies that the process or facility is not vulnerable to a catastrophic event due to a process release. For most facilities, this implies that pipelines that could supply fuel to the incident (i.e., incoming and outgoing) are shut off (i.e., isolated) and that high pressure, high volume material supplies that are part of the incident are relieved to a remote disposal system.

ESD system performance is measured in terms of reliability and availability. Reliability is the probability a component or system will perform its logic function under stated operating conditions for a defined time period. Availability is the probability or mean fraction to total time that a protective component or system is able to function on demand. Increased reliability does not necessarily mean increased availability.

Reliability is a function of the system failure rate or its reciprocal, mean time between failure (MTBF). The system failure rate in non-redundant systems is numerically equal to the sum of component failure rates.

Failures can either be fail safe or fail dangerously. Fail safe incidents can be initiated by spurious trips that result in incidental shutdown of equipment or processes. Fail dangerously incidents are initiated by undetected process design errors or operations, which disable the safety interlock. The fail dangerously activation may also result from a process liquid or gas release, equipment damage, toxic vapor release, or fire and explosions.

The ESD system should be designed to be sufficiently reliable and fail safe so that (1) an unintended initiation of the ESD is reduced to acceptable low levels or as low as reasonably practical, (2) availability is maximized as a function of the frequency of system testing and maintenance, and (3) the fractional MTBF for the system is sufficiently large to reduce the hazard rate to an acceptable level, consistent with the demand rate of the system.

Fail safe logic is referred to as de-energized to trip logic, since any impact to the inputs, outputs, wiring utility supplies, or component function should de-energize the final output allowing the safety device to revert to its fail safe mode. The specification of fail safe for valves can be accomplished by failing close (FC), failing open (FO), or failing steady (FS), i.e., in the last operating position depending on the service the valve is intended to perform. Valves that are specified to fail close on air or power failure should be provided with spring return actuators. The use of accumulators (pressurized vessels) should be avoided since these are less reliable fail safe mechanisms (i.e., they require verification of pressure, filling, periodic certification testing, etc.) and are more vulnerable to external impacts of an incident. Control mechanisms including power, air, or hydraulic supplies to emergency valves (isolation, blowdown, depressurization, etc.) should be fireproofed if the valves are required to be operable during a fire situation.

For ESD emergency isolation valves (i.e., EIVs), a fail safe mode is normally defined as fail close in order to prevent the continued flow of fuel to an incident. Blowdown or depressurization valves would be specified as fail open to allow inventories to be disposed of during an incident. Special circumstances may require the use of a fail steady valve for operational or specialized purposes. These specialized applications are usually at isolation valves for individual components such as vessels, pumps, compressors, etc., where a backup EIV is also provided at the battery limits of the plant that is specified as fail close. The fail safe mode can be defined as the action that is taken when the ESD system is activated. Since the function of the ESD system is to place the facility in its safest mode, by definition, the ESD activation mode is the fail safe mode.

Table 11.2 Typical Safety Integrity Levels (SIL)

SIL	Availability	Risk Reduction Factor (RRF)
0	BPCS-inherent	None
1	90–99%	10–100
2	99–99.9%	100–1000
3	99.9–99.99%	1000–10,000
4	99.99–99.999%	10,000–100,000

The utilization of a fail steady–fail safe mode may allow an undetected failure to occur unless additional instrumentation is provided on the ESD system components or unless the system is constantly fully function tested. The prime feature of a full fail close or fail open mode is that it will immediately indicate if the component is functioning properly.

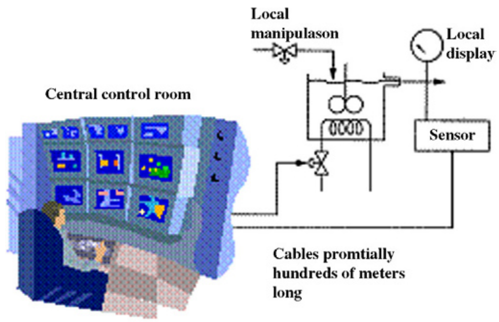
The different safety integrity levels (SIL) normally applied within petroleum and related industries are usually as given in Table 11.2.

Generally by increasing the independent layers of protection (IPLs), which are applied to a potential hazardous event, the SIL number can be reduced. It should be noted that a SIL level of 4 is seldom used in process industries, but is commonly utilized in the avionics, aerospace, and nuclear industries.

Safety integrity level 1 equates to a simple non-redundant single path designed to fail safe with a typical availability of 0.99. Level 2 involves a partially redundant logic structure, with redundant independent paths for elements with lower availability. Overall availability is in the range of 0.999. Level 3 is composed of a totally redundant logic structure. Redundant independent circuits are used for the total interlock system. Diversity is considered an important factor and is used where appropriate. Fault tolerance is enhanced since a single fault of an ESD system component is unlikely to result in a loss of process protection.

11.6. ESD/DCS INTERFACES

Where ESD and Distributed Control Systems (DCS) are provided, they should be functionally segregated such that a failure of the DCS does not prevent the ESD from shutting down and isolating the facilities. Alternatively, failure of the ESD system should not prevent an operator from using the DCS to shutdown and isolate the facility. There should be no executable commands over the ESD-DCS communications links. Communication links should only be used for bypasses, status information, and the transmission of reports. Confirmation of ESD reset actions can be incorporated into the DCS but actual reset capability should not.



11.7. ACTIVATION POINTS

The activation points for ESD systems should be systematically arranged to provide optimum availability and afford adequate protection to the facility. The following guidelines should be considered:

- The activation points should be located a minimum of 8 m (25 ft.) away from a high hazard location but not more than 5 min away from any location within the facility. Five minutes is taken as the maximum allowable time, since historical evidence indicates process vessel rupture may occur after this period from flame impingement. If risk analysis calculations demonstrate a longer time period to vessel rupture, longer time periods may be acceptable.
- The chosen locations should be preferably upwind from the protected hazard. Downwind sites may be affected by heat, smoke, or toxic gases.
- They should be located in the path of normal and emergency evacuation routes from the immediate area. In an emergency situation, personnel may immediately evacuate and not activate emergency controls if they are located in an inconvenient location.
- Locating sites furthest from the sources of largest liquid holdups or highly probable leakage sources (i.e., the relatively higher hazards) is preferred.
- They should be located near other emergency devices or equipment that may need utilization during an incident (i.e., deluge activation valve(s), firewater monitors, manual blowdown valves, etc.).

- The main access into the affected area should not be impaired. Location of activation points in normal vehicle or maintenance access routes will affect operations and will eventually cause the device to be damaged or relocated.
- The activation point should be mounted at a height that is convenient to personnel. The ergonomics of personnel access to emergency controls should be accommodated.
- Manned control rooms should always be provided with hardwired ESD points located on the main console, easily accessible to operators.

11.8. ACTIVATION HARDWARE FEATURES

Hardwired ESD activation means have traditionally been a push-in knobs or buttons. These devices have been subject to false activation as individuals can inadvertently lean on them and cause activation. Such buttons are usually protected with a cover that an individual has to physically lift in order to allow the button to be pushed in. Alternatively, buttons are available that have to be "pulled out" in order to activate the signal. Both of these selections require a confirmed action for the ESD activation to prevent false activation by an operator. All devices should only be manually resettable.

Each activation point should be labeled with the area of coverage and provided with an identification as to which valves it operates or equipment it shuts down. A specific number should be assigned to each device. The location itself should be highly visible, preferably highlighted in contrasting colors to normal equipment housings.

In some instances, it may be beneficial to maintain process inventories of certain process vessels until the incident actually threatens the container since the inventory of the vessel may be crucial to the restart of the facility or the contents may be highly valuable. Loss of inventory may be criticized if frequent false trips of the ESD blowdown system occur. In these cases an automatic fusible plug blowdown valve could be installed that would activate from the heat of a real fire incident. In this way the false disposal of the inventory would be avoided.

11.9. EMERGENCY SHUTDOWN VALVES (ESDVs)

The failure mode of ESDVs for gas processing should always fail in the closed position, since this is the only mechanism to resolve gas-fed fires or prevent explosive vapor releases and buildups. The valves should be provided with an automatic fail close device such as an actuator with a spring return specification.

The ESD valves should lock in the fail safe mode once activated and be manually reset once it has been confirmed the emergency has been resolved.

Emergency isolation devices should be arranged so that they can be fully function tested without affecting the process operation. This requires that a full flow bypass may be necessary at each isolation valve if flow cannot be easily interrupted. These bypass installations should be locked closed when not in service for function testing the ESDV.

Where motor operated valves (MOVs) or air operated valves (AOVs) are selected as ESDVs, they should, as a minimum, have backup activation power sources, and the utility service lines should be highly reliable and protected. It should noted that full motor operated and air operated ESDVs are not the same as fail safe spring return valves, even if frequent functional testing is undertaken. The reliability of an internal spring return actuator is considered better than a self-contained MOV or AOV with its own local power source and protection of cabling. This is because additional components of a MOV or AOV contribute to additional failure points and will also have a higher level or vulnerability from external events than an internal spring mechanism.

11.10. EMERGENCY ISOLATION VALVES (EIVs)

Emergency isolation valves (EIVs) should be located based on two principles: (1) the amount of isolatable inventory that is desired and (2) protection of the EIVs from the effects of external events. EIVs are normally required to have a fire safe rating (i.e., minimal leakage and operability rating) to a particular standard, e.g., API 607. Valves and their actuating mechanisms should be afforded adequate protection where they are required to be located in areas that have the potential for explosion and fire incidents.

11.11. SUBSEA ISOLATION VALVES (SSIVs)

Subsea pipeline emergency isolation valves for offshore facilities are provided where a facility risk analysis indicates a topside isolation may be considered vulnerable. A SSIV is designated as an emergency safety device and therefore is not intended or designed for operational activities, such as production/injection reduction, production control, or as a backflow valve.

It should be arranged so it is protected from ship impacts, anchor dragging, combustible liquid spills, and heavy objects that may be dropped from the offshore facility or during ship to facility transfers. API RP 14A provides specifications for SSIV design and construction.

11.12. PROTECTION REQUIREMENTS

ESD system components that are located in areas that would be considered vulnerable to fire exposures (e.g., within tank dike areas, close to pumps, compressors, etc.) should be provided with appropriate fire protection measures to ensure integrity during ESD operation and during major efforts to control an incident. Actuating mechanisms may include control panels, valve actuators, air receivers instrumentation, cabling, tubing, etc.

11.13. SYSTEM INTERACTIONS

Process facilities may exist where operations personnel may be hesitant to activate the ESD system for fear of rupturing the incoming production pipeline due to their poor construction or current conditions. This points out the fact that all mechanism that introduce a change to the normal operating configuration of the system must first be analyzed to determine what effect the proposed actions will produce. Whenever an ESD isolation valve is closed, it will stop incoming or outgoing flows that may produce instantaneous pressure variations and can detrimentally affect the process system. An analysis of measures to prevent additional consequences should be undertaken such as slower valve closing times, increasing integrity of piping systems, etc., whenever possible.

FURTHER READING

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CHAPTER 12

Depressurization, Blowdown, and Venting

Process facilities pose severe risks with respect to fire, explosions, and vessel ruptures. Among the prime methods to prevent and limit the loss potential from such incidents are the provisions of inventory isolation and removal systems. These systems are commonly referred to in the process industry as ESD (emergency shutdown), venting, depressuring, or blowdown. Their objective is to prevent and limit the loss potential from system overpressure events that could lead to the loss of system integrity (i.e., ruptures, BLEVEs, etc.).

12.1. OBJECTIVE OF EMERGENCY PROCESS INVENTORY ISOLATION AND REMOVAL SYSTEMS

Typical process vessels are provided with a pressure relief valve (PRV) to relieve internal vessel pressure that develops above its design working pressure. The purpose of the PRSV is to protect the vessel from rupturing due to overpressure generated from process conditions or exposure to fire heat loads that generate additional vaporization pressures inside the vessel. The engineering calculation behind this application assumes that the process vessel strength is unaffected by direct fire exposure causing the increase in pressure. If the vessel is kept at or near its design temperature this can be assumed to be the case, but when steel is exposed to a high temperature

Hbk of Fire and Explosion Protection, http://dx.doi.org/10.1016/B978-0-323-31301-8.00012-X

from a hydrocarbon fire, its ability to contain normal operating pressure deteriorates rapidly, sometimes within a few minutes, since the strength of the material is rapidly deteriorating during this process, regardless of the vessel internal pressure. A rupture of a vessel can easily occur below the operating pressure of the vessel, within minutes of the vessel being exposed to a major heat source.

Pressure safety valves (PSVs) are typically sized to activate at 121% of the working pressure for fire conditions and 110% of the working pressure for non-fire conditions and only to prevent overpressure, not to relieve operating pressures. A fire exposure may weaken process vessel steel strength below the strength needed to contain its normal operating pressure. In this case, the vessel may rupture before or during activation of the PSV, when it is trying to relieve pressures above operating pressures.

Two major hazards may occur from high pressure vessel failures. The vessel itself may rupture and the formation of vapor cloud as a result of the rupture is possible. If the vessel ruptures, it will produce flying projectiles and usually release large quantities of vapors, and in the case of most hydrocarbons are combustible. The projectiles could harm individuals or damage the process facility, possibly increasing the incident proportions. Secondly, the release of a combustible gas from a pressurized vessel may cause the formation of combustible vapor cloud, which if a suitable amount of congestion is present or some turbulence of the cloud occurs, an explosive blast may result once the cloud contacts an ignition source.

Industry literature typically cites concern over open air vapor explosions when 4536 kg (10,000 lbs) or more of combustible gas is released; however, open air vapor explosions at lower amounts of materials are not unheard of. When the release quantity is less than 4536 kg (10,000 lbs), a flash fire is usually the result. The resulting fire or explosion damage can cripple a process facility. Extreme care must be taken to prevent the release of materials from vessels resulting in vapor clouds and explosive blast over-pressures. Measures such as hydro-testing, weld inspection, pressure control valves, adequate pressure safety valves, etc., should be prudently applied.

Several methods are used to overcome the possibility of a vessel rupture from a fire exposure. Depressuring, insulation, water cooling, or drainage (pump-out) are usually employed in some fashion to prevent the possibility of a vessel rupture from its own operating pressures. A generalized method to qualitatively determine the effect of a hydrocarbon fire on the strength of vessels constructed of steel is available. With this method, one can estimate the time to a vessel rupture and therefore the need to provide protective measures.

The API conducted open pool hydrocarbon fire exposure tests (mostly naptha and gasoline fires) on process vessels during the 1940s and 1950s. Data obtained from these test fires was collected and plotted using the parameters of:

1. Fire exposure temperature
2. Rupture stress of the vessel
3. Time to rupture

These were plotted and are currently complied in API RP 521, Figure 2, p. 48. The data plotted is for vessels constructed of ASTM A 515, Grade 70 steel, a steel that is typically employed for the construction of process vessels. If other materials are used, an allowance of their stress characteristics under heat application needs to be made. Therefore, by using this information a general determination of the need for protective measures, such as depressurization, can be made for a particular vessel by comparison with the Figure 2 chart and selected fire exposure temperatures.

The Underwriters Laboratories (UL) high risk (hydrocarbon) fire test UL 1709, *Rapid Rise Fire Tests of Protection Materials for Structural Steel*, has an average fire temperature of 1093°C (2000°F) after 5 min. The API recommended practice does not define the surface temperature from an actual fire exposure to be applied for the purposes of calculating rupture periods, but provides data from 482°C (990°F) to 760°C (1400°F) for determining rupture times. It should be remembered that free burning fires in general do not achieve theoretical combustion temperatures for the fuels involved. Petroleum fires can reach as high as 1300°C (2400°F), but average 1000°F (1850°F) because of the various factors involved, i.e., cooling of the fire, winds, geometry, etc. Thus, some engineering judgment of the arrangement for the vessel involved should be applied in selecting the appropriate fire temperature. Typically 649°C (1200°F) is chosen as a starting point as it correlates well with fireproofing test requirements. A particular point noticed when using the API chart is that a 100°C (212°F) difference in the fire exposure temperature can have a dramatic difference on the time to vessel rupture. Therefore, the chosen exposure temperature has to be selected carefully and adequately justified.

The ASME pressure vessel stress formula to calculate the applied vessel stress is:

$$S = P(R + 0.6t)Et$$

where S = Rupture stress; P = Operating pressure, psig; R = Shell inside radius, inch; T = Shell wall thickness, inch; E = Well joint efficiency (generally assume 100%).

The shortest time for a vessel to rupture from recorded incidents is thought to be 10 min. Rupture periods calculated for less than 10 min therefore may not be highly accurate, as the historical evidence and the typical growth period of a hydrocarbon fire indicate that immediate rupture of a vessel does not occur. Further investigations may be undertaken to verify if fire exposure conditions could produce such results, i.e., flange leak, gas fire exposure, etc.

If a vessel is insulated, some credit can be taken for the reduced heat input rate provided by the insulation, but this depends upon the quality and thickness of the insulation, plus the time for the insulation to rise to the ambient exposure temperature. Typically in the sizing of relief valves, it is normally assumed that lightweight concrete insulation (fireproofing) reduces the heat input to approximately one-third of its original value. Therefore, depending on the rating of the fireproofing, the time to a vessel rupture from operating pressures can be increased (the time delay of the fireproofing material added to the time it takes to cause the steel to weaken and rupture). Commercially available hydrocarbon fire-rated fireproofing materials are available in several fire resistance periods. If connecting pipelines are not isolated with an ESD valve or insulated from fire exposure sources, they could also be a source of hydrocarbon release that has to be taken into account when making these assumptions.

Similarly, if a vessel is provided with a reliable and dependable water cooling system, i.e., firewater deluge spray, according to recognized standards, e.g., NFPA 15, *Water Spray Systems for Fire Protection*, it would not be affected by explosive blast pressures or the fire exposure, and it may theoretically demonstrate that a vessel does not need a depressurization system for the prevention of a rupture from fire exposures. Similarly, API RP 2000 does not allow credit for water cooling of pressure relief valves unless they are demonstrated to have extremely high integrity during an incident.

If the area under a vessel is provided with adequate drainage capability credit may also be taken for reduced heat input due to the runoff of any combustible liquids producing the fire exposure. Usually drainage requirements of NFPA 30, *Flammable and Combustible Liquids Code*, would have to be met, namely 1% sloped away grade to a 15 m (50 ft) radius (a specific NFPA standard or code for process system depressurization is not available). Published literature also suggests that un-insulated vessel rupture time could be increased by 100% for a highly effective drainage system.

Two examples of calculating vessel rupture time are shown in Figures 12.1 and 12.2.

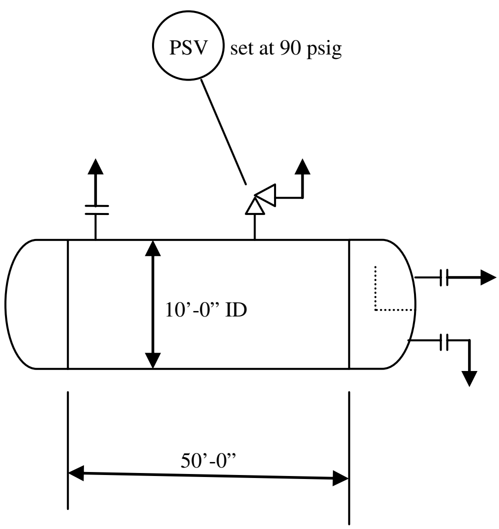

Figure 12.1 Horizontal separator.

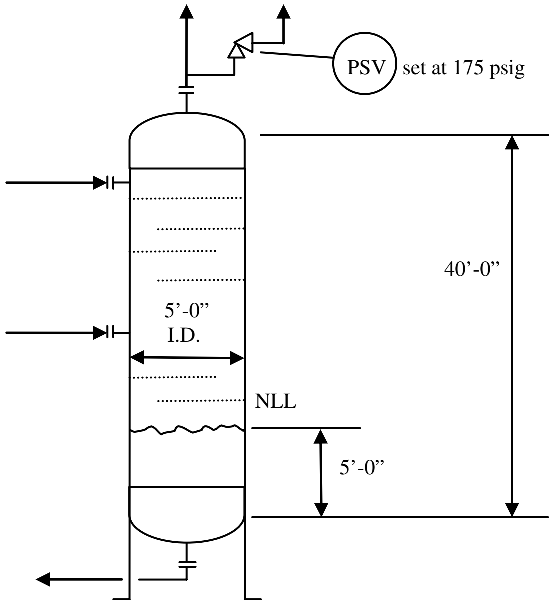

Figure 12.2 Crude stabilizer column.

12.2. SEPARATOR (HORIZONTAL)

Assumptions	Size	10′-0″ I.D. × 50′-0″ s/s
	Shell wall thickness	0.5 in.
	Liquid sp. gravity	1.0
	Material of construction	ASTM A 515 grade 70 carbon steel
	Operating pressure	50 psig
	Design pressure	90 psig
	Normal liquid level	9′0″ from bottom
$S = P\ (R + 0.6t)Et$	Ref. ASME DIV VIII (for circumferential stress)	
$S = 50\ (60 + 0.6 \times 0.5)\ 1.0 \times 0.5$		
	where	S = Rupture stress
$S = 6030$ psi		P = Operating pressure in psig
		R = Shell inside radius, inch
		t = Shell wall thickness, inch
		E = Joint efficiency (assumed 100%)

Source: From Figure 2, API RP 521

Time before rupture at 6030 psi and 1300 °F is approximately 5 h. Conclusion Depressurization capability is not required.

12.3. CRUDE STABILIZER COLUMN

Assumptions	Size	5′-0″ I.D. × 40′-0″ s/s
	Shell wall thickness	07/16 in.
	Liquid sp. gravity	0.85
	Material of construction	ASTM A 515 grade 70 carbon steel
	Operating pressure	150 psig
	Design pressure	175 psig
	Normal liquid level	5′0″ from bottom seam
$S = P\ (R + 0.6t)Et$	Ref. ASME DIV VIII (for circumferential stress)	
$S = 150\ (30 + 0.6 \times 0.4375)\ 1.0 \times 0.4375$		
	where	S = Rupture stress
S = 10,374 psi		P = Operating pressure in psig
		R = Shell inside radius, inch
		t = Shell wall thickness, inch
		E = Joint efficiency (assumed 100%)

Source: From Figure 2, API RP 521
Time before rupture at 10,374 psi and 1300°F is approximately 0.3 h. Conclusion: Depressurization required.

Once a time to rupture has been established, it needs to be compared against the worst case credible event (WCCE) for the facility. A very short duration fire exposure would likely indicate that a vessel depressurization capability may not be necessary. Typically most process facilities have an ESD system, which at the very minimum, should isolate the incoming and outgoing pipelines. In this fashion, the remaining fuel inventory at the facility is what remains in vessels, tanks, and the piping infrastructure. It should also be considered that after 2–4 h of a high temperature fire, equipment cannot usually be salvaged. So beyond these periods, little value is gained in additional protection measures. Typically if the rupture period is several hours long, the need for a depressurization system (or blowdown) is not highly demonstrated or recommended.

Normally, emergency vessel depressurization is automatically activated though an ESD level 1 (i.e., worst case) interface and completed within 15 min. A vessel should be depressurized to a minimum of 50% of its design operating pressure or preferably completely depressurized. Interconnecting vessels to the primary vessel should also be included in this depressurization. If vessels are not completely depressurized, there is still a risk of vapor release from the remaining pressure (i.e., inventory) in the vessel or in its interconnecting piping. An engineering evaluation of depressurization arrangements and calculations of depressurization periods should be performed.

Certain conditions and arrangements (e.g., process restarts) may preclude the provision of an automatic and immediate depressurization system for all vessels. Some volumes of gaseous products may be necessary for an adequate plant restart process. If the facility were to inadvertently depressurize, the operation may suffer an economic loss or business interruption event if gas supplies have to be obtained outside the facility. In these cases, alternative protection methods may be employed. These may include remote placement of storage gas for plant restart, local fusible plug-activated depressurization outlet valves, insulation (fireproofing), dedicated vessel firewater deluge, adequate and immediate area drainage, etc. An engineering evaluation should be undertaken whenever a fully automatic (ESD) depressurization system is not provided.

Published literature also suggests that explosions and major damage are unlikely when less than 907 kg (2000 lbs) of material is released. API RP 521 also suggests that vessels operated at relatively lower process pressures should consider depressurization capability for certain fire scenarios.

The following are general conservative guidelines that can be considered to generally classify process vessels that may require depressurization capabilities (summarized in Figure 12.3).

Vessels requiring depressurization capability:

- A vessel operated above 690 kPa (100 psi)
- A vessel that contains volatile liquids (e.g., butanes, propanes, ethanes, etc.) with vapor pressures above atmospheric
- operational requirements exist (i.e., compressor blowdowns)
- A vessel exposed to a fire condition may occur that weakens the vessel steel to below safe strength levels (as defined by API RP 521), within several hours, which may cause a significant loss exposure

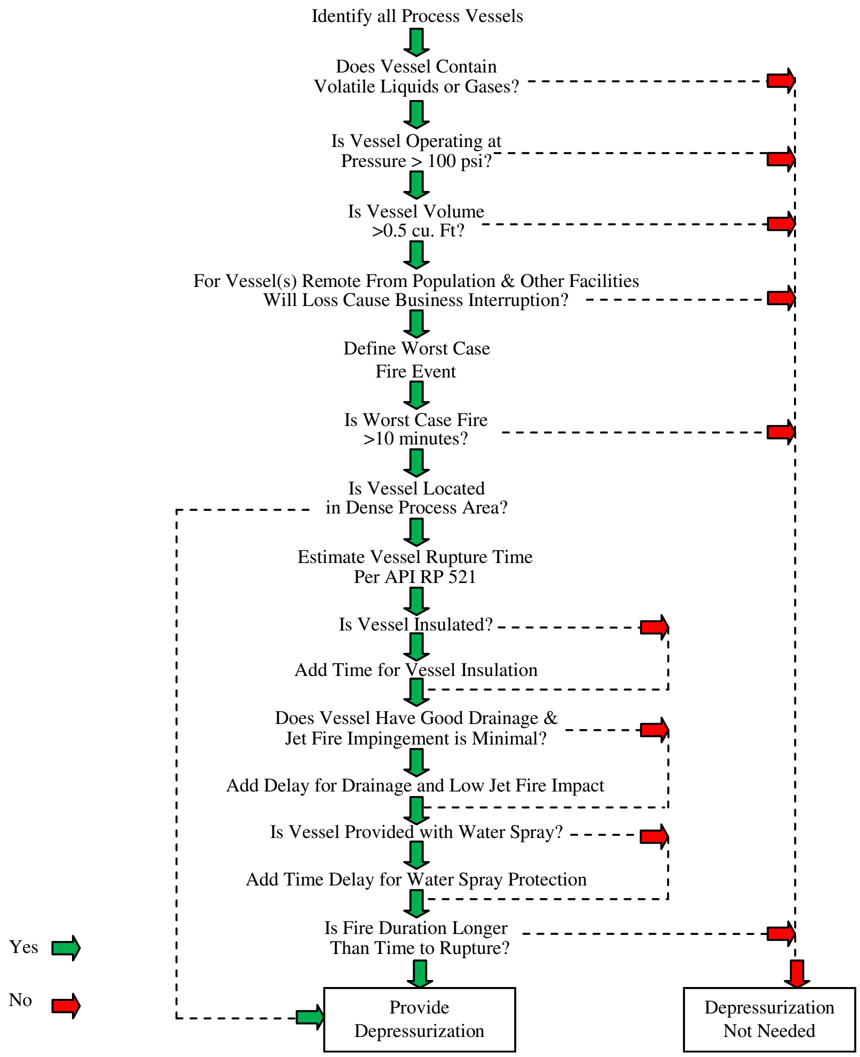

Figure 12.3 Process vessel depressurization decision flow chart example.

Vessels that may not require depressurization capability:

- A vessel operated at less than 690 kPa (100 psi)
- A vessel containing less than 907 kg (2000 lbs) of vapors
- A vessel whose time to rupture from a fire exposure is several hours

- A vessel provided with fireproofing material (insulation) rated to withstand the expected fire exposures until other fire protection measures are employed (e.g., manual firefighting)
- A vessel provided with a firewater deluge system to protect against fire exposures for the duration of the worst case plausible event that will not be impacted by the event
- A vessel whose time to rupture, insulation, fixed fire protection (water spray), or drainage arrangements would not cause the vessel to rupture during the process incident
- A vessel that if ruptured due to a fire exposure would not endanger personnel, damage important or critical facilities, cause significant financial impacts, create an environmental hazard, or create an undesirable reaction from the general public

The objectives of depressurization are to (1) prevent a vessel from rupturing during major fire exposure (from weakened condition of the vessel steel), (2) prevent further fire escalation, and (3) minimize the impacts to the vessel itself. It is therefore incumbent to depressurize a vessel so that its stress is less than the stress that would cause a rupture from fire conditions. These stresses and rupture periods can be estimated to determine the need for depressurization systems for process vessels. These estimates can provide a rough evaluation of the need of a depressurization system for a particular process plant or entire facility.

Vapors from depressurization valves are typically routed to a pipe header and then to the flare to safely remove the vapors from the area and dispose of them without impact to the environment. A special concern when high levels of pressurized gases are released into a piping system is the possibility of auto-refrigeration of the piping material that may cause a brittle fracture. A process engineer should verify which pipe materials and flow rates, specified for the depressurization system, are suitable for the pressures, flows, and gases under consideration.

Once calculations are completed on a depressurization system, it will become readily apparent whether high volumes of gases will be flowing through the pipe header to the flare. In some cases, simultaneously depressurizing all the process and equipment, vessels, and piping in a plant will be difficult to accomplish (due to pipe sizing and economic impacts). In these cases, sequential or segmented depressurization of vessels should be considered. Providing for the worst vessels first or controlling the system to depressurize the area most affected first are possible options that can be employed.

High noise levels will also be generated when high flows are encountered. In these circumstances, special noise reducing fittings are available to limit noise impacts from the system to the surrounding area.

12.4. BLOWDOWN

Blowdown is the removal of liquid contents of vessels and equipment to prevent its contribution to a fire or explosive incident. Blowdown is similar to depressurization but entails liquids instead of gases. A liquid blowdown should never be sent a facility flare that is designed to only handle gaseous materials. A liquid release of the flare may result in a flare out, and if the flare is elevated, a shower of liquids on the process facilities can result. Ideally, liquid blowdowns should be routed to facilities that are specifically designed to handle large quantities of liquid materials. The blowdown could be routed to storage tanks, an open pit, burn pit, another process facility, the closed drain system (CDS), or a pressurized sewer. A blowdown to a tank is generally avoided since entrained gases or failure or undersized of relieving devices may cause the tank to rupture. Similarly, disposal to an open pit poses the hazards of exposed combustible liquids and gases. For avoidance of environmental impact a CDS or pressurized sewer is commonly employed. The temperature of blowdown liquids also has to be considered when selecting the materials for a blowdown system to avoid undue thermal effects. API RP 520 provides guidance for blowdown design arrangements.

12.5. VENTING

Direct venting of hydrocarbon and toxic gases to the atmosphere should be avoided for the following reasons:

1. It may create a combustible vapor cloud with fire or explosion potential
2. It may be harmful to personnel (immediate or long-term health effects).
3. It may be an environmental pollutant.
4. It is a waste of the vented material (i.e., economic loss).

5. It represents a poor community or public image to release waste to the atmosphere.
6. It may be a violation of local or national environmental governmental regulations.
7. Vented gases may not adequately disperse, then drift considerable distances and ignite or have a toxic effect.

Whenever possible waste vapors or gases should be disposed of through the facility flare system or re-injected into the production process for recovery. Non-polluting materials such as steam can be freely vented to the atmosphere if they do not pose burn hazards to personnel.

12.6. FLARES AND BURN PITS

In most process facility operations gas and vapor have to be disposed of safely, quickly, and without environmental impact. Where the gas or vapor cannot be converted to useful energy it is routed to a remote point for safe incineration, which is called flaring. Flares are the most economical and customary means of disposing of excess light combustible gases in the process industries. The primary function of a flare is to convert flammable, toxic, or corrosive vapors to an environmentally acceptable gas for release to the atmosphere from both normal operational venting and relief during abnormal conditions. Both elevated flares and ground flares, referred to as burn pits, can be used. Burn pits are utilized where liquids are required to be disposed of.

The type of flare used depends on several factors including:

- Available space of onshore and offshore arrangements.
- Characteristics of the flare gas: composition, quantity, pressure, etc.
- Economics: both initial capital costs and periodic maintenance.
- Public impression (i.e., if flaring is smoky or noisy, the general public will object to it).

The primary features of a flare are safety and reliability, while the primary objective of the flare is to prevent the release of any gases that not been burnt in order to prevent hazards elsewhere. In reviewing existing facilities worldwide—from Russia to South America, onshore and offshore—it has been found that most installations have admitted either officially or unofficially that on occasion, liquid release has occurred from the top of an elevated flare stack. This has occurred even with the installation of a flare header liquid collection (i.e., knock-out) drum. In most cases, it has caused no apparent problems, but in a few cases it has been disastrous. It is suspected that liquid releases occur much more frequently than actually reported. Technically, these problems may be because most flare systems are designed for unrestricted gas flow through the flare header and knock-out drums, but which can induce liquids to carryover. Therefore, the possibility of liquid releases from vapor disposal flares cannot be entirely ruled out.

During typical plant design, the flare location has to be carefully examined. All wind velocities and directions should be considered in the design. Some experts suggest that flares should be located downwind while others propose they should be upwind of the facility. This is based on the assumption that a flare may overflow with liquids or un-ignited gas may occur and therefore the flare should be downwind so these materials would not disperse on the facility, while vice versa, an upwind location would allow gases to travel downwind onto the plant and be ignited in the process.

The ideal solution is to locate the flare in a perpendicular location to the prevailing wind (i.e., crosswind) with adequate spacing from the facility. This should preferably also be at a lower elevation than the rest of the facility. This is in case of release of heavy vapors that have not been adequately combusted in the flare exhaust. Because of the larger spacing requirements for flares (i.e., distance to avoid heat radiation effects and vapor dispersion requirements), they should be one of the first items sited for the design of a new facility.

Flare safety precautions should include:

- Use of an automatic flame monitoring device to warn of flameout conditions.
- Provision of a liquid knock-out drum, which is equipped with high level alarms to warn of an excessive accumulation of liquids and possible carryover to the flare.
- Prevention of the introduction of vapors into the system when it is not operational

Important safety aspects of flares also include the following:

- The flare is a readily available ignition source to combustible vapors that can reach it or the radiant heat it produces.
- Flame-out (flame lift-off or blow-outs) sometimes occur at a flare, at which time flammable vapors will be discharged. If heavier than air and wind conditions permit, they will travel along the ground to other areas until dissipated. Provision of a windshield around the flare tip will assist in preventing flame-out conditions from occurring.
- An elevated flare may emit liquids under certain conditions, which will rain down on the surrounding area or adjacent processes. This may occur even if the flare is lit. Provisions to entrap and contain liquids in the flare header, for worst case conditions, should be provided at the flare tower.
- Flares have the added consideration of being designed to always have a flame present, even when there is a very low flow rate. They are typically equipped with molecular or fluidic seals and a small amount of purge gas to protect against flashback.

Liquid knock-out drums or separators are normally used to remove any liquids from gas streams flowing to flares designed to burn vapors. The drums should not only be designed to collect liquids running along the bottom of the pipe, but to disengage entrained liquid droplets in the gas stream. API RP 521 provides guidance on the collection of liquid

Table 12.1 General Guidelines for Material Disposal Methods

Material	Vent	Flare	Process	Sewer
Process vapors				
Combustible, non-toxic and toxic		X	X	
Process vapors				
Non-combustible and toxic		X	X	
Process vapors				
Non-combustible and non-toxic	X			
Steam	X			X
Sewer vapors	X			
Liquids				
Process blowdown			X	X
Thermal relief			X	X
Process drain				X
Surface runoff				X

particles that should be removed before gas is sent to the flare tip for burning. Additionally, the knock-out drum should be sized to accommodate the maximum amount of liquid that might be required to be withdrawn during depressurization of the entire or any portion of the facility as the design of the system may dictate. If large quantities of propanes or butanes at low temperatures may be reached in the flare header and drum due to auto-refrigeration, this must be taken into account during the design of the flare system (see Table 12.1).

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CHAPTER 13

Overpressure and Thermal Relief

The term pressure relief refers to the automatic release of fluids or gases from a system or component to a predetermined level. Pressure relief systems are designed to prevent pressures in equipment or processes from reaching levels where rupture or mechanical failure may occur, automatically releasing the material contained within.

Almost all portions of a process or system can conceivably be exposed to conditions that would result in internal pressures, either positive or negative, exceeding the normal operating pressures of the system. There is also the possibility of mixed vapor-liquid (two-phase) releases. Two-phase relief is likely where reactive systems are involved.

13.1. CAUSES OF OVERPRESSURE

The most common causes for overpressure included the following:

- **Exposure to Fire:** If a vessel is exposed to heat radiation from a fire, internal pressure may rise primarily due to the generation of vapor from the internal liquid or from thermal expansion of the contained commodity.
- **Excessive Process Heat Input:** Most process systems require or contain varying amounts of heat exchange. Should a process upset occur that inputs more heat than design conditions have allowed, an overpressure may result due to expansion of liquid or vapor contained within the system.
- **Failure of Flow, Pressure, or Temperature Control Valves or Devices:** Control valves or instrumentation that regulates process conditions may fail causing a process upset to occur. Once the process upset occurs, pressure regulation will not be effectively controlled and pressure increase may result.
- **Unexpected Process Chemical Reactions:** Unexpected/runaway chemical reactions that result in heat or vapor evolutions may produce overpressures that have not been previously evaluated.

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- **Failure of Cooling Water Supply:** A reduction in cooling water flow to condense vapors in a vessel may lead to increased pressure drop through the condensers resulting in increased pressure in the vessel.
- **Isolation:** If a vessel or tank becomes isolated, either fully or partially, from normal process conditions, internal pressure may build up if it has no outlet for venting.
- **Failure of Heat Exchanger Tubes:** If a heat exchanger shell rating is less than the pressure level of the circulating medium and an internal heat exchanger tube ruptures or leaks, it will overpressure the vessel.
- **Introduction of a Volatile Material:** The introduction of liquid into a vessel, where the temperature is above the boiling point of the commodity, will result in the rapid vaporization of the material, causing an increase in vapor output requirements and raising the pressure of the vessel. Materials with low molecular weight are especially prone to this effect.
- **Introduction of a Reactive Foreign Material:** The introduction of a reactive foreign material to the process may produce a vapor that could overpressure the system.
- **Reflux System Failure:** The quantity of reflux used in fractionation systems determines the amount of vapor generation and the consequent pressure differential through the condenser system. If a reflux system fails, lower pressures through the condensers and vessel may result in higher pressure risk in the system as a whole.
- **Internal Detonation or Explosion:** An internal detonation or explosion may occur due to several scenarios. Air leakage into the system may cause a combustible mixture to form, undesired chemical reactions may occur, and extremely rapid vapor expansion may occur. These almost instantaneous events have to be carefully protected against as many overpressure devices do not react quickly enough to prevent a vessel from rupturing.
- **Thermal Expansion:** Contained liquids may be subject to heat input that causes them to expand, resulting in a pressure increase. Typical heat sources are direct sunlight and fire exposures.
- **Non-Condensable Gas Accumulation:** If non-condensable gases are not removed, overpressure can result when a heat exchanger surface becomes blanketed or pressure drop through the condenser is increased by the presence of the non-condensable gas.
- **Outflow Rate Exceeds Inflow Rate:** If material is being withdrawn from a tank or vessel faster than the incoming rate to compensate for the removal suction, a vacuum will occur. If the vessel or tank is not strong enough to withstand the negative pressure levels, it will collapse in on itself.

There are numerous types of pressure relieving devices available, which include relief valves, safety valves, rupture or frangible discs, and blowout hatches or panels.

Methods for design of mixed vapor-liquid (2-phase) releases have been developed by the American Institute of Chemical Engineers (AIChE), Design Institute of Emergency Relief Systems (DIERS) program. These methods include two comprehensive computer programs (DEERS and SAFIRE) and a simplified calculation method based on test data.

13.2. PRESSURE RELIEF VALVES

Pressure relief valves are used to cater to two main conditions of the process—normal conditions and emergency conditions. Because these causes of overpressure are considered random and infrequent, the pressure relief capability has to be automatic and constantly available. Excessive pressure can be caused when a process is upset, an instrument malfunctions, or equipment fails. The set point for discharge of the emergency relief device is determined by criteria of the ASME, Boiler, and Pressure Vessel Code, Section VIII. ANSI/ASME Code B31.3, Process Piping, which specifies the type of pipe and the corrosion resistance specifications that should be met for relief system piping. Schedule 40, carbon steel pipe is the material most commonly used in relief systems. The discharge piping should be sloped from the outlet to facilitate drainage.

Where relief valves are provided on liquid storage tanks or vessels, there is the possibility of a liquid release, i.e., a liquid slug, and a careful evaluation of the relief disposal system needs to be undertaken. In some cases, a liquid slug may block a pipe header from releasing pressure and defeat the purpose of the pressure relief system.

13.3. THERMAL RELIEF

Thermal relief is necessary in sections of liquid piping when it is expected that the liquid will be isolated when the piping is also subject to temperature rises from solar radiation, warm ambient air, steam tracing, fire exposures, or other external sources of heat input.

High temperature input to a piping system will cause both the piping and the fluid contained within it to expand. Liquids have a high coefficient of expansion compared to metals (e.g., oil will expand approximately 25 times that of a metal pipe). It therefore should be expected that high pressures can develop in piping systems that are isolated and exposed to heat input. Thermal expansion of the pipe and expansion of pipe material from internal pressure may be adequate for relief of liquid thermal expansion before strength limits are reached for piping, valves, or blinds. Research tests have shown that pressure from thermal expansion of liquid hydrocarbon may increase 553 kPa to 789 kPa (70–100 psi) for each °F in temperature increase. The length of piping has no effect on the pressure that will result from thermal expansion of a liquid in an isolated section. However, the volume of the fluid that must be released to prevent excess pressure build-up is directly proportional to the line length.

Temperature increases in hydrocarbon process lines that are not in circulation but receive heat input can easily achieve temperature increases that can result in pressure buildup that requires evaluation for thermal expansion relief. Normal solar radiation in some cases is enough to raise the pressure in lines containing liquids as much as 23,685 kPa–78,950 kPa (3,000–10,000 psi). The main reason more ruptures have not occurred in lines without thermal pressure relief devices is that most isolation valves have some tolerance of leakage and pipe flange gaskets may also leak or fail. Further reliance on quality isolation means, such as double block valves, double-seated gate valves, line blinds, etc., creates a greater chance of line rupture from thermal expansions. Also, reliance on flange leaks to relieve trapped piping pressure is no longer an acceptable environmental alternative. Increased verification of a leak-free facility to prevent VOC emissions to the environment will require elimination of pressure relief points that may have unknowingly been relied upon in the past. Any relief design must also assume that the relief effluent is contained within system piping and properly contained and disposed of.

Overpressure from thermal expansion can occur in any pipe size or length with only a small rise in temperature. It may be argued that all sections of piping that can be isolated theoretically need provisions for thermal relief. As pressure is built up in a line, sensors may warn of pressure increases, valves can leak, or pressure buildup is not likely. There are some instances where the provision of a thermal relief valve is not justified, such as cold water lines inside buildings, buried or insulated lines, firewater lines, piping operated at elevated temperatures, etc. There are also operational procedures that can be instituted to alleviate thermal pressure concerns such as partially draining liquid lines before isolation, continuous pressure monitoring, etc. However, these methods are not the preferred method of protection, since they are prone to human error. Relief valves are the preferred and recommended method of preventing pressure buildup.

For liquid-packed vessels, thermal relief valves are generally characterized by the relatively small size of valve necessary to provide protection from excess pressure caused by thermal expansion. In this case, a small valve is adequate because most liquids are nearly incompressible, and so a relatively small amount of fluid discharged through the relief valve will produce a substantial reduction in pressure.

13.4. SOLAR HEAT

For geographical locations between 60° north and 60° south latitudes, solar heat input to pipelines and the resultant thermal expansion is essentially the same. Orientation will have some effect on the total amount of heat input, i.e., north-south provides more exposure than east-west, but the maximum rate of heat input is the same as that which occurs at the highest sun position, i.e., at noon. This is a rather trivial aspect as the cost of pipe length and installation costs generally overrule orientation concerns for thermal radiation input. Wind effects will normally dissipate some heat from pipelines. However, in the case of thermal expansion concerns, it is common practice not to consider wind for purposes of heat input (or loss) to a piping system. Pipe color will also have an impact on heat absorption. Flat black is the highest heat absorber (1.0), while lighter colors are quite less (0.2–0.3). Reflectivity characteristics also assist in reflecting radiation.

13.4.1 Thermal Relief Fluid Disposal

There are three main methods to dispose of releases from thermal relief valves. Discharge around a block valve (isolation circumvention) is widely used in most situations. Where this is not practical or economical, disposal to a sewer is specified in certain cases. These methods include:

- **Isolation Circumvention:** Where the fluid is the same on each side of the isolation means, and no contamination will result, this is the optimum choice for thermal relief release. Consideration of the possible backpressure onto the thermal relief valve, rendering the valve ineffective, should be considered as part of the review for the installation.

- **Disposal to Oily Water Sewer (OWS):** A process oil water sewer system is a convenient location to direct oily waste from process systems including thermal relief outlets. The oily water system normally collects fluids and directs them to the local sump. If several lines connect into a common OWS header, care should be taken to prevent backflow into another outlet source. In such cases, use of air gap, i.e., drainage into a collection funnel, has been advantageous.
- **Plant Surface Runoff:** Disposal to plant surface runoff should be avoided as a viable disposal method. This method may result in a fire hazard, safety and health hazard, or an environmental concern.

13.5. PRESSURE RELIEF DEVICE LOCATIONS

Pressure relief capability is generally provided or required at the following locations:

- **Pressurized Vessels:** Unexpected process upsets may result in pressure above normal operating conditions.
- **Storage Tanks:** All storage tanks subject to high flow rates in or out require compensation for the displaced vapor.
- **Equipment Susceptible to Thermal Expansion**
  - **i.** Vessels or tanks subject to ambient or thermal expansion.
  - **ii.** The cold side of a heat exchanger, if blocked off, may be subject to excessive heat input from the hot side.
  - **iii.** Circulation lines of a heater, where they may be blocked off.
- **Discharge of Compressors:** Variable speed drivers can increase compressor discharge pressures above desired amounts, causing a process upset. With the provision of constant speed drivers, such as electric motors, the possibility of overspeed is highly remote.
- **Pumps with Variable Speed Drivers:** Variable speed drivers can increase pump discharge pressures above desired amounts, causing a process upset. With the provision of constant speed drivers, the possibility of overspeed is unlikely.
- **Heat Exchangers:** Heat exchangers that can be blocked in or where the shell of the exchanger may be subject to high pressure if an internal tube leak occurs.

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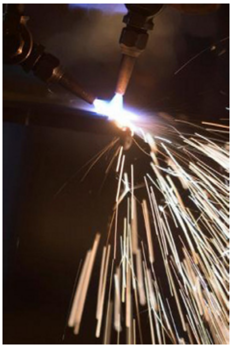
CHAPTER 14

Control of Ignition Sources

In process operations that contain combustible liquids or gases, any leak or spillage may create risk for an explosive atmosphere. To protect both personnel and the plant, precautions must be taken to ensure that the atmosphere cannot be ignited. It is generally recognized that there are various ignition sources in a process facility—e.g., open flames, electrical devices, and sparks. The overall objective is to remove or provide a barrier in between these ignition sources and materials that can readily ignite if contact is made. The ability of these sources to ignite a material depends on its available energy and configuration.

Ignition sources are typically the following: (1) Open flames, (2) Cutting and welding, (3) Hot surfaces, (4) Radiant heat, (5) Lightning, (6) Smoking, (7) Spontaneous ignition, (8) Frictional heat or sparks, (9) Static electricity, (10) Electrical sparks, (11) Stray currents, (12) Ovens, furnaces, and heating equipment, and (13) Pyrotechnic materials.

14.1. OPEN FLAMES, HOT WORK, CUTTING, AND WELDING



Open flames in process facilities usually occur due to welding, cutting, or other similar hot work operations, and the facility flare. NFPA 51 B provides guidance in the fire safety precautions for the conduction of cutting and welding operations. Process facilities typically institute a work order or work permit to manage hot work operations and to ensure safety precautions are instituted.

One of the prime safe guards used in process facilities for hot work is the provision of a fire watch. International standards ANSI Z49.1, API RP 2201, and NFPA 51B list specific duties for a fire watch before, during, and after any hot work operations. Assigned fire watch individuals should understand and be trained in fire watch duties and responsibilities along with being provided with

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communication capability with area personnel and appropriate fire extinguishing equipment.

14.2. ELECTRICAL ARRANGEMENTS

Facility electrical systems and components provide a convenient source of ignition within a process facility or ordinary occupancies wherever the design, installation, or maintenance is substandard. Electrical systems or components may short, overheat, operate incorrectly, etc. These failures will present themselves as available ignition sources for hydrocarbon vapor releases. All electrical installations should be provided and maintained in accordance with recognized electrical industry standards such as API RP 540 and the National Electrical Code (NFPA 70).

14.3. ELECTRICAL AREA CLASSIFICATION

The overall intent of electrical area classification is to provide for safety of personnel and equipment. This is achieved by the elimination of electrical sources near combustible gases or vapors that could explode or burn. The specific reasons for classifying facilities and equipment into hazardous areas are typically due to the following:

1. To ensure that sources of ignition are safely separated from sources of combustible liquids and gases
2. To ensure electrical apparatus selected for use near combustible liquids and gases is of adequate design and construction to prevent it from being a source of ignition
3. To assist in the location of air inlets for ventilation systems and combustion equipment (i.e., to prevent the ingestion of combustible vapors or gases)
4. To define the extent of combustible vapor travel from vents, drains, and other such open gas or vapor emission sources
5. To assist in the location of combustible gas detectors and fire detection devices.
6. To permit the location of life-saving equipment and appliances, combustible liquid stores, radioactive, and emergency control points in safe areas where practical

7. To achieve an economical electrical installation that will provide an acceptable level of safety at the lowest possible costs.

It might be argued that if the ignition sources were not all removed, but still present in process areas containing combustible gases or vapors, that any subsequent leakage would be ignited preventing the formation of a large vapor cloud that potentially could inflict more damage. The rationale is that if these leaks are involved in combustion, the fuel is consumed, thus avoiding major damage, and the cost for the installation of electrically classified equipment is avoided.

It should be remembered that leakages may be large or small in nature and can be orientated in infinite directions, so considerable fuel leakages may occur, even where ignition sources are readily available. Additionally, many incidents have occurred where large leakages have existed, which have not been ignited, since ignition sources were removed from the area. Therefore, prevention measures should always be employed to avoid ignition of combustible vapors or gases whenever possible.

To enable electrical equipment to be used safely in potential atmospheres containing combustible vapors or gases (i.e., hazardous atmospheres), various, although essentially similar, hazardous area definition techniques have been developed by professional organizations. Various international and national standards or codes of practice govern each of these techniques. These methods define how equipment is to be designed and applied. Independent certifying bodies ensure a specified design meets the performance requirements of the standard or code. The basic premise of these techniques is to specify a "hazardous area" that combustible gas or vapor may likely to be encountered based on gas or fluid concentration and the configuration of the facility. The purpose of these hazardous area classifications is to limit the probability of electrical ignition of flammable vapors and gases. This is achieved by limiting the types of electrical equipment that may be installed in the areas where combustible vapors or gases may exist for any length of time. Hazardous areas for US industry are typically prescribed by Article 500 of the National Electrical Code (NFPA 70), American Petroleum Institute Recommended Practice (RP) 500 and NFPA 30, Flammable and Combustible Liquids Code. Other international codes and specifications exist that may alter the requirements of these codes, some of which are more stringent.

Countries in Western Europe generally work to CENELEC standards. European Union (EU) member countries issue Certificates of Conformity to these standards and accept products and systems certified by other

Table 14.1 Recognized International Electrical Approval Testing Agencies

Country	Name	Approval Agency
Belgium	INIEX	Institute National des Industries Extractives
Canada	CSA	Canadian Standards Association
France	LCIE	Laboratoire Central des Industries Electricques
Germany	PTB	Physikalisch Technische Bundesanstalt
Italy	CESI	Centro Electtrotechnico Sperimentle Italiano
Switzerland	SEV	Schweizerrischer Elctrotechnischer Verein
UK	BASEEFA	British Approvals Service for Electrical Equipment in Flammable Atmospheres
USA	FM	Factory Mutual Global
USA	UL	Underwriters Laboratories, Inc.

members. Other countries (e.g., Australia, Brazil, Japan, etc.) work to their own standards based on IEC-60079, or accept equipment or systems certified to European or North American standards.

Some specific internationally recognized electrical hazardous location equipment testing agencies are listed in Table 14.1.

Simple devices that do not generate or store significant electrical energy can be used without certification. They include thermocouples, resistive sensors, LEDs, and some specific switches. In some cases, the interconnecting cables may store energy in their capacitance or inductance and release it suddenly if there is a fault. The certificate for any interface device defines the maximum permitted "cable parameters." Interface devices are usually designed to tolerate long cables and in practice, although the user should check, there is very seldom a problem.

14.4. ELECTRICAL AREA CLASSIFICATION

In the US, the electrical area classification for areas that contain flammable/combustible liquids and gases are usually defined by the requirements of the National Electrical Code (NEC), i.e., NFPA 70, API RP 500, and NFPA 30, which are similar in content.

The classification uses the nomenclature of classes, divisions, and groups, which are defined as follows:

Class I: Gases and vapors

Division 1: Gases and vapors can normally exist

Division 2: Gas and vapors normally confined

Classes I, II, and III are also used by the NFPA to define the range of certain materials in categories based mainly on flash points. Classes II and III materials generally do not provide sufficient vapors to require specification of an electrically classified area, so areas are mainly defined by Class I flammable materials. Class II and Class III areas are typically for dusts and fibers, respectively, and are typically not extensively used in process industries unless such materials are specifically present.

Flammable materials are also differentiated according to the spark energy needed to ignite them, which is defined by the group rating:

Group A: Acetylene

Group B: Hydrogen and fuel gases containing greater than 30% hydrogen, butadiene, ethylene oxide, proplyene oxide, and acrolein

Group C: Ethyl ether, ethylene, or gases of equivalent hazard

Group D: Acetone, ammonia, benzene, butane, cyclopropane, ethanol, gasoline, hexane, methanol, methane, natural gas, naptha, propane, or gases and vapors of equivalent hazard

14.5. SURFACE TEMPERATURE LIMITS

Hazardous area apparatus is classified according to the maximum surface temperature produced under fault conditions at an ambient temperature of 40°C (104°F) or as otherwise specified. Some desert locations may produce ambient temperatures higher than 40°C (104°F) and suitable adjustments must be made in these circumstances (see Table 14.2).

14.6. CLASSIFIED LOCATIONS AND RELEASE SOURCES

Some typically defined classified locations are listed below (when hydrocarbon materials are present):

- Relief valve outlets
- Packing glands or seals on pumps and compressors handling combustible materials
- Pipe flanges, fittings, and valve stems
- Threaded fittings that are not seal-welded at the thread joint
- Sampling stations with an air break

Table 14.2 Electrical Apparatus Surface Temperature Limits

Rating	Maximum Allowable Temperature, °C (°F)
T1	450 (842)
T2	300 (572)
T2A	280 (536)
T2B	260 (500)
T2C	230 (446)
T2D	215 (419)
T3	200 (392)
T3A	180 (356)
T3B	165 (329)
T3C	160 (320)
T4	135 (275)
T4A	120 (248)
T5	100 (212)
T6	85 (185)

- Manways and piping connections to vessels and tanks
- Piping to equipment connections
- Vent and drain openings associated with combustible fluids or gases
- Drainage ditches, gulleys, trenches, and associated remote impounding basins
- Pits, sumps, open trenches, and other below grade locations where heavier vapor can accumulate
- Laboratory hoods, ducting, and storage rooms where combustible liquids and gases are handled
- Oily water gravity and pressure sewer systems
- Ship, rail, or truck loading points, bays, and connections
- Storage vessels or tanks and their associated diked areas for flammable and combustible liquids
- Pipeways at grade bordered by elevated road or dike walls, 1 m (3 ft.) or higher on two sides
- Pipeline scraper traps and stations
- Drilling, wireline, and workover rigs (including the mud pits)
- Underground tanks or closed sumps (for collection of volatile liquids)
- Container and portable tank storage areas
- Container and portable tank filling stations
- Gasoline dispensing and service stations
- Tank vehicles and tank cars for volatile liquids
- Emergency or uninterruptible power supply facilities—Battery room exhaust systems (if unsealed batteries are used).

- Analyzer houses
- Sewage treatment facilities (floatation units and biological oxidation units)
- Cooling towers (handling process water)

14.7. PROTECTION MEASURES

14.7.1 Explosion-proof Rated Equipment

Electrical devices that are in areas that may produce an ignition source to combustible vapors are specified to prevent such an occurrence and can be rated as "explosion-proof." An explosion-proof rating means that a device is rated to withstand an explosion of a specific gas or vapor that may occur within it and prevent the ignition of a specific gas or vapor surrounding it. It also limits the operating external temperature, so that a surrounding atmosphere of combustible gases or vapors will not be ignited. Various enclosures, sealing devices, and mechanisms are employed to achieve the desired rating for a particular piece of equipment (see also Appendix B-3).

14.7.2 Intrinsically Safe Rated Equipment

Intrinsic safety is based on the principle of restricting the electrical energy available in hazardous area circuits such that any sparks or hot surfaces that may occur as a result of electrical faults are too weak to cause an ignition of combustible materials. The useful power is typically about 1W, which is sufficient for most instrumentation. It also provides a personnel safety factor since the voltages are low and it can allow field equipment to be maintained and calibrated "live" without the need for a gas-free environment verification. Electrical components or equipment can be manufactured as intrinsically safe and therefore readily useable in areas where combustible gases or vapors may be present.

14.7.3 Hermetically Sealed Electrical Equipment

Specially designated electrical equipment can be manufactured so that its internal components are completely sealed. This eliminates the possibility of electrical arcing components or circuits that can contact combustible vapors or gases.

14.7.4 Purging

Electrical housings may be purged with an inert gas or air flows at a sufficient rate to dilute the atmosphere immediately around an energized circuit so that atmospheric released gases will be pushed away and will not be ignited.

Facilities that are required to be provided in hazardous locations but for which provision of electrically classified equipment is economically prohibitive or technically unavailable, a pressurized location is usually provided instead. The pressurized air is provided from a safe source and fitted with gas detection devices for alarm and shutdown. Entranceway areas should be fitted with air locks that are technically still classified locations, since they will let in hazardous vapors when opened. The air locks should be fitted with ventilation to disperse any vapors that accumulate.

For enclosed areas, they can be considered adequately ventilated if they meet one of the following conditions:

1. The ventilation rate provided is a least four times the ventilation rate required to dilute the anticipated fugitive emissions to below 25% of the lower explosive limit (LEL), as determined by detailed calculations for the enclosed area.
2. The enclosed area is provided with six air changes per hour by artificial (mechanical) means.
3. If natural ventilation is used, 12 air changes per hour are obtained throughout the enclosed area.
4. The area is not defined as "enclosed" per the definition of API Recommended Practice 500.

14.7.5 Relocation of Devices

Often, it may be easier to relocate electrical equipment outside an electrically classified area rather than incur additional expense to obtain an explosion-proof rating. For example, most internal combustion engines are not rated for a classified area environment and therefore have to be placed in a safe location.

14.7.6 Smoking

Smoking should be considered a readily available ignition source. The ignition can be from the smoking materials themselves or the devices used to ignite the materials. Smoking should be controlled by elimination of smoking at the facility or relocation of smoking areas to areas considered remote and safe.

14.8. STATIC ELECTRICITY

14.8.1 Static Electric Generation

A static electrical charge may be either positive (+) or negative (−) and is manifested when some force has separated the positive electrons from the negative protons of an atom. Typical forces include flowing, mixing, pouring, pumping, filtering, or agitating materials where there is the forceful separation of two like or unlike materials. Examples of static generation are common with operations involving the movement of liquid hydrocarbons, gases contaminated with particles (e.g., metal scale and rust), liquid particles (e.g., paint spray, steam), and dust or fibers (e.g., drive belts, conveyors). The static electric charging rate is increased greatly by increasing the speed of separation (e.g., flow rate and turbulence), low conductivity materials (e.g., hydrocarbon liquids), and surface area of the interface (e.g., pipe or hose length, and micropore filters).

14.8.2 Static Electric Accumulation

Electrostatic charges typically leak from a charged body because they are under the attraction of an equal but opposite charge. Thus, most static sparks are produced only while the generating mechanism is active. However, some refined petroleum products have insulating qualities and the charges generated during movement will remain for a short period of time after the product has stopped moving. This accumulation, rather than dissipation, is influenced by how well the bodies are insulated with respect to each other. Since air or air/vapor mixtures are often the insulating body between the opposite charges, both temperature and humidity are factors in this insulation. Thus, very low or high temperatures, with resulting low humidity, will increase the accumulation of the electrostatic charge both while it is being generated and during the normal relaxation period.

14.8.3 Spark Gap

A spark results from the sudden break down of the insulating strength of a dielectric (e.g., air) that separates two electrodes of different potentials. This breakdown produces a flow of electricity across the spark gap and is accompanied by a flash of light, indicating high temperature. For static electricity to discharge a spark, the voltage across the gap must be above a certain magnitude. In air, at sea level, the minimum sparking voltage is approximately 350V for the shortest measurable gap. The voltage required will vary with the dielectric strength of the materials (e.g., air and vapor) that fill the gap and with the geometry of the gap.

Static electricity can be formed in various locations in process, storage, and transfer operations of an industrial facility. Experimental tests have generally demonstrated that saturated hydrocarbon vapors and gases under normal conditions will ignite when approximately 0.25 mJ of spark discharge energy is released. Some gases have even have lower minimum energies for ignition as indicated in Table 14.3.

The essential requirement for protection against the effects of static electricity can be segregated into three areas:

1. Identification of potential static electricity buildup areas
2. Measures to reduce the rate of static electricity generation
3. Provisions to dissipate accumulated static electricity charges

The major generators of static electricity at process facilities include the following:

- Flowing liquids or gases containing impurities or particulates
- Sprayed liquids
- Liquid mixing or blending operations
- Moving machinery
- Personnel

If a gas contains liquid, water vapor, or solid particles such as rust particles or dirt, a static charge can be generated.

14.8.4 Reducing Static Generation

Static charge voltage may be prevented from reaching sparking potential by reducing the rate of static generation. In the case of petroleum products, decreasing the activities that produce static can reduce the rate of generation. Since static is generated whenever two dissimilar materials are in relative motion to each other, a slowing down of this motion will reduce the rate of generation. This means reducing agitation by avoiding air or vapor bubbling, reducing flow velocity, reducing jet and propeller blending, and

Table 14.3 Minimum Ignition Energy for Selected Gases

Gas	Energy for Ignition (mJ)
Methane	0.29
Propane	0.25
Cyclopropane	0.18
Ethylene	0.08
Acetylene	0.017
Hydrogen	0.017

avoiding free falling-liquid. However, such static control methods may not be commercially acceptable because of slower production. Thus, reducing or rapidly dissipating the charge by bonding or grounding is commonly used to reduce static electricity.

14.8.5 Increasing Static Dissipation—Bonding and Grounding

Sparking between two conducting bodies can be prevented by means of an electrical bond attached to both bodies. Bonding prevents the accumulation of a difference in potential across the gap, thus no charge can accumulate and no spark can occur. Bonding tries to achieve a common electrical potential on all equipment so that a charge does not have an opportunity to accumulate. The earth may be used as part of the bonding system. This is known as grounding and is used when a potentially electrically charged body is insulated from the ground. Thus, the ground connection bypasses this insulation. Grounding is the process of electrically connecting one or more conducting objects to a ground potential to dissipate the charge buildup in a safe manner. Most process facilities are provided with a grounding grid. The primary purpose of the grounding grid is to limit the effects of corrosion induced by charges, but it also serves as a means to dissipate electrical charges that could be a source of ignition.

For static charge buildup from flowing liquids in piping and loading operations, API RP 2003 has specific guidance for estimating the potential charge buildup and pipe design recommendations to reduce the static charge to acceptable limits.

Since the dissipation of the static charge is a function of the liquids conductivity, anti-static additives may be used. These additives do not reduce static generation, but will permit the charge to dissipate more quickly. They should be introduced at the distribution beginning point, and their effectiveness may be reduced by passage through clay filters.

14.8.6 Controlling the Environment—Inerting and Ventilation

When static discharge cannot be avoided by bonding, grounding, reducing static generation, or increasing static dissipation, ignition can be prevented by excluding ignitable vapor-air mixtures where sparks may occur. Two commonly used methods are inerting and mechanical ventilation. Inerting is a method of displacing the air with an inert gas to make the mixture non-flammable. Mechanical ventilation can be applied to dilute the ignitable mixture well below the flammable range.

The following additional measures can also be employed:

- Maintaining high atmospheric humidity
- Increasing the conductivity of air by ionization
- Use of conductive materials where practical
- Increasing the conductivity of non-conducting materials with additives
- Reducing the velocity of fluids in pipelines
- Avoiding the transfer of non-conductive materials through non-conductive equipment, piping, or containers
- Avoiding the use of non-conductive containers where practical
- Avoiding the transfer of non-conductive materials through non-conductive atmospheres
- Application of non-metallic guards or shields to prevent contact by personnel to exposed metal equipment

14.9. SPECIAL STATIC IGNITION CONCERNS

14.9.1 Switch Loading

Potential ignition conditions can exist when a low pressure product is loaded into a vessel that contains a flammable vapor from previous use at or above the lower flammable limit. The most common example is the loading of diesel fuel into a tank transport that previously contained gasoline. However, similar conditions can develop when product lines are flushed, manifold valves leak, and during vacuum truck operations. Static generation will be reduced by filling at the lowest possible rate until agitation is minimized or blanketing the liquid surface with an inert gas.

14.9.2 Sampling, Gauging, and High-Level Devices

Both conductive probes and insulating conductive floats can cause sparking at surface potentials much lower than those required for sparking from the free oil surface to the vessel or the vessel's internal supports. It has been found that there is a slower than normal decay of field strength (i.e., due to relaxation) in large storage or ships tanks; thus, 30 min delay should be observed before hand gauging or sampling. In smaller vessels (e.g., tank trucks, tank cars), a one-minute delay time should be sufficient to allow for dissipation of the static charge.

14.9.3 Purging and Cleaning Tanks and Vessels

Purging involves removing a fuel vapor from an enclosed space and completely replacing it with air or inert gas. The purging operation can involve static electricity generation if steam jets or CO_2 jets are discharged into a flammable vapor-air mixture. Both steam and CO_2 can generate static charges on the nozzle and should be avoided.

Vacuum trucks are often used to remove hydrocarbon liquids from vessels that are being cleaned. Ignitions may occur unless suction hoses and conductive pipe wands have electrical continuity.

The refilling of empty vessels when returned to service should begin at the lowest flow rate to avoid the incoming stream from breaking the liquid surface. In the case of floating roofs, the flow should be reduced until the roof is floating off its support legs.

14.10. LIGHTNING

Lightning is generally considered a form of static electricity that is being discharged from particles in the atmosphere. Many instances of lightning-induced hydrocarbon fires have been recorded, especially at atmospheric storage tanks. NFPA requirements state that if equipment, process vessels or columns, and tanks are suitably constructed of substantial steel construction that is adequately grounded and do not give off combustible vapors, no other mechanism of lightning protection is required. This is also true of flares, vent stacks, and metal chimneys by nature of their construction and grounding facilities.

Since most storage tanks release combustible vapors at seals and vents, they are susceptible to lightning-induced fires. Common European practice is to provide lightning rods on the highest vessel at a facility to provide a cone of protection. NFPA 780 provides additional guidance for the provision of lightning protection measures.

Direct lightning strikes can ignite the combustible contents of cone roof storage tanks unless the roof is provided with bonding for the structural members. Floating roof tanks with seal hangers in the vapor space may be ignited indirectly when charges on the roof are released by a nearby lightning strike. Floating roof tanks are commonly protected against lightning ignition by bonding the floating roof to the seal shoes at no less than 3 m (10 ft.) intervals, use of insulating sections in the hanging linkages, covering sharp points on hangers with insulating materials, and installation of electrical bond straps across each pinned hanger joint.

Buildings that are more than 15.2 m (50 ft.) high and contain combustible liquids in large amounts or store explosive materials should be provided with lightning protection measures in accordance with the requirements of NFPA 780.

Ships with steel hulls or masts have suffered little or no damage from lightning and no special protection measures are considered necessary. During loading or unloading of vessels it is common practice to suspend operations and close all openings in tanks during the appearance of lightning storms.

14.11. STRAY CURRENTS

Stray current applies to any electrical current flowing in paths other than those deliberately provided for it. Such paths include the earth, pipelines, and other metallic structures in contact with the earth. Stray currents can accidentally result from faults in electrical power circuits, cathodic protection systems, or galvanic currents resulting from the corrosion of buried metallic objects. While stray current voltages are typically not high enough to spark across an air gap, intermittent charges can result in a spark that would ignite a flammable mixture, if present.

14.11.1 Protection against Stray Currents

Pipelines—Where stray currents are known or suspected in a pipeline, arcing at points of separation (e.g., valves and spools) is reduced by connecting a bond wire of reasonably low electrical resistance.

Railroad Spur Tracks—Railroad tank car's loading/unloading locations on spur tracks into a facility are typically served by a pipeline located alongside the rails. Stray currents may flow in the pipelines or in the rails. Thus, both the pipeline and rail should be permanently bonded with low electrical resistance material.

Shipping Ports—The resistance of the vessel's hull to ground (water) is very low and the connecting and disconnecting of loading dock piping may produce sparks. Insulating flanges in the pipe manifold are normally provided as the best assurance against sparking at the point of connection and disconnection of the subject hoses.

Cathodic Protection Systems—Generally, an engineering study is required to locate and size bonding when cathodic protection systems are employed to protect a facility against corrosion. For example, the option of de-energizing an impressed current system does not immediately remove the potential and render it safe, since the polarized metal structure will persist for a period of time.

14.12. INTERNAL COMBUSTION ENGINES

Internal combustion engines contain several features that may be considered ignition sources in a process facility. They exhaust hot combustion gases that can ignite vapors, they have hot surfaces (exhaust manifolds and piping), and they have instrumentation and ignition systems that may not be rated for an environment where combustible gases may be present. Operational controls, e.g., hot work permits, must be instituted where internal engines will be used in process facilities.

Another concern with internal combustion engines is that they could possibly overspeed from the intake of additional combustible vapors during an unexpected combustible vapor cloud release at a facility. The engines may accelerate and overspeed, but most are provided with protection devices to protect against this occurrence and additionally those engines who drive electrical generators would have an increase in voltage frequency that would also cause them to automatically shutdown.

14.13. HOT SURFACE IGNITION

Exposed hot surfaces may be a readily available ignition source in a process facility. In general, studies by the API on the ignition of hydrocarbons by a hot surface suggest it should not be assumed unless the surface temperature is approximately 182°C (360°F) above the minimum ignition temperature of the hydrocarbon involved. Test data and field experience both indicate that the ignition of flammable hydrocarbon vapors by hot surfaces in the open air requires temperatures considerably above the reported minimum auto-ignition temperature of the hydrocarbons involved.

As a precaution, hot surfaces should be insulated, cooled, or relocated when they pose a threat of ignition to combustible gas or liquid potential leak sources. Required equipment that contains hot surfaces should be rated to operate in such environments.

14.14. PYROPHORIC MATERIALS

Pyrophoric iron sulfide is formed by the action of corrosive sulfur compounds on iron and steel in process facilities, particularly in vessels, storage tanks, and pipeline scraper traps. If such equipment has contained asphalt, aromatic tars, sour crude, high sulfur fuel oil, aromatic gases, and similar products, the potential exists for the formation of black or brownish colored pyrophoric iron sulfide scale, powder, or deposits on the equipment interior and in the collected residue and sludge.

After equipment is emptied, preparatory to cleaning and during ventilation, iron sulfide deposits will dry out and react with oxygen in the air, generating heat and spontaneously igniting. The equipment should be purged with gas containing low (e.g., 5%) levels of oxygen and kept wet. This approach keeps the pyrophoric deposits wet until the atmosphere is non-combustible and the deposits are either oxidized or removed.

14.15. SPARK ARRESTORS

Spark arrestors are provided for those locations where sparks may constitute a hazard to the surrounding environment. The exhaust of internal combustion engines, incinerator stacks, and chimneys are normal examples. A spark arrestor usually consists of screening material to prevent the passage of sparks or flying brands to the outside of the exhaust stack.

14.16. HAND TOOLS

The API has investigated the necessity of requiring non-sparking hand tools and the possible ignition risk since the 1950s. They concluded that non-sparking hand tools do not significantly decrease the ignition potential from hand tools. Hand tool operations in most instances do not produce enough spark energy for ignition, and simultaneous gas release, and sufficient spark generation from a hand tool is considered extremely low.

14.17. MOBILE TELEPHONES, LAPTOPS, AND PORTABLE ELECTRONIC FIELD DEVICES

Any non-stationary electrical or electronic apparatus such as cellular phones, tablets, audio or video recording and playback devices, portable radio devices that operate via the Push-To-Talk mechanism, navigation receivers or transmitters (i.e., GPS), portable wireless communication

equipment, and laptop computers should be considered an ignition source that could ignite combustible vapors or gases, unless specifically reviewed and approved for use in electrically classified areas. Where unapproved devices need to be used in electrically classified areas, they should be managed and controlled through a mechanism used for any potential ignition source, e.g., work permit controls, unless the devices are listed for the applicable area classification. Appropriate warning or restriction signs should be posted at entrances to classified areas as a reminder of the restrictions of such devices.

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CHAPTER 15

Elimination of Process Releases

Atmospheric vapor, gas, or liquid releases or spills within a process facility occur every day. They are a major cause of catastrophic incidents. In order to provide an inherently safer facility the common release of vapors or gases to the atmosphere or liquids should be prevented or eliminated wherever practical. Not only does this improve the safety of a facility, it also decreases the amount of fugitive emissions or liquids that occur therefore decreasing any potential harm to the environment. Containment of waste gases, vapors, and liquids, human surveillance, increased testing, inspection and maintenance, gas detection (fixed systems and portable devices), and adequate vapor dispersion features are all measures to lessen the probability of an incident occurring.

The other common source of process releases is leakages. Contained combustible liquids will not burn unless an oxidizer is available, but once a leak is present adequate oxygen supplies are immediately available from the surrounding air. To prevent explosions and fires, the integrity of the plant must always be kept at its highest and introduction of air supplies to closed systems must be eliminated.

Typically the following mechanisms can release a combustible vapor or gas into the atmosphere during normal operations:

1. Open tanks and containers
2. Vents of storage tanks
3. Safety valves, pressure relief valves, or vents that release to the flare or and atmospheric vent
4. Glands of pumps and compressors
5. Process system, vessel, or tank drains
6. Oily water sewer (OWS), vents, and drain funnels
7. Pipeline scraper traps and filters
8. Sample points

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Process facilities should be designed so that, where practical, these exposed combustible vapors do not exist. Methods of achieving this objective are defined below.

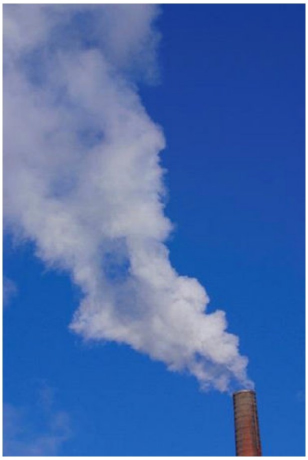
Methods of preventing air intrusion include:

- Purging
- Inerting
- Flooding

15.1. INVENTORY REDUCTION

In the event of a process or storage facility failure, immediate large quantities of hazardous materials may be released before activation of protective detection and mitigation measures. This is especially a concern where the fluid can rapidly vaporize or the material already exists as a gas. In the petroleum industry these commodities generally include liquefied petroleum gas (LPG), natural gas liquid (NGL), condensate, liquids with a high vapor pressure at operation for such materials in process or storage systems. Based on historical data that suggest vapor cloud explosions generally have not occurred for amounts less than 22,000 kgs (10,000 lbs), a limit in the order of this magnitude should be considered for process areas where congestion is higher. If highly volatile and hazardous materials in highly congested areas are involved, lower limits should be considered (e.g., 4400 kgs (2000 lbs)).

15.2. VENTS AND RELIEF VALVES



Ideally all waste combustion gases from vents, relief valves, blowdowns, etc., should be routed to a flare or returned to the process through a closed piping header system. Release of vapors or gases to the atmosphere may produce a vapor cloud, and even though such a release might be far from a facility, it may drift or the effects of ignition, i.e., an explosion blast overpressure, of the cloud will be felt at the facility, which may result in injuries and damage.

Atmospheric storage tanks are normally fitted with pressure-vacuum relief valves to reduce vapor emissions and evaporation losses to the atmosphere.

15.3. SAMPLE POINTS

Sampling techniques and mechanisms should use a closed system. Open vessel collection means should be avoided as spillage may occur due to container mishandling or inappropriate or faulty operation of the sample valve. Open sampling may also lead to inaccurate results since volatile portions of the sample may be dispersed during the sampling process. Automatic sampling methods are commonly available that eliminate the need for manual sampling processes.

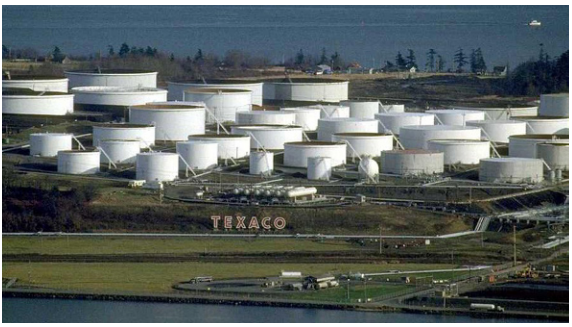
If open sampling is provided, the sampling point should be located where adequate dispersion of released vapors will occur. The sampling point should be located so it is easily accessible and human error is reduced.

15.4. DRAINAGE SYSTEMS

Process equipment drains should be provided with a sealed drainage system where it is practical and backpressure from the system or contamination is not a concern. Open drain ports should be avoided and separate sewage and process/oily water or closed drain system capability provided. Surface drainage should be provided to remove liquid spills immediately and effectively from the process area. Vents on drainage systems should be elevated so as to freely disperse highly volatile combustible gases or vapors above congested areas that could be released from the system.

15.5. STORAGE FACILITIES

With proper safety precautions and operating procedures explosions in the vapor space of fixed roof storage tanks is rare. A frequency estimate of an explosion every 1000 years has been reported. Explosive mixtures may exist in the vapor space of a tank unless precautions are taken. Any vapor will seek an ignition source, so prevention of an ignition source cannot be guaranteed. This is especially true with liquids that have low conductivity, which will allow charges to build up on liquid. Precautions to safeguard against internal tank explosions include insuring air does not enter the vapor space for tanks containing combustible liquids above their flash points. This is commonly achieved with production gas or with an inert gas such as nitrogen. A safer approach in the long term is to store such liquids in a floating roof tank that does not have such vapor enclosures.



Floating roof storage tanks are inherently safer than fixed roof tanks as they essentially eliminate the creation of a vapor space in the tank above the combustible liquid. Floating roof storage tanks have their roofs actually resting on the stored liquid and rise and fall as the inventory level changes. They limit the area of vapor release to the circumferential seal at the edge of the floating roof. Low flash point liquids should always be stored in tanks that will not allow the creation of vapors in sizable quantities. Floating roof tanks are generally about twice as expensive to construct as fixed roof tanks so there is a trade-off of risk against cost. However, by reducing emissions, the increased costs can be offset or justified on the basis of reduced product loss though evaporation (a product savings) and less impact to the environment.

Floating roof tanks, both internal and open top, are constructed with a circumferential seal to allow the roof to rise and fall. A single seal will allow some vapors to escape. However, typical practice is to provide a secondary seal over the first seal. This provides additional mitigation against the release of most vapors or gases, increasing safety and protecting the environment.

Most fires on floating roof tanks are small rim seal fires caused by vapors leaking through the circumferential seal. The source of ignition is normally lighting strikes that ignite the leaking vapors. With proper seal maintenance and inspection, coupled with adequate bonding or grounding of shunt straps across the seal at every meter or so, the probability of a tank fire is reduced.

Atmospheric fixed roof tanks that are built in accordance with American Petroleum Institute requirements will have a weak seam at the junction of the roof with the tank side. If there is an internal overpressure, such as an explosion, the seam will separate and the roof will blow off, leaving the shell in place to retain the contents and minimize the impact of the incident. The resulting fire will therefore only initially involve the exposed surface of the liquids still in the tank.

15.6. PUMP SEALS

Rotating pump shafts require a means to seal the circulating fluid from escaping but still allow the pump shaft to rotate. As the pump seal wears or more volatile materials are handled, the more difficult it is to prevent leakages through the seal. Historically the process industry has had considerable problems with pump seals, therefore fire hazardous areas are designated for almost all pumps handling combustible liquids. Double seals with alarm indications are provided to mitigate the consequences of a pump seal failure instead of a single mechanical rope seal. Additionally, most critical large pumps are provided with vibration monitoring that will also alert in advance if pump rotational components are deteriorating.

15.7. VIBRATION STRESS FAILURE OF PIPING

In a review of petroleum industry release incidents, one of the contributing factors was found to be the metallurgical failure of small diameter vent, drain, and sample piping located near rotating equipment (i.e., pumps, compressors, gearboxes, etc.). Rotating equipment induces stress on the piping connected to it due to the rotational force it generates. Although the equipment itself is restrained, it still induces stress in the connecting pipework that is normally not detected by common human observation. Since small diameter piping is not as substantial as main process piping, usually less attention is paid to its restraint. However, because of this, it is the most vulnerable location for a failure at rotating equipment. The failure point is usually at the connection point of the small diameter line to the main line, where it has a stress location from the "loose end" of the small line.

For existing equipment, a vibration measurement survey should be undertaken or examination of piping suspected of being under stress by a qualified inspection authority. Critical examination of connection points should be made where the induced piping stress is the greatest. For new designs, a stress analysis can be prepared on the pipework by specialized consultants.

15.8. ROTATING EQUIPMENT

Turbines, compressors, gearboxes, blowers, and alternators may suffer damage from bearing failure, inadequate lubrication, blade or diffuser failure, vibration or coupling failures. These failures can lead to the release of lubricants, combustible liquids or gases that can ignite and cause an explosion or fire. Additional monitoring and equipment shutdown capabilities should be provided in these cases. Consultation with the manufacturer will provide the best instrumentation and shutdown logic to be adopted. In cases where large quantities of volatile combustible gases or vapors may be released, the provision of gas detection should be highly considered.

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CHAPTER 16

Fire and Explosion Resistant Systems

The petroleum and chemical industries handle and process a tremendous amount of flammable and combustible materials on a daily basis. Additionally, these materials may be handled at extremely high temperatures and pressures where explosive, corrosive, and toxic properties may be present. It is therefore imperative not to be complacent about their destructive natures and the required protective arrangements that must be instituted whenever they are handled.

Fire and explosion resistant materials and barriers for critical equipment and personnel protection should always be considered whenever petroleum operations are involved. They prolong or preserve the integrity of facility critical features to ensure a safe and orderly evacuation and protection of plant.

Ideally most process industry incidents should be controlled by process shutdown systems (i.e., ESD, depressurization, drainage, etc.) and hopefully fire protection systems (fireproofing, water deluge, etc.) will not be required. However, these primary fire defense systems may not be able to control such incidents if previous explosions have immediately occurred. Before any consideration of fire suppression efforts, explosion effects must first be analyzed to determine the extent of protection needed. Most major fire incidents associated with hydrocarbon process incidents are preceded by an explosion event.

Hbk of Fire and Explosion Protection, http://dx.doi.org/10.1016/B978-0-323-31301-8.00016-7

16.1. EXPLOSIONS

Explosions are the most destructive event that can transpire at a process facility. Explosions may occur too quickly for conventional fire protection systems to be effective. Once an explosion occurs, damage may result from several events:

1. Overpressure—The pressure developed between the explosion's expanding gas and its surrounding atmosphere.
2. Pulse—The differential pressure across a plant as a pressure wave passes, which might cause collapse or movement.
3. Projectiles, Missiles, and Shrapnel—Items thrown off by the blast of expanding gases, which might cause damage or escalation of the event.

Explosion overpressure levels are generally considered the most critical measurement. Estimates are normally prepared on the amount of overpressure that can be generated at various damaging levels. These levels are commonly referred to as overpressure circles. They are typically drawn from the point of ignition and for the sake of expediency and highest probability as the point of leakage or release unless some other likely ignition point is identified. See Figure 16.1.

16.2. DEFINITION OF EXPLOSION POTENTIALS

The first step in protection against explosion incidents is to identify if they have the possibility of occurring at the facility and to acknowledge that fact. This may be for both internal and open air explosions. Once it is confirmed by an examination of the process materials, an estimate of their probability should be defined by a risk analysis. If the risk analysis level is indicated as unacceptable, additional measures for prevention mitigation should be implemented.

Typical locations where explosion overpressure potentials should be considered or evaluated include the following:

- Gases stored as liquids either by application refrigeration or pressure.
- Flammable or combustible liquids existing above atmospheric boiling point and maintained as a liquid because of the application of pressure.
- Gases contained under pressure of 3448kPa (500psi) or more.
- Any combination of vessels and piping that has the potential to release a total volume containing more than 907kg (2000lbs) of hydrocarbon vapors.
- Onshore areas that are considered to have confinement (fully or partially) and may release commodities meeting the above criteria.

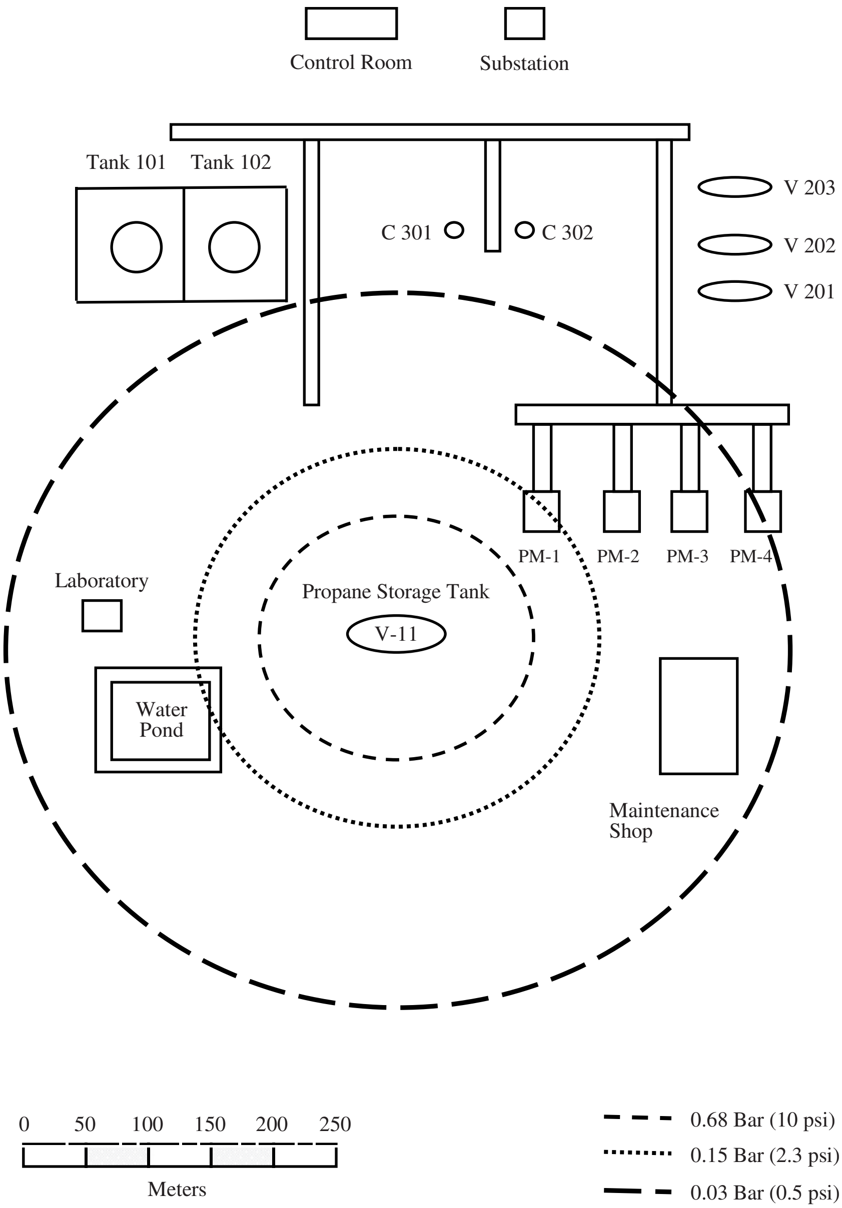

Figure 16.1 Overpressure consequence diagram.

- Locations that may have a manned control room less than 46m (150ft) from a process area meeting the above criteria.
- Gas compressor buildings that may be partially or fully enclosed.
- Enclosed buildings handling fluids that have the potential to accumulate flammable gases (e.g., produced water treating facilities).
- Offshore structures that handle or process hydrocarbon materials.

The objective in calculating explosion overpressure levels is to determine if a facility has the potential to experience the hazardous effects of an explosion and, if so, to mitigate the results of these explosions. The calculations can also serve to demonstrate where mitigating measures are not needed due to the lack of a potential to produce damaging overpressures either because of low explosion effects or distance from the explosion for the facility under evaluation.

As an aid in determining the severity of vapor cloud explosions, overpressure radius circles are normally plotted on a plot plan from the source of leakage or ignition. Computer applications are available that can easily calculate and plot these on electronic plant design and drafting applications. These overpressure circles can be determined at the levels at which destructive damage may occur to the facility from the worst case credible event (WCCE).

Facilities that are deemed critical or highly manned should be relocated out of the overpressure circles or provided with explosion protection measures. Other systems within these overpressure zones should be evaluated for the specific benefits of providing explosive protective design arrangements. An example is provided in Figure 16.1.

16.3. EXPLOSION PROTECTION DESIGN ARRANGEMENTS

Explosion suppression systems are now on the commercial market for small enclosures based on powder and gaseous inerting fire suppression agents. These systems have some disadvantages that must be considered before being applied at any facility. For example, a leak may continue for some time and the ignition source is usually not likely to dissipate. Re-ignition of the gas cloud is a high risk with a "one-shot" system. For large enclosures, a tremendous volume of the suppression agent is necessary and therefore there is a point of diminishing return for the protection (i.e., cost versus benefit).

Research on water explosion inhibiting systems is providing an avenue for future protection possibilities against vapor cloud explosions. Industry experimentation on the mitigation of explosions by water sprays indicates that flame speeds of an explosion may be reduced by this method. The research indicates that small droplet spray systems can act to reduce the rate of flame speed acceleration and therefore the consequential damage that could be produced. Normal water deluge systems appear to produce too large a droplet size to be effective in flame speed retardation and may actually increase the air turbulence in the areas subject to explosion potentials.

The following are some of the methods used in the process industry to prevent vapor cloud explosions:

1. All areas that are subject to a possible vapor cloud formation should be provided with maximum ventilation capability. Specific examination should be undertaken at all areas where the hazardous area classification is defined as Class I, Division 1 or Class II, Division 2. These are areas where hydrocarbon vapors are expected to be present, so verification that adequate ventilation is provided to aide in the dispersion of combustible vapors or gases is necessary.

   The following practices are preferred:

   - Enclosed spaces should be avoided. Enclosed locations will not receive adequate ventilation and could allow the buildup of combustible vapors or gases. Vapors with heavy densities can be particularly cumbersome as they will seek the low areas that are normally not provided with fresh air circulation.
   - Walls and roofs should be used only where absolutely necessary (including firewalls). Walls or roofs tend to block vision and access, trap sand, debris, and reduce ventilation so that combustible gases and vapors are not as quickly dispersed. They may also collapse if there is an explosion or deflagration. They can therefore contribute to secondary effects by debris falling onto process piping or equipment that may substantially exceed damage from the original explosion or deflagration. They can also lead to a false sense of security.
   - A minimum of six air changes per hour should be provided to enclosed areas. A minimum of six air changes for enclosed areas is cited by most standards for protection against the buildup of combustible gases or vapors.
   - Floor areas that are elevated should be constructed of open grating. Open grating allows for free air circulation, prevents the collection of vapors in pockets, and avoids collection of liquids. Solid floors should be are provided where there is a need for spill protection or a fire or explosion barrier; otherwise, ventilation requirements should prevail.

2. Area congestion should be kept to a minimum.
   - Vessels should be orientated to allow maximum ventilation or explosion venting.
   - Bulky equipment should not block air circulation or dispersion capability.
3. Release or exposure of combustible vapors or gases to the atmosphere should be avoided.
   - Waste combustible vapors or gases (process vents, relief valves, and blowdown) should be routed to the flare or returned to the process through a closed header.
   - Sampling techniques should use a closed system.
   - Process equipment liquid drains should use a sealed drainage system.
   - Open drain ports should be avoided and separate sewage and oily water drain system should be provided.
   - Surface drainage should be provided to remove spills immediately and effectively from the process area.
4. Gas detection should be provided particularly in areas handling low flash point materials with a negative or neutral buoyancy (i.e., vapor density is 1.0 or less), since these materials have the highest probability to collect or have an inherent property to resist dispersion.
5. Air or oxygen should be eliminated from the interior of process systems, i.e., vessels, piping, and tanks. Combustible gases or vapors will exist in the interior of process systems by the nature of work. Inclusion of air inside a process will at some time form a combustible atmosphere that will explode once an ignition source is available.
6. Protective devices (e.g., emergency shutdown switches) should be provided outside hazardous areas or behind protective barriers from the potential hazard.
7. Semi or permanently occupied buildings required to be in or adjacent to process areas should be constructed to withstand explosive overpressures or they should be relocated at a distance not expected to receive an explosive overpressure that would inflict serious damage on the structure. Nonessential personnel or facilities should always be relocated to areas that are not vulnerable to explosions.
8. Pressure vessel orientation should avoid pointing vessel ends toward critical equipment or high inventory locations. The ends of long horizontal pressure vessels are vulnerable to initial failure in a fire exposure and therefore they may project off like a projectile from a canon. It is therefore best to orientate the ends of these vessels so they will not project the ends to other critical facilities or areas that could escalate the incident.

16.4. VAPOR DISPERSION ENHANCEMENTS

16.4.1 Location Optimized Based on Prevailing Winds

The prevailing winds for a facility should be analyzed and plotted on a wind rose (diagram indicating the frequency for wind from every direction). From this the most probable wind direction that is likely to affect the facility can be identified. During the plot plan layout, equipment that normally handles large amounts of highly volatile materials should be sited so the prevailing wind direction will disperse potential releases to locations that would not endanger other equipment or provide for an ignition source for the released material. See Figures 16.2 and 8.2.

16.4.2 Water Sprays

Water spray systems have been demonstrated to assist in the dispersion of vapor or gas releases. The sprays assist in dilution of the vapors or gases with the induced air current created by the velocity of the projected water particles. They cannot guarantee that a gas or vapor will not reach an ignition source but do improve the probabilities that dispersion mechanisms will be enhanced.

16.4.3 Air Cooler Fans

Large updraft air cooler fans create induced air currents to provide cooling for process requirements. These air coolers create a considerable updraft current that ingests the surrounding atmosphere and disperses it upwards.

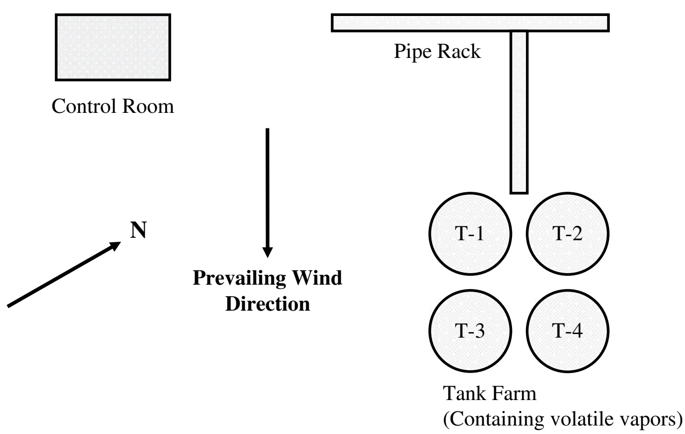

Figure 16.2 Utilization of prevailing wind for facility arrangements.

Judicious placement of fans during the initial stages of plant design can also serve as help in the dilution of combustible vapors or gases during an incident.

16.4.4 Supplemental Ventilation Systems

Enclosed locations that may be susceptible to build-up of combustible gases are typically provided with ventilation systems that will disperse the gases or provide sufficient air changes to the enclosures such that leakages will not accumulate. Typical examples include battery rooms, gas turbine enclosures, offshore enclosed modules, etc.

16.4.5. Damage Limiting Construction

Various methods are available to limit the damage from the effects of explosions. The best options are to provide some pre-installed or engineered features into the design of the facility or equipment that allows for the dissipation or diversion of the effects of a blast to non-consequential areas. Wherever these mechanisms are used the overpressure levels utilized should be consistent with the risk analysis estimates of the worst case creditable event (WCCE) incident.

Where enclosed spaces may produce overpressures, blow-out panels or walls are provided to relieve the pressure forces. The connections of the panels are specified at lower strength than normal panels so they will fail at the lower level and relieve the pressure. Similarly, combustible or flammable liquid storage tanks are provided with weak roof to shell seams so that in the case of an internal explosion, the built-up pressure will be relieved by blowing off the roof and the entire tank will not collapse.

For exposed buildings, usually monolithic construction is utilized, such as reinforced concrete structures, to withstand explosive blasts. The design strength of the structures is determined by the estimated blast force and the specific detailed design particulars of the structural components. Entranceways are provided with heavy blast resistant doors that do not face exposed areas.

16.5. FIREPROOFING

Following an explosion incident, local fires will typically develop that if left uncontrolled may result in a conflagration of the entire facility and its destruction. Fire protection measures are provided as required to control these occurrences. The ideal fire protection measure is one that does not require additional action to implement and is always in place. These methods are considered passive protection measures and the most familiar and commonly applied is fireproofing.

It has been demonstrated that ordinary steel strength decreases rapidly with temperature increases above 260°C (500°F). At 538°C (1000°F), its strength both in tension and compression is approximately half, at 649°C (1200°F) its strength to less than one quarter. Bare steel exposed to hydrocarbon fires may absorb heat at rates from 10,000 to 30,000Btu/hr/ft^2, depending on the configuration of the exposure. Due to the high heat conduction properties of steel, it is readily possible for normally loaded steel members or vessels to lose their strength to the point of failure within ten minutes or less from a hydrocarbon fire exposure.

In a strict sense, fireproofing is a misnomer, as nothing is entirely "fireproof." In the petroleum and related process industries, the term fireproofing is used to refer to materials that are resistive to a certain set of fire conditions for a specified time. The basic objective of fireproofing is to provide a passive means of protection against the effects of fire to structural components, fixed property, or to maintain the integrity of emergency control systems or mechanisms. Personnel shelters or refuges should not be considered adequately protected by fireproofing unless measures to provide fresh air and protection against smoke and toxic vapor inhalation are also provided. In itself, fireproofing should also not be considered protection against the effects of explosions, in fact, quite the opposite may be true. Fireproofing may be just as susceptible to the effects of an explosion, unless specific arrangements have been stipulated to protect it from the effects of explosion overpressures.

Fireproofing for the process industries follows uses same standards as other industries except that the possible fire exposures are more severe in nature. The primary destructive effects of fire in the process industry are very high heat, very rapidly, in the form of radiation, conduction, and convection. This cause the immediate collapse of structures made of exposed steel construction. Radiation and convection effects usually heavily outweigh the factor of heat conduction for the purposes of fireproofing applications. Fireproofing is not tested to prevent the passage of toxic vapors or smoke. Other barriers must be installed to prevent the passage of these harmful materials. The collapse of structural components in it are not of high concern, as these can be easily replaced. The concern of structural collapse is the destruction of items being supported, impact damage, and spread of large quantities of combustible fluids or gases that might release to other portions of the facility. Where either of these features might occur that would have high economic impact, either in immediate physical damage or in a business interruption aspect, the application of fireproofing should be considered. Usually where essentially only piping is involved, in which case enormous amounts of combustible materials would not be released, fireproofing for pipe racks is not economically justified if it is to be applied to steel structures. Common piping and structural steel normally can be easily and quickly replaced. It is usually limited to locations that have long replacement times, might be damaged if the rack collapses, or are supportive of emergency incident control function, such as depressuring and blowdown headers that are routed to the flare.

The primary value of fireproofing is obtained in the very early stages of a fire when efforts are primarily directed at shutting down processes, isolating fuel supplies to the fire, actuating fixed or portable fire suppression equipment, and conducting personnel evacuation. If equipment is not protected, then it is likely to collapse during this initial period. This will cause further impact damage and possibly additional hydrocarbon leakages. It may be impossible actuate emergency shutdown devices, vent vessels, or operate fire suppression systems. During further escalation of the fire, larger vessels still containing hydrocarbon inventories can rupture or collapse, causing a conflagration of the entire facility.

It is theoretically possible, based on the assumption of the type of fire exposure (i.e., pool, jet, etc.), to calculate the heat effects from the predicted fire on every portion of the process facility. As of yet this is extremely costly and cannot be performed economically for an entire facility.

What is typically applied are the standard effects of a petroleum fire (i.e., a risk exposure area is defined) for a basic set of conditions used for most locations in a facility. If necessary, examinations of critical portions of a facility for precise fire conditions are then undertaken by theoretical calculations. In general, the need for fireproofing is typically defined by identifying areas where equipment and processes can release liquid or gaseous fuel that can burn with sufficient intensity and duration to result in substantial property damage. In the process industry these locations are normally characterized by locations with a high liquid holdups or pressures historically having a probability of release and high pressure gas release sources.

Typical locations where fire risk exposures are considered prevalent are:

- Fire heaters
- Pumps handling combustible materials

- Reactors
- Compressors
- Large amounts of combustible materials contained in vessels, columns, and drums

Additionally, wherever equipment is elevated, which could be a source of liquid spillage, long times for replacement, or supports flare or blowdown headers in a fire exposure risk area, fireproofing of the supports is normally applied. API publication 2218 provides further guidance on the exact nature of items and conditions that the industry considers prudent for protection.

A standard fire duration (e.g., 2h) is applied and a high temperature (i.e., time-temperature exposure of UL 1709) is normally assumed from the hydrocarbon release sources.

The International Marine Organization (IMO)/American Bureau of Shipping (ABS) has fire test performance requirements for the protection of piping systems (primarily for shipping) that utilize a fire exposure very similar to UL 1709 for durations of 30 and 60min. Four different level ratings are used. There has been some limited application of these in the industry:

- Level 1 ensures the integrity of the system during a full-scale hydrocarbon fire, and is particularly applicable to systems where loss of integrity may cause outflow of flammable liquids and worsen the fire situation. Piping is exposed to a fire endurance test for a minimum duration of one hour without loss of integrity in dry conditions.
- Level 2 intends to ensure the availability of systems essential to the safe operation of the installation after a fire of short duration, allowing the system to be restored after the fire has been extinguished. Piping having passed the fire endurance test for a minimum duration of 30min without loss of integrity in dry conditions.
- Level 3 is considered to provide the fire endurance necessary for a water-filled piping installation to survive a local fire of short duration. The system's functions are capable of being restored after the fire has been extinguished. Piping is exposed to a fire endurance test for a minimum duration of 30min without loss of integrity in wet conditions.
- Level 4 Modified Test for deluge systems is considered to provide the fire endurance necessary for a piping installation to survive a local fire of short duration, with simulated dry conditions and subsequent flowing water conditions. The system's functions are capable of being restored after the fire has been extinguished. Piping is exposed to a fire

endurance test for a minimum duration of 5min in dry conditions and 25min in wet conditions without loss of integrity.

The following material specifications aspects should be considered when application of fireproofing is considered:

- Fire performance data (fire exposure and duration)
- Costs (materials, installation labor, and maintenance)
- Weight
- Explosion resistance
- Mechanical strength (resistance to accidental impacts)
- Smoke or toxic vapor generation (when life safety is associated with protection)
- Water absorption
- Degradation with age
- Application method
- Surface preparation
- Curing time and temperature requirements
- Inspection methods for coated surfaces
- Thickness control method
- Weather resistance
- Corrosivity
- Ease of repair

16.5.1 Fireproofing Specifications

Typically fireproofing materials are specified for either cellulosic (ordinary) or hydrocarbon fire exposures at various durations. The essential feature of fireproofing is that it does not allow the passage of flame or heat and therefore can protect against structural collapse for certain conditions. Because fireproofing is normally not tested to prevent the passage of smoke or toxic vapors its use as protection for human habitation should be carefully examined, in particular its effects of the passage of smoke and lack of oxygen in the environment. Is should be kept in mind that fireproofing is tested to a set of basic standards. These standards cannot be expected to correlate to every fire condition that can be produced in a process facility. The spacing, configuration, and arrangement of any process can render the application of fireproofing inadequate for the fire duration if the fire intensity is a higher magnitude than the rating of the fireproofing. Fire resistance enclosures should not only be rated for protection against the predicted fire exposure but to ensure the continued operation of the equipment being protected. For example, if the maximum operating temperature of a valve actuator is 100°C (212°F), ambient temperature limits inside the enclosure should not be allowed to rise above, even though the fireproofed enclosure has met the requirements of a standard fire test. The operating requirements for emergency systems must always be accommodated.

There are a number of fire test laboratories in the world that can conduct fire tests according to defined standards and on occasion specialized tests. Table 16.1 provides a list of test agencies recognized by the process industries.

Structural steel begins to soften at 316°C (600°F) and at 538°C (1000°F) it loses 50% of its strength. Therefore the minimum accepted steel temperature for structural tolerance, with fireproofing application for process facilities, is normally set to 400°C (752°F) for a period of 2h, exposed to a high temperature hydrocarbon fire (Ref. UL Standard 1709) (see Figure 16.3).

Recent work suggests that heat flux is a more realistic method to determine the heat transmission into fire barriers. Typical heat flux values of 30–50kw/m^2 (9375–15,625Btu/ft^2) for pool fires and 200–300kw/m^2 (62,500–93,750Btu/ft^2) for jet fires are normally the basis of heat flux exposure calculations.

Table 16.1 Recognized Fire Testing Laboratories

Laboratory	Name	Location
FM	Factory mutual research corporation	Norwood, MA, USA
LPC	Loss prevention council	Borehamwood, Herts., UK
SINTEF	Norwegian fire test laboratory	Tronheim, Norway
SWRI	Southwest research institute	San Antonio, TX, USA
TNO	Dutch fire test laboratories	Delft, Netherlands
UL	Underwriters laboratories	Northbrook, IL, USA
ULC	Underwriters laboratories, Canada	Ottawa, Canada
WFRC	Warrington fire research center	Warrington, Cheshire, UK

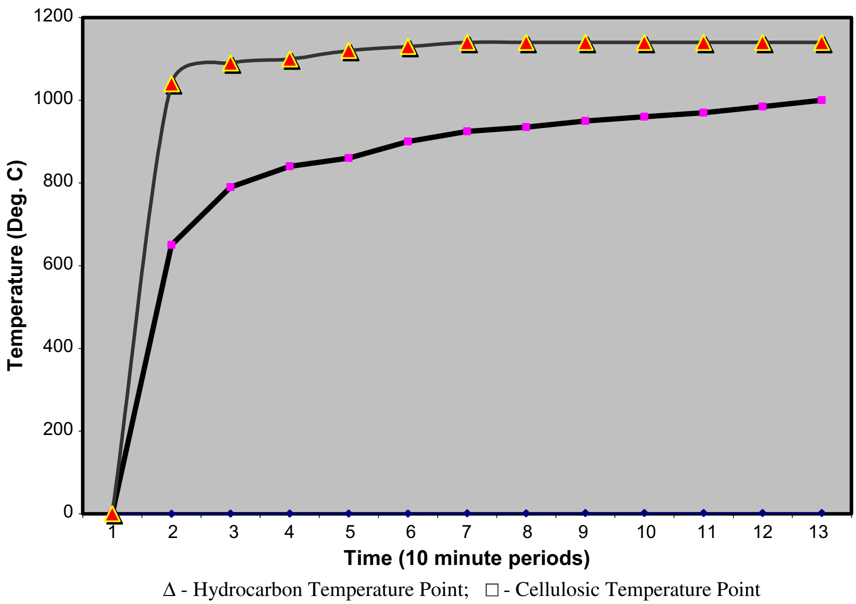

Figure 16.3 Time temperature curves for hydrocarbon versus cellulosic fires.

16.5.1.1 Fireproofing Materials

There are numerous fireproofing materials available commercially and the selection of the material most suitable is based on the application and advantages or disadvantages of each along with economic factors. Usually no single material is ideally suited for a particular application and an evaluation of cost, durability, weatherability, ease of installation, and a combination of factors is necessary.

16.5.2 Cementitious Materials

Cementitious materials use a hydraulically setting cement, such as Portland cement, as a binder, with a filler material of good insulation properties, e.g., vermiculite, perlite, etc. Concrete is frequently used for fireproofing because it is easily installed, readily available, is quite durable, and generally economical compared to other materials. It is heavy compared to other materials and requires more steel to support than other methods.

16.5.3 Pre-formed Masonry and Inorganic Panels

Brick, concrete blocks, or pre-cast cement aggregate panels have been commonly used in the past. These materials tend to be labor intensive to install, if large panels are required, require crane and access clearances, and are sometimes less economical than other methods.

16.5.4 Metallic Enclosures

Stainless steel hollow panels filled with mineral wool are fabricated in precise dimensions to withstand the fire exposure. Typically critical electrical equipment must operate within a specified level for a period of time when a fire exposure occurs and is protected by such enclosures.

16.5.5 Thermal Insulation

These can be inorganic materials such as calcium silicate, mineral wool, diatomaceous earth or perlite, and mineral wool. If provided as an assembly, they are fitted with steel panels or jackets. These are woven with noncombustible or flame retardant materials to provide insulation properties to the fire barrier for the blockage of heat transfer.

16.5.6 Intumescent Coatings

Intumescent coatings have an organic base that when subjected to a fire will expand and produce a char and an underlying insulating layer to provide against the heat effects from a fire exposure.

16.5.7 Refractory Fibers

Fibrous materials with a high melting point are used to form fire resistant boards and blankets. The fibers are derived from glass minerals or ceramics. They may be woven into cloths and are used as blankets around the object to be protected.

16.5.8 Composite Materials

Lightweight materials. Composite materials, typically of glass fiber and polyester resins, are available as sheet boards that can be arranged into protective walls or enclosures. They offer lightweight, inherent insulation and can be configured to achieve blast protection. These materials are corrosion free and wear resistant.

The principle features of passive protection from fire exposures are summarized below.

Advantages:

- No initiation required
- Immediate protection with low conductivity materials; reactive materials respond when threshold temperature is reached

- No power required
- Meet regulatory requirements
- Low maintenance
- Can be upgraded
- Certain materials can provide anti-corrosion benefits
- No periodic testing required

Disadvantages:

- Provide only short duration protection when compared to active systems
- Not renewable during or after an incident
- Inspection of substrate for permanent materials for corrosion can be difficult
- May be subject to damage from an explosion incident

Choice Determined By:

- Application
- Protection time
- Performance
- Physical properties
- Economics

16.5.9 Radiation Shields

In some cases, radiation shields are provided to protect against heat effects from fire incidents and operational requirements. These shields are usually composed of two styles—a dual layer of wire mesh screen or a plexi-glass see-though barrier. The shields provide a barrier from the effects of radiant heat for specific-levels. They are most often used for protection against flare heat and for see-though barriers at fixed firewater monitor locations, most notably at the heli-decks of offshore facilities so the operator of the device can accurately aim the water stream to be most effective in an incident.

16.5.10 Water Cooling Sprays

Water sprays are sometimes used instead of fireproofing where the fireproofing application may be considered detrimental to the situation or uneconomical. Typical examples are the surface of pressure vessels or piping where metal thickness checks are necessary; structural facilities that cannot accept additional loads of fireproofing materials due to the dead weight or winds loads; inaccessibility of the surface for application of fireproofing; and impracticability of the fireproofing application.

Normally where it is necessary, fireproofing is preferred over water spray for several reasons. The fireproofing is a passive inherent safety feature, while the water spray is a vulnerable active system that requires auxiliary control to be activated. Additionally the water spray relies on supplemental support systems that may be vulnerable to failures, i.e., pumps, distribution network, valves, etc. The integrity of fireproofing system is generally considered superior to explosion incidents compared to water spray piping systems. The typical application of water sprays in place of fireproofing is for process vessel protection.

A water spray system protects the exposure by:

- Cooling the surface of the exposure
- Cooling the atmosphere surrounding the exposure and from the source
- Limiting the travel of radiant heat from the flames to the adjacent exposures

16.5.11 Vapor Dispersion Water Sprays

Firewater sprays are sometimes employed as an aid to vapor dispersions. Some literature on the subject suggest two mechanisms are involved that assist in vapor dispersion with water sprays. First, a water spray arrangement will start a current of air in the direction of the water spray. The force of the water spray engulfs air and disperses it further from its normal circulating pattern. In this fashion, released gases will also be engulfed and directed in the direction of the nozzles. Normal arrangements are to point the spray upward to direct ground and neutrally buoyant vapors and gases upward for enhanced dispersion by natural means at higher levels. Secondly, a water spray will warm a gas or vapor to neutral or higher buoyancy to also aid in natural atmospheric dispersion.

16.6. LOCATIONS REQUIRING CONSIDERATION OF FIRE RESISTANT MEASURES

The application of fire resistant materials is commonly afforded to locations where large combustible material spillages or high pressure high volume gas releases may occur with a high probability (i.e., fire hazardous zone). These locations are commonly associated with rotating equipment and locations where high erosion or corrosion effects could occur. Alternatively, fireproofing materials are used to provide a fire barrier where adequate spacing distances are unavailable (i.e., offshore installations, escape measures, etc.).

API Publication 2218 provides further guidance ion the application and materials used in the industry.

The most common areas where fireproofing is applied in the process industry are presented below:

- **Onshore**
  Vessel, tank, and piping supports in a fire hazardous zone
  Critical services (emergency shutdown systems, controls, and instrumentation)
  Pumps and high volume or pressure gas compressors.
- **Offshore**
  Hydrocarbon processing compartments
  Floors, walls, and roofs for accommodations
  Facility structural support located in fire hazardous zone
  Pumps and high volume or pressure gas compressors
- **Common Process Industry Fireproofing Material Applications**
  Vessel and Pipe Supports:
    Onshore: 2in. of concrete; UL 1709, 2h rating
    Offshore: Ablative or intumescent materials; UL 1709, 2h rating
  Cable Trays: Stainless steel cabinets or fire rated mats; UL 1709, 20min rating
  ESD Control Panels: Stainless steel cabinets or fire rated mats; UL 1709, 20min. rating
  EIVs (if directly exposed): Stainless steel cabinets/fire rated mats; UL 1709, 60min rating
  EIV Actuators: Stainless steel cabinets or fire rated mats; UL 1709, 20min rating
  Firewalls:
    Onshore: Concrete or masonry construction; UL 1709, 2h rating
    Offshore: Ablative, composite, or intumescent; UL 1709, 2h rating

16.6.1 Enhanced Safety Helideck

One vendor has developed an "Enhanced Safety Helideck" that incorporates a patented, passive fire-retarding system that works by allowing burning fuel to pass through densely packed layers of compressed aluminum explosion suppression mesh. The mesh is packed in batts inside the punched heli-decking, which comprises the landing surface. A full-perimeter drainage system ensures that liquids are channeled, sub-surface from heli-decking to drain. Burning fuel is starved of oxygen and rapid heat dissipation occurs in the mesh. The fire is retarded immediately.

Spilt fuel is quickly and safely drained away unburned and any remaining vapor burn-off can be extinguished in seconds with minimal water spray. Up to 97% of spilt fuel is recovered unburned.

The "XE Enhanced Safety Helideck" has been rigorously tested with actual fire tests in the presence of Det Norske Veritas, Lloyds Register, UK Civil Aviation Authority, various helicopter operators and manufacturers, public safety groups, offshore safety crews, pilots, and user groups.

The deck is currently installed on numerous offshore vessels, FPSOs and drilling platforms, hospitals, and other similar locations. It can be fitted to a new-build structure or retrofitted to existing locations that require additional safety. For retrofitting, the existing steel structure can be utilized to the maximum extent by only laying down the safety decking and drainage system.

This type of helideck does not need foam or other extinguishing agents to deal with a fire on its surface and only water is sufficient to extinguish the residual fire vapor burn after the bulk of the fuel has been drained off. In recent tests on this helideck attended by representatives from UKCAA, ICAO, DNV, LRS, ABS, a 450L jet fuel fire was controlled as follows:

- Purely passive basis, i.e., with no intervention: less than 90s
- Using a water Deck Integrated Fire Fighting System (DIFFS) unit: less than 4s

UKCAA CAP 437, 6th edition, 2008, chapter 5 allows installations with an "XE Enhanced Safety Helideck" to use seawater instead of foam for foam monitor or DIFFS systems. This results in a huge reduction in cost, complexity, testing, maintenance, and renewals.

16.7. FLAME RESISTANCE

16.7.1 Interior Surfaces

Most building fire codes set fire resistance standards for interior wall and ceiling finishes and overall requirements for building construction fire resistance features (e.g., insulation, cabling, etc.). Based on fire statistics, the lack of proper control over the interior surface is second only to the vertical spread of fire through openings in floors as the cause of loss of life in buildings. The dangers of unregulated interior finish materials are mainly: (1) The rapid spread of fire presents a threat to the occupants of the building by either limiting or delaying their use of exitways within and out of the building. The production of black smoke also obscures the exit path and exit signs. (2) The contribution of additional fuel to a fire.

Unregulated finish materials have the potential for adding fuel to a fire, thereby increasing its intensity and shortening the time available for occupants to escape.

16.7.2 Electrical Cables

Electrical conductors are normally insulated for safety, protection, and avoidance of electrical shorting and grounding concerns. Typical insulating materials are plastics that can readily burn with toxic vapors. The National Electrical Code (NEC) specifies certain fire resistance ratings for electrical cables to lessen the possibility of cable insulation ignitability and fire spread. High hazard occupancies and locations are usually specified with a high fire resistance rating due to the critical risk they pose.

16.7.3 Optical Fire Cables

Fiber optics are commonly used for electronic communication applications and pose critical communication risks that may affect all aspects of how a facility is maintained and operated. The fire resistance requirements are similar to the requirements for fire ratings as applied to electrical cabling within the specifications of the National Electrical Code (NEC).

16.7.3.1 Fire Dampers

Fire dampers are an assembly of shutter louvers in HVAC ductwork or similar openings fire barriers, which are arranged to close to prevent the passage of flame and heat. Such dampers are installed in ventilation openings or shafts to maintain the fire rated barrier equal to the surrounding barrier. The louvers are closed or "activated" by a spring release by the melting of a fusible link or by remote control signals that hold the spring in normal circumstances.

Acceptance testing of fusible link fire dampers should always include a random sample of the actual fusible link (melting) test of the installed assembly that allows the damper to close. Many times an improperly installed damper will not close correctly and the shutter louvers become hung up or twisted. An alternative that is sometimes available is a link assembly that can be temporarily installed that is easily cut by a pair of clippers. The fusible link melting temperature can then be tested separately at a convenient location without subjecting the installation to heat or flames for testing purposes.

16.7.3.2 Smoke Dampers

Smoke dampers are used to prevent the spread of products of combustion within ventilation systems of occupied facilities. They are usually activated by fire alarm and detection systems. Smoke dampers are specified by leakage class, maximum pressure, maximum velocity, installation mode (horizontal or vertical), and degradation test temperature of the fire.

16.7.3.3 Flame and Spark Arrestors

Flame arrestors stop flame propagation from entering through an opening. The device contains an assembly of perforated plates, slots, screens, etc., enclosed in a case or frame that will absorb the heat of a flame entering and thereby extinguish it before it can pass. When burning occurs within a pipe, some of the heat of combustion is absorbed by the pipe wall. As the pipe diameter decreases, an increasing percentage of the total heat absorbed by the pipe wall and the flame speed decreases. By using a very small diameter (e.g., one or two millimeters), it is possible to completely prevent the passage of flame, regardless of flame speed. A typical flame arrestor is a bundle of small tubes that achieves the required venting capacity but prevents that passage of flame.

The "Davy" miners' lamp was the first use of a flame arrestor in which a fine mesh screen with high heat absorption properties was placed in front of the flame of a miner lamp to prevent ignition of the methane gas in coal mines.

16.7.3.4 Piping Detonation Arrestors

If a pipe arrangement is very long, or if enough turbulence occurs, a flame front that exists in such piping may accelerate to the point where a detonation incident may occur. Detonations travel at or above the speed of sound (which is a function of the density of the mixture within the piping) and typically reach speeds of several thousand feet per second. Pressure pulses accompanying the flame front may exceed 20 times the initial pressure. In locations in piping where there is a high possibility of flame fronts occurring, piping detonation arrestors are provided to prevent such occurrences.

Not all flame arresters are designed to quench or withstand the elevated pressure and impulse of a detonation. Some regulations (e.g., USCG) require use of detonation-type flame arresters when those regulations require flame arresters in vapor collection systems.

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CHAPTER 17

Fire and Gas Detection and Alarm Systems

Various simple and sophisticated fire and gas detection systems are available to provide early detection and warnings of a hydrocarbon release that supplement process instrumentation and alarms. The overall objectives of fire and gas detection systems are to warn of possible impending events that may be threatening to life, property, and continued business operations, external to the process operations.

Process controls and instrumentation only provide feedback for conditions within the process system. They do not report or control conditions outside the assumed process integrity limits. Fire and gas detection systems supplement process information systems with instrumentation that is located external to the process to warn of conditions that could be considered harmful if found outside the normal process environment. Fire and gas detections systems may be used to confirm the existence of major process releases or to report conditions that process instrumentation may not adequately report or be unable to report (i.e., minor process releases).

Most process industry vapors and gases (i.e., hydrocarbons) immediately burn with flame temperatures that are considerably higher than that of an ordinary combustible (i.e., wood, paper, etc.) fire. The objective of a fire detection system for the process industries is to rapidly detect a fire where personnel, valves, and critical equipment may be involved. Once detected, executive action is initiated to alert personnel for evacuation and while simultaneously controlling and suppressing the fire incident.

Hbk of Fire and Explosion Protection, http://dx.doi.org/10.1016/B978-0-323-31301-8.00017-9

17.1. FIRE AND SMOKE DETECTION METHODS

17.1.1 Human Surveillance

Individuals can provide the first line of observation and defense for any facility. Periodic or constant operator on-site surveillance of processes provides careful observation and reporting of all activities within a facility. Human beings have keen senses that have yet to be fully expertly duplicated by instrumentation devices or sophisticated technical surveillance mechanisms. For this reason they are more valuable in the observation of system performance than ordinary process control systems may be.

It should be remembered that humans may also be prone to panic and confusion at the time of an emergency and so may also be unreliable in some instances. Where proper procedures are available, training undertaken, and a selection of personnel capable to undertaken incident control actions, situations of panic and confusion may be overcome.

17.1.1.1 Manual Pull Station (MPS)/Manual Activation Callpoint (MAC)

Simple switches that can be manually activated can be considered fire alarm devices. Most devices employed normally require the use of positive force, i.e., to avoid inadvertent and fraudulent trips. Fire alarm switches typically were made so they could only be reset by special tools in order to trace the source of the alarm, but sophisticated data reporting systems with addressable data collection now make this requirement obsolete.

Manual activation devices are normally located in the main egress routes from the facility or process area. Usually placement in the immediate high hazard location egress route and the periphery evacuation routes or muster location of the installation is appropriate.

17.1.1.2 Telephone Reporting

All telephone points can be considered as methods of notification. Telephones can be easily placed in a facility but may be susceptible to ambient noise impacts and the effects of a fire or explosion. Additionally, information from verbal sources can be easily misunderstood during an emergency. Simultaneous use of the phone system during an emergency may also cause it to be overloaded, making use difficult.

17.1.1.3 Portable Radios

Operations personnel are normally provided with portable radios in large process facilities. They have similar deficiencies to telephones but offer the advantage of onsite portability with continuous communication access. Typically facilities have a special emergency communications frequency specified for incident command and control operations.

17.1.2 Smoke Detectors

Smoke detectors are employed where the type of fire anticipated and equipment protection needs a faster response time than heat detectors can provide. A smoke detector will detect the generation of the invisible and visible products of combustion before temperature changes are sufficient to activate heat detectors. The ability of a smoke detector to sense a fire is dependent on the rise, spread, rate of burn, coagulation, and air movement of the smoke itself. Where the safety of personnel is a concern, it is crucial to detect a fire incident at its early stages because of the toxic gases, lack of oxygen that may occur, and obscuration of escape routes by smoke. Smoke detection should be considered when these factors are present.

17.1.2.1 Ionization

Ionization and condensation nuclei detectors alarm at the presence of invisible combustion products. Most industrial ionization smoke detectors are of the dual chamber type. One chamber is a sample chamber and the other chamber is a reference chamber. Combustion products enter an outer chamber of an ionization detector and disturb the balance between the ionization chambers and trip a highly sensitive cold cathode tube that causes the alarm. The ionization air in the chambers is caused by a radioactive source. Smoke particles impede the ionization process and trigger the alarm. Condensation nuclei detectors operate on the cloud chamber principle, which allows invisible particles to be detected by an optical technique. They are more effective on Class A fires (ordinary combustibles) and Class C fires (electrical).

17.1.2.2 Photoelectric

Photoelectric detectors are the spot type or light-scattering type. In each, visible products of combustion partially obscure or reflect a beam of light between its source and a photoelectric receiving element. The disruption of the light source is detected by the receiving unit and as a result an alarm is actuated. Photoelectric detectors are best used where it is expected that visible smoke products will be produced. They are sometimes used where other types of smoke detection are too sensitive to the invisible products of combustion that are produced in the area as part of normal operations such as in garages, furnace rooms, welding operations, etc.

17.1.2.3 Dual Chamber

Combinations of photoelectric and ionization detectors are available that operate as described above. They are used to detect either smoldering or rapidly spreading fires.

17.1.2.4 Laser

A laser based and microprocessor controlled high sensitivity spot type smoke detector. It appears similar to an ionization smoke detector. It works on the light-scattering principle but with 100 times greater sensitivity than ionization type detectors due to the use of laser. It achieves a greater sensitivity because the laser can detect extremely small products of an early fire (which cannot be seen by the human eye); therefore it is comparable in detection capability to a VESDA system (see the next section). At this time, it is considered the highest sensitivity spot type smoke detector available. Common applications include critical control and communication facilities.

17.1.2.5 Very Early Smoke Detection and Alarm (VESDA)

High sensitivity sampling smoke detection systems provide the best form of rapid smoke detection for highly critical equipment or in high air flow situations. The Very Early Smoke Detection and Alarm (VESDA) system is basically a suction pump with collection tubes or pipes that use an optical smoke detection device test for evidence of smoke particles. Since it gathers air samples from the protected area, it is much faster in detection than ordinary detection devices that have to wait for the smoke to arrive to it. VESDA systems may be subject to some dilution effect to the sampling mechanism since the tubes may collect air samples from several sampling ports. This may reduce its response time.

In the process industry VESDA systems are typically used for the interior of electrical or electronic cabinets or racks that are considered critical for the process control and shutdown activities. Especially important are such cabinets that contain power supplies or transformers that may overheat. The use of such detectors can detect incidents in the very early stages of smoldering. Care must be taken that the sampling tubes are protected from mechanical damage and from the initial effects of an incident.

17.1.3 Thermal or Heat Detectors

Thermal or heat detectors respond to the energy emission from a fire in the form of heat. The normal means by which the detector is activated is by conventional currents of heat air or combustion products or by radiation effects. Because this means of activation takes some time to achieve, thermal detectors are slower to respond to a fire when compared to some other detection devices.

There are two common types of heat detectors—fixed temperature and rate of rise. Both rely on the heat of a fire incident to activate the signal device. Fixed temperature detectors signal when the detection element is heated to a predetermined temperature point. Rate of rise detectors signal when the temperature rises to a level exceeding a predetermined degree. Rate of rise detection devices can be set to operate rapidly, are effective across a wide range of ambient temperatures, usually recycle rapidly, and can tolerate a slow increase in ambient temperatures without sounding an alarm. Combination fixed temperature and rate of rise devices will respond directly to rapid rise in ambient temperatures caused by a fire, devices will tolerate a slow increase in ambient temperatures without effecting an alarm, and recycle automatically on a drop in ambient temperature.

Heat detectors normally have a higher reliability factor than other types of fire detectors. This tends to lead to fewer false alarms. Overall, they are slower to activate than other detecting devices. They should be considered for installation only where speed of activation is not considered critical or as a backup fire detection device to other fire detection devices. They have an advantage of suitability for outdoor applications but the disadvantage of not sensing smoke particles or visible flame from a fire.

Some systems can be strung as line devices and offer detection over long paths; alternatively they can be used as spot detectors. A common deficiency after installation is that they tend to be become painted over, susceptible to damage, or the fusible element may suffer a change in activation temperature over a long installation period.

Heat detectors are activated by either melting a fusible material, changes in electrical current induced by heat loads on bi-metallic metals, destruction of the device itself by the heat, or by sensing a rate of ambient temperature rise.

The following are some of the most common heat detector devices that are commercially available and used in the process industries:

- Fusible plastic tubing (pneumatic)
- Fusible optical fiber
- Bi-metallic strip or wire
- Fusible plug (pneumatic pressure release)
- Quartzoid bulb (pneumatic pressure release)
- Fusible link (under spring tension)
- Fixed temperature detector
- Rate of rise detector
- Rate compensated
- Combination rate of rise and fixed temperature

The author has even observed the provision of a tensioned string connected to a pressure switch that has been provided as detection over the vapor seal of a floating roof crude oil storage tank. Although this method may be considered primitive and inexpensive, it is effective and beneficial compared to the option of no detection.

17.1.3.1 Optical (Flame) Detectors

Flame detectors alarm at the presence of light from flames, usually in the ultraviolet or infrared range. The detectors are set to detect the light flicker of a flame. They may be equipped with time delay features to eliminate false alarms from transient flickering light sources.

There are six types of optical detectors commonly used in the process industries:

1. Ultraviolet (UV)
2. Single frequency infrared (IR)
3. Dual frequency infrared (IR/IR)
4. Ultraviolet/infrared—simple voting (UV/IR)
5. Ultraviolet/infrared—ratio measurement (UV/IR)
6. Multi-band

Each of the five types of detectors listed has advantages and limitations, making each more or less suitable for an application or a specific risk. There is not a uniform performance standard for flame detectors, such as there is with smoke detectors. Flame detection for a particular model has to be analyzed by evaluation of its technical specification to the expected fire development.

17.1.3.2 Ultraviolet (UV) Detectors

Responds to the relative low energy levels produced at wavelengths between 0.185 and 0.245μ. This wavelength is outside the range of normal human visibility and outside that of sunlight.

Advantages

The UV detector is a general all-purpose detector. It responds to most burning materials but at different rates. The detector can be extremely fast, i.e., less than 12ms for special applications (e.g., explosive handling). It is generally indifferent to the physical characteristics of flames and does not require a "flicker" to meet signal input functions. It is not greatly affected by deposits of ice on the lens. Special modules are available that can be used in high temperature applications up to 125°C (257°F). Hot black body sources (stationary or vibrating) are not normally a problem. A UV detectors is blind to solar radiation and most forms of artificial light. An automatic self-testing facility can be specified or it can be tested with a handheld source at a distance of more than 10m (30ft) from the detector. Most models can be field adjusted for either flame sensitivity or time delay functions.

Limitations

A UV detector responds to electrical arc from welding operations. It can be affected by deposits of grease and oil on the lens. This reduces its ability to sense a fire. Lighting with long duration strikes can cause false alarm problems. Some vapors, typically those with unsaturated bonds, may cause signal attenuation. Smoke will cause a reduction in signal level seen during a fire. It may produce a false alarm response when subject to other forms of radiation such as from radiological testing, i.e., nondestructive testing (NDT), which is periodically performed on process system vessels and piping.

17.1.3.3 Single Frequency Infrared (IR) Detectors

This detector responds to infrared emissions from the narrow CO_2 band at 4.4μ. It requires the satisfaction of a flicker frequency discrimination at between 2 and 10Hz.

Advantages

It responds well to a wide range of hydrocarbon fires and is blind to welding arcs except when very close to the detector. It can see through smoke and other contaminates that could blind a UV detector. It generally ignores lightning, electrical arcs, and other forms of radiation. It is blind to solar radiation and resistant to most forms of artificial lighting.

Limitations

There are few models with automatic test capability. Testing is usually limited to handheld devices of only 2m (7ft) from the detector or directly on the lens test unit. It can be ineffective if ice forms on the lens. It is sensitive to modulated emissions from hot black body sources. Most of the detectors have fixed sensitivities. The standard being under 5s to a petroleum fire of $0.1m^2$ (1.08sq. ft.), located 20m (66ft) from the detector. Response times increase as the distance increases. It cannot be used in locations where the ambient temperature could reach up to 75°C (167°F). It is resistant to contaminants that could affect a UV detector. Its response is dependent on fires possessing a flicker characteristic so detection of high pressure gas flames may be difficult.

17.1.3.4 Dual or Multiple Frequency Infrared (IR/IR) Detectors

This detector responds to infrared emissions in at least two wavelengths. Typically CO_2 reference at 4.45μ is established and a second reference channel that is away from the CO_2 and H_2O wavelengths is made. It requires that the two signals are confirmed as synchronous and that the ratio between the two signals is correct.

Advantages

It responds well to a wide range of hydrocarbon fires and is blind to welding arcs. It can detect fires though smoke and other containments, although the signal pickup will be reduced. It generally ignores lightning and electrical arcs. It has minimal problems with solar radiation and artificial lighting. It is also insensitive to steady or modulated black body radiation. There is a high level of false alarm rejection with this model of detector.

Limitations

Detectors with complete black body rejection capability are usually less sensitive to fires than a single frequency infrared optical detector. Because its discrimination of fire and non-fire sources depends upon an analysis of the ratio between fire and reference frequencies, there is a variation in the amount of black body rejection achieved. A detector's degree of black body radiation rejection is inversely proportional to its ability to sense a fire.

17.1.3.5 Ultraviolet/Infrared (UV/IR) Detectors

There are two types of detectors under UV/IR classifications. Both types respond to frequencies in the UV wavelength and IR in the CO_2 wavelength. In both types simultaneous presence of UV and IR signals must be available for alarm signaling. In a simple voting device, an alarm is generated once both conditions are met. In a ratio device, satisfaction of the ratio between the level of UV signal received and the IR signal received must also be achieved before an alarm condition is confirmed.

Advantages

It responds well to a wide range of hydrocarbon fires and is indifferent to welding or electrical arcs. There are minimal problems with other forms of radiation. They are blind to solar radiation and artificial lighting. They ignore black body radiation. Its fairly fast response is slightly better than a single frequency IR detector but not as fast as a UV detector. The simple voting type will respond to a fire in the presence of an arc welding operation. It is not desensitized by the presence of high background IR sources. The flame sensitivities of the simple voting detector can be field adjusted.

Limitations

The sensitivity to a flame can be affected by deposits of IR and UV absorbing materials on the lens, if not frequently maintained. The IR channel can be blinded by ice particles on the lens, while the UV channel can be blinded by oil and grease on the lens. Smoke and some chemical vapors will cause reduced sensitivity to flames. UV/IR detectors require a flickering flame to achieve an IR signal input. The ratio type will lock out when an intense signal source such as arc welding or high steady state IR source is nearby. Flame response for a ratio type is affected by attenuators, while in the voting type there are negligible effects.

17.1.3.6 Multi-Band Detectors

Multi-band fire detectors monitor several wavelengths of predominate fire radiation frequencies by photocells. They compare these measurements to normal ambient frequencies through micro-processing. Where these are found to be above certain levels, an alarm is indicated. False alarms may even be "recognized."

Advantages

These detectors have very high sensitivity and very encouraging stability. The microprocessor has the capability to be programmed to recognize certain fire types.

Limitations

May be inadvertently mis-programmed.

17.1.3.7 Projected IR Beam Detectors

There are two basic types of beam detectors, both of which operate on the principle of light obscuration: an infrared beam is projected across the area to be protected and is monitored for obscuration due to smoke. If smoke is present in the beam, usually for a period of 8–10s, a fire alarm indication is activated. There are two basic types.

An end-to-end type detector has separate transmitter and receiver units, mounted at either end of the area to be protected. A beam of infrared light is projected from the transmitter towards the receiver, and the signal strength received is monitored. End-to End type detectors require power to be supplied both to the transmitter and the receiver ends of the detector. This leads to longer wiring runs and thus greater installation costs than the reflective type device.

Reflective or single-ended type detectors have all the electronics, including the transmitter and receiver, mounted in the same housing. The beam is transmitted towards a specially designed reflector mounted at the far end of the area to be protected, and the receiver monitors the attenuation of the returned signal.

Advantages

The response of beam smoke detectors is generally less sensitive to the type and color of smoke. Therefore, a beam smoke detector may be well suited to applications unsuitable for point optical smoke detectors, such as applications where the anticipated fire would produce black smoke. Beam smoke detectors do, however, require visible smoke and therefore may not be as sensitive as ion detectors in some applications.

Since the sudden and total obscuration of the light beam is not a typical smoke signature, the detector will normally see this as a fault condition, rather than an alarm. This minimizes the possibility of an unwanted alarm due to the blockage of the beam by a solid object, such as a sign or ladder, being inadvertently placed in the beam path.

Table 17.1 Comparison of Fire Detectors

Type of Detection	Detector Type	Speed	Cost
Human	Human	Moderate	Expensive
	Telephone	Moderate	Moderate
	Portable Radio	Moderate	Expensive
	MPS/MAC	Moderate	Moderate
Smoke	Ionization	Fast	Moderate
	Photo-Electric	Fast	Moderate
	VESDA	Very Fast	High
	Laser	Extremely Fast	Moderate-High
Heat	Fusible Link	Low to Moderate	Moderate
	Plastic Tube	Low to Moderate	Low
	Fusible Plug	Low to Moderate	Moderate
	Quartzoid Bulb	Low to Moderate	Moderate
	Optical Fiber	Low to Moderate	Moderate
	Bi-metallic Wire	Low to Moderate	Low to Moderate
	Heat Act/Rate of Rise	Low to Moderate	Moderate
Optical	IR	Very Fast	High
	UV	Very Fast	High
	IR/IR	Very Fast	High
	IR/UV	Very Fast	High
	Multi-band	Very Fast	High
	Projected IR Beam	Very Fast	High
	Video Camera	Fast	Expensive

Limitations

It may be initially sensitive to dusty environments and detect the dust as smoke and therefore provide a false alarm. Some manufacturers offer a sensitivity selection level to compensate for this (see Tables 17.1 and 17.2).

17.2. GAS DETECTORS

Gas detection is provided in the process industries to warn and possibly prevent the formation of a combustible gas or vapor mixture that could cause an explosive overpressure blast of damaging proportions or initiate a fire. There are three types of gas detectors used in the process industries. The most common and widely used is the point source catalytic detector.

Table 17.2 Application of Fixed Fire Detection Devices

Location or Facility	Hazard	Fixed Detector Type Options	Reference
Office	Ordinary Combustibles	MPS	NFPA 101
	Electrical Fire	Heat Smoke	
Accommodation	Ordinary Combustibles	MPS	NFPA 101
	Electrical Fire	Heat Smoke	
Kitchen or Cafeteria	Ordinary Combustible	MPS	NFPA 101
	Cooking/Grease Fire Electrical Fire	Heat	NFPA 96
Control Room	Ordinary Combustibles	MPS	NFPA 75
	Electrical Fire	Smoke	
Switchgear Room	Electrical Fire	MPS Smoke Optical Projected Beam	NFPA 850
Turbine Package	Electrical Fire Hydrocarbon Fire	Heat Optical	NFPA 30
Process Unit	Hydrocarbon Fire	MPS Heat Optical	NFPA 30
Pump Station	Hydrocarbon Fire Electrical Fire	MPS Heat Optical	NFPA 30
Loading Facility	Hydrocarbon Fire	MPS Heat Optical	NFPA 30

Table 17.2 Continued

Location or Facility	Hazard	Fixed Detector Type Options	Reference
Tank or Vessel Storage	Hydrocarbon Fire	MPS Heat Optical	NFPA 30
Offshore Drilling or Production Facility	Hydrocarbon Fire Electrical Fire	MPS Smoke Heat Optical	NFPA 30 API 14 C
Laboratory	Hydrocarbon Fire Electrical Fire	MPS Heat	NFPA 45

Secondly are infrared (IR) beam detectors that are employed for a special line of sight applications such as perimeter, boundary, and offsite monitoring or process pump alleys. Thirdly and most recent is the ultrasonic area detector that relies on the sound of a leak to detect its presence. Underwriters Laboratories (UL) tests gas detectors under UL 2075, Standard for Gas and Vapor Detectors and Sensors.

A gas detection system monitors the most likely source of releases and activates alarms or protective devices to prevent the ignition of a gas or vapor release and possibly mitigate the effects of flash fires or explosions.

Most hydrocarbon processes contain gases or vapors in mixtures. Therefore the gas detection vapor selected for detection must be chosen carefully. The most prudent approach in such cases is to choose to detect the gas or vapor that is considered the highest risk for the area under examination.

The basis for the highest risk should account for:

1. The gas with the widest flammable range of the gases that is present
2. The largest percentage by volume of particular gas in the stream
3. The gas with the lowest ignition temperature
4. The gas with the highest vapor density
5. Spark energy necessary for ignition (i.e., Group A, B, C, or D)
6. Process temperature of the inventory which may be released

Since no specific property can define the entire risk for a particular process, the consequences for each material should be examined when deciding upon the optimum gas detection philosophy for a particular area.

Table 17.3 Comparison of Common Hydrocarbon Vapor Hazards

Material	LEL/UEL%	AIT (°C)	VD	Group
Hydrogen	4.0–75.6	500	0.07	B
Ethane	3.0–15.5	472	1.04	D
Methane	5.0–15.0	537	0.55	D
Propane	2.0–9.5	450	1.56	D
Butane	1.5–8.5	287	2.01	D
Pentane	1.4–8.0	260	2.48	D
Hexane	1.7–7.4	225	2.97	D
Heptane	1.1–6.6	204	3.45	D

By an analysis of the composition of a gas or liquid stream of the process under examination and the arrangement or conditions at the particular facility, one can prudently arrive at the optimum detection philosophy that should be employed for gas detection at the facility.

Table 17.3 provides a brief comparison of the characteristics of the most common gases that may be encountered in a hydrocarbon process facility.

17.2.1 Application

There is no specific detailed guidance available in the industry or from regulatory bodies on the siting of combustible gas detectors. Due to the wide variety of material that needs to be detected, variances in ambient environmental conditions, variations in process composition, temperatures and pressures, the ability to predict the manner in which gas releases can be detected by placement to detectors is not available as of yet. Most detectors are suggested to be placed "near" sources of potential leakages. For example, per NFPA 15, gas detectors are to be located with consideration for the density and temperature of the potential flammable gas release and its proximity to the equipment where leakage could occur. In API 14C (for offshore structures) gas detection is to be provided in enclosed classified areas, in all enclosed areas that there is natural gas fired prime movers, and in buildings where personnel sleep and there is a flammable gas source.

Assuming that the main objective of a combustible gas detector is to warn of the formation of a vapor cloud, which ignited, would produce harmful explosion effects, then the rough approximation of 5.5m (18ft) as proposed by the Christian Michelson Institute, Norway, should be the standard for the spacing of combustible gas detectors for general area coverage. A three-dimensional triangular spatial arrangement of 5m (16ft), allowing for a 10% adjustment and contingency factor, would provide a satisfactory arrangement for gas detection in confined areas. The first step is to define all possible leakage sources and then narrow the possibilities by selecting equipment that has the highest probability leakage. This can be accomplished by first referring to the electrical area classification drawings for each facility. Equipment that handles low flash point material should be given the highest priority, with materials that have high vapor density of most concern, since these vapors are easiest to collect and less likely to disperse.

Pump and compressors (which do not have dry seals) are by far the most common areas where vapor or gas releases may occur. This is followed by instrumentation sources, valves seals, gaskets, drain and sample points, and most rare but occasionally catastrophic, erosion and corrosion failures of process piping.

The nature of the release has to be analyzed to determine the path of the gas or vapors, i.e., high or low. This will determine whether the detectors need to be sited above or below the risk. Detectors should also be sited with due regard to the normal air flow patterns. High and low points where gas may settle should be considered.

Enclosed areas or spaces that may be subject to a gas leak that have intrinsic production value or are high capital items should be provided with gas detection. Typically these locations are gas compressors and metering houses.

As a preventive measure, gas detectors are normally placed at the air intakes of manned facilities, critical switchgear shelters, and internal combustion engines subject to vapor or gas exposures, i.e., near process areas that handle such materials. The facility air intakes themselves should be positioned to prevent the possible intake of combustible gases from these areas, even during incident scenarios (i.e., elevated, facing downwind, etc.).

Normally point detectors are positioned with the sensor head facing downwards to improve the capture of the released gases by the device.

No gas detector should be located where it would be constantly affected by ambient conditions such as surface drainage runoff, sand, and ice or snow accumulation. Special consideration should be given near open sewer gratings and oily water sewer funnels where frequent alarms may appear due to vapor emissions.

17.2.1.1. Typical Process Facility Applications

The following locations are typical applications where combustible gas detectors are provided and should be considered for process facilities:

- All hydrocarbon process areas containing materials with gaseous materials that are not adequately ventilated (i.e., would not achieve a minimum of six air changes per hour or would allow the buildup of combustible gas due to non-circulating air spaces. Typically such applications include compressor enclosures, process modules on offshore structures, and enclosed arctic facilities.

For enclosed areas they can be considered adequately ventilated if they meet one of the following:

1. The ventilation rate provided is at least four times the ventilation rate required to dilute the anticipated fugitive emissions to below 25% of the LEL as determined by detailed calculations for the enclosed area
2. The enclosed area is provided with six air changes per hour by artificial means (mechanical means)
3. If natural ventilation is used, 12 air changes per hour are achieved throughout the enclosed area
4. The area is not defined as enclosed per the definition of API RP 500

- Gas compressors that do not have dry seals should be provided with gas detection near seal points and especially if fitted in an enclosure. Fitted enclosures should be provided with area detection and at the air intake and exhaust.
- Pumps handing high vapor pressure hydrocarbon liquids (detector sited close to the pump seals).
- All intakes for fresh air for HVAC systems to buildings in an electrically classified area according to the National Electrical Code (NEC) or subject to ingestion of combustible gases or vapors based on a facility gas dispersion analysis. Especially if they are considered inhabited, critical, or of high value. Typically control rooms, critical switchgear, or main process power sources are provided with gas detection.
- All critical internal combustion prime movers subject to the possible ingestion of combustible gases or vapors.
- In all battery or UPS rooms in which significant hydrogen vapors may be vented or released from battery charging operations.
- Entrances and air intakes to the accommodation module or continuously manned enclosed locations for offshore facilities if a vapor dispersion analysis indicates there is a possibility of vapor exposure.
- Petroleum drilling areas such as the mud room, drilling platform, and areas around enclosed wellheads.
- Possible hydrocarbon leaks points in process cooling towers.

- Sensitive (critical or high value) processing areas where immediate activation of incident and vapor mitigation measures is vital to prevent the occurrence of a vapor cloud formation and possible explosion.
- Enclosed water treating facilities that can release entrained gases or vapors, especially a concern at petroleum operations for produced water-treating operations.
- Process locations containing large volumes or high pressure hydrocarbon gases that might be susceptible to extreme effects of erosions or corrosion from process activity.

17.2.2. Catalytic Point Gas Detectors

The catalytic gas detector was originally developed in 1958 for the mining industry. It has become the standard means of detection worldwide in virtually all oil and gas operations. It is also used extensively in the chemical process industry and in coal extraction.

Catalytic gas detection is based on the principle of oxidation of a combustible gas in air that is promoted at the surface of a heated catalyst such as a precious metal. The oxidation reaction results in the generation of heat that provides a direct measure of the concentration of the gas that has been reacted. The sensing element embodying the catalyst is a small bead that is supported with the sensor.

They are sensitive to all combustible gases, and they give approximately the same response to the presence of the lower explosive limit (LEL) concentrations of all the common hydrocarbon gases and vapors. However, it should be remembered that gas detectors do not respond equally to different combustible gases. The multi-volt signal output of a typical catalytic detector for hexane or xylene is roughly one half the signal output for methane.

They have two disadvantages. First, they are only capable of sensing combustible gas at a single point. If the position of the sensor is unfavorable in relation to the origin of the combustible gas release and the pattern of wind flow and ventilation in the hazardous area, then the gas detector will not detect a dangerous release of gas until it is too late to take effective action. Generally point gas detectors can only provide adequate protection at a facility if deployed in large numbers.

Secondly, small quantities of airborne pollutants may poison the catalyst in the detector. This severely reduces its sensitivity. The detector becomes less reliable and often makes duplication, voting logic, and frequent maintenance necessary.

The following substances have been known to poison catalytic gas detectors:

- Tetraethyl lead
- Sulfur compounds
- Phosphate esters (used in corrosion inhibitors in lubricating oils and hydraulic fluids)
- Carbon tetrachloride and trichloroethylene (found in degreasing agents and dry cleaning fluids)
- Flame inhibitors in plastic materials
- Thermal decomposition products of neoprene and PVC plastics
- Glycols
- Dirt or fiber particles

17.2.3. Infra-Red (IR) Beam Gas Detectors

A gas detector that utilizes an infrared beam to detect gas along a straight open path that can be up to several hundred meters in length. The sensor is based on the differential absorption technique and has a reasonably even response to a range of hydrocarbons. A microprocessor is used for signal processing that produces the alarm and trouble indications. Many frequency lines of infrared radiation are absorbed by hydrocarbon gases. By selection of a particular frequency, a detector can be made that is either specific to a specific gas or if the frequency is common to several gases, a particular group of gases may be detected.

IR beams are typically provided as a special gas detection application. They offer a direct view and surveillance over a long area rather than a point source origination of gas. The most frequent use of these is verifying whether a gas release would be carried offsite from a facility. Other possible applications would be overall monitoring in the area of several possible leak sources but within a line of sight arrangement such as a pump ally or an offshore module.

- **Pump Alleys**—Where a number of pumps are used, they are usually arranged in parallel to each other facilitating the use of an IR beam over the line of pumps.
- **Perimeter Monitoring**—The perimeter of a hazardous area or process unit can be effectively monitored for a gas or vapor release by IR beam arrangements on the edges. Theoretically they can be used to warn of open air combustible vapors or gases approaching ignition sources in a reverse role, e.g., to the flare from a process area.
- **Boundary and Offsite**—Especially critical for locations near public exposures, an IR beam detector can be used to signal if vapors or gases may be released to offsite locations.

17.2.4. Ultrasonic Area Gas Detectors

A gas detector that uses a microphone to listen to the noise from leakages to detect leaks, instead of gas concentrations. It utilizes the acoustic sound generated from gas releases in open well ventilated areas for determining if a leak exists. Ultrasonic gas detectors are unaffected by changing wind directions, gas dilution, and the direction of the gas release. The Ultrasonic gas leak detector coverage is between 4 and 20m (13–65ft) in radius around the detector for gas leaks of with a leak rate (mass flow rate) of 0.1kg/s. The variation of detection coverage is due to the fact that the detectors alarm trigger level will have to be set different in a high noise area compared to a low noise area. In other words, in a high noise area (e.g., a gas compressor area) the ultrasonic gas leak detector will have a detection radius of 6–8m (20–26ft) for 0.1kg/s gas leaks where it will have 10–12m (33–39ft) detection radius at normal plant noise for the same leak rate of 0.1kg/s. The devices are usually configured to screen out ambient noises that could produce a false alarm by conducting a baseline noise survey for the instrument. The response time to detect a leak is reported to be less than 1s (see Figure 17.1 and Table 17.4).

Figure 17.1 General Monitors, Gassonic Observer ultrasonic gas leak detector. (Photo Courtesy of Gassonic A/S, A General Monitors Company.)

Table 17.4 Comparisons of Gas Detection Systems

Type	Speed	Cost	Advantages	Disadvantages	Applications
Catalytic Point Detection	Moderate	Moderate	Easily Positioned Commonly used in process industry Sources the point of leakage	Requires gas to pass by device for detection Expert judgment for placement Poisoning & clogging Costly maintenance	Point sources (pumps, major packing, seal, or gasket failure points, etc).
IR Beam	High	High	High reliability Long line coverage Less dependent on specific location	Requires clear line of sight view May not capture small releases Requires gas to pass through beam for detection Does not precisely pin-point source of leak	Boundaries Pump alleys Perimeters Room monitoring
Ultrasonic Area	Very High	High	Does not require gas to be at device for detection High reliability Wide area coverage Less dependent on specific location	Requires background noise survey and calibration Does not precisely pin-point source of leak	General process areas Storage and loading facilities Gas turbine power plants Pipeline stations

17.2.5. Alarm Settings

To achieve early and reliable warnings of leakages, the sensitivity of detectors should be at the highest level commensurate with the level of false alarm rates.

Alarm panels are normally set to respond to two levels of warning: a first alarm at low level and a second alarm at high level. Typical practice is to set these at 25% and 50% of the lower explosive limit (LEL) for the "low" and "high" levels, respectively. Some organizations desire more sensitive settings and 10% and 25% set points are also employed. NFPA 15 states in its Appendix A that the first alarm point should be set between 10–20% of the LEL and 25–50% LEL as the second alarm point at which executive actions should occur (e.g., activation of a water spray for fire protection). API 14C, Appendix C, also recommends that gas detectors alarm at two levels. The first should be activated at no greater than 25% LEL to alert operating personnel and the second activated at no greater than 60% LEL, which should initiate executive actions (i.e., emergency shutdown commands).

From a safety viewpoint the lower the alarm levels are set the better. However, the lower the level of alarm the greater the possibility of a false alarm and disruption to operations. On the other hand, some practical experience has shown that with lower levels of sensitivity, minor leakages be detected and fixed. As these leakage sources are corrected, fewer real alarms are sounded than if the detectors were set at the higher LEL levels (i.e., 25 and 60% LEL). It should also be realized that for immediate leaks the concentration of gas or vapor in the area will immediately rise to the LEL ranges (or past), so settings below the LEL may not be significant. The most important feature is to have detection capability for the gases that may be encountered at the installation.

In general practice, the gas detection set points are those settings recommended by the manufacturer of the device or by the operating requirements of the company to effect an acceptable compromise on any given field of operation. The lower the set points the higher the sensitivity to possible leakage emissions.

17.3. CALIBRATION

Operation of detectors with their associated alarm panels should be checked and calibrated after installation. Detector performance can be impaired in a hostile environment by blockages to the detector, i.e., windblown particles, ice, salt crystals, water, and even firefighting foam, or by inhibition of the detector catalyst form airborne contaminants such as compounds of silicon, phosphorus, chlorine, or lead. It is essential that detectors and alarm panels be checked and recalibrated on a routine basis.

It is also possible for detectors to be calibrated using one gas (e.g., methane) for use thereafter in detecting a second gas (i.e., propane or butane), provided the relative sensitivity of the detector to each of the gases is known. A procedure for calibration of the detector for a different gas than that which is being used is normally available from the manufacturer of the detector.

Detectors should be calibrated after installation as recommended by the manufacturer. However, if experience indicates that the detectors are either in calibration or out of calibration, the period of re-examination should be lengthened or shortened accordingly.

17.3.1 Hazardous Area Classification

Since detectors are by definition exposed to combustible gases and vapors, they should be rated for electrically classified areas, such as Class I, Division 1 or 2, the specific gas groups, commonly groups C and D, and temperature ratings.

17.3.2 Fire and Gas Detection Control Panels

Standalone fire or gas detection and alarm panels may be provided in the main control facility for the installation. Recent trends may incorporate the transmittal of fire and gas alarms through the facility process control system (i.e., DCS). When alarm panels are located within a protected building, they should be located for easy access for emergency response personnel and proximity to manual electrical power shutoff facilities.

17.3.3 Graphic Annunciation

Alarms should be displayed on a conventional dedicated annunciator panel or if control room based on a dedicated console display for fire and gas detection systems. Each detector location should be highlighted with indications for trouble, alarm low and alarm high. Where an annunciator window panel is provided, alarm indication lights should be provided with specific labels indicating the exact location of alarms.

17.3.4 Plant/Field Display of Alarms

See Chapter 18, Evacuation Alerting and Arrangements.

17.3.5 Power Supplies

Commercially available combustible gas detection systems generally use 24 VDC as the power supply for field devices. 24 VDC power is inherently safer and corresponds to the voltage commonly being used by most instrument systems in process areas. A main supply voltage converter can be used to step down or convert from AC to DC power supplies.

17.3.6 Emergency Backup Power

The power for combustible gas detection systems should be provided from the facility's uninterruptible power supply (UPS) or if this is unavailable, normal power with a reliable battery backup source that has a minimum of 30 min duration.

17.3.7 Time Delay

Where instantaneous reaction is not imperative, susceptibility to false alarms can be reduced by requiring a fire signal to be present for a predetermined period of time. However, the time delay reduces the advantages of high speed early detection. In most applications, the tradeoffs between false alarms and the damage incurred in the first few seconds of a fire have been inconsequential.

17.3.8 Voting Logic

Activation of a single fire or gas detector should not be trusted to assure executive action for process facilities. The present technology suggests they are too vulnerable to false alarms. They should be arranged for a voting logic for alarms and executive actions. Voting is the requirement for more than one sensor to detect a fire or gas presence before the confirmation of the alarm. The method would prevent a false alarm caused by a single spurious source or electronic failure of a single component. Usually a one out of two (1oo2) or a two out of three (2oo3) voting network of detectors is used to offer a confirmed alarm reception.

17.3.9 Cross Zoning

Cross zoning refers to the use of two separate electrical or mechanical zones of detectors, both of which must be actuated before the confirmation of a fire or gas detection. For example, the detectors in one zone could all be placed on the north side of a protected area and positioned to view the protected area looking south, while the detectors in the second zone would be located on the south side and positioned to view the northern area. Requiring both zones to be actuated reduces the probability of a false alarm activated by a non-incident fire source, such as welding, from either the north or the south outside the protected area. However, this is not effective if the zone facing away from the source sees the radiation. Another method of cross zoning is to have one set of detectors in the area to be protected and another set located to face away from the protected area to intercept external sources of nuisance UV. If welding or lighting should occur outside the protected area, activation of the alarm for the protected area would be inhibited by second detector activation. Although this method is quite effective, a fire outside the protected area would inhibit the activation for the protected area.

17.3.10 Executive Action

Once an alarm has been confirmed, actions should be taken to prevent or reduce the impact from the incident. Depending on the priority of the alarms, the following actions should be taken at the point of activation:

- The facility evacuation and warning alarms (audio and visual) should be activated and personnel evacuation or muster should commence.
- Activate the process emergency shutdown system (ESD), i.e., isolation, depressurization and blowdown, power shutdowns.
- Activate fixed fire suppression systems or vapor dispersions mechanisms, i.e. water sprays.
- Start fire and foam solution pumps.
- Shut down HVAC fans (unless arranged for automatic smoke control and management or toxic gas ingestion prevention—shutdown or re-circulation).
- On confirmed gas detection, sources of ignition such as welding or small power circuits should be immediately shut down in the affected

area (for equipment not rated to operate where combustible gases may be present).

- Messages should be sent alerting outside agencies of the incident and current situation.

17.3.11 Circuit Supervision

The detection and alarm circuits of fire and gas detection systems should be continuously supervised to determine if the system is operational. Normal mechanisms provide for limited current flow through the circuits for normal operation. During alarm conditions current flow is increased while during failure modes the current is nonexistent. By measuring the levels at a control point the health of the circuit or monitoring devices can be continuously determined. End-of-line-resistors (EOLR) are commonly provided in each circuit to provide supervisory signal levels to the control location.

17.3.12 Vibration Avoidance

Detectors can be susceptible to false alarms if affected by vibrational influences. Careful mounting locations must be chosen that will not be influenced by equipment vibration that may cause false alarms or premature failure of the equipment.

FURTHER READING

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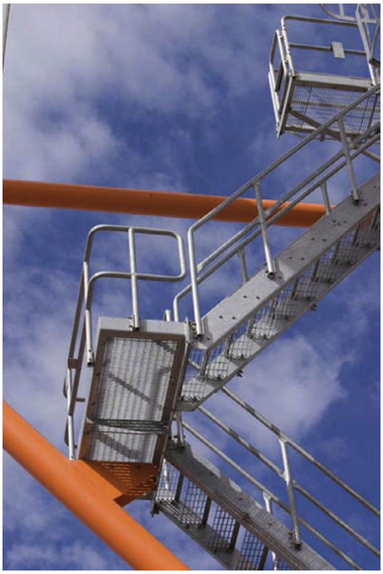
CHAPTER 18

Evacuation Alerting and Arrangements



The primary safety feature for any installation should be its evacuation mechanism for its personnel. If personnel cannot escape from an incident they may be affected by it. Personnel must first be aware that an incident has occurred, they then need an available means to escape or evacuate from it or have the means provided to shelter from its effects. An adequate means of escape should be provided from all buildings, process areas, elevated structures, and offshore installations. Provisions for an adequate means of escape are listed in most national safety regulations for the process industries as a whole, as well as in local building code ordinances.

The number of personnel in any process facility is usually quite low. Initial glances at an operating unit could indicate the facility might be unmanned. The highest concentrations of personnel are typically found in control rooms, transportation mechanisms, drilling or maintenance activities, project offices and accommodations. These locations have the highest probability of large life loss within the process industry. Historical evidence of hydrocarbon and chemical facilities indicate that for the majority of incidents, a relatively low level of fatalities occurs. When a large loss of life does occur, it is usually due to the congestion of personnel in a single area with the in ability to escape or to avoid or protect themselves from the impending hazard.

When an emergency egress route is provided, it should be protected from the effects of fire and smoke or personnel should be equipped with a

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means to protect themselves when transversing it. It has been shown that people are reluctant to enter into smoke that reduces visibility to less than 10 m (33 ft), even when it is not hazardous to do so. When the effects of fire, smoke, and explosions are likely to preclude the use of an emergency egress route, it is the same as not providing such an egress route.

18.1. EMERGENCY RESPONSE PLAN

An emergency response plan (ERP) should include appropriate measures for building occupants or a process facility to take in the event of a flammable or toxic gas release incident. These actions may include remaining in a building (i.e., shelter-in-place) or evacuation to a safe location that is upwind or cross-wind from the incident release.

18.2. ALARMS AND NOTIFICATION

Alarms should be able to be noticed at all areas of the facility, whether manned or considered technically unmanned. The basic theory for determining the number and location of audible alarms devices is to strategically place and distribute devices that will allow an effective distribution of the level of sound than one centrally located device.

As a rule of thumb, the unobstructed sound radius of a typical siren, horn, or bell is about 61 m (200 ft). If an area is segregated by walls, equipment, or structures, it should be provided with its own audible alarm. If unobstructed areas from 61 to 305 m (200–1000 ft) are encountered, a large plant-wide siren or horn may be suitable in some cases, depending on background noise and orientation of the device(s).

Where several different alarm signals are necessary they should be easily distinguishable from one another for the purposes they are intending to provide, i.e., fire alarm, toxic gas warning, evacuation, etc. Different signals can range from horns, sirens, klaxons, buzzers, etc. In addition, the intensity, pitch, warbling, etc., can also be varied. Electronic programmable controllers are available that can easily be configured to produce the different emergency sounds.

Fire and evacuation alarms should normally have a sound level between 85 and 100 decibels (dB), with a maximum of 120 dB. They should be in the range of 200–5000 Hertz (Hz), preferably between 500 and 1500 Hz. Where ambient noise levels are higher, and for higher awareness, flashing beacons should be used. Beacon colors for the selected incident of concern (e.g., gas release, fire, stop work, evacuation, all clear) should be consistent with the alarm color coding philosophy adopted for the entire facility.

Panel alarms and indications should not be mounted lower than approximately 0.76 m (2.5 ft) or higher than 1.83 m (6 ft). Outside of these limits the alarm indicators are less noticeable and awkward for maintenance personnel activities.

18.2.1 Alarm Initiation

Alarms should be initiated by the local or main control facility for the location. Manual activation means should be provided for all emergency, fire, and toxic vapor alarm signals. Activation of fire suppression systems by automatic means should also indicate a facility alarm. Most fire and gas detection systems are also set to automatically activate alarms after confirmation and set points have been reached. Manual activation of field or plant alarm stations should activate the process or facility alarms.

Alarm activation points have to be clearly highlighted and marked. Their operation should be simple, direct, and consistent throughout the facility or company, especially if personnel may be transferred or rotated from one location to another. A protective mechanism is usually incorporated to prevent false activation of manual switches (e.g., protective lift cover, depress button, and pull to operate rather than just push to operate, etc.).

18.3. EVACUATION ROUTES

Evacuation routes are of prime importance for the safety of plant workers during an emergency. They should contain the following features:

- Two evacuation routes, situated as far apart as practical, should be provided from all processes or normally occupied work areas. Areas that are considered low hazard (e.g., no hydrocarbons, chemicals, or other flammables are in the immediate area) may be allowed one escape route.

The exception to this provision is areas that are located on an offshore structure in proximity to hydrocarbon processes.

- Exit routes should not be affected by the effects of fire or explosions (i.e., blast overpressure, heat, toxic vapors, and smoke).
- A minimum width of 1.0 m (39 in.) should be maintained on all evacuation routes.
- Evacuation routes should be generally straight and direct to points of safety or embarkation.
- Passage from one level to another level should be by stairways; where impractical, vertical ladders are normally provided. Preferably stairways and ladders should be located on the exterior faces of structures that face away from the plant. Stairway designs that require evacuation to be through other process equipment or areas should be avoided. On fired units, where the towers may be very close to the furnace, providing an additional walkway bridge link to an adjacent tower or structure may be more cost effective if the towers need to be climbed frequently.
- The evacuation route should be simple to locate and negotiable even in an emergency lighting condition. If the route is not obvious, adequate demarcation (i.e., signs, arrows, etc.) should be provided on the route and exit points.
- An emergency muster location should be designated. This affords a means to account for personnel and issue further evacuation instructions.
- Egress arrangements should not be exposed to drainage provided at the facility.

18.4. EMERGENCY DOORS, STAIRS, EXITS, AND ESCAPE HATCHES

Exit routes and doors from all facilities should be provided according to the requirements of NFPA 101, Life Safety Code. The design of stairways with two or more risers is critical for safe evacuation. Stair widths, rise, and run are to be arranged for an effective and orderly evacuation. Studies of people traveling on stairways show that the greatest hazard is the individual himself. Inattention has been shown to be the single most factor producing the greatest mishaps, incidents, and injuries. Life safety code requirements for stairs place limitations on the use of winding, circular, and spiral stairways to ensure adequate egress routes are provided for emergency purposes.

Evacuation routes should not be located within 1.8 m (6 ft) of incidental combustible liquid storage (e.g., lube oil reservoirs, fuel day tanks, etc.).

Where low occupancy rooms are provided in offshore facilities near process areas, a secondary emergency escape hatch is generally provided as an alternative means of escape in addition to the normal means of egress.

18.4.1 Marking and Identification

Where practical, routes between exit points should be defined by lines painted on the floor or facility pavement in reflective oil resistant paint. All exit doors should be plainly marked. Direction arrows and wordings should be positioned along escape routes where necessary to guide personnel to exit points or the perimeter of the facility. The directional exit arrows should be self-illuminating (i.e., luminescent).

18.4.2 Emergency Illumination

A minimum of 1.0 ft candle of illumination should be provided to the centerline of the evacuation route. This illumination should be available for the evacuation routes for the duration of the expected emergency evacuation period, but not less than 90 min.

18.5. SHELTER-IN-PLACE (SIP)

Shelter-in-place is used when an evacuation through an area may cause or threaten greater harm to the individuals who are evacuating, such as direct exposure to flames, toxic vapors, or explosions. Typical methods used to achieve such protection include shelters, safe havens, and areas of refuge.

A SIP shelter may be any building that provides passive protection for inhabitants when ventilation is off and all windows and other openings are closed. A SIP safe haven is typically designed to provide protection against air inflow once ventilation is shut off; it is usually an airtight room containing a supply of breathing air. Sometimes control rooms are designed as safe havens to enable operators to safely shut down critical systems during an emergency. An SIP area of refuge usually refers to a specially designed space that incorporates all the aspects of a safe haven but that has been specifically designed to afford protection against particular hazards and is suitable for longer-term protection.

Shelter-in-place facilities should be located away from probable incident areas and can be easily reached by personnel. They should be structurally able to withstand fire and blast effects, with no holes, cracks, voids, or other structural weaknesses that could allow hazardous gases to penetrate into the interior. They should have adequate seals on doors and windows and ventilation control or shutoff. They should be arranged to support personnel for the maximum period of a credible event.

18.6. OFFSHORE EVACUATION

The methods of evacuation offshore are dependent on the ambient environmental conditions that may develop in the area and relative distance to the mainland. The US Gulf of Mexico has nearly 4000 active oil and gas platforms plus a sprawling array of drilling rigs and supply ships.

Regions that experience colder ambient conditions inhibit water immersion opportunities and remote offshore locations retard onshore assistance capabilities. The preferred and most expedient evacuation means from an offshore installation is by helicopter. Because of the nature of fire and explosion incidents to affect the vertical atmosphere around an offshore installation, helicopter evacuation means cannot always be accommodated and should be considered a low probability where accommodation quarters are located on the same structure as a hydrocarbon process operation.

18.6.1 North/South Atlantic and North/South Pacific Environments

Areas of the North and South Atlantic and North and South Pacific present continual extreme and hostile ambient conditions that make survival in such conditions a very limited probability without protection measures. In these locations the probability of survival is increased with the provision of a fixed safe refuge rather than the provision of an immediate means of escape. Offshore facility historical evidence indicates that both helicopter and lifeboat mechanisms may be unavailable in some catastrophic incidents. Remote onshore facilities may also experience severe winter conditions that also render this philosophy applicable.

18.6.2 Temperate and Tropical Environments

Temperate and tropical environments are less severe locations where supplemental exposure protection from the normal ambient conditions is not necessary. But these locations may contain other threats that need to be accounted for when offshore structures are present; these typically include storm weather events such as hurricanes and predators (sharks).

18.6.3 Means of Egress

At least two means of access should be provided from all "facility" evacuation muster areas to the sea for offshore facilities. These are usually selected from the following:

1. Stairway or ladder
2. Lifeboat or davit launched life raft
3. Abseiling device
4. Scramble net or knotted rope
5. Slide tube

Where other semi-occupied areas exist, they are usually provided sufficient and properly arranged evacuation means to the sea by way of two remote locations. These include the following (see Figure 18.1):

1. Abseiling device
2. Scramble net or knotted rope
3. Ladder or stairway

18.6.4 Floatation Assistance

Several methods of floatation assistance in the open sea are usually provided for the number of personnel on board (POB) the installation:

- Lifejacket or inflatable survival suit
- Lifeboats and life rafts
- Floatation device (life buoy or life ring)

A prime consideration in the provision of lifeboats for offshore installations

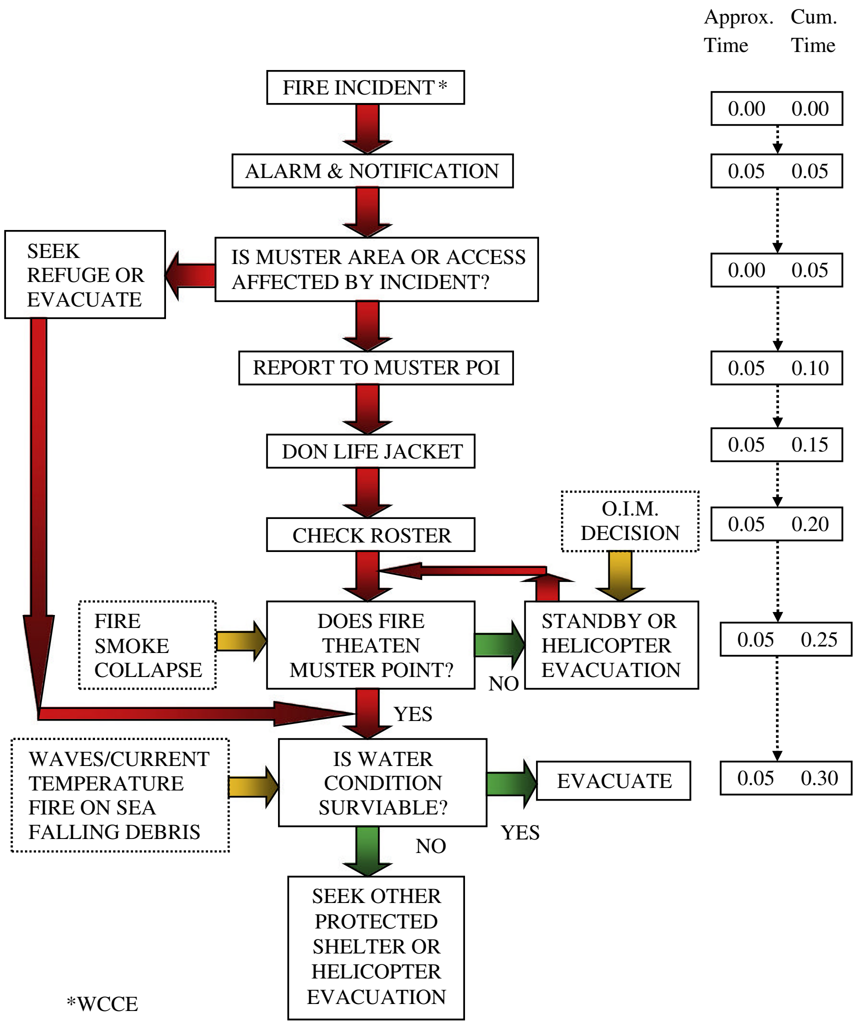

Figure 18.1 Offshore evacuation flowchart.

is that they be readily available and can immediately be maneuvered away from the structure of the installation. Recent trends have been for the orientation of lifeboats to point outwards so the egress away from the structure is improved and fear of being swept into the structure or platform by waves or currents is lessened. Positioning in an outward orientation also improves the evacuation time for the boat to load personnel and get away from the incident. With lifeboats pointing outwards the access doors are located at the rear of the vessel instead of on the side, which facilitates improved egress into the boat.

FURTHER READING

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CHAPTER 19

Methods of Fire Suppression

The objectives of fire suppression systems are to provide cooling, to control the fire (i.e., prevent it from spreading), and to provide extinguishment of the fire incident. A variety of fire suppression methods are available to protect a facility. Both portable and fixed systems can be utilized. The effectiveness of all fire extinguishing measures can be determined by the rate of flow of the extinguishing medium and the method or arrangements of delivery.

Before the needs of fire protection measures are defined, the types of fire exposure should be identified and analyzed. By determining the type of fire expected, the adequacy of fire protection measures based on the philosophy of protection adopted for the facility can be assessed. The easiest method to arrive at the protection requirements is to identify the materials and pressures involved in the process. Once this is accomplished, the most appropriate fire control or suppression mechanism can be identified from NFPA 325 M. Tables 19.3 and 19.4 provide examples that can be used to document the fire control mechanisms that have been selected (see Tables 19.5–19.7).

19.1. PORTABLE FIRE EXTINGUISHERS

Historical evidence indicates that portable (i.e., manually manipulated and operated) fire extinguishers are the most common method of extinguishing a fire in the process industry in the incipient stage. Human surveillance

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combined with the ability to quickly and effectively react to the beginning of an incipient fire has prevented countless process incidents from developing into-large scale disasters. The objective of providing portable fire extinguishers is to have an available supply of plentiful extinguishers that can be easily used in the early stages of a fire. When these extinguishing means are exhausted or the incipient fire has grown to the point of uncontrollability by manual methods, fixed fire suppression systems and process incident control systems should be activated (e.g., emergency shutdown). Only personnel trained in portable fire extinguisher use should be expected to use them.

A portable fire extinguisher is a device used to put out fires of limited size. Portable extinguishers are classified by expected application on a specific type of fire (i.e., A, B, C, or D) and the expected area of suppression. The four types of fires are grouped according to the type of material that is burning. Class A fires are those in which ordinary combustibles such as wood, cloth, and paper are burning. Class B fires are those in which flammable liquids, oils, and grease are burning. Class C fires are those involving live electrical equipment. Class D fires involve combustible metals such as magnesium, potassium, and odium.

The numerical rating on the fire extinguisher is a relative rating number. It is assigned by recognized testing laboratories for the amount of average fire area that can be extinguished according to methods established by the National Fire Protection Association (NFPA). The rating does not equate to the amount of square feet that can be expected to be extinguished by an individual using the extinguisher.

The classes of portable fire extinguishers manufactured and used in industry are defined below. Other countries have similar classifications (although these may not be exactly the same).

Extinguishers for Class A Fires

Class A fire extinguishers are usually water based. Water provides a heat-absorbing (cooling) effect on the burning material to extinguish the fire. Pressurized water extinguishers use air under pressure to expel the water which is directed with a short hose.

Extinguishers for Class B Fires

Class B fires are put out by excluding air, by slowing down the release of flammable vapors or by interrupting the chain reaction of the combustion. Three types of extinguishing agents are typically used—carbon dioxide, dry chemical, and foam water for fires involving flammable liquids, greases, and oils. Carbon dioxide is a compressed gas agent that prevents combustion by displacing the oxygen in the air surrounding the fire. The two types of dry chemical extinguishers include one that contains ordinary sodium potassium bicarbonate, urea potassium bicarbonate, and potassium chloride base agents. The second, multipurpose type contains an ammonium phosphate base. The multipurpose extinguisher can be used on Class A, B, and C fires. Most dry chemical extinguishers use stored pressure to discharge the agent, and the fire is extinguished mainly by the interruption of the combustion chain reaction. Foam extinguishers use an aqueous film forming foam (AFFF) agent that expels a layer of foam when it is discharged through a nozzle. It acts as a barrier to exclude oxygen from a fire.

Extinguishers for Class C Fires

The extinguishing agent in a Class C fire extinguisher must be electrically non-conductive. Both carbon dioxide and dry chemicals can be used for electrical fires. An advantage of carbon dioxide is that it leaves no residue after the fire is extinguished. When electrical equipment is not energized, extinguishers for Class A or B fires may be used. Note that since an extinguisher rated solely for a Class C fire is not manufactured, and an ABC or BC rated fire extinguisher will have to be specified for this hazard application.

Extinguishers for Class D Fires

A heat-absorbing extinguishing medium is needed for fires in combustible metals. Also the extinguishing medium must not react with the burning metal. The extinguishing agents, known as dry powders, cover the burning metal and provide a smothering blanket.

The extinguisher label provides operating instructions and identifies the class or classes of the fire on which the extinguisher may be used safely. Approved extinguishers also carry the labels of the laboratories at which they were tested.

Portable fire extinguishers should be positioned in all process facility areas so that the travel distance to any extinguisher is 15 m (50 ft) or less. They are generally sited on the main walkways or exits from an area, near the high hazard itself and near other emergency devices. They are mounted so individuals can easily retrieve them, typically approximately 1 m (2.5 ft) from the walking surface with red highlighting at the mounting location.

19.2. WATER SUPPRESSION SYSTEMS

Water is the most useful and vital fire suppression medium, whether used for fixed systems or manual firefighting efforts for process facilities. It is relatively inexpensive and normally plentiful. It has enormous heat absorption properties. Approximately 3.8 L (1.0 gal) of water absorbs about 1512 k cal (6000 Btu) when vaporized to steam. Steam created by water evaporation expands to about 17,000 times its volume in open atmospheres, thereby limiting combustion processes by displacing oxygen in the area.

When water is combined with other additives, it can control most petroleum fires. A water suppression system consists of a supply source, distribution system, and personnel using equipment such as fixed spray systems, monitors, hose reels, and hydrants. The objective of water suppression systems is to provide exposure cooling, fire control suppression of fire incidents, and assist in the dispersion of combustible or toxic vapors.

When water suppression systems are provided, due concern should be made for the disposal of the released water. Of primary importance is the capability and location of surface drainage systems. Firewater usage usually places greater demands on the facility gravity sewer system than rainfall or incidental process fluid spillages.

19.3. WATER SUPPLIES

Firewater supply sources can be city public water mains, a dedicated storage tank and pumps, or the most convenient, lake, riser, or if an offshore installation, the open sea. Brackish or salt water supplied can be used if suitable corrosion protection measures are applied to the entire firewater system if it is planned to be used for an extended time (i.e., greater than five years). If a short life span is expected, short life span corrosion resistant materials may be used (i.e., carbon steel, galvanized steel, etc.), provided periodic testing indicates their integrity is still adequate and scale and corrosion particles do not affect operational efficiencies.

Most process facility areas and high volume storage areas have been standardized for a minimum supply or availability of 4 h of firewater for the worst case credible event. The performance of a risk analysis may reveal the level of firewater protection needs to be more or less than this requirement. Once a detailed design is completed on the facility or verification of existing water demands is done a tabular calculation for firewater requirements can be made. This table can be used to document spray density requirements, duration levels, code requirements, and other features. Table 19.1 provides an example of ways to document such information (see Table 19.2).

19.4. FIRE PUMPS

Fire protection water pumping systems are almost universally required to be installed according to NFPA 20, Standard for the Installation of Stationary Fire Pumps for Fire Protection, requirements. They are inspected per NFPA 25, Inspection and Testing of Water-Based Fire Protection Systems. Pump sizes depend on the water delivery requirements to suppress the hazard. When fire pumps are designated to provide fixed fire protection water supplies—two sources are required, i.e., a main and a backup source. The preferred driver for fire pumps at most process facilities, when there is a reliable and non-vulnerable power grid available, is by an electric motor that receives energy from two different power sources (i.e., generator stations). Alternatively, at least one electric and one prime mover standby (diesel, natural gas, or steam engine is available) unit should be provided. Where the electrical power grid is unreliable or from a single source, fire pumps that are powered by prime movers should be provided.

Table 19.1 Example of Firewater Demand Calculations

Area/Hazard	Equipment Utilized	Ref.	Design Density & Duration	Firewater (GPM)	Foam Conc. (GAL.)	Water Supply (HOURS)	Comments
FWKO AREA OIL FIRE	(3) 600 gpm monitors (2) 280 gpm hoses	NFPA 15-4.4.3.2	$0.25\ gpm/ft^2$ $0.1\ gpm/ft^2$	1800	1560		Area is too large to extinguish simultaneously. One section should be extinguished and secured before moving to next section.
Exposure Cooling of FWKO & Desalters		NFPA 11-3.1.5	15 min	560	500	6.96	
Extinguish oil fire with foam from hoses				2360	2060		
FWKO AREA GAS FIRE Exposure cooling of FWKO & Desalters	(3) 600 gpm Monitors (1) 300 gpm Hose	IRI 12.2.1.2	$0.35\ gpm/ft^2$ within 50 ft radius	2100	N/A	7.83	Radius of exposure protection determined from largest anticipated gas release and radiation calculations.

HEATER TREATER OIL FIRE	(2) 600 gpm monitors (3) 220 gpm hoses	NFPA 15-4.4.3.2 NFPA 11-3.1.5	0.25 gpm/ft^2 0.1 gpm/ft^2 15 min	1200	1080		Area is too large to extinguish simultaneously. One section should be extinguished and secured before moving to next section.
Exposure cooling of Heater Treater and Heat Exchangers				660	1190	8.83	
Extinguish oil fire with foam from hoses				1860	2270		
HEATER TREATER GAS FIRE Exposure cooling of the Heater Treaters and Heat Exchangers	(3) 600 gpm monitors (2) 150 gpm hoses	IRI 12.2.1.2	0.35 gpm/ft^2 within 50 ft radius	2100	N/A	7.83	Radius of exposure protection determined from largest anticipated gas release and radiation calculations.

(Continued)

Table 19.1 Continued

Area/Hazard	Equipment Utilized	Ref.	Design Density & Duration	Firewater (GPM)	FoamConc. (GAL.)	Water Supply (HOURS)	Comments
SHIPPING TANK FIRE	Foam to tank (3) 300 gpm monitors	NFPA 11-3.2.6.3	0.1 gpm/ft^2, 55 min	640	1050		Dike spill fire protection
Sub-surface foam injection	(2) 250 gpm hoses	IRI 12.2.1.2	3 gpm/ft circumference	900	1490		exceeds NFPA 11-3.2.8.2, 1 hose,
Tank shell exposure cooling		NFPA 11-3.2.8.2	1/6 area, 0.1 g/ft2, 20 min	500	300	8.06	50 gpm, 20 min. duration req.
Dike spill fire extinguishment		IRI 12.2.1.2	Not required, D > 1 Dia	2040	2840		IRI does not require tank shell
Adjacent tank exposure protection							cooling. Tank shell cooling only rec. for tanks >300,000 bbls.
REJECT TANK FIRE	Foam to tank (1) 300 gpm monitor	NFPA 11-3.2.4	0.1 gpm/ft^2, 55 min	200	330		Dike spill fire protection exceeds
Type II surface foam application	(2) 150 gpm hoses (3) 200 gpm hose	IRI 12.2.1.2	0.2 gpm/ft^2, 3 gpm/ft circumference	600	990		NFPA 11-3.2.8.2, 1 hose, 50 gpm, 20 min. duration
Tank shell exposure cooling and adjacent tank exposure protect.		NFPA 11-3.2.8.2 IRI 12.2.1.2	1/6 area, 0.1 g/ft2, 20 min Not required, D > 1 Dia	200	120	16.43	req. IRI does not require tank shell cooling. Tank
Dike spill fire extinguishment				1000	1440		shell cooling only rec. for tanks >300,000 bbls.

Table 19.2 Fire Pump Standards

Standard	Title
API 610	Centrifugal pumps for refinery service
BS 5316	Acceptance tests for centrifugal, mixed flow, and axial pumps
NFPA 20	Standard for the installation of stationary fire pumps for fire protection
UL 448	Standard for safety pumps for fire protection service

Today the power grids of industrial countries and commercially available high horsepower electrical motors are highly reliable, so the need for independent prime movers, as may have been the case several decades ago, is not highly demonstrated. The maintenance, failure points, fuel inventories, instrumentation drift, and controls needed for an internal combustion engine versus an electrical motor all demonstrate it is not as cost effective as compared to an electric motor. Of course, adequate integrity and reliability of electric motor power sources and infrastructure must be assured. Where several fire pumps are necessary, it is still good common sense practice to provide a prime mover source to accompany electric motor drives. Offshore installations are particularly attractive for this option, where a prime mover adjacent to a generator provides power for an electrically submersible pump or hydraulic drive unit fire pump, thereby eliminating the need for long line shaft turbine pumps needing specialized alignments for correct operation. Process facilities in third-world locations are generally dependent on their own power generation, so shelf contained prime mover options for fire pumps are selected to decrease sizing and costs for the production power generation facilities.

To avoid common failure incidents, prime mover and backup fire pumps preferably should not be located immediately next to each other and ideally should be housed at separate locations at the facility. They should feed into the firewater distribution at points that are as remote as practical from each other. In practical applications, except for offshore installations, most small to medium sized facilities contain a single firewater storage tank, requiring the siting of all firewater pumps close to it. Even in these circumstances it may be wise to segregate the main and backup fire pumps from each other with tie-in points to the firewater distribution loops. This mostly depends on the hazard level of the facility and the distance of the firewater pump location from the high risk processes. Firewater pumps should be located as remote from the process as feasible, preferably at a higher elevation in the upwind direction. In a review of one hundred major petroleum industry fires, the failure of the firewater pump was a major contributor to ensuing large-scale destruction of the facility for twelve of the incidents.

The metallurgy selected for construction of a firewater pump is dependent on the properties of the water to be used. For freshwater sources (i.e., public water mains), cast iron has normally been adequate, although bronze internals may be optional. Brackish or seawater utilization will require the use of highly corrosive resistant materials and possibly coatings. Typically specified metals include ally bronze, monel, ni-resistant, or duplex stainless steels sometimes combined with a corrosion resistant paint or specialized coating.

For onshore facilities, water may be supplied from local public water mains, storage tanks, lakes, and rivers. In these cases, a conventional horizontal pump is typically employed. The preferred design for onshore firewater pumps is a horizontal centrifugal type with a relatively flat performance curve (i.e., pressure versus volume). The discharge pressure is determined by the minimum residual pressure required at the most remote location of the facility, flowing its highest practical demand with allowances added for piping friction losses.

Where a significant lift is required, such as at an offshore facility, several options are available such as a shaft driven, hydraulic drive, or electrical submersible pumps. Shaft driven vertical turbine pumps historically have been used extensively offshore. Reliability improvements for electrical submersible pumps with hydraulically driven units have been used more often as they eliminate alignment concerns, topside weight is limited, and in some instances, are less complex than the right angle engine driven vertical line shaft pumps. Hydraulic calculations for offshore pump installations must remember to account for wave and tide fluctuation.

Especially critical in fire pump installations from open bodies of water is the activity of underwater diver operations in close proximity of the underwater fire pump suction bell or opening. Underwater diving operations routinely occur at the structural support (i.e., the jacket) for offshore installations for corrosion monitoring, modifications, inspections, etc. The high water current at the intake to the submerged pump poses a safety hazard to divers as they may be pulled into this intake. During the operation of the ill fated Piper Alpha platform it was common practice to switch the fire pump to manual startup mode (requiring an individual to visit the pump location) to start it up during diving operations. This was the case on the night when the installation was destroyed by fire and gas explosions. A simple solution is to provide a large protective grid at a far enough distance around the pump intake so the water velocities will be limited to below that which would cause concern to divers. The international Association of Underwater Engineering Contractors has issued a notice (AODC 055) describing these requirements.

When more than one pump is installed, they should be coordinated to start in sequence, since immediate startup of all pumps may not be necessary and could cause damage to the system. Depending on the number of pumps available they can be set up on sequentially decreasing fire main pressure set points. All firewater pumps should be able to be started from remote activation switches located in manned control rooms, but shutdown should only be accomplished at the pump itself.

Small capacity pumps, commonly referred to as "jockey" pumps, are provided on a firewater system to compensate for small leakages and incidental usage without the main pump(s) startup. They are set to start at 0.70–1.05 kg/sq.cm. (10–15 psi) above the startup pressure of main firewater pumps. In some cases, a cross-over from the utility water system can be used in place of a jockey pump, but a check valve is installed to prevent drain down of the firewater system by the utility water system. Jockey pumps do not require the same reliability of firewater pumps and should not be credited for firewater supply when calculating firewater supplies available.

Firewater pumps should be solely dedicated to fire protection. They may be used to feed into a backup system for emergency process cooling but not as the primary supply. If such backup is allowed, it should be tightly controlled and easily accessible for prompt shutdown in case of a real emergency.

A method of testing firewater pumps should be provided to verify adequate performance. Additionally, most fire protection audits, insurance surveys, and local maintenance requirements require firewater pumps to be routinely tested for performance verification. In fact, predictive maintenance can be performed before the firewater pumps reach reduced flow or pressure performance levels requiring removal. Pressure gauges on the suction and discharge should be provided and methods to verify the flowing water quantity at each test point. The sizing of the flow in test piping should account for the maximum flowrate of the unit, not just its rated capacity.

The latest trend is to install a solid-state electromagnet flowmeter with precise digital readout; however, orifice plat flowmeters are still commonly employed. Alternatively, a test header with 63.5 (2.5 in.) outlets for pitot flow measuring can be used with reference to hydraulic tables. In dire circumstances, where flow measuring devices are not directly available at the firewater pump, plant hydrants or hose reel outlets may be used (refer to Appendix A), or even portable clamp-on electromagnetic and ultrasonic flowmeters. The ideal situation is to design the system so flow test water is re-circulated back into the storage reservoir from which it has be withdrawn, thus avoiding extensive setup requirements and unnecessary water spillage. Offshore, a drainage test line is routed back to the sea surface, since disposal directly underneath the structure may affect personnel who periodically work at lower locations or sea levels.

19.4.1 Fire Pump Standards and Tests

The purchase or specification of a firewater pump to support process facility operations should be in compliance with recognized international standards for such equipment. The most commonly referred to standards are listed below. All of these standards require a factory acceptance test of the unit.

19.5. FIREWATER DISTRIBUTION SYSTEMS

The distribution system is an arrangement of piping configured to ensure delivery of water to the desired area, even if a portion of the system is isolated for repairs. This is accomplished by a looped network of pipes and isolation valves at strategic locations. A loop network should be provided around each process area. For onshore facilities, firewater piping is normally buried for protection purposes. Offshore it should be routed against and behind structural members for protection against damage from fires and particular explosions. If the piping needs to be exposed, it should be secured in both horizontal and vertical directions against potential blast overpressure loads. Flanged connections should be avoided since they may prove to be the weakest point of leakage, but they are much favored for offshore construction purposes as they eliminate specialized welder costs during installation and repairs.

The sizing of piping is based on a hydraulic analysis for the water distribution network for the worst case credible event (WCCE). The main delivery pipe should be sized to provide 150% of the design flow rate.

The residual pressure flow requirement at the most remote process area or storage location from the supply location dictates the sizing of the remaining system. Normal reliability requirements usually suggest that a minimum of two sources of supply be available that are in themselves remote from each other. Therefore two remote flow calculations must be performed to determine the minimum pipe distribution size. NFPA 24, Installation of Private Fire Service Mains and Their Appurtenances, requires that the minimum residual pressure available in a fire main not be less than 6.9 bars (100 psi). Velocity calculations should be performed that verify flows are not more than the limits of the material that is employed.

Normally firewater mains are of metal (e.g., carbon steel, kunifer, etc.) construction. The latest installations are increasingly using reinforced plastic piping for underground portions of the distribution network. This is acceptable provided the firewater system is maintained pressurized. If the pressure is removed, the weight of the earth covering the pipe will deform it into an oval shape. Eventually leaks will develop at fitting connections, which are usually at a higher pressure rating than the piping and can withstand the weight of the overburden. Additionally, special care and inspection should be made during the placement of plastic pipes in fittings. It is usually difficult to determine if the pipe has been fully fitting into a fitting and if a correct connection has not been accomplished this will be a failure point early in the life of the system as the connection will eventually pull apart. Distribution piping should not be routed under monolithic foundations, buildings, tanks, equipment structural foundations, etc. Both for needs of future accessibility and due to the additional loads the foundations may impose. Some applications of plastic piping for aboveground have been undertaken for economic and weight considerations (for offshore), but where they have the potential for fire exposures, fireproofing has been applied to provide protection for a minimum of 2 h of hydrocarbon fire exposure (i.e., UL 1709 fire exposure rating). There is also an additional concern of UV sunlight deterioration to the plastic over time.

The firewater system should be dedicated for firewater usage. Utilization for process or domestic services erodes the function and capability of the firewater system, particularly its pressure, possibly during an emergency.

A hydraulically designed system is preferred over a standardized approach for optimization of the firewater flows, water storage requirements, and piping materials. In any case, the main header should not be less than 203 mm (8 in.) in diameter. Piping routed to hydrants, monitors, hose reels, and other protective systems should be not less than 152 mm (6 in.) in diameter.

Table 19.3 UL Test Standards for Fire Protection Valves

Valve Type	Test Standard
Gate valve	UL 262
Check valve	UL 312
Sprinkler valve	UL 193
Deluge valve	UL 260
Foam water valve	UL 260
Pre-action valve	UL 260
Butterfly valve	UL 1091

19.6. FIREWATER CONTROL AND ISOLATION VALVES

Firewater control valves are usually required to be tested to a recognized standard. The most common listing is by Underwriters' Laboratories (see Table 19.3).

All fixed fire suppression system control valves should be located out of the fire hazard area but still within reach of manual activation. For high hazard areas (such as offshore facilities), dual feeds to fire suppression systems should be considered from opposite areas. For onshore facilities, firewater isolation valve handles should not be contained within a valve pit or a below grade enclosure within the vicinity of process facilities that may release materials that would allow heavy vapors to settle in low areas.

If a firewater line needs to be temporarily isolated and an isolation means is not available on the immediate portion of the system needing work, a unique solution is to use a liquid nitrogen low temperature coil line freezing apparatus. This mechanism causes an ice plug to form in the line, effectively sealing the line from leakage, during the period the temporary isolation is needed.

19.7. SPRINKLER SYSTEMS

Wet and dry pipe sprinkler systems are commonly provided to indoor occupancies, such as warehouses, offices, repair shops, inspection shops, etc. They are considered essentially 100% effective for fire suppression if properly maintained and the hazard has not changed since the original design and installation. Sprinkler systems are normally activated by the heat of the fire melting a tension loaded cap at the sprinkler head. The cap melts or falls away releasing water from the pipe distribution network. Thus they do not activate until a fire condition is absolutely real. Fire protection sprinkler systems are required to be designed and installed per specific requirements and normally NFPA 13, Standard for the Installation of Sprinkler Systems, is mandated.

19.8. WATER DELUGE SYSTEMS

Deluge systems are provided where immediate water spray coverages are needed for a large surface area, especially for cooling purposes such as for vessels and tanks. They are typically activated by automatic means. Activation by manual means defeats the objective of installing a deluge system, and firewater monitors should be provided instead as they are more effective where manual means are relied upon (unless accessibility is an issue) and are also more cost effective. Most deluge systems provided at process facilities are activated by a heat detection system. Usually a fusible plug pneumatic loop detection system or UV/IR detectors are placed around the equipment. This insures activation when operators are not present and only when a real fire situation is present.

For vessels protected by deluge systems, the most important points are the vessel ends, the portion of the vessel that contains a vapor space (i.e., the internal unwetted portion), flange connections that can leak, and if the vessel is located close to the ground without good surface drainage, the immediate underneath surface of the vessel that would be exposed to flames from a liquid spill.

19.9. WATER SPRAY SYSTEMS

Water spray systems for process facilities are routinely specified because of the rapid application means the systems can provide and the excellent heat absorption a water-based system represents. Water sprays are also used when passive fire protection measures (i.e., fireproofing, spacing, etc.) cannot be practically utilized. The key to providing an effective system is to ensure the surfaces to be protected receive adequate water densities and the arrangement to activate the systems are equally fact acting. By far the highest application is the utilization of cooling vessels. The important surfaces for process vessels to be protected are the vapor spaces and hemispherical ends. Electrical transformers containing combustible fluids are provided with water sprays where their value or criticality is considered high.

19.10. WATER FLOODING

Water flooding is done by injecting water into the interior of a storage tank or vessel for the purposes of preventing combustible liquids from being released from a leakage point or to extinguish a fire. The principle involves filling a tank or vessel with water so that the lighter density hydrocarbon fluids will float on the water and only water will be released from the container. In practice, the logistics of performing such an operation while also conducting prevention or firefighting efforts for the immediate hydrocarbon spillage make this method of fire protection generally unviable for the large volumes of major tanks or vessels to make it useful. Additionally, for products stored under pressure and possibly with low temperatures (e.g., NGLs), additional precautions must be arranged for in advance.

19.11. STEAM SMOTHERING

The use of steam smothering in the process industries is typically limited to fires that might occur as a result of a tube leak in a furnace or a heater box. The steam is most effective in smothering fires when they are located in relatively small confined areas. Steam extinguishes the fire by the exclusion of free air and the reduction of available oxygen content to the immediate area, similar to other gaseous suppression agents. Use of snuffing steam requires some knowledge of the principle of fire smothering and readily available supplies of steam generation. Snuffing steam also presents a personal burn hazard from superheated water vapor exposure if directed onto or near unprotected skin. Use of other fire extinguishing agents is generally preferred over the use of snuffing steam. A standard on the use of snuffing steam has never been published; however, Annex F of NFPA 86, Standard for Ovens and Furnaces, provides some limited information on the general requirements in designing and limitations of such a system.

19.12. WATER CURTAINS

Firewater sprays are sometimes employed as an aid to vapor dispersion and can also mitigate available ignition sources. Literature on the subject suggests two mechanisms are involved that enhance protection when using water sprays for vapor dispersion. First, a water spray arrangement will start a current of air in the direction of the water spray. The force of the water spray engulfs the air and disperses it further from its normal circulating pattern. In this fashion, released gases will also be engulfed and directed in the direction of the nozzles. Normal arrangement is to point the water spray upward to direct ground and neutral buoyancy vapors upwards for enhanced dispersion by natural means at higher levels. Second, a water spray will warm a vapor to neutral or higher buoyancy to aid its natural atmospheric dispersion characteristics. One spray head operating at 276 kPa (40 psi) will move 7835 L/s (16,000 cfm) of air at a 3 m (10 ft.) elevation. This air movement can reduce flammable vapor concentrations within a relatively short period.

Water curtains can also cool or eliminate an available ignition source to a released vapor cloud. In this fashion, they can also be a mitigating feature to prevent vapor cloud explosions. Hot surfaces, sparking devices, and open flames in the immediate area of a vapor release can all be eliminated as a result of a directed water curtain where these sources exist.

For water curtains to be highly effective they should be automatically activated upon confirmed gas detection for the area of concern.

19.13. BLOW-OUT WATER INJECTION SYSTEMS

A patented water injection system is available for extinguishing oil and gas well fires in case of a blow-out. The "Blow-out Suppression System" (BOSS) consists of finely atomized water injected into the fluid stream of a gas and oil mixture before it exits a release point. The added water lowers the flame temperature and flame velocities thereby reducing the flame stability. In the case where the flame cannot be completely dissipated, the fire intensity is noticeably decreased, persevering structural integrity and allowing manual intervention activities. A precaution in the use of such a device is that, if a gas release fire is suppressed but the flow is not immediately isolated, a gas cloud may develop and explode, which would be more destructive than the pre-existing fire condition.

19.14. MONITORS, HYDRANTS, AND HOSE REELS

Monitors are considered the primary manual firewater delivery device for process facilities, while hydrants and hose reels are considered secondary. Monitors are initial manual fire suppression devices that can be activated by operations with limited firefighting training or experience. Use of hydrants and hoses usually require additional manpower and previous training. However, the use of a fire hose provides more flexibility in the application of water sprays and where it may be needed when it is impractical

to install a monitor. Monitors are usually placed at the process areas, while hydrants are placed at the perimeter roads, accessible to mobile fire apparatus. Most monitor pipe connections may also be fitted with fire hose connections.

Hydrants should be considered as a backup water supply source to monitors and fixed fire suppression systems. Hydrants should be located on the ring main at intervals to suitably direct water to the fire hazard with a fire hose. Hydrant monitors and hose reels should be placed a minimum of 15 m (50 ft) from the hazard they protect for onshore facilities. Hydrants in process areas should be located so that any portion of the process unit can be reached from at least two opposite directions with the use of 76 m (250 ft) hose lines if the approach is made from the upwind side of the fire. Offshore hydrants are located at the main access ways at the edges of the platform for each module. Normal access into a location should not be impeded by the placement of monitors or hydrants. This is especially important for heavy crane access during maintenance and turnaround activities.

For offshore installations, the placement of fire protection devices is more rigidly regulated. Monitors are normally required by regulations for the heli-deck and on open decks, such as drilling or pipe deck where the reach and area of coverage can be effective without blockages that would be encountered in an enclosed module. They can be effectively used in an open deck when positioned at the edge of the deck. Heli-deck monitors should be arranged so they are normally below the heli-deck level and should be provided with radiation heat protection screens due to their close proximity to aircraft hazards. The heli-deck monitors are normally at the highest point in the system, requiring the highest pressure to the firewater pumps and the source where trapped air will accumulate. NFPA and other international regulatory bodies provide guidance on the placement of heli-deck firewater provisions.

Monitors should be provided at all rotating equipment handling combustible materials and large liquid holdup vessels. They should also be located to provide cooling water spray to the process equipment, preferably from an upwind location. A minimum of two remotely located firewater

monitors provided at sources of potential large combustible material release is usually standard, i.e., rotating equipment such as pumps, compressors, storage vessels, and tanks. These monitors are typically placed to provide a water spray in-between the selected equipment besides providing general area protection, i.e., a water spray between two pumps to protect one pump from a seal leak from another. Where additional monitor coverage is desired, but placement is unavailable, such as at ship loading docks, monitors can be elevated on towers to improve the area of coverage. Where monitors need to be sited in close proximity to a hazard, such as offshore heli-decks, a heat shield is provided for the operator.

Before final placement is made on a monitor location during design preparation, based solely on the distance a water stream can reach, verification should be made than an obstruction does not exist that can block the stream (e.g., pipes and cables trays). Typical practice is to draw "coverage circles" from the monitor on a plot plan. Where these circles intersect pipe racks, large vessels, or process columns the water coverage will be blocked and the coverage circle should be modified accordingly. Generally, where extreme congestion exists, such as in offshore facilities, monitor coverage would be ineffective due to major obstructions and congestion. Exposure to personnel activating the device due to its proximity to the hazard would also be detrimental. Similar coverage for fire hydrants may also be drawn for straight-length distances of hose segments. These may not have to accommodate most obstructions such as pipe racks as the hose can be easily routed through or under the pipe rack. Monitors, hydrants, and hose reels should not be located in areas that are designated spill collection areas (i.e., tank dikes, spill curbing, drainage swales, etc.).

Monitors can be set and locked in place, while the operator evacuates or attends to other emergency duties. A residual pressure of 690 kPa (100 psi) is required for most monitors to effectively provide suppression and cooling water (NFPA 14) and should be verified when several are flowing simultaneously in a high risk area.

Oncoming or cross-wind effects may reduce the performance of water monitors. When winds of 8 km/h (5 mph) are present they may reduce the range of water sprays by as much as 50%. Consideration should be given to the placement of monitors when the normal wind speed is such to cause performance effects.

Hard rubber hose is preferred to collapsible fabric hose for process area hose reel and for preference of immediate availability. The tuber hose should not be allowed to be stored or exposed to direct sunlight for any considerable period of time as it will cause deterioration of the material.

The surface slope at the placement of all hydrants, monitors, and hose reels should be slightly away from the device itself so water will drain away and prevent corrosion effects. Where automotive traffic may be prevalent, protective posts or railings may be provided around the devices to prevent impacts. The protective barriers should not affect the hose connection, use of hoses, or obscure the spray from monitors. The post should be provided with highly visible markings or reflective paint.

19.14.1 Nozzles

There are a variety of nozzles that can be provided for hoses and monitor appliances. They are capable of projecting a solid, spray, or fog stream of water depending on the requirements and at varying flow rates.

Straight stream nozzles have greater reach and penetration, while fog and water sprays absorb more heat because the water droplets contain a greater surface area for heat absorption than straight water streams. Fog and water spray nozzles are also sometimes used to assist in the dispersion of vapor or gas releases.

A 32 L/s (500 gpm) nozzle with an adjustable combination straight stream and fog tip is normally provided for fixed installation hoses. Nozzles up to 63 l/s (1000 gpm) may be used at high hazard locations. Higher capacity nozzles are retrofitted to existing systems, and both the firewater capacity and the drainage system capacity should be reviewed for adequacy. Where foam agents are available, the nozzles should have the capability to aspirate the foam solution if desired.

19.15. FOAM SUPPRESSION SYSTEMS

Foam systems are provided wherever there are large quantities of liquid hydrocarbons that pose a high fire risk. Foam is an aggregate of water, chemical compounds, and air-filled bubbles that float on the surface of combustible liquids to prevent vapor formation. They are used primarily to provide a cohesive floating blanket on the liquid surface of the liquid material it is protecting. It extinguishes a fire by smothering and cooling the fuel, i.e., covering the liquid surface, and prevents re-ignition by preventing the formation of combustible mixtures of vapor and air over the liquid surface. Foam will also cool the fuel and surrounding equipment involved in the fire. Foams are supplied in concentrates that are appropriately proportioned into water supply systems. They are then aspirated with air to produce the foam bubbles.

19.15.1 Types

Foam is a homogenous blanket of a mixture of liquid chemical and air or a non-flammable gas. Foam fire suppression systems are classified as high or low expansion. High expansion foam is an aggregate of bubbles resulting from the mechanical expansion of foam solution by air or other non-flammable gas. Expansion ratios range from 100–1 to 1000–1. Foam with an expansion ratio less than 100–1 is produced from air foam, protein foam, fluoro-protein foam, or synthetic foam concentrates. It is inserted at a definite portion in a liquid stream that is later aspirated just before or at a distribution nozzle. High expansion type foams are produced in a high expansion generator by blowing air through a wet screen with a continuous spray of water producing additive. High expansion foam is very light.

It can be applied to completely and quickly fill an enclosure or room. The various types of foam provide similar protection. They are principally selected on the basis of compatibility of foam equipment provided, materials involved, and use with other agents. All foams are electrically conductive and should not be used on fires involving electrical equipment.

Low expansion foams are typically applied to the surface of exposed flammable liquids, especially in outdoor areas. High expansion foams are commonly applied to large enclosed areas where high winds would not affect the foam usefulness and where interior locations are hard to reach.

Special alcohol resistant (or compatible) type foam is needed for application to alcohols, esters, or ketone type liquids and organic solvents, all of which seriously break down the commonly used foams. Commercially available foam products are now available that can be used on both alcohols and hydrocarbons, only alcohols, or only hydrocarbons. It is therefore imperative to design foam systems in a cost-effective fashion if several products are in use that may require special foam application requirements.

Chemical foams were widely used in the industry before the availability of liquid concentrates and are now considered to be obsolete.

19.15.2 Concentrations

Foam concentrations currently on the market range from 1 to 6 mixing or proportioning percent with water. The advantage of lower percentage mixing means less foam concentrate is needed for a particular hazard. This is economical in both amount of agent needed and in storage facilities necessary and is particularly useful for offshore facilities where a weight savings can also be realized. Foam systems of very low percentages require a "cleaner" system to perform adequately.

19.15.3 Systems

In the petroleum and process industries there is generally five foam fire protection systems commonly encountered:

1. General area coverage with foam water monitors, hoses, or portable towers
2. Fixed foam water deluge spray systems for general areas or specific equipment
3. Atmospheric or low pressure storage tank protection by overhead foam chambers
4. Atmospheric or low pressure storage tank protection by subsurface injection
5. High expansion foam applied to special hazards such as warehouses or confined spaces

19.15.4 General Area Coverage

General area coverage is usually provided where there is fully or partially enclosed areas, e.g., offshore modules, truck loading racks, liquid storage warehouses, etc., where liquid spills can easily spray, spread, or drain over a large area. Where the protected areas are critical or high value, immediate detection and release mechanisms are chosen (i.e., deluge systems). Aspirating or non-aspirating nozzles may be used. Aspirating nozzles generally produce foams with a longer life span after discharge. Aspirating nozzles also produce foam with a higher expansion ration than non-aspirating nozzles.

19.15.5 Foam Water Deluge Systems

Deluge systems are generally used in areas requiring an immediate application of foam over a large area, such as a process area, truck loading racks, etc. The system employs nozzles connected to a pipe distribution network that are in turn connected to an automatic control valve referred to as a deluge valve. Automatic detection in the hazard area or manual activation opens the deluge valve. Guidance on the design of foam water deluge system for process facilities is provided in NFPA 16, Installation of Foam-Water Sprinkler and Foam-Water Spray Systems.

19.15.6 Overhead Foam Injection

Overhead foam injection systems are provided for the protection of atmospheric or low pressure storage tanks. They consist of one or more foam chambers installed on the shell of a tank just below the roof joint. A foam solution pipe is extended from the proportioning source, which is located in a safe location, to a foam aspirating mechanism just upstream of the foam chamber or pourer. A deflector is usually positioned on the inside tank wall at the foam chamber. It is used to deflect the foam against the tank wall and onto the surface of the tank or the tank and the shell seal area.

Two types of designs are commonly applied. For cone top tanks or internal floating roof tanks with other than pontoon decks, multiple foam makers are mounted on the upper edge of the tank shell. These systems are designed to deliver and protect the entire surface area of the liquid of the tank. For open and covered floating roof tanks with pontoon decks, the foam system is designed to protect the seal area. Foam makers are mounted on the outside of the tank shell near the rim and foam is run down inside to the seal area that is provided with vertical barrier adjacent to the seal area i.e., a "foam dam" to hold the foam in the seal area. This method tends to cause the movement of cooler product to the surface to aid in extinguishment of the fire and the amount of water delivered to the hat layer in heaver products can be controlled to prevent excessive frothing and slop-over.

19.15.7 Subsurface Foam Injection

Subsurface foam injection another method to protect atmospheric or low pressure storage tanks. This method produces foam through a "high back pressure foam maker" and forces it into the bottom of the storage tank. The injection line may be an existing product line or a dedicated permanent subsurface foam injection line. Due to its buoyancy and entrainment of air, the foam travels up though the tank contents to form a vapor tight blanket on the surface of the liquid. It can be applied to any of the various types of atmospheric pressure storage tanks but is generally not recommended for application to storage tanks with a floating roof since distribution of the foam to the seal area from the internal dispersion is difficult to obtain.

19.15.8 Deck Integrated Fire Fighting System (DIFFS)

A Deck Integrated Fire Fighting System (DIFFS) is a specialized fire protection system for utilization on the deck of a heli-pad or in a concrete floor for aircraft hangar applications that integrates the fire fighting system with structural construction of the deck surface to make a more integrated and less obstructive fire fighting system (see Figure 19.1). DIFFS consist of foam mixing skids and pop-up nozzles. These are permanently installed

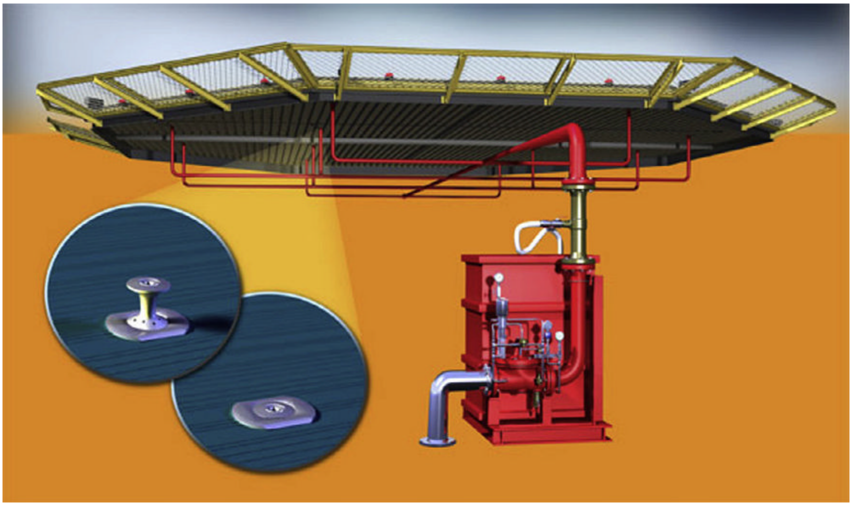

Figure 19.1 Deck integrated fire fighting system (DIFFS).

high capacity deluge or flexi nozzles and pop-up nozzles for heli-decks or larger areas such as hangars. DIFFS can be automatically activated by a detection system or manually by release panels (push buttons). Rescue personnel can safely perform rescue operations on the heli-deck even when the system is fully activated.

An activated DIFFS will extinguish a major spill fire on the heli-deck within 15 seconds, although tests have shown that such fires in most cases are extinguished in less than 10 seconds.

19.15.9 High Expansion Foam

High expansion foam is generally applied to ordinary combustibles, i.e., Class A material, fires that occur in relatively confined areas that would be inaccessible or hazardous for fire fighting personnel to enter. The system controls fires by cooling, smothering, and reducing oxygen content by steam dilution. The system uses high forced air aspirating devices, typically large fans, to produce foams with an expansion ratio of 100 to 1000 to 1. Proportioning of 1½% is normally used, providing large quantities of foam from relatively small amounts of concentrates. Use in the petroleum industry is normally reserved for manual fire fighting efforts.

19.16. MANUAL FIRE FIGHTING UTILIZATION

In some cases, the proximity of a local fire station or provision of a dedicated fire station within a large industrial complex can be relied upon to provide backup firewater pumping capability to the fire protection system. In fact, historical evidence indicates that when the fixed firewater pumps have been impacted by a major fire or explosion incident, mobile fire apparatus has to be heavily relied upon as a backup mechanism. Previous coordination with the fire station as to their capabilities, mobile apparatus accessibility, connection points, drafting sites, emergency admittance, and manpower should be evaluated and incorporated into emergency pre-fire plans for the facility.

19.17. GASEOUS SYSTEMS

19.17.1 Carbon Dioxide Systems

Carbon dioxide (CO_2) is a non-combustible gas that can penetrate and spread to all parts of a fire, diluting the available oxygen to a concentration that will not support combustion. Carbon dioxide systems will extinguish fires in practically all combustibles except those which have their own oxygen supply and certain metals that cause decomposition of the carbon dioxide. CO_2 does not conduct electricity and can be used on energized electrical equipment. It will not freeze or deteriorate with age. Carbon dioxide is a dangerous gas to human life since it displaces oxygen. Concentrations above 9% are considered hazardous, while 30% or more are needed for fire extinguishing systems. Carbon dioxide systems are generally ineffective in outdoor applications, since wind effects will dissipate the gas rapidly. It has a vapor density of 1.529 and therefore will settle in the low points of an enclosure.

For fire extinguishing and inerting purposes CO_2 is stored in liquid form that provides for its own pressurized discharge.

19.17.1.1 Applications

Carbon dioxide may be applied for fire extinguishment through three different mechanisms:

1. Hand hoses from portable storage cylinders
2. Total flooding fixed systems
3. Local application fixed systems

Carbon dioxide is an effective extinguishing agent for fires of ordinary combustibles, flammable liquids, and electrical fires. It is a clean agent in that it will not damage equipment or leave a residue. Some cooling is realized upon agent discharge, but a thermal shock to equipment should not occur if the system is properly designed and installed.

Fixed systems are classified in the manner they are stored. Low pressure 2068 kPa (300 psi) or high pressure 5860 kPa (850 psi) systems can be specified. Low pressure systems are normally provided when the quantity of agent required exceeds 907 kgs (2000 lbs). Protection of electronic or electrical hazards generally requires a design concentration of 50% by volume. NFPA 12 provides a table specifying the exact concentration requirements for specific hazards. As a guide, 0.45 kgs (1 lb.) of CO_2 liquid may be considered to produce 0.23 m^3 (8 cu.ft.) of free gas at atmospheric pressure.

Fixed carbon dioxide systems are almost used exclusively for protecting highly valuable or critical equipment where an electrically non-conductive, non-residue forming agent is desired and where the location is unmanned.

In the process industries, CO_2 systems are usually provided to protect unmanned critical areas or equipment such as electrical or electronic switchgear rooms, cable tunnels or vaults, turbine or compressor enclosures, etc. Where rotating equipment is involved, both primary and supplemental discharge occurs to account for leakages during the rotating equipment "run-downs." Concentrations are to be achieved in 1 min and normally maintained for 20 min.

19.17.1.2 Safety Precautions

Carbon dioxide is a non-flammable gas and therefore it does not present a fire or explosion hazard. The gas is generally considered toxic, and it will displace oxygen in the air, since it is 1.5 times heavier than air and will settle. Air supplies will be pushed out of the area where a CO_2 discharge has occurred. The CO_2 gas is considered an asphyxiation hazard to personnel for this reason. Since the gas is odorless and colorless, it cannot be easily detected by human observation in normal environments. Fire protection carbon dioxide gas is normally stored under high pressure as a liquid and expands 350 times its liquid volume upon release.

The normal concentration of oxygen in air is from 21% to 17%. When the concentration of oxygen in air is below 18%, personnel should vacate the location and not enter it due the asphyxiation hazard. Alternatively they can be provided with protective self-contained breathing apparatus to work in low oxygen environments.

There are two factors from a CO_2 release:

1. When increasing amounts of CO_2 are introduced into an environment, the rate and depth of an individual's breathing increases. For example, at 2% CO_2 concentration, breathing increases 50% and at 10% concentration an individual will gradually experience dizziness, fainting, etc.
2. When atmosphere oxygen content is lowered below 17% an individual's motor coordination will be impaired, and below 10%, they will become unconscious.

Adequate warning signs, alarms, and possibly interlocks should be provided at any location where CO_2 systems are provided to alert personnel of the life safety concerns with the discharge of a CO_2 system.

19.17.1.3 System Discharges

Where fixed automatic CO_2 systems are installed, a time delay of 30 seconds (to allow personnel evacuation), warning signs, and alarms (audio and visual) are provided to warn occupants of the impending discharge and hazard to individuals. An "abort" switch is also usually provided to prevent the activation if it has been readily found to have been inadvertently activated.

19.17.1.4 System Leakages

Leakages from carbon dioxide systems are considered extremely rare. With adequate inspection and maintenance procedures a leak on the system should generally not be expected to occur. If pressure gauges are installed on the CO_2 cylinders they should be frequently checked against initial pressure readings, otherwise the cylinders can be weighed to determine if there has been agent loss. If a difference is noted immediate action should be taken to investigate the source of the leakage for correction.

In small rooms, where high pressure CO_2 storage bottles are kept, it is apparent that with a 350 expansion ratio, the room could easily be a hazard to personnel from system leakages. A calculation could be preformed that would identify the amount of potential CO_2 buildup (i.e., percent of CO_2 concentration) from the immediate to the complete (i.e., leak) from a single storage container (based on liquid capacity of the container storage, room size, ventilation rates, etc.). Where CO_2 fire protection storage cylinders are contained in enclosed areas they should be well labeled for the possibility of an oxygen deficient atmosphere. The room should normally be a controlled location (i.e., doors locked) and all personnel entering the enclosure must be equipped with a portable oxygen monitoring device (unless a fixed oxygen monitoring system is installed) as dictated by the organization's safety procedures for entry into an area where there is the possibility of an oxygen deficient atmosphere. A log should be maintained of all entries and exits from the location.

Should a leak occur in the protected area, a portable exhaust fan can be positioned to evacuate any accumulated CO_2 gases to allow for safe entry. The provision of a permanent exhaust fan for these areas would not necessarily guarantee that when a minor CO_2 leakage occurs it would be adequately ventilated from the area, thereby precluding the need for oxygen monitoring and a controlled location. Since CO_2 gases are heavier than air, they will normally seek the lower portions of an enclosure. The subject gases may not reach the exhaust fan, especially if the exhaust is not positioned to collect vapors from a remote location in the room. Depending on the size of the leak, gases may propagate from the leaking storage container for a considerable amount of time. Even when an exhaust fan is installed to dissipate gases, it cannot guarantee that the gases will be entirely removed when an individual enters the room.

In rooms that are provided with air conditioning, an exhaust fan would always be evacuating the cooled air. This would defeat the purpose of the air conditioner (the exhaust fan would have to be continuously operated since a lead cannot be accurately predicted unless sensing instruments are provided). So an exhaust fan as a preventive safety device would then be considered somewhat irrelevant.

In instances where CO_2 storage cylinders are installed in an enclosed space, an exhaust fan is provided to evacuate dispensed gases after system discharge and the incident is declared over. It is used as an operational device rather than as a preventive feature.

Supplemental measures that may be considered for carbon dioxide systems are fixed oxygen monitoring systems, low pressure storage alarms, and odorization of the stored CO_2 gas.

19.17.1.5 Disadvantages

Carbon dioxide systems have the following disadvantages:

1. The expelled CO_2 gas presents a suffocation hazard to humans in the exposed areas. All such areas require strict access control and additional safety alert systems.
2. CO_2 gas is considered a "greenhouse" gas and may in the future be considered an environmental concern restricting its use.
3. Deep-seated fires may not be fully extinguished by a gaseous fire suppression agent (see Figure 19.2).
4. Fixed CO_2 systems require a large storage area and have considerable width which limits their benefits offshore.

19.17.1.6 Halons

Halons are considered an agent that will cause damage to the ozone layer and therefore for environmental protection aspects are no longer recommended for fire protection purposes. They are considered obsolete. Existing systems are to be removed under the Montreal Protocol.

19.18. CLEAN AGENT SYSTEMS

Clean agent systems refer to fire protection systems that use an electrically non-conducting, volatile, or gaseous fire extinguishant that does not leave a residue upon evaporation. They typically have been specified in place of halon fire protection systems for the protection of critical electronic facilities as they are considered environmentally friendly. They are to meet the requirements of NFPA 2001, Standard on Clean Agent Fire Extinguishing Systems, for design and installation requirements. These systems may be considered a hazard to personnel when they discharge and therefore

suitable alarms, warnings, and signs are required for their utilization. NFPA recommends that exposure to personnel from agent discharged be limited to a maximum of 5 min. Table 19.4 provides a list of acceptable clean agent systems available at this time.

19.18.1 Oxygen Deficient Gas Inerting Systems

To reduce the risk of explosion and fires from enclosed spaces of volatile hydrocarbon storage

Table 19.4 Clean Agent Types

Trade Name	Description	Formula
FK-5-1-12	Dodecafluoro-2-methylpentan-3-one	$CF_2CF_2C(O)CF(CF_3)_2$
HCFC Blend A	Dichlorotrifluoroethane HCFC-123 (4.75%)	$CHCl_3CF_3$
	Chlorodifluoromethane HCFC-22 (82%)	$CHCIF_2$
	Chlorotetrafluoroethane HFCF-124 (9.5%)	$CHCIFCF_3$
	Isopropenyl-l-methylcyclohexene (3.75%)	
HCFC-124	Chlorotetrafluoroethane	$CHCIFCF_3$
HFC-125	Pentafluoroethane	CHF_2CF_3
HFC-227ea	Heptafluoropropane	CF_3CHFCF_3
HFC-23	Trifluoromethane	CHF_3
HFC-236fa	Hexafluoropropane	$CF_3CH_2CF_3$
FIC-1311	Trifluoroiodine	CF_3I
IG-01	Argon	Ar
IG-100	Nitrogen	N_2
IG-541	Nitrogen (52%)	N_2
	Argon (40%)	Ar
	Carbon dioxide (8%)	CO_2
IG-55	Nitrogen (50%)	N_2
	Argon (50%)	Ar
HFC Blend B	Tetrafluoroethane (86%)	$CH_2FCF_3CHF_2$
	Pentafluoroethane (9%)	CF_3
	Carbon dioxide (5%)	CO_2

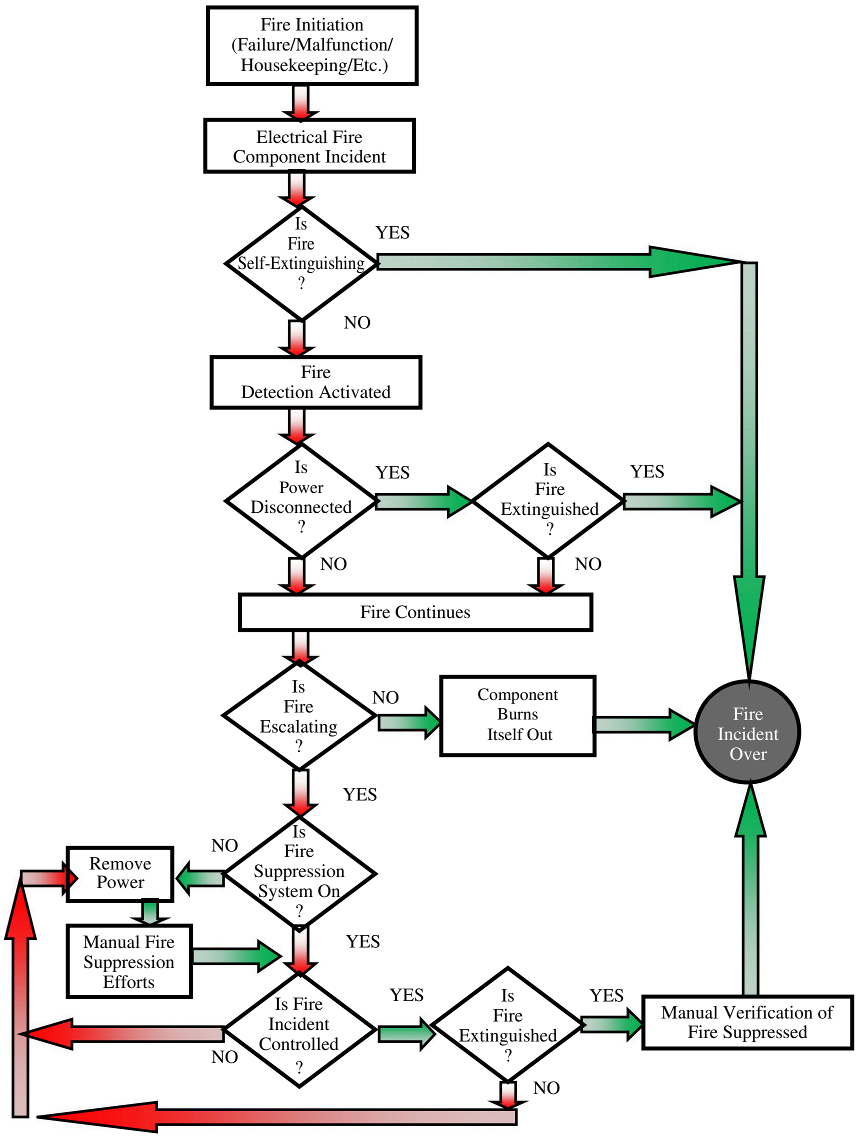

Figure 19.2 Electrical fire incident control.

tanks, a gas that would be considered deficient in oxygen is provided to exclude oxygen from entering these enclosures. Large ocean going tanker vessels are typically equipped with a continuous inert gas system that blankets storage tank holds or tanks with an oxygen deficient gas, typically the exhaust gases from prime movers. Similarly some crude oil storage tanks for process facilities are provided with a process gas as a method of excluding oxygen from entering the vapor space of cone roof storage tanks (see Figure 19.2).

19.19. CHEMICAL SYSTEMS

19.19.1 Wet Chemical

Wet chemical systems have a slight advantage over dry chemical systems in that they can coat the liquid surface of the fire and can absorb the heat, thereby preventing re-ignition. Wet chemical systems are primarily provided for kitchen cooking appliances—grills, fryers, etc. They provide a fixed fire suppression application of liquid fire suppressant through fixed nozzles. The typical application for process facilities is in the kitchens of onsite cafeterias. Spray coverage is provided to exhaust plenums and cooking surfaces activated by fusible links or manual activation points. The fusible links should be rated for the maximum normal temperature expected in the exhaust fumes, usually 232°C (450°F). Common practice is to conduct a one time agent discharge and operational test during the initial installation acceptance, together with a hydrostatic test of the system piping.

19.19.2 Dry Chemical

Dry chemical agents currently used are a mixture of powders, primarily sodium bicarbonate (ordinary), potassium bicarbonate ("Purple K"), and mono-ammonium phosphate (multi-purpose). When applied to a fire, they cause extinguishment by smothering the fire process. They will not provide secure extinguishment of a flammable liquid spill or pool fire which can re-flash after it is initially suppressed if an ignition source is present (e.g., hot surface). Dry chemical is still very effective for extinguishment of three-dimensional flammable liquid or gas fires. It is non-conductive and therefore can be used on live electrical equipment.

Dry chemical agents reduce visibility when they are discharged, they pose a breathing hazard to humans, clog ventilation filters, and the residue may induce corrosion of exposed metal surfaces. Dry chemicals should not be used where delicate electrical equipment is located, since the insulation properties of the dry chemical may render the contact inoperative. Dry chemicals also present a clean-up problem after use, especially for indoor applications. The system should activate fast enough to prevent equipment from becoming too hot to cause re-ignition once the system has been discharged. All dry chemical agents are corrosive to exposed metal surfaces.

Fixed systems may be fixed nozzles or hand hose line systems. They usually range in capacity from 68 to 1360 kgs (150–3000 lbs). Most use a high pressure nitrogen cylinder bank to fluidize and expel the dry chemical from the master storage tank. Where immediate water supplies are unavailable, fixed dry chemical systems may be a suitable alternative.

19.20. DUAL AGENT SYSTEMS

19.20.1 Chemical and Foam

Dual agent suppression systems are a combination of simultaneous application of foam water and dry chemical to provide for greater fire fighting capabilities. Usually aqueous film forming foam (AFFF) and potassium bicarbonates are used as the extinguishing agents. They are typically provided in separate vessels on a self-contained skid. When needed they are charged by a bank of high pressure nitrogen cylinders and the agents are discharged through two manually operated and directed nozzles. The nozzles are provided with an approximately 30 m (100 ft) length of hard rubber hose to provide for fire attack tactics.

Self-contained dual agent systems (foam/water and dry chemical) are provided for manual fire fighting efforts against three-dimensional pressure leaks and large diameter pool fires. The design affords fast fire knockdown, extinguishment, and sealant against re-flash. A skid mounted unit is provided at locations where flammable liquids are present and personnel may be in the direct vicinity of the hazard. Typical applications are associated with aircraft operations, both fixed wing and rotary (i.e., helicopters). For land-based operations, the skid is provided on a flatbed of a truck or small trailer for greater mobility at aircraft landing fields. Offshore the equipment is normally fixed at the heli-deck periphery.

Table 19.5 Fixed Fire Suppression Design Options Basis

Areas or Equipment	Hazard	Protection Requirement	Protection Options	Design Specifications
Onshore Process Area	Liquid spill Gas release	NFPA 30	1. Hydrants 2. Monitors 3. Hose reel 4. Vapor dispersion deluge spray	1. NFPA 24 2. NFPA 24 3. NFPA 24 4. NFPA 15
Offshore Process Module	Liquid spill Gas release	NFPA 30	1. Hydrants 2. Monitors 3. Hose reel 4. Overhead foam deluge	1. NFPA 24 2. NFPA 24 3. NFPA 24 4. NFPA 16
Process Vessels	Liquid spill Gas release	NFPA 30	1. Hydrants 2. Monitors 3. Hose reel 4. Water deluge cooling spray	1. NFPA 24 2. NFPA 24 3. NFPA 24 4. NFPA 15
Fired Heater	Liquid spill Gas release	NFPA 30	1. Hydrants 2. Monitors 3. Snuffing steam	1. NFPA 24 2. NFPA 24 3. NFPA 86
Tank Farm	Liquid spill Gas release	NFPA 30	1. Hydrants 2. Monitors 3. Water deluge cooling spray 4. Subsurface foam injection 5. Foam topside delivery	1. NFPA 24 2. NFPA 24 3. NFPA 15 4. NFPA 11 5. NFPA 11
Truck Loading	Liquid spill Gas release	NFPA 30	1. Hydrants 2. Monitors 3. Overhead foam deluge	1. NFPA 24 2. NFPA 24 3. NFPA 16
Rail Loading	Liquid spill Gas release	NFPA 30	1. Hydrants 2. Monitors	1. NFPA 24 2. NFPA 24
Marine Loading	Liquid spill Gas release	NFPA 30	1. Hydrants 2. Monitors	1. NFPA 24 2. NFPA 24
Pump Station	Liquid spill	NFPA 30	1. Hydrants 2. Monitors	1. NFPA 24 2. NFPA 24

Table 19.5 Continued

Areas or Equipment	Hazard	Protection Requirement	Protection Options	Design Specifications
Gas Compression Station	Gas release	NFPA 30	1. Hydrants 2. Monitors 3. CO_2 system 4. Pre-action sprinkler	1. NFPA 24 2. NFPA 24 3. NFPA 12 4. NFPA 13
Flare	Liquid spill Gas release	NFPA 30	1. Hydrants	1. NFPA 24
Switchgear Facility	Electrical fire	NFPA 850 IEEE 979	1. CO_2 system 2. Pre-action sprinkler	1. NFPA 12 2. NFPA 13
Oil Filled Transformers	Liquid spill	NFPA 850 NFPA 70	1. Hydrants 2. Deluge water spray	1. NFPA 24 2. NFPA 15
Cooling Tower	Combustible Fire	NFPA 214	1. Hydrants 2. Hose reels 3. Dry pipe deluge	1. NFPA 24 2. NFPA 24 3. NFPA 15
Offshore Heli-deck	Liquid spill	NFPA 418 API 14G	1. Hydrants 2. Foamwater monitors 3. Agent systems	1. NFPA 24 2. NFPA 24 3. NFPA 11/17
Accommo-dation	Combustible Fire	NFPA 101	1. Standpipe system 2. Sprinkler system	1. NFPA 14 2. NFPA 13
Warehouse	Combustible Fire	NFPA 231	1. Hydrants 2. Standpipe system 3. Sprinkler system	1. NFPA 24 2. NFPA 14 3. NFPA 13
Kitchen	Liquid spill Combustible fire	NFPA 101	1. Dry chemical system 2. Wet chemical system	1. NFPA 17 2. NFPA 17A
Administrative office	Combustible fire	NFPA 101	1. Hydrants 2. Standpipe system 3. Sprinkler system	1. NFPA 24 2. NFPA 14 3. NFPA 13

Table 19.6 Fire Suppression System Applications

Fire Suppression System	Typical Application
Portable Extinguisher	• Offices • Warehouses • Switchgear facilities • All plant areas • Loading facilities
Hydrants (if fire brigade available)	• All process and utility areas • Commodity storage areas (tank farms) • Shops • Warehouses • Offices
Hose Reels	• Process areas • Warehouses • Loading facilities • Offices • Accommodations
Firewater Monitors	• Process areas • Commodity storage areas (tank farms) • Loading facilities
Wet Pipe Sprinklers	• Offices • Accommodations • Warehouses
Dry Pipe Sprinklers	• Warehouses • Critical cable vaults • Cooling towers
Water Spray or Deluge	• Process vessel cooling • General area coverage • Pumps • Critical or high value transformers
Firewater Deluge and Monitors	• Hydrocarbon spill potentials • Truck, rail, and marine loading facilities • Pump stations
CO_2 Systems	• Electrical switchgear facilities • Gas turbine enclosures • Communication panels or racks
Clean Agent Systems	• Critical computer processing facilities • Vital communication equipment
Dry Chemical Systems	• Kitchens • Loading and unloading racks (mostly where water system is uneconomical or unavailable)
Dual Agent Systems	• Aircraft operations (fixed and rotary wing)

Table 19.7 Advantages and Disadvantages of Firewater Systems

System	Advantages	Disadvantages
Water deluge (general overhead)	If large orifice nozzles are used, system is less prone to plugging	Water may be loss due wind currents
	More likely to survive an explosion	Potential problem with dirt and scale deposits
	Can be activated automatically without operator involvement	Supplemental sprays needed for vessels supports and undersides
	Can be activated rapidly	Uneven water distribution for horizontal vessels
	More effective for spheres, vessels, and tanks	Generally used more for jet fires throughout a process
Water sprays (directed at equipment)	Can be activated automatically without operator involvement	More susceptible to plugging of nozzles due to orientation
	Can be activated rapidly	More susceptible to damage from explosions
	Less susceptible to wetabilty and rundown problems	Less effective for jet fires
	Least affected by wind	Overall can consume more water for specific hazards than general water deluge coverage
	Effective water use for hazard protected	Periodic testing may accelerate or induce corrosion of protected equipment
	Most effective fire control option	Normally most expensive option
Fixed monitors	Can be used to provide coverage to several hazards and then directed to specific incident occurring	Requires operator attendance for manual startup

(*Continued*)

Table 19.7 Continued

System	Advantages	Disadvantages
	Less prone to plugging	Personnel may be exposed to fire incident
	Easy to use	Consumes large quantities of water than may be ineffective
	Generally easy to install	Limited range to devices
	Spray patterns and densities can be adjusted real-time	Affected by wind at long distances
	Can be arranged for automatic or remote activation	
Hose reel and hydrant hoses	Can be used to provide coverage to several hazards and then directed to specific incident occurring	Requires operator attendance for manual startup
	Spray patterns and densities can be adjusted real-time	Normally requires operator attendance for continual operation
	Generally easy to install	Personnel may be exposed to fire incident
	Less prone to plugging	Consumes large quantities of water than may be ineffective
Portable squipment	Less susceptible to damage from an explosion	Requires manned support
	Easily Installed	Logistically highly intensive
	Can be used to direct water or agents to localized areas	Personnel may be exposed to fire incident
	Can be easily relocated to other areas as need arises	Some equipment is limited capacity
	Least expensive option	Generally requires previous training
		May be affected by wind

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CHAPTER 20

Special Locations, Facilities, and Equipment

Process facilities are found practically everywhere and in diversified environmental constitutions. These environments are so different and remote that unique situations develop that require specialized requirements for fire and explosion protection considerations.

20.1. ARCTIC ENVIRONMENTS

Arctic environments pose different ambient conditions than normally encountered at most process facilities. The most obvious is that the ambient temperature level can reach extremely low levels, as much as −45°C (50°F) and that snow or ice storms can be expected to occur.

The primary concern at these locations is the protection of critical equipment so that it can continue to function. This involves both the metallurgical properties of vessels, piping, control systems, and instrumentation. Personnel operations are also hampered in such environments. Generally, heavily insulated protective clothing must be worn when access to equipment becomes blocked or difficult due to ice and snow accumulations or inclement weather. Locations considerably north or south will also exhibit longer periods of darkness and light during the seasons, causing some disorientation to unfamiliar personnel.

For means of protection, the use of water-based suppression systems may be a hazard due to the disposal of firewater, which will freeze quite readily in exposed locations. This may also be the case with exposed process fluid lines that, if isolated for emergency shutdown (ESD) activation, may freeze up due to lack of circulation. This will hamper restart operations for the facility. Typically this use of gas fire suppression systems is utilized for enclosed areas. Other methods include

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firewater storage tanks that are kept warm, together with fire mains that are deeply buried and continually circulated.

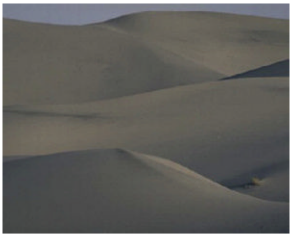
20.2. DESERT ARID ENVIRONMENTS

Desert environments also pose different ambient conditions than normally encountered at most process facilities. The most obvious is that the ambient temperature level can reach extremely high levels, as much as 54°C (130°F) and that sand storms can be expected to occur. Typical problems of free-range roving livestock (sheep, goats, cattle, camels, etc.) with their nomadic herders may also exist.

Special consideration of thermal relief for piping exposedure to sunlight (solar radiation) needs to be undertaken. This is usually accomplished by painting with reflective paint or burial. Process piping is usually painted in a reflective color for the advantage of reflection of solar radiation (heat input) to avoid thermal expansion of fluids in blocked systems.

Where facilities are exposed to the constant radiation of the sun, sun shades are provided over exterior exposed equipment that may not function properly at elevated temperatures or would deteriorate rapidly if left continually exposed to the direct sunlight. Most electrical or electronic equipment is rated for a maximum operating temperature of 40°C (114°F) unless otherwise specified, e.g., hazardous area lighting temperatures are normally specified for a 40°C (114°F) limit. Of particular concern for fire protection systems are those containing foam concentrates, rubber hoses, and other rubber components that may dry and crack. Rapid deterioration of "rubber" or "plastic" components may occur because of prolonged exposure to elevated temperatures or sunlight radiation (i.e., seals, drive belts, etc.) causing them to lose their elasticity.

Sand barriers and filters are provided on facilities and equipment where fresh air intakes are needed. These can also be orientated to face opposite the prevailing wind direction to limit the direct exposure to dust intake. Sand storms can also cause abrasive actions to occur on exposed equipment hardware that might cause it to malfunction.



Signs, labels, and instructions exposed to direct sunlight may begin to fade after a relatively short period after installation or the surface erode if impacted by sand storms.

20.3. TROPICAL ENVIRONMENTS

Tropical environments have unique ambient effects that have to be considered for process facilities and the installed equipment. Heavy rains (monsoons, hurricanes, typhoons, etc.), animal or insect infestations, and direct sunlight exposure are the most common concerns for firewater system components located in tropical locations. Heavy rains can produce flooding conditions that may envelope a firewater pump location, especially if it is taking suction from a river source, without flood control measures. Elevated locations should be considered in these cases. Heavy rains are usually accompanied by high winds that can carry objects that can damage system components. Insect or rodent infestations can cause blockages in pump driver vents or contamination of fuel systems and deterioration of soft materials. Frequent inspections and suitable screens should be considered. Direct sunlight can damage rubber components and reduce their elasticity. Firewater pumps houses are provided to protect against the rain, winds, sunlight, and animal disturbances.

20.4. EARTHQUAKE ZONES

Process facilities susceptible to earthquakes should be provided with suitable restraints for fire protection systems. The extent of these restraints are normally dictated by local ordinances and primarily concern the bracing of pipework and adequate securing of firewater pump base plates and controller panels for earthquake forces. Pump houses should be adequately constructed and braced so they will not collapse onto the firewater pump or distribution piping.

20.5. WELLHEADS—EXPLORATION (ONSHORE AND OFFSHORE)

The primary concern with exploration wellheads is the possibility of a blow-out during drilling operations. A blow-out is a loss of control of the wellhead pressure. Normally the wellhead pressure in a well being drilled is controlled with counterbalance of drilling “mud” that equalizes its weight with the upward pressure of the oil or gas in the well (i.e., the reservoir being drilled into). If the flow of mud is interrupted, such as through loss of circulation (i.e., though the formation, drill pipe, circulation pump failure, etc.), the only thing between the drilling rig and its crew on the surface and the oil and gas forcing itself up the well at 34.5–68,948 kPa

(5–10,000 psi) is a stack of valves called blow-out preventers (BOPs). In theory, they can stop the upward flow of pressure, so long as the well pressure is less than their seals are rated at and they are operated on time and function properly.

An underground blow-out can also occur during a drilling operation. An underground blow-out occurs when a loss of mud control occurs and the reservoir fluid begins to flow from one underground zone into a zone of lower pressure. Because the loss of flow is below the surface it is considered an underground blow-out and is more difficult and complex to evaluate and correct.

Drilling mud is a mixture of barite, clay, water, and chemical additives. Initially, in the early days of exploration, the drilling mud was provided from river beds in Texas, Arkansas, and Louisiana. The mud is provided to pits at the drilling site. From the mud pits it is pumped into the drill pipe to lubricate the drill, remove cuttings, and maintain pressure control. After exiting the drillhead, it is circulated in the annulus of the wellpipe borehole back up to the surface where it is reused after the particulates are removed. By varying the weight of the drilling mud into the drillstack, wellhead pressure control can be effectively maintained. Naturally occurring barite has a specific weight of 4.2; drilling mud of 8 or 9 pounds is considered light and 18 or 20 is considered heavy. Heavier mud, containing larger quantities of barite, is considerably more expensive than light mud, so a drilling company may try to use the lightest weight mud possible when drilling a well. It has also been theorized that heavier drilling mud might precipitate reservoir formation damage by blocking the pores in the reservoir that the oil flows out of or through. On occasion such frugality and reservoir concerns may have been a contributing factor to a wellhead blow-out.

Blow-out preventers (BOPs) cut off the flow of a potential blow-out. In all wells being drilled there are normally three holes or pipes within pipes that are at the surface of the wellhead—conductor pipe, casing pipe, and drilling pipe. The drilling pipe is the actual hole, while the outer two are annulus formed around the inner pipe. Any one of these, under varying conditions, can be a source through which oil or gas can escape during drilling. The annular preventer is a valve that appears as a rounded barrel and is positioned on one or more other blow-out preventers on the preventer stack. The annular preventer seals off the annulus area of the well, the space between the drill pipe and the side of the hole. It could also be used to seal off a well with no drill pipe in it. If a well "kicks," but does not blow-out, the annular preventer allows fluid such as drilling mud to be pumped down the hole to control the pressure while it prevents material from coming out. Blow-out preventers below the annular preventer are called ram preventers because they use large rams—rubber-faced steel blocks that are shoved together to seal off a well. They can withstand more pressure than an annular preventer and are considered a second line of defense. There are blind rams that seal off an open hole and pipe rams that are used to close a hole when drill pipe is in use. They are also shear rams that simply cut the pipe off. Using the shear ram is the last resort, since it will cut the drill pipe and bit and send it down to the bottom of the hole. Blow-out preventers are operated hydraulically from an accumulator that should be located as remotely from the wellhead as practical. The control panel for activation should be readily available at the drilling operations and in some cases (such as offshore), a duplicate activation panel is provided at other critical emergency control points.

The most common cause of a well to be uncontrolled and develop into a blow-out is improper mud control operations and the inability of the blow-out prevention systems to contain it because of system failures, i.e., lack of testing and maintenance.

Once a wellhead fire exists it is best to allow the well to keep burning to alleviate explosion hazards and pollution concerns until the well itself can be capped or plugged or a relief well drilled to intercept the blow-out well. Adjacent exposures, especially other wellheads, if in close proximity should be cooled. Testing by research agencies and operating companies indicates that the fire and heat radiation of a wellhead incident can be considerably lessoned when the waters pray is provided immediately at the wellhead and

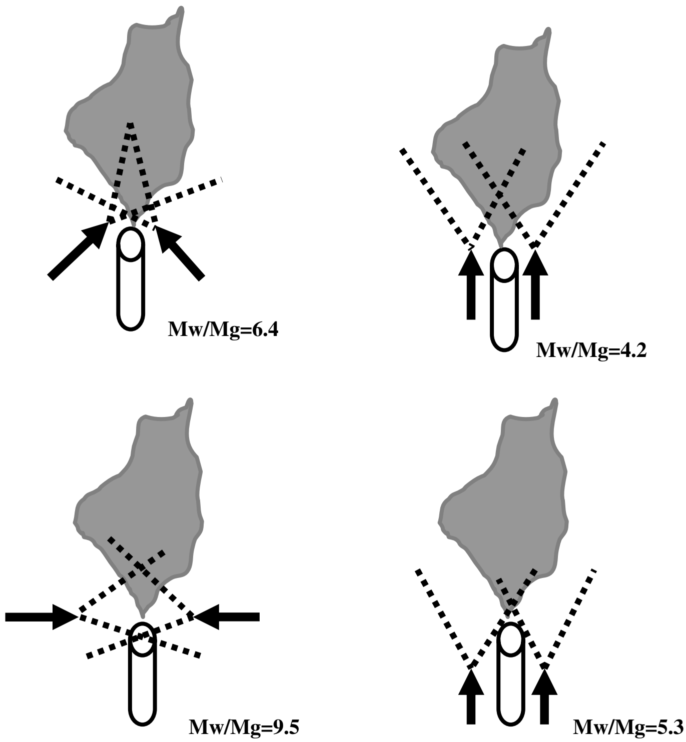


Figure 20.1 Relative effectiveness of various spray arrangements at wellhead flames.

is directed upwards instead of downwards. Figure 20.1 shows the general results of tests conducted that indicte the most efficient water spray geometry consists of nozzles spraying parallel to the flame axis based on the mass flow rate of water (Mw) to the mass flow rate of the released gas (Mg).

20.6. PIPELINES

Cross-country pipelines provide a highly economic system for the transport of both liquid and gaseous petroleum products. They also have some inherent safety risks that need to be examined prior to their design, routing, and construction. For the purposes of risk analysis, a pipeline should be thought of as an elongated pressure vessel with unlimited flow. They normally contain large inventories of combustible materials usually at elevated pressures. Damage to an entire pipeline is highly unlikely and a damaged portion of a pipeline can generally be easily replaced. The primary risks of pipelines are the exposures they pose to nearby populations and facilities, business interruption concerns, and environmental impacts. To maintain adequate protection against their hazards, adequate siting, isolation capability, and integrity assurance must be provided. For both hazardous liquid and gas transmission pipelines, the predominant failure causes for line pipe are corrosion, material/weld failures, and excavation damage.

Transmission pipelines are often located in rights-of-way adjacent to and across land used for other purposes, such as residences, businesses, farms, and industrial facilities. In these locations, people may spend extended periods of time in close proximity to pipelines. Many of these transmission pipelines have been in place for decades and often pre-date the surrounding development. Many portions of existing transmission pipelines were originally constructed in sparsely populated areas, but subsequent population growth over time transformed some of these areas into more populated and developed areas, with increasing development of housing subdivisions, schools, shopping centers, industrial/business parks, etc. Simultaneously, economic growth over time has generated demand for construction of more pipelines to meet growing needs for energy.

As additional homes, businesses, and schools are constructed and other development occurs, more people will be living, working, and shopping in the vicinity of transmission pipelines. Similarly, with increasing demand for energy, it is likely that new transmission pipelines will be constructed in areas of existing development. Because of these expected trends, local governments are increasingly required to make decisions concerning land use planning and development in the vicinity of transmission pipelines.

The potential consequences of a pipeline release vary according to the commodity that is released as well as characteristics of the surrounding area. If an ignition source exists, a release of gas can result in an immediate fire or explosion near the point of the release. This hazard is reduced over a relatively short period after the release ends as the gas disperses. If the pipeline contains gas with poisonous hydrogen sulfide (H_2S), toxic effects could be felt at extended distances from pipeline more so than for a fire or explosion. If the vapors accumulate inside a building, then the hazard may remain longer. There is also the possibility that the size or movement of a vapor cloud could result in consequences away from the initial point of the release, but because natural gas is lighter than air, this situation is not common. Structures and topographic features in the vicinity of a release can serve as barriers and mitigate the consequences of the release for other nearby areas.

Assessing the potential consequences of releases from specific pipelines in specific locations should be based on a pipeline- and location-specific evaluation of the following four elements:

1. Which commodity or commodities might be released?

2. How much of the transported commodity might be released? The answer to this differs at different locations along a pipeline and can be derived from pipeline flow rates, spill detection time, pipeline shutdown time, drain down volume, and other technical factors.

3. Where might the released substance go? The answer to this is derived by considering the released commodity, release volume, and potential flow paths over land and water, as well as potential air dispersion. Overland flow can be affected by factors such as gas or liquid properties, topography at and near the spill location, soil type, nearby drainage systems, and flow barriers. Similarly, flow in water can be affected by the water flow rate and direction and properties of the spilled fluids. Air dispersion can be affected by the properties of released vapors and wind direction and speed.

4. What locations might be impacted? This question is answered by considering how potential impacts, including thermal impacts from fire, blast overpressure from explosion, toxic and asphyxiation effects, and environmental contamination, could affect locations where the released commodity travels. Planned evacuation routes should be considered when performing these assessments.

Various commercially available software modeling programs have been developed to examine and predict the impacts of pipeline releases in nearby areas. These models support analysis of such elements as spill volumes, release paths along land or water, air dispersion patterns, and spill impacts on human health, property, and the environment. A critical factor in using these models is to ensure correct input data is used and consistent assumptions for leak sizes and wind factors.

20.6.1 Main Pipeline Safety Features

Siting—The preferred arrangement of bulk transport pipeline systems is for burial underground. This provides for enhanced protection against overhead events. These are also utilized for offshore pipelines where there have been numerous incidents of dragged anchors from fishing vessels to pipelines exposed on the seabed. A radius of exposure from a pipeline can also be easily calculated for potential fires, explosions, and toxic vapors based on the commodity, pressure, release opening, wind effects, etc. From these calculations an impact zone can be determined from which protection measures as determined by the risk can be evaluated.

Isolation Capability—All pipelines should be provided with a means of emergency isolation at its entries and exits from a facility. Offshore facilities may be particularly vulnerable to pipeline incidents, as the Piper Alpha disaster has shown. In that incident, a contributing factor to the destruction was the back feed of the contents of the gas pipeline to the platform once the topside isolation valve or piping lost its integrity due to fire exposure. Further isolation means (i.e., a subsea isolation valve) was not available.

Integrity Assurance—When first installed, piping systems will be checked for leakages at weld joints and flange connections. Weld joints are usually verified by NDT means (i.e., x-ray or dye penetrants). Depending on the service, the pipeline will be usually hydrostatically or pneumatically pressure tested. Normally a section is specified for testing from flange point to flange point. Once tested the blank flanges at the ends of the test section are removed and the tested portions are permanently connected for operational startup. This usually leaves the flange joint or connection that has not been tested for integrity aspects and will most probably be the point of system leakage upon system startup. Once operational, pipelines will be susceptible to corrosion or erosion. They must be subjected to periodic thickness verification to determine their acceptable life span and prevention of leaks or ruptures. It has been shown that the addition of isolation valves at periodic intervals is not as cost effective as prevention measures such as thickness inspections or tests.

20.6.2 Causes of Pipeline Failures

For both hazardous liquid and gas transmission pipelines, the predominant failure causes for line pipe are corrosion, material/weld failures, and excavation damage. For hazardous liquid pipeline facilities (pump stations, tank facilities, etc.), the highest-percentage failure causes are equipment failures, incorrect operation, and corrosion. For gas transmission pipeline facilities (compressor stations, regulator/metering stations), a high percentage of incidents are caused by equipment failures, outside force damage, and natural force damage, but the highest percentage of incidents are classified as being due to "other" causes. Incidents are assigned to this category if the cause of the incident was unknown or was not tied to one of the other defined failure cause categories. The gas transmission incidents assigned to the "other" cause category included several releases due to equipment malfunctions at compressor stations.

For serious incidents (i.e., those which include a fatality or an injury requiring hospitalization), both hazardous liquid and gas transmission pipelines, excavation damage, incorrect operation, outside force damage, and "other" causes are the causes for these (although the number of incidents in any category is small). Corrosion, material/weld failures, and equipment failures are the cause of a lower percentage of serious incidents than they are for the larger population of significant incidents.

Corrosion is by far the most serious hazard of pipeline incidents. It is imperative that adequate corrosion monitoring programs be provided for all pipelines containing hazardous commodities. Older pipelines, which may have had water containments or other similar corrosion materials within the product stream, operated at elevated temperatures appear more susceptible to corrosion failures than other pipelines.

Other failures of pipelines generally occur as a result of third party activity or natural hazards. Offshore pipelines are vulnerable to ship anchor dragging, while onshore pipelines are susceptible to impacts from earth moving operations for construction or road grading. On occasion impacts from mobile equipment may also directly strike and damage a pipeline.

20.6.3 Pipeline Incident History

The incident history of hazardous liquid pipelines in the USA for the past 20 years (1999–2009) indicates a general downward trend in the annual number of significant hazardous liquid pipeline incidents; on average, about 3% of significant hazardous liquid incidents included death or injury and are classified as "serious" incidents. Fatalities and injuries in these data were experienced by both the general public and by pipeline operator personnel.

The incident history for gas transmission pipelines in the USA for the past 20 years (1999–2009) indicates an overall increasing trend in the annual number of natural gas transmission pipeline significant incidents over the time period. A major reason for this trend is a relatively high number of gas transmission pipeline significant incidents in 2003, 2005, 2006, and 2009. In 2003 and 2006, the higher number of incidents was primarily due to a higher number of incidents caused by materials and weld failures (15 in 2003 and 16 in 2006 due to this cause vs. an average of 8 per year over 1990–2009). In 2005, the relatively high number of incidents reflects the natural force damages to pipelines from the effects of hurricanes Katrina and Rita (11 incidents due to this cause vs. an average of 4 per year over 1990–2009). In 2009, the higher number of incidents is spread among several cause categories, including materials and weld failures and equipment failures. On average, about 16% of significant gas transmission pipeline incidents included death or injury and are classified as "serious" incidents. Fatalities and injuries in these data were experienced by both the general public and by pipeline operator personnel.

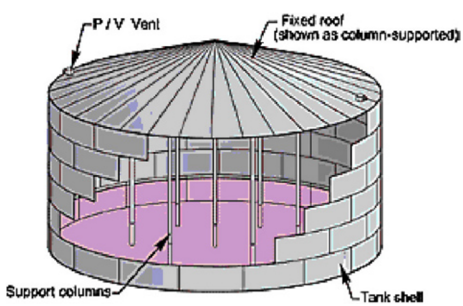
20.7. STORAGE TANKS

20.7.1 Incidents

A total of 242 tank farm incidents worldwide have been reported from the period of 1960 to 2003. An analysis of these incidents revealed that the most frequent cause was lightning strikes, followed by poor maintenance practices, sabotage, crack, leak, or line ruptures, static electricity, and proximity to open flames. From 2005 to 2013, there were six major tank farm incidents (Buncefield, UK 2005; India Oil Corp, Jaipur, India 2009; China NPC 2010; Miami Airport, FL, USA 2011; Amuay Refinery, Venezuela 2012; India Oil Corp, Hazira, India 2013).

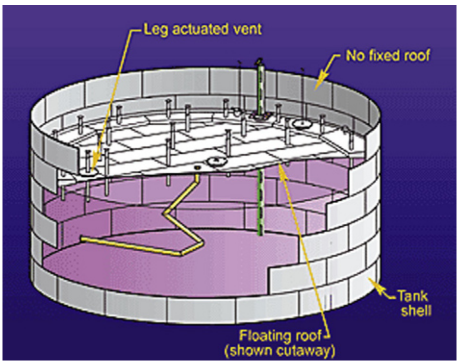
There are three general types of aboveground storage tanks used in the petroleum and petrochemical industries. They are selected based on the service intended and the flash points of the content. These tanks include fixed roof, external floating roof, and internal floating roof.

Fixed Roof Tank—These consist of a cylinder shaped base with a permanently attached typically cone shaped roof. They normally store high flash point liquids. The cone shaped roof reduces environmental emissions and provides additional strength to allow slightly higher storage



pressures than atmospheric pressure. These tanks typically have a weak seam at the roof attachment to the tank shell. This allows the tank roof to separate in the event of an internal explosion, leaving the shell intact. This allows the tank to retain its contents and any resulting fire will only involve the surface of the exposed flammable liquid.

External Floating Roof Tank—This is an open top cylinder shaped base with a pontoon type roof that floats on the liquid surface as the contents raise and lower with tank operation. The top of the tank is open to the atmosphere. The floating roof has a mechanical shoe or tube seal at its perimeter to seal the exposed liquid surface. The design eliminates space for vapors inside a tank and greatly reduces product loss through evaporation. Medium flash point liquids such as naptha, kerosene, diesel, and crude oil are typical placed in these tanks.



Internal Floating Roof Tanks—These are tanks with a permanent fixed roof over an internal floating roof. The design helps prevent toxic gases from leaking into the atmosphere. They are typically used to store highly flammable liquids.

API, ASME, NFPA, and other international standards and insurance guidelines provide information for the safe construction, material selection, design, operation, and maintenance of storage tanks and their associated equipment. These cover loss prevention aspects for tank selection, venting, location, spacing, drainage and impounding, fire protection systems, static electricity/grounding, and lighting protection. Additionally, a risk review of the tank design and installation will assist in the prudent safety features that should be considered for it. Figure 20.2 illustrates a qualitative fishbone risk review for storage tanks.

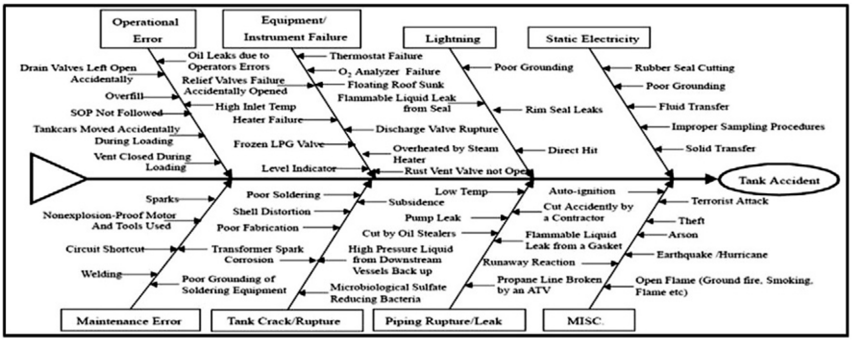


Figure 20.2 Fishbone risk diagram example for storage tanks.

20.8. LOADING FACILITIES

Loading is one of the most hazardous operations in the process industries. These facilities represent a strategic point in the process that, if lost, may adversely affect the entire operation of the facility. Pipeline transport is the preferred method of material transport but cannot be accommodated in instances where smaller quantities are involved or where trans-ocean shipment is required. The most prevalent hazard with loading facilities is the possibility of overfilling, displacement and release of combustible vapors, buildup of static electricity, and collisions with transferring facilities and carrying vehicle (primarily ships, barges, or trucks).

The main safety features for loading operations include:

- Spacing from other facilities
- Shutdown and isolation capability (ESD: valves, buttons, controller, etc.)
- Overfill protection (metering, level indicator, etc.)
- Structural integrity of the loading structure (piping stress, wind, load, etc.)
- Static dissipation and rack grounding (flowrates, materials, bonding/grounding)
- Integrity of connection hoses and loading arms
- Collision protection of loading rack structure impacts from the loading container (ship, truck)
- Fixed fire protection systems (detection and suppression) and portable fire suppression equipment
- Safe access/egress, heat protection, slippage and fall protection
- Ship, rail car, or truck traffic flow arrangements, inspection and waiting areas
- Loading operator training and certification
- Personal protection equipment and eyewashes/safety showers
- Spillage containment and cleanup
- Emergency response plan (alarm, notification, governmental assistance)

Loading facilities should be sited where the shipping vehicles will not be exposed or expose other processing facilities during or traveling to and from the loading devices. All manual loading facilities should be provided with self-closing valves. A method for emergency isolation of the product flow and transfer pump shutdown should be considered for all facilities.

The primary area of protection should be centered on the fixed equipment at the product transfer area, the highest probable leak, or the spillage location. These include loading arms, hoses, pipe connections, and transfer pumps. Protection of fixed equipment ensures rapid restart after the incident with

limited business interruption. Of secondary importance is the protection of the transfer vehicle (ship, rail, or truck). The most critical of these are the large shipping vessels where considerable monetary losses would be incurred. The immense size of some shipping vessels and loading arrangements make protection of the complete vehicle impractical. Risk analysis of shipping incidents generally indicates the probability of immediate complete vessel fire involvement is a low probability versus the possible destruction from internal vessel explosions from vapor accumulations during deballasting.

The most practical protection method for protection of ship and rail loading facilities is though fixed monitors. Due to the relatively small size of truck loading racks and liquid spillage accumulation, they are normally provided with an overhead foam water general area deluge system supplemented with nozzles directed at leakage points. Some truck loading facilities have been protected with large fixed dry chemical systems where the water supplies have not been adequate.

20.9. OFFSHORE FACILITIES

Offshore facilities are dramatically different than onshore facilities because of instead of being spread out, the equipment is typically segregated into compartments or placed on a complex of platforms. Offshore facilities pose critical questions of personnel evacuation and the possibility of total asset destruction if prudent risk assessments are not performed. A thorough analysis of both life safety and asset protection must be undertaken. These analyses should commensurate with the level of risk a particular facility represents, either in personnel exposed, financial loss, or environmental impact. An unmanned wellhead platform might only require the review of wellhead shut-in, flowline protection, and platform ship collisions to be effective, while manned drilling and production platforms require the most extensive analysis. Generally the highest risks in offshore facilities are drilling blow-outs, transportation impacts, and process upsets. Where inadequate isolation means are provided for either wellheads or pipeline connections to the installation, considerable fuel inventories will be available to an incident.

20.9.1 Helicopter Landing Decks Offshore

The heli-decks of offshore facilities are usually provided at the highest point of the offshore installation for avoidance of obstructions during aircraft maneuvering and available space. As a result, the roof of the accommodation is usually selected as the optimum location for the heli-deck. The location also facilitates the evacuation of personnel from the installation by helicopter due to its proximity to the highest concentration of personnel. This enhances one of the avenues of escape from the installation but also exposes the accommodation to several hazards. The accommodation becomes subject to the hazards of helicopter impacts or crashes, fuel spillages, and incidental helicopter fuel storage and transfer facilities.

Because of the inherent hazards associated with heli-deck operations, they should be provided with foam water monitor coverage that has a minimum duration of 20 min. The monitors should be placed as a minimum on opposite sides of the deck, but preferably from three sides. The monitors should be located below deck level and provided with a heat radiation shield that can be seen through. There has been a recent innovation to incorporate a fire protection system with the deck of the heli-deck whereby the spray nozzles pop up from the deck surface during activation, which is known as a deck integrated fire fighting system (DIFFS). Further details of the DIFFS are provided in Chapter 19.

The heli-deck should be elevated above the accommodation by an air gap to ensure vapor dispersals from fuel spillages. Fuel loading and storage for the helicopters should be located so the tanks can be jettisoned or disposed of in an emergency if they are located near the accommodation.

20.9.2 Offshore Floating Exploration and Production Facilities

Floating exploration and production facilities are sometimes provided on jack-up rigs, semi-submersible vessels, or ex-crude oil shipping tankers converted to production treatment vessels. These facilities are essentially the same as fixed offshore platforms or installations except they are moored in place or provided with a temporary support structure instead of being provided with fixed supports to the seabed. The major process fire and explosion risks are identical to the risks produced on offshore platforms. They have one additional major facility risk, which is the maintenance of the buoyancy of the installation. Should a fire or explosion effect cause a loss of buoyancy (or even stability), the entire facility is at risk of submergence. Adequate compartmentalization and integrity assurances must be implemented in these circumstances.

20.10. ELECTRICAL EQUIPMENT AND COMMUNICATIONS ROOMS

All process facilities contain electrical power and communication facilities to control and manage the operation. These facilities are commonly found in classified areas due to the need to site these close to the processes. They are typically kept pressurized to prevent the ingress of hazardous vapors or gases and keep the interior of the facility as non-classified electrically.

Combustible gas detectors for the air intakes should be considered with the enclosures that are in close proximity to processes containing combustible materials. This is especially important when the processes can be demonstrated to be within areas where a worst case credible event (WCCE) will not have dissipated at the distance the facility is placed from it. An alternative is to have the air handling system self-circulating so it does not direct fresh air supplies from the outside to the interior of the facility. Such facilities are normally provided at unmanned facilities.

Switchgear and process control rooms are required to have smoke detection per NFPA 850, Recommend Practice for Fire Protection for Electric Generating Plans and High Voltage Direct Current Converter Stations and IEEE 979, Guide for Substation Fire Protection. The activation of the fire alarm should shut down the air handling systems. If the facility is especially critical to the continued process operation, consideration of a fixed fire suppression system should be evaluated.

Electrical breaker facilities sometimes have what is termed an "electrical arc flash," primarily due to incorrect maintenance operations or dust accumulation that allows a conductive path in humid environments to develop. This is a continuous electric discharge of high current between conductors, generating very high bright light and intensive heat. The electrical arc primarily presents the serious hazard, which could be fatal to personnel because of the risk of severe burn injuries caused by intensive heat and molten metal splashes. The electrical arc also generates hazardous noise and pressure and due to the damage inflected on associated cabling insulation there is also a potential for inhalation injuries. The heat energy that can be produced is determined by the amount of arc current, duration of the arc, the distance between a worker and the arc, and the configuration of the conductors and surrounding environment. The incident usually does extend past the initial arc flash environment primarily because of non-combustible materials at these installations. The primary protection for personnel in these environments is the use of adequate thermal protective flame resistant fabric used for the worker clothing. NFPA 70E, Standard for Electrical Safety in the Workplace, recommends both a shock hazard analysis and an arc flash hazard analysis (AFHA) be undertaken to determine appropriate work practices to prevent injuries from such electrical hazards.

20.11. OIL-FILLED TRANSFORMERS

Transformers filled with combustible oils pose a fire hazard. Outdoor transformers should be adequately spaced from other each other and adjacent structures per the requirements of NFPA 70, National Electrical Code, NFPA 850, Recommended Practice for Fire Protection for Electric

Generating Plants and High Voltage Direct Current Converter Station, or IEEE 979, Guide for Substation Fire Protection, or separated by a 2 h firewall. Firewalls constructed of precast concrete panels or concrete masonry walls have been found to be the most cost effective in these instances.

NFPA 850, Par 7.8.6 recommends that oil-filled main, station service, and startup transformers at power generation plants not meeting the separation or fire barrier recommendations should be protected with automatic water spray or foam-water spray systems. Additionally, it recommends that substations and switchyards located at the generating facility and utilizing combustible oil-filled equipment should be protected by fire hydrants where practical and consideration should be given to water spray protection of transformers critical to the transmission of the generated power.

Adequate containment and removal of spillages should be provided. Spillage immediately at a transformer should drain into a gravel covered basin, which prevents the spilled liquid from being exposed, thus preventing vapor and fire development, but which also allows drainage to be collected.

20.12. BATTERY ROOMS

Battery rooms are provided for backup and uninterruptible power supplies (UPS) for process control functions. They are usually provided at or near the facility control room or electrical switchgear facilities. Battery rooms should be provided with ventilation to limit the concentration of hydrogen to 1% by volume. For further information refer to ANSI/IEEE 484, Recommended Practice for Installation Design and Installation of Large Lead Storage Batteries for Generating Stations and Substations.

Typical industry practice is to provide an explosion proof rated fan in the exhaust system for the battery room and classify the exhaust duct and a radius of 1.5 m (5 ft.) from the exhaust vent as a classified area.

Where drainage provisions are provided to the battery room, the fluid should be first collected into a neutralizing tank before entering the oily water sewer system (OWS) to prevent battery acids from affecting the sewer piping and for environmental protection.

Where sealed and unserviceable batteries are used, these requirements do not apply, since no free hydrogen is released.

Fire detection capability is considered optional as the batteries themselves have little combustibility and only a limited amount of cabling or charging equipment is normally provided. A fire incident has a low probably of occurring, while historical evidence indicates the buildup of hydrogen vapors (possibly by fan failure or battery overcharging) and a minor room explosion as the likely incident to occur and damage the contents of the room.

20.13. ENCLOSED TURBINES OR GAS COMPRESSOR PACKAGES

Turbines and gas compressors are commonly provided as a complete assembly by vendors in an acoustical enclosure. Because the equipment is enclosed and handles gas supplies, it is a prime candidate for the possibility of a gas explosion and fire. The most obvious source of a gas accumulation is a fuel leak. Other rare losses have occurred due to lubrication failures, causing the equipment to overheat, with subsequent metal fatigue and disintegration. Once disintegration occurs, heat release from the combustion chamber will occur along with shrapnel and small projectiles that will be thrown from the unit from the inertia momentum of the rotating device.

Most enclosures are provided with high interior air cooling flow that is also helpful to disperse any gas release. Combustible gas detection is provided in the interior of the enclosure and at the air exhaust vent. Fixed temperature devices are also installed.

The prime method of protection from a gas explosion in the enclosure is through gas detection and oxygen displacement or by inerting. CO_2 or clean agent fire suppression systems have been used as inerting and fire suppression agents. The agents are stored outside, at a convenient location, and applied to the appropriate hazard. Emergency shutdown (ESD) signals shutdown of the fuel supplies to the turbine once an incident occurs. Of critical importance is integrity protection to the ESD fuel isolation valve.

A one hour rated fire barrier or "substantial space" should be provided between the turbine and gas compressor. The utilization of blow-out panels in the acoustical enclosure will also limit damage from an explosion. Although strengthened panels could be provided to protect against shrapnel ejection, the cost of such an installation and the low probability of such an occurrence and low personnel exposure periods generally render this as a non-cost effective improvement.

20.14. EMERGENCY GENERATORS

Emergency generators are provided in the process industries for backup power for vital and critical equipment. The main equipment fire hazards result from fuel usage and storage. Additionally, since these systems are usually required during a major incident, they must be protected from fire and explosion impacts, either by remote location or by suitable blast resistance enclosures. The capacity should account for all services anticipated at the time of the worst case credible event (WCCE).

20.15. HEAT TRANSFER SYSTEMS

Heat transfer systems are normally provided to utilize available process heat, to economize heat for dilation purposes, to preheat fuel supplies prior to usage, or for heat recovery for power generation. They are generally considered a secondary process support system to the main process production processes, but they may be so critical to the process that they might be considered a single point failure if not adequately designed.

Most heat transfer systems are comprised of a closed loop design that circulates a heat transfer medium between heaters and heat exchangers. Circulation pumps provide flow and regulating valves are used for process control. The heat transfer medium is usually steam, a high flash point oil, or in process plants, flammable liquids and gases. Inherently steam is a safer medium to use and is preferred over other mediums. When steam supplies are unavailable, high flash point oils (organic or synthetics) are sometimes used.

For oil systems, commonly referred to as hot oil systems, a reservoir is sometimes provided in an elevated storage tank. The fire risks associated with hot oil systems comprise the temperature of the circulating oil, location of transfer pumps, and protection of the storage reservoir.

The circulating oil may be heated to above its flash point, therefore producing a "flammable" liquid in the system rather than a "combustible" liquid. This may be further compounded by the fact the circulating system (i.e., pumps, valves, and piping) may also eventually reach temperatures above the flash point of the combustible circulating oil (through conduction of the circulating oil), so any leak will be immediately ignited.

Small hot oil systems are sometimes provided as a prefabricated skid package with pumps, valves, and an elevated storage tank on the same skid. Any leak from the circulating pumps will immediately endanger the components on the skid and storage tank. The circulating pump seals are usually the source of leakage on the system. Leakage of the medium being heated, usually of low flash point hydrocarbons into the hot oil system, occurs on occasion, further increasing the fire hazard risk unexpectedly. Such leakages may precipitate considerable low flash point hydrocarbons, such that the hot oil system eventually takes on the characteristics of a flammable liquid, essentially creating a major fire risk, akin to a process vessel operation instead of an inherently safe heat exchange system. Should leaks be suspected, a sample of the hot oil should be tested for verification of its composition. Leaks should be immediately corrected and a method to degas the system also incorporated.

If the system itself is critical to production operations, the pumps may be the most critical components. They should be adequately located away from other process risks and provided with typical drainage facilities (containment curbing, surface grading, sewer capability, etc.). The collapse of the storage tank should be analyzed to determine what impact it will have on the heat transfer system and the surrounding facilities to determine the application of fireproofing of supports. Normally, if the storage tank is within the risk of other fire hazards or if its storage temperature is above its flash point its structural supports should be fireproofed. Otherwise, fireproofing the supports may not be economically justified. Consideration should also be given to the design amounts kept in storage and this kept to the minimal amounts.

20.16. COOLING TOWERS

Cooling towers provided in most process industries are typically constructed of ordinary combustible materials (e.g., wood, fiberglass, etc.). Although abundant water flows through the interior of the tower, outside surfaces and some interior portions remain totally dry. During maintenance activities most cooling towers are also not in operation and the entire unit will become dry. The principle causes of cooling tower fires are electrical defects to wiring, lighting, motors, and switches. These defects in turn ignite exposed surfaces of the dry combustible structure. On occasion, combustible vapors are released from the process water and are ignited. Water used for cooling flammable gases or ignitable liquids may constitute an unusual hazard. The hazard exists when the cooling water pressure is less than that of the material being cooled. The gas or liquid can mix with the cooling water, be transported via the cooling water return line, and be released at the tower distribution system where it can be ignited. Since cooling towers are designed to circulate high flow rates of air for cooling, they will also increase the probabilities of an electrical hot spot ignition to a combustible surface of the cooling tower.

A significant percentage of fires in cooling towers of combustible construction are caused by ignition from outside sources, such as incinerators, smoke stacks, or exposure fires. Fires in cooling towers also may create an exposure hazard to adjacent structures, buildings, and other cooling towers. Therefore, distance separation from other structures, buildings, and sources of ignition, protection for the towers, and the use of non-combustible construction are primary considerations in preventing these fires.

NFPA 214, Water Cooling Towers, provides guidance on the provision and design of fire protection systems and protective measures for cooling towers constructed of combustible materials. Specific protection for the interior of the cooling tower combustible materials, but also for the probable source of ignition (e.g., motors), should be made. Where they are critical to operations, a sprinkler system is usually provided, otherwise hose reels or monitors are installed. High corrosion protection measures must be considered wherever a sprinkler system is provided for a cooling tower due to the interior environment of the cooling tower, which is ideally suited for corrosion development to exposed metal surfaces.

There is an increasing industry trend to use non-combustible materials of construction for the cooling towers due to the high fire hazard characteristics and maintenance costs associated with combustible materials and fire sprinkler inspection and maintenance.

20.17. TESTING LABORATORIES (INCLUDING OIL OR WATER TESTING, DARKROOMS, ETC.)

Laboratories are normally classified as non-hazardous locations if the quantities of combustible materials are within the requirements of NFPA. Normally a vapor collection hood is provided when sampling and measurements are conducted with exposed hazardous materials. The primary concern is the exhaust of vapors or gases and the storage and removal of materials saturated with hazardous liquids. The exhaust hood, ducting, and a radius of 1.5 m (5 ft) from the exhaust vent should be considered an electrically classified area.

20.18. WAREHOUSES

Warehouses are normally considered as low risk occupancy unless high value, critical, or hazardous materials are being stored. Some high valve components normally overlooked in warehouses are diamond (industrial grade) drill bits or critical process control computer hardware components. In these cases the economic benefits of installing an automatic fire sprinkler system should be investigated.

20.19. CAFETERIAS AND KITCHENS

Most process facilities provide onsite cafeterias for employees. Wet or dry chemical fixed fire suppression systems are usually provided over the kitchen cooling appliances and in the exhaust plenums and ducts. Activation means are afforded by fusible links located in the exhaust ducts or plenums usually rated at 232°C (450°F). Manual activation means should not be provided near the cooking area, but in the exit route from the facility. The faculty fire alarm should be activated upon activation of the fixed fire suppression system and power or gas to the cooking appliances should be automatically shut off. The ventilation system should be also shut down to decrease oxygen supplies to the incident. Protective caps should be provided to suppression nozzles to prevent plugging by grease or cooking particulates.

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CHAPTER 21

Human Factors and Ergonomic Considerations

Human factors and ergonomics constitute a key role in the prevention of incidents in the petroleum and chemical industries. Some of the most recent major incident investigations—the 1987 Marathon Refinery Texas City incident, the 1988 Occidental Piper Alpha offshore platform disaster, the 1989 Phillips 66 Polyethylene Plant explosion, the 1984 PEMEX LPG Terminal destruction in Mexico City—have human error as the principal cause, either in design, operations, maintenance, or in the management of safety. Some theories and insurance organizations attribute from 80% to 90% of all incidents to human factors. It is therefore imperative that an examination of human factors and ergonomics be undertaken to prevent fire and explosions at process facilities since historical evidence has also shown it to be a major contributor either as a primary or underlying root cause. These include actions by designers, operators, or managers that may contribute to or result in incidents.

Human factors and ergonomics concern the ability of personnel to perform their job functions with the physical and mental capabilities or limitations of a human being. Human beings have certain tolerances and personal attitudes. Tolerances can be related to the ability to accept information, how quickly the information can be understood, and the ability and speed to perform manual activities. When information is confusing, lacking, or overtaxing, the ability to understand it and act upon it quickly or effectively is absent. It is therefore imperative to provide concise, adequate, and only pertinent information to do all the tasks associated with activities required for each particular assignment. This includes activities associated with emergency fire and explosion protection measures.

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Attitudes reflect the leadership of management, company culture, and the personal traits of the employees, which if not constructive, can lead to negative influences that can precipitate incidents.

It should be realized that it may be virtually impossible to eliminate human errors from occurring and therefore it is incumbent upon an organization to provide additional safeguards that are necessary. Personnel may forget, become confused in some cases, or are not admittedly knowledgeable in the tasks at hand, especially during stressful circumstances and environments. It is therefore useful in critical operations to design systems that may not only be specified as "fail-safe," but also be considered "foolproof." This applies not only to the design of the system for operations, but for maintenance activities, the time when most historically catastrophic incidents have occurred.

A Human Error or Reliability Analysis (HRA) can be performed to identify points that may contribute to an incident. Human errors may occur in all facets of the life cycle of a facility. They are generally related to the complexity of the equipment, human-equipment interfaces, hardware for emergency actions, and procedures for operations, testing, and training. The probability of certain types of errors occurring are normally predicted as indicated in Table 21.1. Individual tasks can be analyzed to deter the probability of an error occurring. From these probabilities, consequences can be identified that determine the risk of a particular error.

Drug and alcohol influences also contribute to an incident occurring. Locations where strict controls or testing for such influences have a relatively lower level of incident occurrence.

Table 21.1 Probability of Human Errors

Probability	Description of Error Type
1.0–0.1	Processes involving creative thinking, unfamiliar operations, a short period of time, or high stress
0.1–0.01	Errors of omission, where dependence is on situational cues and personal memory
0.01–0.001	Errors of commission, i.e., operating wrong buttons, reading the wrong display/gauge, etc.
0.001–0.0001	Errors regularly performed in commonplace tasks
0.0001–0.00001	Extraordinary errors for which it is difficult to conceive how they might occur, occurring in stress-free environments with powerful cues

21.1. HUMAN ATTITUDE

One of the single most influential effects of human performance is attitude. Attitude is the mindset, point of view, cultural influence and the way we look at things. The way we look at things is partly responsible for the nature of our behavior and performance. A poor attitude may lead to errors resulting in an incident. Many organizations today strive to create a learning organization, which can be defined as one that is continually learning new KSAs (Knowledge, Skills, Abilities, and Attitudes). Considerable formal effort is applied to increasing our knowledge, skills, and abilities. The results can often be measured with a picture of "where are we now," through key performance indicators (KPIs). In the KSAs group, the one not easily seen or measured is often the one that enables or impairs the learning organization. This is attitude. Why are workers' attitudes so important? Because they're the route to safe behavior within the organization. Recent studies have indicated that employee "success" factors are related 85% to behavior features and only 15% to skills.

Some of the more common attitudes that influence incident behavior are listed below.

Attitude	Description and Consequence
Apathy or indifference	Sluggish, don't care, passive not alert. Such attitude has a detrimental affect on co-workers, in that it can infect the entire organization
Complacency	Satisfied, content, and comfortable. This happens when things are going smoothly. The workers then drop their guard and become vulnerable
Hostility	Getting angry or mad. Chip on the shoulder, arrogance, and argumentative, sometimes sullen. Vision narrows and they become victims of unseen hazards
Impatience	Hasty, hurried, and anxious. Impatience makes you do things you would not normally do. This increases risk-taking mentality, especially if peer pressure is involved
Impulsiveness	Spontaneous or spur-of-the-moment. This is risk-taking activity and is characterized by undertaking an act first and asking questions later attitude
Impunity	No penalty or consequence feeling, it can't happen to me. Immune from sanctions
Invulnerability	Invincible, superman complex. Invulnerability is an illusion that does not recognize reality

(*Continued*)

Attitude	Description and Consequence
Negligence	Lax, remiss, or not prudent. This is a failure to do what should be done or deliberately doing what should not be done. Forms the basis of most negative legal actions
Overconfidence	Brash risk taker. May take shortcuts
Nepotism	Family relationship in organization will support me so can undertake anything with impunity and others will not challenge actions for fear of retribution
Rebelliousness	Defiant, disobedient, rule breaker. Often in hostile nature. Difficult to work with
Recklessness	Irresponsible, not trustworthy or reliable, often self-centered. A risk taker
No ownership	No personal stake in anything. This is opposite of accountability
Procrastination	Constantly leaving activities to the last minute. Lack of organization and discipline for meeting obligations. This may eventually lead to needed activities not being undertaken at required times

The best treatment for most of these attitudes is the development of an effective safety culture within the organization. A positive safety culture is exemplified by senior management with employee involvement that demonstrates the mutual benefits of an incident-free environment for both the organization and the individual. Sometimes supervisors find they can't always directly influence workers' behavior. Rules may not work; training may not work. But attitudes usually drive behavior. People learn by watching others. They pay attention to what others do and what they say are teaching tools. Workers' attitudes reflect their evaluation of what they've learned.

Employees can help change each other's attitudes by their own beliefs and the attitude they exhibit toward those beliefs. If they believe that incidents in the workplace can be prevented, others in the workplace (attitudes and behaviors) will reflect that belief. Their attitude in turn will affect what other workers believe and, ultimately, how they behave. What I do, what I say, and how I say it can change lives and prevent an incident from occurring. Organizations that can effect this change in attitude are true learning organizations.

21.2. CONTROL ROOM CONSOLES

Control room consoles are where the main observation and commands to process systems are undertaken and are vitally important for safe plant operations. Proper display, ease of operation, and understanding are required parameters for these operations. Common major concerns for any of these facilities include the following:

- **Observation Error**—Reading the wrong information from a display
- **Wrong Indication**—Reading an item and mistaking it for another
- **Information Saturation**—A display with too much information or where information has to be searched for
- **Alarm Saturation**—Providing too many possible alarms that could occur at one time that can overwhelm an operator
- **Lack of Anticipation**—Observation of satisfactory process condition may lead to complacency in foreseeing developing problems if the "ordinary" data is not clearly understood
- **Manipulation Error**—Undertaking the wrong action from received data possibly from poor graphic design

Control room monitoring is commonly undertaken with computer console video displays to indicate and control the process immediately. To reduce the frequency of errors the following technical solutions should be implemented:

- All devices on display should be provided with names and identification numbers.
- The display should be cleared divided into separate areas, with sub-screens provided for more details or support systems.
- Color coding of equipment and its status should be provided.
- Individual instrument readings for equipment should be available for call-up and provided whenever possible.
- The display should provide for verification of device parameters, i.e., pump operation, valve position, etc.
- Provision of alarm hierarchy programming so than highly important alarms are given more highlighting in display than other common alarms.
- Reviewing the level of operations alarms received for consistency with limits of acceptability for the industry.

21.3. FIELD DEVICES

Field alarm indications and control panels should be easily viewable, accessible, and strategically placed. Emergency equipment, process controls/valves, and firefighting devices should be arranged and mounted at heights assessable by the average individual. This includes portable fire extinguishers, hose connections to fire hydrants, plant fixed fire hose reels, access to emergency shut-off valves, emergency stop/ESD push buttons, etc.

21.4. INSTRUCTIONS, MARKINGS, AND IDENTIFICATION

There are six basic categories of signs that can be provided. These are normally considered the following:

- **Firefighting**—Those giving information or instructions about fire prevention and firefighting equipment (e.g., no smoking, no open lights, fire extinguisher location, etc.).
- **Mandatory**—Those giving instruction or information that must be obeyed or observed (e.g., no photography, no parking, etc.).
- **Emergency**—Those giving instructions to be followed in case of emergency (e.g., in case of fire, exit, assembly areas, etc.).
- **Warning**—Those giving precautionary information that should be heeded to avoid a possible dangerous occurrence (e.g., hard hart required, noise hazard, hazard material information system placard, toxic gas notices, etc.).
- **Prohibition**—Those that prohibit a particular activity (e.g., no cell phone use, no horseplay, etc.).
- **General/Informatory**—Those that convey general information of a non-critical nature and are not covered by the five categories above (e.g., plant safety incident statistics, information/location of areas, etc.).

Instruction signs should be posted at all emergency systems in which the operation of the device or system is not inherently obvious, i.e., fire pump startup, fixed foam systems, etc. Flow arrows should be provided on piping where isolation means is provided. Numbering of hydrants, monitors, and pumps foam chambers can all enhance the operational use of such equipment. Even the numbering of pipe rack supports, pipe culverts, etc., can assist in identifying a location during an emergency incident. Control panel labels should be provided that are descriptive instead of just numerical.

Warning and instructional signs and instructions should be primarily provided in the national language of the country of operation. They should be concise and direct. Use of jargon, slang, or local dialect references should always be avoided, unless the abbreviation is commonly known and used by the population, versus the descriptive word or words. English has primarily been in used in worldwide locations where western oil companies operate and is generally utilized in the industry for these areas.

Labels should be as precise as possible without distorting the intended meaning or information. They should not be ambiguous, use trade names, company logos, or other information not directly involved in the performance of the required functions.

The following are common problems that may be faced in the petroleum and chemical industries pertaining to labeling:

- Poor, deteriorated, or missing labels
- Similar names are used that may be confusing or misleading
- Supplied labels are not understood
- Labels are not supplied in a consistent format
- Labels (i.e., equipment) are not specified in sequential or logical order
- Labels are printed incorrectly and not quality checked
- Labels are placed in a location that makes them difficult to read
- There is no consistent national standard for the technical information to provide (e.g., hazard rating levels for HMIS material data, which leads to inconsistency in numerical ratings that may be used)

21.5. COLORS AND IDENTIFICATION

21.5.1 Colors

Standard colors have been adopted in the industrial world for the identification of hazards, marking of safety equipment, and operating modes of typical equipment. These conventions have been incorporated into regulations and standards (Ref. OSHA 29 CFR 1910.144) used worldwide for the recognition of such devices and are categorized in Table 21.2.

The colors purple, brown, black, and gray have not been assigned a safety connotation. Specific color codes are also employed in the identification of alarm panel indicators, piping, compressed gas cylinders, electrical wiring, fire sprinkler temperature ratings, etc. It should be noted that the color coding from one type of object to another (e.g., piping to cylinders) typically does not correspond.

It should also be mentioned that there may be slight confusion caused by certain color indicating lamps, console displays, or buttons by the industry. Typically the industry uses red for hazardous running conditions (e.g., operating a pump) versus the common traffic signal red for stop and

Table 21.2 Color Coding Applications

Color	Application
Red	• Stop buttons or electrical switches used for stopping machines • Emergency handles or bars on machines • Hazardous indication lights on control panels, alarm panels, or in the installation • Fire protection equipment and systems (e.g., fire hydrants, hose reels, alarm points, etc.) • Stop condition • Identification of ESD isolation actuators and valves • Barrier lights • Danger signs
Orange	• Warning signs • Marking of guards for machines • Wind socks • Personal floatation devices and lifeboats
Yellow	• Caution signs • Highlighting physical hazards (e.g., yellow and black striping, hazard alerting signs) • Cabinets for flammable liquid storage • Marking of containers or corrosive or unstable materials • Caution condition • Traffic or road markings
Green	• Safety instruction and safety equipment location signs • Marking of safety equipment (e.g., stretchers, first aid kit) • Marking of emergency egress and evacuation routes • Control panel indication of a safe status of a operating mechanism • Safety showers and eyewashes • Electrical grounding conductors • Safe or acceptable condition indicators
Blue	• Notice signs • Advisory, informational, and instructional signs • Mandatory action signs • H_2S warning indicator (beacon)
White	• Road markings • Medical or fire suppression vehicles

vice versa. Red is also used as the color of an ESD push button to stop an operation. On the face value it appears this is a conflict of meanings. If the overall meaning of hazardous versus safe is kept in mind, then the colors have more relevance. NFPA 79 provides a definition of when a particular color is used, but this may be slightly confusing to personnel new to the industry as the example of red above highlights.

21.5.2 Numbering and Identification

Process instrumentation displays should be arranged in relation to each other according to their sequence of use or functional relationship to the components they represent. They should be arranged in groups, whenever possible, to provide viewing flow from left to right, top to bottom.

Process vessels and equipment should be provided with identification for the field that is legible from approximately 30 m (100 ft.) away. It should be viewable from the normal access points to the facility or equipment and should use contrasting colors. The identifications normally consist of the equipment identification number and the common name of the equipment, e.g., "V-201, Propane Surge Drum." This is beneficial during routine and emergency periods where the quick identification of process equipment is critical and necessary from a distance.

21.5.3 Noise Control

High noise levels emitted by facility equipment can damage the hearing of personnel working at the installation, be a nuisance to the local community, and interfere with the annunciation of emergency alarms and instructions. The main sources of noise are rotating equipment (pumps, compressors, turbines, etc.), air-cooler fans, furnaces or heaters, vents, and flares. Noise levels may be extremely high during an emergency due to the operation of relief systems, depressurization, blowdown, and flare systems operating at their maximum capacities without adequate measures to control the ambient noise levels. This may be simultaneous with plant sirens and emergency vehicle horns.

Distance is a major factor in reducing nuisance noise and suitable spacing should be considered in the plant initial layout. The acceptable amount of noise generation should be specified on the purchase order for equipment. Where sound levels cannot be alleviated by purchasing a different make of equipment, sound attenuation devices should be fitted (e.g., enclosures) as an alternative.

Whenever ambient noise levels are above emergency alarm signals or tones, flashing lights or beacons should be considered that are visible in all portions of the affected area. The color of flashing lights should be consistent with safety warning colors adopted at the facility.

21.5.4 Panic

Panic or irrational behavior might occur during any emergency. It is the result of unfamiliarity, confusion, and fright. Panic affects individuals in different ways. Individual panic occurs as a unique individual response without triggering a similar response in others. Panic may exacerbate the consequences of an explosion and prevent personnel from performing their responsibilities correctly. It has been observed to affect individuals in the following manner:

- It may produce illogical or indecisive actions to control or minimize an incident, for example, operating the wrong valve or failure to activate process emergency controls or functions.
- Personnel may impede escape mechanisms by using the wrong routes, not being organized for orderly evacuations, etc. (Recent research indicates physical competition between participants has typically not occurred in fire incident evacuations.)
- It may produce hyperactivity in personnel. Hyperventilation will exacerbate the effects of irritants and toxic gases present.
- Personnel required to perform emergency functions may freeze or become unable to undertake decisive actions. Without decisive action they may succumb to the ever increasing effects of the incident.

Training (such as frequent realistic emergency drills), clear instructions (outlined in emergency response plans), and personal self-awareness are ways to prevent or minimize the effects of panic. Personnel should be trained for all creditable emergencies with adequately written generic procedures that outline contingencies. Regular training for emergencies and evacuation, with both plant and governmental support agencies, should familiarize personnel with emergency events, location of emergency equipment and techniques, and alleviate concerns and doubts. Follow-up drill/training critique meetings are helpful in resolving issues that may arise. Mechanisms that can be automated (e.g., emergency call systems) once an emergency has been realized should be considered in order to avoid undue stress to personnel and avoidance of human errors.

21.5.5 Security

Unfortunately most process facilities, especially petroleum producing ones, have become targets for political/religious extremists. Numerous terrorist activities have been directed toward these installations as either figurative demonstrations or for real intent of destruction. Additionally, industrial facilities can become the target of labor unrest.

In 2007, the US Department of Homeland Security (DHS) issued the Chemical Facility Anti-Terrorism Standard (CFATS). The objective is to identify, assess, and ensure effective security at high-risk chemical facilities. Included in the standard is the requirement for facilities handing chemicals above a threshold amount to submit a Security Vulnerability Assessment (SVA) for DHS review and approval along with a Site Security Plan (SSP). Additionally, nowadays internal company procedures, although confidential, should mandate the need to identify and assess such a risk. Both API and AIChE have issued guidelines to assist in such security reviews and these are undertaken in a manner similar to a Safety Qualitative Risk Assessment. The first step in these reviews, however, to undertake a threat analysis to identity those threats that are deemed most applicable to the facility and to the locations that are likely targets. The threat analysis identifies the source of threats, potential goals, and objectives of the adversaries and assessment of the likelihood of the threat, taking into account the motivation and capabilities and the target's attractiveness. From this the SVA is undertaken to determine consequences and safeguards.

Similar to fire and explosion protection methodology, a layered level of security measures is usually instituted for protection.

21.5.6 Accommodation of Religious Functions

In some parts of the world, religious functions may occur several times a day and every day of the week. These activities are required to be performed at the immediate location of the individual. These activities must be respected and accommodated for the employees and personnel who may be in attendance at the facility. Typically where facilities are located in areas where such practices are performed, a specialized installation (i.e., mosque) is normally provided. The primary concern is that such an installation does not interfere with the operation of the facility, is not provided within the confines of a hazardous location (i.e., process location), and that it is shielded or removed from the effects of an explosion or fire. Typical applications provide these specialized facilities just outside the security fencing and access gate to a facility.

FURTHER READING

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APPENDIX A

Testing Firewater Systems

The following appendices provide generic information on the periodic operational testing parameters used in the process industries for active fire protection systems (i.e., pumps, deluge systems, monitors, hose reels, foam systems, etc.). Further information can be found in the publication, NFPA 25 Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems.

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APPENDIX A-1

Testing of Firewater Pumping Systems

The following is a generic test procedure that may be used to for flow performance tests of fixed firewater pumps. The purpose of this procedure is to provide operations and engineering personnel the basic steps and engineering knowledge to adequately and efficiently perform the performance testing that may be necessary to comply with company policies and procedures. The procedure should be revised and modified as appropriate to highlight the exact items and valve setups that are necessary. The procedure should also be performed according to local work permit arrangements and procedures.

Testing periods should be arranged with the appropriate management of any installation though approved work orders or permits for the facility. Careful observation of the equipment under testing should be made to detect any abnormalities and signs of impending failures. The operational testing area should be restricted to the personnel solely involved in the testing.

Normal fire protection practices and standards recommend fire pumps be tested annually to determine performance levels. Common practice in the process industries is to trend the flow performance to prepare predictive maintenance and replacement forecasts. Such forecasts can predict poor pump performance and help maintenance organizations implement corrective actions before this occurs. Typically a variance of 5% or more from the rated pump curve warrants further investigation and improvement (NFPA 25, Chapter 8, and Appendix C).

A-1.1. BASIC PROCEDURE

1. Obtain the manufacturer's pump curve for the unit to be tested. Confirm the pump to be tested is properly identified, i.e., verify name-plate tag number, manufacturer's serial number, etc.
2. Confirm that pump piping arrangements have been installed to NFPA 20 requirements, i.e., connections, cooling water take-offs, reducers, etc.
3. Observe the condition of the fire pump controller panel. Verify no trouble indications, normal readings, and in operation.

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4. Ensure calibrated pressure gauges, 0–1, 380 kPa (0–200 psig), are installed on the suction and discharge of each fire pump to be tested (record calibration dates on the flow performance data sheet, with +/−3% accuracy). For pumps taking suction lift, calculate the NPSH to the level of pump discharge. Offshore installation vertical turbine lift fire pumps require a calculation of the vertical head loss to the point of pressure reading, taking into account tide levels and seawater densities.
5. Determine the flow measurement method to be used during the test, i.e., flowmeter or pitot tube measurement from the nearest available water outlets on the system. Ensure the flow measurement devices are calibrated or adjusted for the fire pump maximum flow output.
6. Ensure independent measurement devices for verification of driver (i.e., engine) and pump rpm are available and accurate, i.e., strobe light handheld tachometer.
7. Ensure the recycle valve is closed if water is to be measured at the local water outlet or the system discharge valve is closed if water is to be recycled into storage.
8. If a relief valves is fitted (for variable speed drivers), verify piping is rated for maximum pump pressure output then isolate relief valve only during testing period, otherwise leave relief valve in service during testing activities.
9. Open the fire pump discharge valve approximately 50%.
10. Start the fire pump to be tested and let it run for a minimum of 30 min, for stabilization of the mechanical systems. The firewater pump can be started manually from the controller, but it is typically preferred that a local fire water device is opened (i.e., fire hydrant(s)) to simulate firewater pump auto-start on low fire main pressure detection. If several fire pumps are arranged to start in sequence, the sequence startup should be verified to confirm programming logic arrangements.
11. Adjust the driver (i.e., engine) rpm to operate the pump as close as possible to the rated rpm performance curve.
12. Record five pressure (at both inlet and outlet) and flow readings for the pump, near the following rated flow points—0%, 50%, 100%, 125%, and 150% (by opening or closing the outlet piping valve), while simultaneously recording the rpm. The time of flow for each of these test points should be adequate to ensure the flow has been stabilized.

13. While performing the test, continuous monitoring of the driver and pump should be maintained during the test. Special attention should be given to observe pump bearing lubrication, seal performance, driver condition (oil leakages, water cooling, gauge operation, etc.), abnormal vibration, water leaks, and fire pump controller alarms. Any unusual observations should be brought to the attention of maintenance personnel immediately.
14. Plot the test points against the rated pump curve adjusted for the rated rpm of the firewater pump under testing. If conditions permit, data should be plotted immediately during the test to indicate abnormalities that may be corrected, e.g., partially closed or open valves.

A-1.2. SUPPLEMENTAL CHECKS

For engine-driven units, a sample of the fuel supply in the day tank should be taken. It should be analyzed for indications of water or sediment contaminations. The sample should be allowed to stabilize for 24 h to determine the content. Entrained water will collect at the bottom of the sample container and hydrocarbon fluids will collect on top of it. Particulates will settle to the bottom.

Certify no leakages of oil or water for the engine-driven units. The flexible connections for cooling water and fuel supplies should be checked for deterioration, cracks, etc.

Verify firewater pump startup on low pressure indication if such capability has been provided and tested while flow performance testing is undertaken.

Verification of fire pump startup and flow and pressure indications in the plant DCS should be confirmed if such indications are provided as part of the plant monitoring system. Remote stopping of the firewater pump should not be allowed.

A-1.3. CORRECTION FACTORS FOR OBSERVED TEST RPM TO RATED RPM OF DRIVER

Flow at Rated RPM = (rated RPM/observed RPM) $\times$ (observed Flow Rate).
Net Pressure at Rated RPM = (rated RPM/observed RPM)^2 $\times$ (Net Pressure).

Typical Data Form for Fire Pump Testing

SUPPLEMENTAL FIRE PUMP TEST INFORMATION

Pump No.____

Location:____

Date of Test:____

Test Conducted By:____

Tide: Meters________________________or Feet____________________________________

Correction for GPM: Rated RPM/Pump RPM x GPM = GPM Correction Factor (GCF)

Correction for PSI: $(\text{Rated RPM})^2/(\text{Pump RPM})^2$ x PSI = PSI Correction Factor (PCF)

Test Point Correction (Each change in driver (engine) speed requires a new correction factor)

GPM________ x GCF ( ) = Corr. GPM 1_____2_____3_____4_____5_____

PSI__________x PCF ( ) = Corr. PSI 1_____2_____3_____4_____5_____

Driver: Performance: Smooth__________Rough__________

Temperature Low______Normal______High______

Fuel Level ¼ ½ ¾ Full

Fuel Sample Clean_____Dirty_____Water____Other________

Comments:____
(Note any unusual noise, smoke, mechanical condition)

Right Angle Drive: Smooth_____Rough_____Comments________________________________

Pump Performance

Flow % Above___________% Below_____________Rated Curve

Pressure % Above___________% Below______________Rated Curve

Comments____

Supplemental Fire Pump Testing Form

FIRE PUMP TEST REPORT

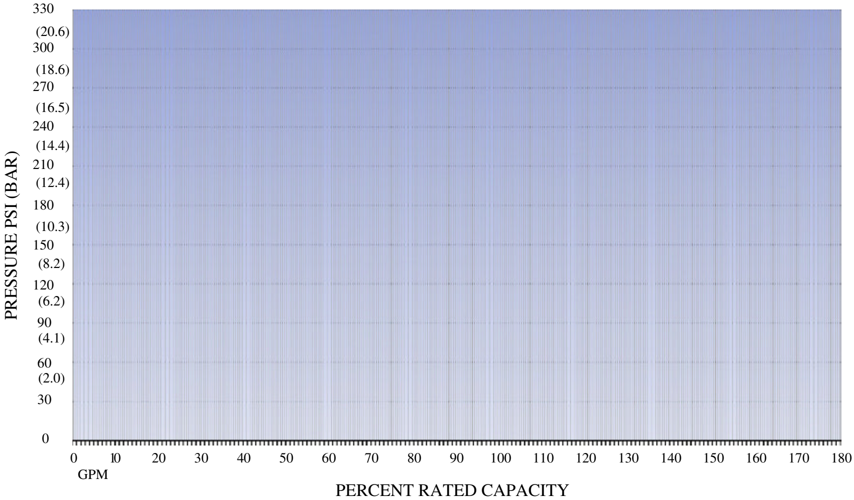
Location	**Pump**	**Driver**
____________________	No.___________________	Mfg._______________________
Date________________	Mfg.__________________	Type_______________________
By__________________	Type__________________	Power______________________
Time: Start___________	Rating_________________	Engine Hours________________
Stop___________	RPM__________________	Gear Ratio__________________

Calibration Dates:

Gages__________Flow Meter__________PSV__________PSV Setting: Bar______PSI_____

RPM	**Pump Pressure**			**Flowmeter**		**Corrected to Rated RPM**		**Percent Rated Capacity**
	Discharge	Suction	Net	Reading	x (GPM)	Net Head	Flow	

PUMP CURVE:


PRESSURE PSI (BAR)
330
(20.6)
300
(18.6)
270
(16.5)
240
(14.4)
210
(12.4)
180
(10.3)
150
(8.2)
120
(6.2)
90
(4.1)
60
(2.0)
30
0
0 10 20 30 40 50 60 70 80 90 100 110 120 130 140 150 160 170 180
GPM
PERCENT RATED CAPACITY

APPENDIX A-2

Testing of Firewater Distribution Systems

A-2.1. GENERAL CONSIDERATIONS

Testing of firewater distributions systems is performed to determine if the condition of the system is adequate to support a worst case credible event (WCCE) need for firewater. The condition of the piping, leaks, existence of closed valves or sediment, operability of valves for firewater delivery systems (sprinklers, deluge, hose reels, monitors) should be determined annually, but at a minimum every 5 years (NFPA 25, Chapter 7).

Typically a network of firewater mains is provided in a process facility that forms loops. These can be segregated into sections or legs and performance of each can be determined by flow tests. Flow tests release quantities of water that can then be measured and graphed. Performing an initial acceptance baseline test and recording the results year to year can show the performance of the firewater system and projections of the useful life of the system can be determined.

The flow is measured by the use of a pitot tool that is inserted into water flow to measure the velocity pressure of the fluid flow. Engineering tables are available that convert the velocity pressure into flow based on the outlet size using the formula $Q=(A)\times(V)$, where Q=Quantity, A=Area, V=Velocity.

The following is a generic test procedure that may be used to undertake a flow performance test of the firewater distribution network.

Determine which fire main is to be analyzed. Within this segment, select the hydrants that are the most remote on the system from the source of supply. Most remote is intended to mean the most remote hydraulically and the selected hydrants may not be the most remote physically. A test hydrant and flow hydrant(s) are then identified. The data collected will refer to the test hydrant. The flow hydrant is the next downstream hydrant(s) from the test hydrant.

It is imperative that the water mains are flowing in one direction only during the test (i.e., from the test hydrant to the flow hydrant). In the case of looped and gridiron mains, the water may be flowing in two directions

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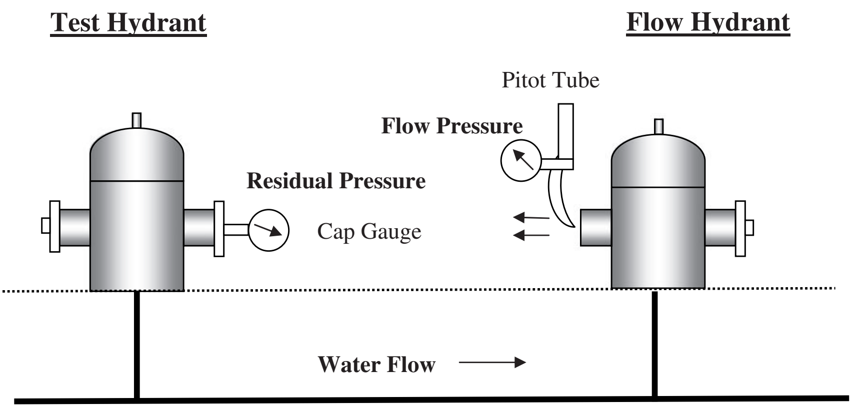
and then issuing from the flow hydrant depending on the particular test being undertaken.

A-2.2. FIREWATER DISTRIBUTION SYSTEM

A-2.2.1 Testing Procedure

- Make preparations to conduct the testing—prepare scheduling, coordinate with operations, obtain calibrated pressure gauges (no greater than ±3% accuracy) and pitot tube measurement tool, ensure water flows will not affect operations, etc.
- Choose the "test hydrant" for the static and residual pressure readings and record the date, time, and location of the test. Remove one of the hydrant outlet caps and attach a recently calibrated pressure gauge cap fitted with a petcock valve. Slowly open the hydrant and bleed off any trapped air through the petcock valve on the pressure gauge cap, then close the petcock valve.
- Record the reading on the pressure gauge as the fire flow static pressure. Leave the test hydrant valve open.
- Continue along the fire main in the direction of water travel to the next hydrant identified as the "flow hydrant(s)." Remove the flow hydrant outlet caps and verify the outlet internal diameter *t* to the nearest 1/16 of an inch.
- Determine the flow hydrant coefficient of discharge, "C" (see Appendix B-4).
- Slowly open the flow hydrant full bore and wait at least 1 min or longer until the flow stabilizes and a clear stream is established.
- Insert the pitot tube flow measuring tool into the center of the flow hydrant outlet water flow, bleed off air from the pitot tool, and then measure the pitot gauge pressure. The pitot tube tip must be inserted into the center of the water flow stream at a distance of one-half the diameter away from the outlet of the hydrant to obtain an accurate reading.
- Record the pitot tube gauge pressure. If the gauge pressure needle is oscillating, record the average of the readings. The most accurate results are obtained with pitot readings between 69.9 and 206.9 (10 and 30 psi). If the pressure gauge readings are higher than this, open another outlet on the flow hydrant and pitot both the flows, or close the outlet on the flow until a pitot reading of less than 206.9 (30 psi) is obtained. Additional flow hydrants may also be used if downstream of the test hydrant. If more than one outlet was opened, always measure the pitot pressure for each outlet and record the readings for each outlet.

- If the pitot gauge pressure reading is less than 69.9 kPa (10 psi), then a smooth bore tapering nozzle should be placed on the flow outlet to reduce the size of the opening and increase the flow pressure.
- Simultaneous with the previous step, record the pressure on the test hydrant as the fire flow, residual pressure.
- If a pressure gradient is desired of the entire system, additional pressure cap gauges can be attached to hydrants along several points of the water main form the source of supply to the flow hydrant and "residual" pressure readings taken for each flow measurement.
- If a second test is desired, the flow hydrant outlet may be throttled to any desired point and the pitot gauge pressure read along with the fire flow residual pressure. Obtaining a second flow point will improve the accuracy of the flow test data.
- If no further test readings are necessary, restore the system back to normal by slowly closing all hydrant valves and replacing the outlet caps. Ensure all water has stopped flowing and the hydrant(s) is drained of water before replacing the cap(s).



Fire Distribution Network Flow Test Arrangements

When water flow encounters a loop or grid, two things occur—(1) the flow splits into a determinable ratio, and (2) the pressure drop across each of the two legs will be the same.

There are four methods to test a loop or grid system:

(1) Isolate the Legs—By closing the proper sectioning valves, the water can be forced to flow through one of the legs only. After recording the appropriate date for one leg, arrange the section valves to isolate and flow the second leg. The two flows can then be combined to give the total flow that can be provided through the system (provided facility fire pumps have the capacity and pressure).

(2) Choose Two Hydrants on a Large Main—Normal water paths are always in the direction of least resistance, in other words, generally from the larger mains to the smaller mains. By choosing two hydrants on a large section of pipe (within a loop or grid) and estimating the water flow direction, a test can be conducted.

(3) Simultaneous Flow—In a multi-supply system in which good pressure and volumes are present, this method is desirable. Choose a symmetrically centered hydrant (this is the test hydrant) and simultaneously flow two or more hydrants. Obtain the pitot test readings.

(4) Single Hydrant Flow Test—This method uses a single hydrant at the test and flow hydrant. Static, residual, and flow pressures are all read from the same hydrant. This technique is considered to produce higher levels of error with test data than other methods.

A-2.3. PREPARING TEST RESULTS

The total firewater available at any single point in a system is sometimes stated as the "gpm available at 137.9 kPa (20 psi) residual pressure." The 137.9 (20 psi) is a safety factor that fire departments or company fire brigades utilize so as not to damage water mains. Usually most firewater tests compare the results from year to year to determine if deterioration of the main is occurring (pressure gradient graph) or to confirm the available water supply and pressure in a particular area for design of a new fixed firewater system. Therefore the complete firewater supply graph for a particular area is always useful.

A-2.3.1 Hydrant Flow Data

Readily available flow tables provide the amount of flow through a given size of orifice, given the pitot pressure reading. All pitot flow measurements should be first converted from a pressure reading into a flow reading and then corrected for the outlet discharge coefficient by multiplying by the appropriate factor. The results of individual flows for each hydrant can then be plotted by marking the static pressure at no flow and then the flow at the residual pressure. Connecting the points provides flows and pressures at any desired point. The graph can be used as a visual presentation of all the pressures and volumes that can be expected at the test hydrant through the water main.

APPENDIX A-3

Testing of Sprinkler and Deluge Systems

A-3.1. WET AND DRY PIPE SPRINKLERS

Wet and dry pipe sprinklers are not normally function tested for coverage since design codes have eliminated problems with distribution patterns, provided the installation has been adequately inspected during its construction to approved plans. The normal testing verifies adequate pressure is available, sprinklers not impacted, piping is not plugged, and activation of flow alarms occurs (NFPA 25, Chapter 5).

- *Main Drain*—A flow of the main drain is accomplished that provides an estimate of the residual pressure for the system. Condition of the water will also confirm if the supplies are clean and debris free.
- *Inspector's Test Valve Flow*—The inspector's test valve flows are accomplished on each portion of the system where fitted to ensure system flow can be accomplished. The inspector's test valve outlet should be fitted with an orifice that simulates the flow of one sprinkler head.
- *Alarm Activation*—All systems should be fitted with alarms that will indicate if water flow has occurred. The alarm activation should occur with the activation of one sprinkler head and is usually accomplished by the fitting of an orifice at the inspectors test valve outlet. Water motor gongs should be tested quarterly, other devices semi-annually.
- *Pressure Gauges*—Pressure gauges fitted at the main riser should be working and accurate (i.e., recently calibrated), with no greater than +/− 3% accuracy.
- *Piping*—No system leakages during test operations.
- *Sprinklers*—No damage, corrosion, modifications, or other signs of impairment.

A-3.2. DELUGE SYSTEMS

A full functional wet test of the deluge system is normally performed. The test verifies coverages and density patterns are being achieved. A calculated density plan can be provided during testing to confirm the density rate

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per minute. The mechanism to activate the deluge should be tested under conditions that will simulate as real as can be reasonably obtained. Where equipment to be protected is not normally in place, i.e., trucks, ships, or rail cars, the test should not be conducted until they are in their normal positions during operations (NFPA 25, Chapter 10).

- *Coverage*—Verification of spray coverages and densities (i.e., no dry surfaces or obstructions). Observation of any plugged or damaged nozzles or excessive corrosion concerns.
- *Activation*—Ease of operation and time to full water flow coverage achieved. If activated by an automatic detection system, test simulates detection system activation arrangements (i.e., fusible plug detection pressure release), and if remote activation available, this is done.
- *Alarm Activation*—All systems should be fitted with alarms that will indicate if water flow has occurred. Verification of alarm activation upon water flow (local or remote alarm indications, e.g., plant DCS indication).
- *Drainage*—Applied firewater should drain away from the protected equipment and not pool or collect (i.e., drains are adequately sized and not plugged), especially under the protected equipment or vessels. The deluge system piping adequately drains after deluge flow is completed.
- *Piping*—Verification made that deluge system piping is restrained from movement during water flows.
- *Pressure Gauges*—Pressure gauges fitted at the main riser should be working and accurate (i.e., recently calibrated), with no greater than +/− 3% accuracy, and indication in plant DCS, if provided.
- *Sprinklers*—No damage, corrosion, modifications, or other signs of impairment.

APPENDIX A-4

Testing of Foam Fire Suppression Systems

Fixed foam fire suppression systems are provided at processing facilities where there are large quantities of combustible liquids that pose a high risk. Additionally mobile firefighting vehicles may use foam applications. The primary concern with foam fire suppression system performance is the proper production of the foam agent and the time to provide adequate foam sealage coverage to the designated surface area requiring protection.

Foam fire suppression systems are designed to proportion liquid foam concentrate in the foamwater distribution network at certain ratios, usually expressed in percentages. The most common of these are 1%, 3%, and 6%. The foamwater can then be aspirated or non-aspirated to the appropriate liquid surface as the risk demands. The foam production should be verified that it is being proportioned in the ratio designed for the system, otherwise foam consistency may be inadequate and foam supplies will be consumed at rates higher than expected. Acceptable ranges of proportioning systems are not less than the rated concentration, and not more than 30% above the rated concentration or one percentage point above the rated concentration, whichever is less. For example, the acceptable proportioning range for a 3% concentrate is 3.0 to 3.9%.

There are two acceptable methods for measuring foam concentrate percentage in water: the Refractive Index Method or the Conductivity Method. Both methods are based on comparing foam solution test samples to premeasured solutions that are plotted on a baseline graph of percent concentration versus instrument reading. The highest degree of accuracy may be achieved using the conductivity meter but results can be skewed when water of varying quality such as salty, brackish, or fluctuating temperatures is used for making foam solution. One manufacturer recommends a handheld refractometer that has an accuracy approaching that of the conductivity meter (but less prone to problems with varying water qualities) as the best option for most proportioning tests.

Coverage confirmation, time to provide full foam coverage, leaks, blockages, rupture disk condition/function, age of foam (i.e., not expired),

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portioning calibration mechanisms, performance of delivery pumps or bladder tanks, foam drain times, etc., should be verified for each unique system. NFPA 11, Standard for Low-, Medium-, and High-Expansion Foam and NFPA 25, Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems provide guidance on the specific test requirements for several characteristic foam systems.

APPENDIX A-5

Testing of Firewater Hose Reels and Monitors

A-5.1. GENERAL REQUIREMENTS

All manually directed devices should be tested for coverage and range of water sprays. Flow testing should uncover water pressure deficiencies, blockages, and verify proper operation of the device. Wind strength can either enhance or degrade the range of water spray depending on if it is upwind or downwind. Residual pressures should be noted during full flow conditions (NFPA 25, Chapter 6, NFPA 1961, and NFPA 1962).

A-5.2. HOSE REELS

Hard rubber fire hoses are usually provided throughout a process facility. The coil of a hose on a hose reel presents a considerable friction loss factor to the flow of water through it. In some instances, a firewater hose reel may not be completely unrolled from the reel before it is used. Therefore it is prudent to conduct a hose reel flow test with partial removal of the hose and full unreeling from it. The spray extent of each can then be fully evaluated and observed.

The following items should be checked:

- *Condition of the Hose*—deterioration—cracking, abrasion, and connections.
- *Condition of the Nozzle*—corrosion, particulate/mineral collection, functionality, etc.
- *Operational Test*—coverage and reach, pressure, water quality, and sediment, isolation valve operation/leakage. It is preferred that an annual flow test be performed, but at a minimum a flow test at the most hydraulically remote hose should be performed every 5 years.
- *Hose Reel Mechanism*—condition-corrosion, ease of use, damage, painting, and identification. Structural support intact.

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- *Accessibility*—clearances/access to hose reel, floor/pavement marking for clear areas.
- *Protection from the Environment*—sunlight, freezing weather, etc.

A-5.3. MONITORS

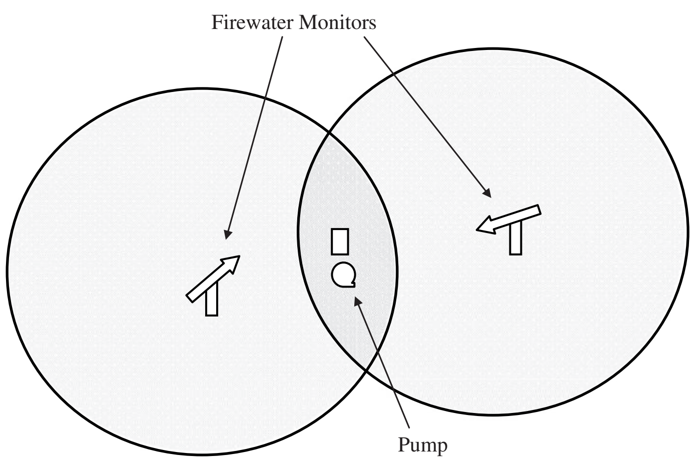
The placement of monitors should be cognizant of obstructions. The arc and depth of the spray coverage should be confirmed.

Where monitors are placed close to hazards, such as helicopter landing sites, supplemental heat shields should be considered for operator protection. The heat shield should not obstruct the vision of the operator and clear heat resistant plexi-glass panels should be used at some installations.

Dual coverage for high leak potential areas, e.g., pumps, compressors, should be verified during actual flow testing.

The following items should be checked:

- *Condition of the monitor*—corrosion, ease of use, damage, painting, and identification.
- *Operational Test*—coverage and reach, pressure, water quality, and sediment, isolation valve/nozzle operation/leakage. It is preferred that an annual flow test be performed.
- *Accessibility*—clearances/access to monitor.



APPENDIX A-6

Fire Protection Hydrostatic Testing Requirements

Fixed System	Pressure Requirement (System Piping)	Duration (h)	Reference
Distribution Network Hydrants and Monitors	1.8 bar (200 psi)	2	NFPA 24, Para. 10.10.2.2.
Standpipe Systems and Hose Reels	1.8 bar (200 psi)	2	NFPA 14, Para. 11.4
Sprinkler Systems	1.8 bar (200 psi)[a]	2	NFPA 13. Para. 10.10.2.2.
Deluge and Water Spray Systems	7.8 bar (200 psi)[a]	2	NFPA 15, Para. 10.2.4.
Foam Water Systems	1.8 bar (200 psi)[a]	2	NFPA 16, Para. 8.2.
CO_2 Fixed Systems[b,c]	No mention	N/A	NFPA 12
Dry Chemical Systems[b]	See Note 1	N/A	NFPA 17, Para. 10.4.3.2 and 11.5.
Wet Chemical Systems[b]	No mention	N/A	NFPA 17A, Para. 7.5.

[a]Or at 3.4 bar (50 psi) in excess of the maximum static pressure where the maximum static pressure exceeds 10.3 bar (150 psi).[b]Limited to hoses and agent containers.[c]Valves used in systems using low pressure storage to withstand a hydrostatic test to 12,411 kPa (1,800 psi).
Note 1: Piping not to be hydrostatically tested.

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APPENDIX B

Reference Data

The following appendices provide references to standards, fire resistance nomenclature, electrical ratings, hydraulic data, and conversion factors commonly referred to while examining and designing fire and explosion protection systems for the process industry.

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APPENDIX B-1

Fire Resistance Testing Standards

The following is a listing of specific US industry standards for fire performance testing for specific fire exposures that may be utilized in the process industries.

API Spec. 6FA	Specification for Fire Test for Valves, Reaffirmed 2011
API Spec. 6FB	Specification for Fire Test for End Connections, Reaffirmed 2011
API Spec. 6FC	Specification for Fire Test for Valves with Automatic Backseats, 2009
API Spec. 6FD	Specification for Fire Test for Check Valves, 2008
API Bul. 6F1	Technical Report on Performance of API and ANSI End Connections in a Fire Test According to API Specification 6FA, 1999
API Bul. 6F2	Technical Report on Fire Resistance Improvements for API Flanges, 1999
API Std. 607	Testing of Valves-Fire Type—Testing Requirements, 2010
ASTM E-84	Test Method for Surface Burning Characteristics of Building Materials, 2013
ASTM E-108	Test Methods for Fire Test of Roof Coverings, 2011
ASTM E-119	Test Methods for Fire Tests of Building Construction and Materials, 2012
ASTM E-136	Test Method for Behavior of Materials in a Vertical Tube Furnace at 750°C, 2012
ASTM E-162	Test Method for Surface Flammability of Materials Using a Radiant Heat Energy Source, 2013
ASTM E-648	Test Method for Critical Radiant Flux of Floor-Covering Systems Using a Radiant Heat Energy Source, 2010
ASTM E-662	Test Method for Specific Optical Density of Smoke Generated by Solid Materials, 2013
ASTM E-814	Test Method for Fire Tests of Penetration Firestop Systems, 2011
ASTM E-1529	Test Methods for Determining Effects of Large Hydrocarbon Pool Fires on Structural Members and Assemblies, 2006

(*Continued*)

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ASTM E-2032	Guide for Extension of Data from Fire Resistance Tests Conducted in Accordance with ASTM E-119, 2009
IEEE 1202	Standard for Flame Testing of Cables for Use in Cable Tray in Industrial and Commercial Occupancies, 2006
IMO A763 (18)	Guidelines for the Application of Plastic Pipes on Ships/Guide for Certification of FRP Hydrocarbon Production Piping Systems, (ABS Publication 137), 2005
NFPA 251	Standard Methods of Tests of Fire Resistance of Building Construction and Materials, 2006
NFPA 252	Standard Methods of Fire Tests of Door Assemblies, 2012
NFPA 253	Standard Method of Test for Critical Radiant Flux of Floor Covering Systems Using a Radiant Heat Energy Source, 2011
NFPA 257	Fire Tests for Window and Glass Block Assemblies, 2012
NFPA 259	Standard Test Method for Potential Heat of Building Materials, 2013
NFPA 260	Standard Methods of Tests and Classification System for Cigarette Ignition Resistance of Components of Upholstered Furniture, 2013
NFPA 262	Standard Method of Test for Flame Travel and Smoke of Wires and Cables for Use in Air-Handling Spaces, 2011
NFPA 268	Standard Test Method for Determining Ignitibility of Exterior Wall Assemblies Using a Radiant Heat Energy Source, 2007
NFPA 288	Methods of Fire Tests of Floor Fire Door Assemblies Installed Horizontally in Fire Resistance-Rated Floor Systems, 2007
SOLAS	Standard Fire Test (Chapter II)
UL 9	Fire Test of Window Assemblies, 2009
UL 10A	Tin-Clad Fire Doors, 2009
UL 10B	Fire Tests of Door Assemblies, 2009
UL 10C	Positive Pressure Fire Tests of Door Assemblies, 2009
UL 263	Fire Tests of Building Construction and Materials, 2011
UL 555	Fire Dampers, 2012
UL 555S	Smoke Dampers, 2013
UL 723	Test for Surface Burning Characteristics of Building Materials, 2013
UL 790	Standard Test Method for Fire Tests of Roof Coverings, 2013

UL 1256	Fire Test of Roof Deck Constructions, 2013
UL 1479	Fire Test of Through-Penetration Fire Stops, 2012
UL 1666	Test for Flame Propagation Height of Electrical and Optical-Fiber Cables Installed Vertically in Shafts, 2012
UL 1685	Vertical Tray Fire-Propagation and Smoke Release Test for Electrical and Optical-Fiber Cables, 2010
UL 1709	Rapid Rise Fire Tess of Protection Materials for Structural Steel, 2011
UL 1715	Fire Test of Interior Finish Material, 2013
UL 1820	Fire Test of Pneumatic Tubing for Flame and Smoke Characteristics, 2013
UL 1887	Fire Test of Plastic Sprinkler Pipe for Flame and Smoke Characteristics, 2013
UL 2080	Fire Resistant Tanks for Flammable and Combustible Liquids, 2000
UL 2196	Tests for Fire Resistive Cables, 2012
UL 2431	Durability of Spray-Applied Fire Resistive Materials, 2012

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APPENDIX B-2

Explosion and Fire Resistance Ratings

B-2.1. FIRE RESISTANCE RATINGS

"A," "B," and "C" fire barriers are normally specified for ships and were originally defined by the Safety of Life at Sea (SOLAS) regulations. Since then they have been used extensively for offshore oil and gas installation construction specifications. As more knowledge of hydrocarbon fires has been gained, "H" fire rated barriers have been specified and are typically defined by a high rise fire test such as UL fire test UL 1709. "J" fire ratings have been discussed and are being used against high pressure hydrocarbon jet fires.

B-2.1.1 A Barriers

A 0	Cellulosic Fire, 60 min barrier against flame and heat passage, no temperature insulation
A 15	Cellulosic Fire, 60 min barrier against flame and heat passage, 15 min temperature insulation
A 30	Cellulosic Fire, 60 min barrier against flame and heat passage, 30 min temperature insulation
A 60	Cellulosic Fire, 60 min barrier against flame and heat passage, 60 min temperature insulation

Class A divisions are those divisions that are formed by decks and bulkheads that comply with the following:

1. They are constructed of steel or of a material of equivalent properties.
2. They are suitable stiffened.
3. They are constructed to prevent the passage of smoke and flame for a one hour standard fire test.
4. They are insulated with approved non-combustible materials such that the average temperature of the unexposed side will not rise more than 180°C (356°F) above the original temperature, within the time listed (A-60: 60 min, A-30: 30 min, A-15: 15 min, A-0: 0 min).

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B-2.1.2 B Barriers

B 0	Cellulosic Fire, 30 min barrier against flame and heat passage, no temperature insulation
B 15	Cellulosic Fire, 30 min barrier against flame and heat passage, 15 min temperature insulation

Class B barriers are those divisions formed by ceilings, bulkheads, or decks that comply with the following:

1. They are constructed to prevent the passage of flame for 30 min for a standard fire test.
2. They have an insulation layer such that the average temperature on the unexposed side will not rise more than 139°C (282°F) above the original temperature, nor will the temperature at any one point, including any joint rise more than 225°C (437°F) above the original temperature (i.e., B-15: 15 min, B-0: 0 min).
3. They are of non-combustible construction.

B-2.1.3 C Barriers

C	Non-combustible construction

Class C barriers are made of non-combustible materials and are not rated to provide any smoke, flame, or temperature restrictions

B-2.1.4 H Barriers

H O	Hydrocarbon Fire, 120 min barrier against flame and heat passage, no temperature insulation
H 60	Hydrocarbon Fire, 120 min barrier against flame and heat passage, 60 min temperature insulation
H 120	Hydrocarbon Fire, 120 min barrier against flame and heat passage, 120 min temperature insulation
H 180	Hydrocarbon Fire, 120 min barrier against flame and heat passage, 180 min temperature insulation
H 240	Hydrocarbon Fire, 120 min barrier against flame and heat passage, 240 min temperature insulation

B-2.1.5 IMO Levels (for Piping Systems, Shipping)

Level 1	60 min hydrocarbon fire exposure, dry pipe
Level 2	30 min hydrocarbon fire exposure, with dry pipe
Level 3	30 min hydrocarbon fire exposure, with 30 min with wet pipe
Level 3 Modified Test	30 min hydrocarbon fire exposure, with initial 5 min dry pipe, 25 remaining minutes as wet pipe

B-2.1.6 J Ratings

Jet fire or "J" ratings are specified by some vendors for resistance to hydrocarbon jet fires. Currently no specific standard or test specification has been adopted by the industry as a whole or by a governmental regulatory body. Some recognized fire testing organizations (e.g., SINTEF, Shell Research, British Gas, etc.) have proposed J fire test standards that are currently being used by some of the major petroleum operators in lieu of a recognized standard.

B-2.1.7 Heat Flux

Heat rate input is normally taken as 205 kW/m2 (65,000 Btu/ft2)—h at 5 min for hydrocarbon fires.

Studies performed on jet fires have reported heat fluxes as high as 400–300 kW/m2 (126,000–94,500 Btu/ft)—h.

B-2.1.8 Fire Doors

0.1 h (20 min), Cellulosic Fire
0.5 h (30 min), Cellulosic Fire
0.75 h (45 min), Cellulosic Fire
1 h, Cellulosic Fire
1.5 h, Cellulosic Fire
3 h, Cellulosic Fire

B-2.1.9 Fire Windows

0.2 h (20 min), Cellulosic Fire
0.5 h (30 min), Cellulosic Fire
0.75 h (45 min), Cellulosic Fire
1 h, Cellulosic Fire
1.5 h, Cellulosic Fire
2 h, Cellulosic Fire
3 h, Cellulosic Fire

B-2.1.10 Explosion Resistance

Refer to the following for guidance:

- ASCE Report Design of Blast-Resistant Buildings in Petrochemical Plants, Second Edition, American Society of Civil Engineers, 2010.

Unified Facilities Criteria (UFC), UFC 3-340-02 Structures to Resist the Effects of Accidental Explosions, (formerly TM 5-1300), US Department of the Army, 2008.

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APPENDIX B-3

National Electrical Manufacturers Association (NEMA) Classifications

The following is a general description of NEMA electrical equipment enclosure definitions from NEMA Publication 250, Enclosures for Electrical Equipment (1000 Volts Maximum).

B-3.1. TYPE 1—GENERAL PURPOSE

A general purpose enclosure that is intended to primarily prevent contact with the enclosed apparatus. It is suitable for general purpose applications indoors where it is not exposed to unusual service conditions and is primarily designed to keep out solid foreign objects such as falling dirt.

B-3.2. TYPE 1A—SEMI-DUST TIGHT

A semi-dust tight enclosure that is similar to a Type 1 enclosure, with the addition of a gasket around the cover.

B-3.3. TYPE 1B—FLUSH TYPE

A flush-type enclosure that is similar to Type 1 enclosure, but is designed for mounting in a wall and is provided with a cover that also serves as a flush plate.

B-3.4. TYPE 2—DRIP PROOF INDOORS

A drip tight enclosure that is intended to prevent contact with the enclosed apparatus and in addition is so constructed as to exclude falling moisture or dirt but is not dust tight. Type 2 enclosures are suitable for applications where condensation may occur, such as encountered in cooling rooms and laundries.

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B-3.5. TYPE 3—DUST TIGHT, RAIN TIGHT, AND SLEET (ICE) RESISTANT OUTDOOR

A weather resistant enclosure intended to provide suitable protection against specified weather hazards. It is suitable for indoor or outdoor use. It is intended to provide a degree of protection against ingress of water (rain, sleet, snow), falling dirt and windblown dust, and undamaged from the formation of external ice on enclosure.

B-3.6. TYPE 3R—RAIN PROOF, SLEET (ICE) RESISTANT, OUTDOOR

A weather resistant enclosure intended to provide suitable protection against specified weather hazards. It is suitable for indoor or outdoor use. It is intended to provide a degree of protection against ingress of water (rain, sleet, snow), falling dirt, and undamaged from the formation of external ice on enclosure. They are to meet the requirements of Underwriters' Laboratories, Inc., Publication No. UL 508, Industrial Control Equipment, applying to "Rainproof Enclosures."

B-3.7. TYPE 3S—DUST TIGHT, RAIN TIGHT, AND SLEET (ICE) PROOF—OUTDOOR

A weather resistant enclosure intended to provide suitable protection against specified weather hazards. It is suitable for indoor or outdoor use. It is intended to provide a degree of protection against ingress of water (rain, sleet, snow), falling dirt and windblown dust, and the external mechanism remain operable when ice laden.

B-3.8. TYPE 3X—DUST TIGHT, RAIN TIGHT, AND SLEET (ICE) PROOF—OUTDOOR, CORROSION RESISTANT

A weather resistant enclosure intended to provide suitable protection against specified weather hazards. It is suitable for indoor or outdoor use. It is intended to provide a degree of protection against ingress of water (rain, sleet, snow), falling dirt and windblown dust, an additional level of protection against corrosion and damage from the formation of external ice on enclosure.

B-3.9. TYPE 3RX—RAIN TIGHT, AND SLEET (ICE) PROOF—OUTDOOR, CORROSION RESISTANT

A weather resistant enclosure intended to provide suitable protection against specified weather hazards. It is suitable for indoor or outdoor use. It is intended to provide a degree of protection against ingress of water (rain, sleet, snow), falling dirt, an additional level of protection against corrosion and damage from the formation of external ice on enclosure.

B-3.10. TYPE 3SX—DUST TIGHT, RAIN TIGHT, ICE RESISTANT, CORROSION RESISTANT

A weather resistant enclosure intended to provide suitable protection against specified weather hazards. It is suitable for indoor or outdoor use. It is intended to provide a degree of protection against ingress of water (rain, sleet, snow), falling dirt and windblown dust, an additional level of protection against corrosion, and the external mechanism remain operable when ice laden.

B-3.11. TYPE 4—WATER TIGHT AND DUST TIGHT

A weather resistant enclosure intended to provide suitable protection against specified weather hazards. It is suitable for indoor or outdoor use. It is intended to provide a degree of protection against ingress of water (rain, sleet, snow, splashing water, and hose directed water), falling dirt and windblown dust, and damage from the formation of external ice on enclosure. Type 4 are suitable for applications on loading docks and in water pump houses but not in electrically classified areas.

B-3.12. TYPE 4X—WATER TIGHT, DUST TIGHT, AND CORROSION RESISTANT

A weather resistant enclosure intended to provide suitable protection against specified weather hazards. It is suitable for indoor or outdoor use. It is intended to provide a degree of protection against ingress of water (rain, sleet, snow, splashing water, and hose directed water), falling dirt and windblown dust, an additional level of protection against corrosion and damage from the formation of external ice on enclosure.

B-3.13. TYPE 5—DUST TIGHT WATER TIGHT

An indoor enclosure with a degree of protection against settling dust, dirt, and non-corrosive liquids (dripping and splashing).

B-3.14. TYPE 6—SUBMERSIBLE

Enclosures intended for indoor or outdoor use primarily to provide a degree of protection against entry of water during occasional temporary submersion at a limited depth (6 feet of water for 30 min). They are not intended to provide protection against conditions such as internal condensation, internal icing or corrosive environments. Type 6 enclosure is suitable for applications where the equipment may be subject to temporary submersion. The design of the enclosure will depend upon the specific conditions of pressure and time. It is also dust tight and sleet (ice) resistant.

B-3.15. TYPE 6P—PROLONGED SUBMERSIBLE

An enclosure for indoor or outdoor use to provide a degree of protection against directed pressurized water application (hose directed water), entry of water during prolonged submersion at limited depth, an additional level of protection against corrosion and damage from external ice formation.

B-3.16. TYPE 7—(A, B, C, OR D) HAZARDOUS LOCATIONS—CLASS I AIR BREAK

National Electrical Code (NEC), Class 1, Division 1, Group A, B, C, or D- Indoor Hazardous Locations-Air-break Equipment—Type 7 enclosures are intended for use indoors, in the atmospheres and locations defined as Class 1, Division I and Group A, B, C, or D in the National Electrical Code. The letter or letters A, B, C, or D which indicate the gas or vapor atmospheres in the hazardous location shall appear as a suffix to the designation "Type 7" to give the complete NEMA designation and correspond to Class 1, Division 1, Group A, B, C, or D, respectively, as defined in the NEC. These enclosures shall be designed in accordance with the requirements of Underwriters' Laboratories, Inc., "Industrial Control Equipment for Use in Hazardous Locations," UL 698, and shall be marked to show the Class and Group letter designations.

B-3.17. TYPE 8—(A, B, C, OR D) HAZARDOUS LOCATIONS—CLASS I OIL IMMERSED

National Electrical Code (NEC), Class 1, Division 1, Group A, B, C, or D-indoor Hazardous Locations-Oil-immersed Equipment—Type 8 enclosures are intended for use indoors, in the atmospheres and locations defined as Class 1, Division I and Group A, B, C, or D in the National Electrical Code. The letter or letters A, B, C, or D which indicate the gas or vapor atmospheres in the hazardous location shall appear as a suffix to the designation "Type 8" to give the complete NEMA designation and correspond to Class 1, Division 1, Group A, B, C, or D, respectively, as defined in the NEC. These enclosures shall be designed in accordance with the requirements of Underwriters' Laboratories, Inc., Publication No. UL 698, "Industrial Control Equipment for Use in Hazardous Locations," and shall be marked to show the Class and Group letter designations.

B-3.18. TYPE 9—(E, F, OR G) HAZARDOUS LOCATIONS—CLASS II

National Electrical Code (NEC), Class II, Division 1, Group E, F, or G-indoor Hazardous Locations-Air-break Equipment—Type 9 enclosures are intended for use indoors in the atmospheres defined as Class 11, Division I and Group E, F, or G in the National Electrical Code. The letter or letters E, F, or G which indicate the dust atmospheres in the hazardous location shall appear as a suffix to the designation "Type 9" to give the complete NEMA designation and correspond to Class 11, Division 1, Group E, F, or G, respectively, as defined in the NEC. These enclosures shall prevent the ingress of explosive amounts of hazardous dust. If gaskets are used, they shall be mechanically attached and of a non-combustible non-deteriorating, vermin proof material. These enclosures shall be designed in accordance with the requirements of Underwriters' Laboratories, Inc., Publication No. UL 698, "Industrial Control Equipment for Use in Hazardous Locations," and shall be marked to show the Class and Group letter designations.

B-3.19. TYPE 10—MINE SAFETY AND HEALTH ADMINISTRATION (MSHA) EXPLOSIONPROOF

An enclosure designed to meet the explosionproof requirements of the US Mine Safety and Health Administration (MSHA) requirements as defined in 30 CFR, Part 18, (Schedule 2G). The equipment is to be used in mines with atmospheres containing methane or natural gas, with or without coal dust. Additional information may be found in their Bulletin 541 and Information Circular 8227.

B-3.20. TYPE 11—CORROSION-RESISTANT AND DRIPPROOF OIL-IMMERSED-INDOOR

Type 11 enclosures are corrosion-resistant and are intended for use indoors to protect the enclosed equipment against dripping, seepage, and external condensation of corrosive liquids. In addition, they protect the enclosed equipment against the corrosive effects of fumes and gases by providing for immersion of the equipment in oil. They are suitable for applications such as chemical plants, plating rooms, sewage plants, etc.

B-3.21. TYPE 12—INDUSTRIAL USE

An indoor enclosure design without knockouts for use in industries where it is desired to exclude such materials such as foreign objects, e.g., dirt, dust, lint fibers, flyings, and ingress of liquids, e.g., dripping and light splashing.

B-3.22. TYPE 12K—INDUSTRIAL USE, WITH KNOCKOUTS

An indoor enclosure design with knockouts for use in industries where it is desired to exclude such materials such as foreign objects, e.g., dirt, dust, lint fibers, flyings, and ingress of liquids, e.g., dripping and light splashing.

B-3.23. TYPE 13—OIL TIGHT AND DUST TIGHT INDOOR

An indoor enclosure design for use in industries where it is desired to exclude such materials such as foreign objects, e.g., dirt, dust, lint fibers, flyings, and ingress of liquids, e.g., dripping and light splashing and a degree of protection against spraying, splashing, and seepage of oil or and non-corrosive coolants. They are intended for use indoors primarily to house pilot devices such as limit switches, foot switches, pushbuttons, selector switches, pilot lights, etc.

Hazardous Atmosphere/NEMA Classification	Type 7				Type 8			
	A	B	C	D	A	B	C	D
Acetylene	X				X			
Hydrogen		X				X		
Diethly Ether, Ethylene, Cylcopropane, etc.			X				X	
Gasoline, Hexane, Naphta, etc.				X				X

NEMA Type 7 (indoor) and Type 8 (indoor and outdoor).
Applications for hydrocarbon environments.
Ref. NEMA publication 250.

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APPENDIX B-4

Hydraulic Data

B-4.1. COEFFICIENT OF DISCHARGE FACTORS

Outlet Type	Discharge Coefficient
Nozzle, Underwriter's Playpipe, or similar	0.97
Nozzle, Deluge Set, or Monitor	0.99
Nozzle, Ring	0.75
Open Pipe, Smooth Opening	0.80
Open Pipe, Burred Opening	0.70
Sprinkler Head (nominal ½ inch orifice)	0.75
Standard Orifice (sharp edge)	0.62
Hydrant butt, smooth on well-rounded outlet, flowing full	0.90
Hydrant butt, square and sharp at hydrant barrel	0.80
Hydrant butt, outlet square, projecting into barrel	0.70

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APPENDIX B-5

Selected Conversion Factors

B-5.1. METRIC PREFIXES, SYMBOLS, AND MULTIPLYING FACTORS

Prefix	Symbol	Multiplying Factor	Word
exa	E	$10^{18} = 1{,}000{,}000{,}000{,}000{,}000{,}000$	
peta	P	$10^{15} = 1{,}000{,}000{,}000{,}000{,}000$	
tera	T	$10^{12} = 1{,}000{,}000{,}000{,}000$	One trillion
giga	G	$10^{9} = 1{,}000{,}000{,}000$	One billion
mega	M	$10^{6} = 1{,}000{,}000$	One million
kilo	k	$10^{3} = 1000$	One thousand
heto	h	$10^{2} = 100$	One hundred
deca	da	$10^{1} = 10$	Ten
		$10^{0} = 1$	One
deci	d	$10^{-1} = 0.1$	One tenth
centi	c	$10^{-2} = 0.01$	One hundredth
milli	m	$10^{-3} = 0.001$	One thousandth
micro	μ	$10^{-6} = 0.000{,}001$	One millionth
nana	n	$10^{-9} = 0.000{,}000{,}001$	One billionth
pico	p	$10^{-12} = 0.000{,}000{,}000{,}001$	One trillionth
femto	f	$10^{-15} = 0.000{,}000{,}000{,}000{,}001$	
atto	a	$10^{-18} = 0.000{,}000{,}000{,}000{,}000{,}001$	

The prefixes should be attached directly to the SI base unit, e.g., kilogram, millisecond, gigameter, etc. Similarly, the abbreviations attach directly to the abbreviation for the SI units, e.g., cm, Mg, mK, etc. Do not use two or more of the SI units. Also, although kilogram is the normal base unit for mass, the prefixes are added to gram (g) not kilogram (kg).

B-5.2. TEMPERATURE CONVERSIONS

$°F = (°C \times 1.8) + 32$
$°C = (°F - 32)/1.8$
$°R = °F + 459.67$
$K = °C + 273.15$

Freezing Point of Water: Celsius 0°; Fahr. = 32°
Boiling Point of Water: Celsius 100°; Fahr. = 212°

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B-5.3. SELECTED CONVERSION FACTORS

Multiply	By	To Obtain
Acres	43,560	Square feet
Acres	4047	Square meters
Acre feet	43,560	Cubic feet
Acre feet	1233	Cubic meters
Acre feet	325,850	Gallons (US)
Atmospheres	29.92	Inches of mercury
Atmospheres	76.0	centimeters of mercury
Atmospheres	33.90	Feet of water
Atmoshperes	14.69595	Pounds/square inch
Atmoshperes	101.325	Kilopascals
Atmospheres	1.01325	Bar
Barrels, Oil	5.614583	Cubic feet
Barrels, Oil	0.1589873	Cubic meters
Barrels, Oil	42	Gallons (US)
Barrels, Oil	158.9873	Liters
Bars	100	kiloPascals
Bars	10^6	Dynes/square centimeter
Bars	10,197	Kilograms/square meter
Bars	14.5	Pounds/square inch
Bars	0.9869233	Atmospheres
Btu	777.98	Foot-pounds
Btu	1054.8	Joules (abs)
Btu	7.565	Kilogram-meter
Btu/ft^2	11.36	Joule/m^2
Btu/ft^2/hr	3.152	Watt/m^2 (K-factor)
Btu/ft^2/hr/F	5.674	Watt/m^2 K
Btu/ft^2/hr/F/in.	0.144	Watt/m K
Btu/lb	2.326	Kilojoule/kilogram
Btu/lb (°F)	4.1868	Kilojoule/kilogram (°C)
Btu/cubic foot	37.25895	Kilojoule/cubic meter
Btu/gallon	278.7136	Kilojoule/cubic meter
Btu/hour	0.2931	Watts
Btu/minute	0.01757	Kilowatts
Btu/minute	12.96	Foot-pounds/second
Btu/minute	0.02356	Horsepower
Centimeters	0.3937	Inches
Centimeters of Mercury	0.01316	Atmospheres
Centimeters of Mercury	0.4461	Feet of water
Centimeters of Mercury	27.85	Pounds/square feet
Centimeters of Mercury	0.1934	Pounds/square inch
Cubic Centimeters	0.06102	Cubic inches
Cubic foot	0.028316847	Cubic meters

Multiply	By	To Obtain
Cubic foot	28.31625	Liters
Cubic foot	7.48052	Gallons
Cubic foot	1728	Cubic inches
Cubic foot	0.02832	Cubic meter
Cubic foot/lb	0.06242796	Cubic meters/kilogram
Cubic foot/minute	472.0	Cubic centimeters/second
Cubic foot/minute	0.472	Liters/second
Cubic foot/minute	0.1247	Gallons/second
Cubic foot/second	448.3	Gallons/minute
Cubic inch	16.39	Cubic centimeters
Cubic inch	0.01639	Liters
Cubic meter	264.1721	Gallons
Cubic meter	35.31467	Cubic feet
Cubic meter	6.289811	Barrels, Oil
Cubic yard	0.76456	Cubic Meters
Cubic yard	27	Cubic feet
Cubic yard	202.0	Gallons
Feet	30.48	Centimeters
Feet	0.3048	Meters
Feet	304.8	Millimeters
Feet of water	0.03048	Kilograms/square centimeter
Feet of water	2989.07	Pascal
Feet of water	0.0294998	Atmospheres
Feet of water	0.0298907	Bars
Foot-pounds	1.356	Joules
Foot/second	30.48	Centimeters/second
Gallons	3.78533	Liters
Gallons	0.13368	Cubic feet
Gallons	231	Cubic inches
Gallons	3785.434	Cubic centimeters
Gallons of water	8.3453	Lbs. of water
Gallons per minute	0.002228	Cubic feet/second
Gallons per minute	8.0208	Cubic feet/hour
Gallons per minute	0.0630902	Liters/second
Horsepower	745.7	Watts
Inch	25.4	Millimeters
Inch	2.54	Centimeters
Inch	0.0254	Meter
Inches of Mercury	3.389	kiloPascals
Inches of Mercury	0.03389	Atmospheres
Inches of Mercury	1.133	Feet of water
Inches of Mercury	0.4912	Pounds/square feet
Inches of water	0.002458	Atmospheres
Inches of water	0.7355	Inches of mercury

(*Continued*)

Multiply	By	To Obtain
Inches of water	5.202	Pounds/square feet
Inches of water	0.03613	Pounds/square inch
Inches of water	248.8	Pascals
Joules	0.000947817	Btu
Joules	0.238846	Calorie
Joule/°C	0.000526565	Btu/°F
Kilocalorie	4.184	kiloJoules
Kilograms	2.20462	Pounds
Kilograms/square centimeter	14.22	Pounds/square inch
Kilograms/mm^2	9.807	MPa
Kilometers	0.6214	Miles
Kilowatts	1.341	Horsepower
Kilowatt	3.412.12	Btu/hour
Kilowatt	1000	Joule/second
Kilowatt-hours	3412.14	Btu
Kilowatt-hours	2.655×10^6	Foot-pounds
Kilowatt-hours	3.6×10^6	Joules
Kilograms/square cm	97.0665	Kilopascals (kPa)
Liters	0.2642	Gallons (US)
Liters	61.02	Cubic inches
Liters	0.03531	Cubic feet
Liters/second	15.85032	Gallons per minute (gpm)
Liters/second	951.0194	Gallons per hour
Liters/second	2.11888	Cubic ft/minute
Lux	1.0	Lumens/square meter
Lux	0.0929	Foot-candles
Meters	3.281	Feet
Meters	39.37	Inches
Meters	1.094	Yards
Meter/minute	0.05468	Feet/second
Miles	1.609344	Kilometers
Miles	5280	Feet
Miles/hour	88	Feet/minute
Miles/hour	1.467	Feet/second
Miles/hour	1.609344	Kilometers/hour
Millibar	100	Pascals
Millimeters	0.03937	Inches
Millimeters of Mercury	0.1333	kiloPascals
MMCFD	28,300	Cubic meters/day
Ounces (fluid)	0.2957	Liters
Pascal	0.000145038	Pounds/square inch
Pound	0.4535924	Kilograms (kgs)
Pounds/square inch	2.307	Feet of water

Multiply	By	To Obtain
Pounds/square inch	0.06804	Atmospheres
Pounds/square inch	2.036	Inches of Mercury
Pounds/square inch	6.894757	KiloPascals (kPa)
Pounds/square inch	6,895	Pascals
Pounds/square inch	0.0689	Bars
Pounds/square foot	47.88	Pascals
Pounds/cubic foot	16.01846	Kilograms/cubic meter
Quarts	0.9463	Liters
Slugs	32.174	Pounds
Square Centimeters	0.00107639	Square feet
Square Centimeters	0.15499969	Square inches
Square foot	0.929	Square meters
Square inches	645.2	Square millimeters
Square meters	1550	Square inches
Square meters	10.76387	Square feet
Square meters	1.196	Square yards
Square yards	0.8361	Square meters
Square yards	1296	Square inches
Watts	3.41304	Btu/hour
Watts	0.7378	Foot-pounds/second
Watts	1.341×10^{-3}	Horsepower
Yards	3.0	Feet
Yards	0.9144	Meters

B-5.4. MISCELLANEOUS CONSTANTS

1 Gallons of fresh water = 8.33 lbs. = 3.8 kg
1 Cubic ft. of fresh water = 62.4 lbs. = 28.3 kgs

Absolute Zero = −273.16°C; −459.69°F

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ACRONYM LIST

1oo2	One Out of Two
2oo2	Two Out of Two
2oo3	Two Out of Three
ABS	American Bureau of Shipping
AC	Alternating Current
AFFF	Aqueous Film Forming Foam
AFHA	Arc Flash Hazard Analysis
AIA	American Insurance Association
AIChE	American Institute of Chemical Engineers
AIT	Auto-ignition Temperature
ALARP	As Low as Reasonably Practical
ANSI	American National Standards Institute
API	American Petroleum Institute
ASA	American Acoustical Society
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ASSE	American Society of Safety Engineers
ASTM	American Society for Testing Materials
ATSDR	Agency for Toxic Substances and Disease Registry
BACT	Best Available Control Technology
BEAST	Building Evaluation and Screening Tool
BLEVE	Boiling Liquid Expanding Vapor Explosion
BMS	Burner Management System
BOM	Bureau of Mines
BOP	Blow-out Preventer
BOSS	Blow-out Spool System
BPCS	Basic Process Control System
BPD	Barrels per Day
BSEE	Bureau of Safety and Environmental Enforcement
BS & W	Basic Sediment and Water
BTA	Bow-Tie Analysis
Btu	British Thermal Unit
°C	degrees Centigrade
CAD	Computer Aided Design
CCPS	Center for Chemical Process Safety
CDS	Closed Drainage System
CFM	Cubic Feet per Minute
CFATS	Chemical Facility Anti-Terrorism Standard
CFR	Code of Federal Regulations
CHA	Chemical Hazard Analysis
CHAZOP	Computer Hazard and Operability Study

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CO_2	Carbon Dioxide
CPI	Chemical Process Industry
CSB	Chemical Safety and Hazard Investigation Board
CVD	Combustible Vapor Dispersion
DCS	Distributed Control System
DIERS	Design Institute of Emergency Relief Systems
DHS	Department of Homeland Safety
EHAZOP	Electrical Hazard and Operability Study
EOC	Emergency Operations Center
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ESD	Emergency Shutdown
ESDV	Emergency Shutdown Valve
ESPs	Electrical Submersible Pumps
EU	European Union
FAR	Fatal Accident Rate
FM	Factory Mutual
FMEA	Failure Modes and Effects Analysis
FMECA	Failure Modes, Effects, and Criticality Analysis
HAZOP	Hazard and Operability Analysis
HIPS	High Integrity Protective Systems
HMIS	Hazardous Material Information System
HRA	Human Reliability Analysis
H_2S	Hydrogen Sulfide
HVAC	Heating, Ventilation and Air Conditioning
IEEE	Institute of Electronic and Electrical Engineers
ILP	Independent Layers of Protection
IMO	International Maritime Organization
IR	Infrared
IS	Intrinsically Safe
ISA	Instrument Society of America
LEL	Lower Explosive Limit
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MODU	Mobile Offshore Drilling Unit
MMS	Mineral Management Service
MPS	Manual Pull Station
MSDS	Material Safety Data Sheet
MSHA	Mine Safety and Health Administration
NACE	National Association of Corrosion Engineers
NFPA	National Fire Protection Association
NIOSH	National Institute for Occupational Safety and Health
NRC	National Response Center
OE	Operational Excellence

OSHA	Occupational Safety and Health Administration
OWS	Oily Water Sewer
PAH	Pressure Alarm High
PAL	Pressure Alarm Low
PC	Personal Computer
PCV	Pressure Control Valve
PDQs	Drilling, Production and Quarters platforms
PFD	Process Flow Diagram
PHA	Preliminary Hazard Analysis or Process Hazard Analysis
PI	Pressure Indicator
PIB	Process Interface Building
PIPITC	Petroleum and Chemical Processing Industry Technology Cooperative
P & A	Plugged and Abandoned
P & ID	Piping and Instrument Drawing
PLC	Programmable Logic Controller
PLL	Potential Loss of Life
PML	Probable Maximum Loss
POB	Personnel On Board
ppm	parts per million
PS	Pressure Sewer
PSH	Pressure Switch High
psi	pounds per square inch
PSM	Process Safety Management
QRA	Quantifiable Risk Assessment
RPM	Revolutions per Minute
RRF	Risk Reduction Factor
RV	Relief Valve
SEMS	Safety and Environmental Management Systems
SIL	Safety Integrity Level
SIP	Shelter-in-Place
SPM	Single Point Moorings
SSP	Site Security Plan
SVA	Security Vulnerability Analysis
TMR	Triple Modular Redundant
TNT	Trinitrotoluene
TSR	Temporary Safe Refuge
UEL	Upper Explosive Limit
ULCC	Ultra Large Crude Carrier
UPS	Uninterruptable Power Supply
USCG	United States Coast Guard
UVCE	Unconfined Vapor Cloud Explosion
VCE	Vapor Cloud Explosion
WIA	What-If Analysis

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GLOSSARY

Accident see incident

Alarm an audible or visible signal that indicates an abnormal or off-standard condition

ALARP (As Low As Reasonably Practical) the principle that no industrial activity is entirely free from risk and that it is never possible to be sure that every eventuality has been covered by safety precautions, but that there would be a gross disproportion between the cost in (money, time, or trouble) of additional preventive or protective measures, and the reduction in risk in order to achieve such low risks

API Gravity the gravity (weight per unit volume) of crude oil expressed in degrees according to the American Petroleum Institute (API) recommended system. API gravity divides the number 141.5 by the actual specific gravity of oil at 15.5°C (60°F) and subtracts 131.5 from the resulting number. The higher the API gravity, the lighter the crude oil. Higher gravity crude oils are generally considered more valuable because more valuable components can be extracted from them with less processing

Arc Flash Hazard Analysis (AFHA) a study to investigate the potential exposure to individuals from electrical arc flash energy, conducted to prevent injuries, property damage, business interruption and to determine the best safe work practices, the arc flash boundary, and appropriate protective measures

Autoignition Temperature (AIT) the lowest temperature at which a flammable gas or vapor-air mixture will ignite from its own heat source or a contacted heat source without the necessity of a spark or a flame. For straight chain hydrocarbons, increasing the chain length decreases the AIT

Availability the probability or mean fractional total time that a protective system is able to function on demand

Barrel (BBL) a barrel has traditionally been the standard liquid quantity of measurement in the petroleum industry for the production of oil. One barrel of oil equals 42 US gallons

Basic Process Control System (BPCS) electronic, hydraulic, pneumatic, or programmable instruments and mechanisms that monitor and/or operate a facility or system to achieve a desired function, i.e., flow control, temperature regulation, etc., which are supervised by human observation

Blast a transient change in gas density, pressure (either positive or negative), and velocity of the air surrounding an explosion point. A discontinuous change is known as a shock wave. A gradual change is known as a pressure wave

Boiling Liquid Expanding Vapor Explosion (BLEVE) the nearly instantaneous vaporization and corresponding release of energy of a liquid upon its sudden release from a containment under greater than atmospheric pressure and at a temperature above its atmospheric boiling point

Bow-Tie Analysis (BTA) a type of qualitative process hazard analysis. The methodology is an adaptation of three conventional system safety techniques: Fault Tree Analysis, Causal Factors Charting, and Event Tree Analysis. Existing safeguards (barriers) are identified and evaluated for adequacy

Blowdown the disposal of voluntary discharges of liquids or condensable vapors from process and vessel drain valves, thermal relief, or pressure relief valves

Blow-out an uncontrolled flow of gas, oil, or other well fluids from a wellbore at the wellhead or into a ground formation, caused by the formation pressure exceeding the drilling fluid pressure. It usually occurs during drilling on unknown (exploratory) reservoirs

Blow-out Preventer (BOP) a mechanism to rapidly close and seal off an oil or gas well borehole to prevent a blow-out. It consists of ram and shear rams, usually hydraulically operated, which are fitted at the top of well being drilled. It is activated if well pressures are encountered that cannot be controlled by the drilling process systems (i.e., drilling mud injection) and could lead to a blow-out of the well

Boilover a boiling liquid eruption in a hydrocarbon storage tank. It is usually described as an event in the burning of certain oils in an open top tank when, after a long period of quiescent burning, there is a sudden increase in fire intensity associated with the expulsion of burning oil from the tank, due to water at the bottom of the tank being heated to vaporization and causing a boiling eruption

Bow-Tie Analysis a qualitative risk analysis that portrays events and consequences on either side of a "bow-tie." Barriers or safeguards are shown in between the two sides. It depicts the risks in ways that are readily understandable to all levels of operations and management

Brainstorming a group problem solving technique that involves the spontaneous contribution of ideas from all members of the group primarily based on their knowledge and experience

CHAZOP a Computer Hazard and Operability study. A structured qualitative study of control and safety systems to access and minimize the effect of failures of its subsystems impacting the plant or affecting the ability of an operator to take corrective action

Chemical Hazard Analysis (CHA) a formal process for identifying and quantifying reactive chemical hazards

Chemical Safety and Hazard Investigation Board (CSB) an independent agency of the US government chartered to investigate chemical industry incidents, determine their root cause, and publish their findings to prevent similar incidents occurring

Christmas Tree an assembly of valves, gauges, and chokes mounted on a well casinghead to control flow and pressure of a oil or gas to pipeline

Classified Area any area that is electrically classified (i.e., restricted in the type of electrical devices allowed) following guidelines of a nationally recognized electrical code such as the requirements of the National Electrical Code Article 500 or API RP 500 that is utilized to prevent the ignition of combustible vapors by electrical devices

Clean Agent a fire suppression agent that uses an electrically non-conducting, volatile, or gaseous fire extinguishant that does not leave a residue upon evaporation

Combustion a rapid chemical process that involves reaction of an oxidizer (usually oxygen in air) with an oxidizable material (i.e., fuel), sufficient to produce radiation effects, i.e., evolution of heat or light

Combustible in a general sense, any material that can burn. This implies a lower degree of flammability, although there is no precise distinction between a material that is flammable and one that is combustible (NFPA 30 defines the difference between the classification of combustible liquids and flammable liquid based on the flash point temperatures and vapor pressure of the materials)

Combustible Liquid as defined by NFPA 30, a liquid having a flash point at or above 37.8°C (100°F) as determined under specific conditions. When the ambient temperature of a combustible liquid is raised above its flash point, it essentially becomes a flammable liquid

Condensate liquid hydrocarbons that have been separated from natural gas, usually by cooling the process stream, which condenses entrained liquids. Typically this includes the fractions C3, C4, C5, or heavier

Consequence the direct undesirable result of an incident sequence usually involving a fire, explosion, release of toxic, or hazardous material. Consequence descriptions may include estimates of the effects of an accident in terms of factors such as health impacts, physical destruction, environmental damage, business interruption, company stock devaluation, and adverse public reaction or negative impact on company prestige

Crude Oil or Petroleum liquid petroleum as it is extracted from the ground. Crude oils range from very light (i.e., high in gasoline) to very heavy (i.e., high in residual oils). Sour crude is high in sulfur content. Sweet crude is low in sulfur and therefore more valuable as it requires less processing. Generally, crude oils are hydrocarbon mixtures that have a flash point below 65.5°C (150°F) and that have not been processed in a refinery

Deflagration a propagating chemical reaction of a substance in which the reaction front advances into the unreacted substance rapidly, but at less than sonic velocity in the unreacted material

Deluge the immediate release of a commodity, usually referring to a water spray release for fire protection purposes

Depressurization the release of unwanted gas pressure and materials from a vessel or piping system to an effective disposal system (e.g., flare)

Detonation a propagating chemical reaction of a substance in which the reaction front advances into the un-reacted substance at greater than sonic velocity in the un-reacted substance

Distillate a generic term for several petroleum fuels that are heavier than gasoline and lighter than residual fuels, e.g., heating oil, diesel oil, and jet fuels

Distributed Control System (DCS) a generic, microprocessor based, regulatory system for managing a system, process, or facility

Diverter the part of the bell nipple at the top of a marine riser that controls the gas or other fluids that may enter the wellbore under pressure before the BOP stack has been set in place. It is used when drilling through shallow underground gas zones for diverting gas kicks in deep high pressure zones

EHAZOP an Electrical Hazard and Operability study. A structured qualitative study of electrical power systems to assess and minimize potential hazards present by incapability or failure of electrical apparatus

Emergency a condition of danger that requires immediate action

Emergency Isolation Valve (EIV) a valve that, in event of fire, rupture, or loss of containment, is used to stop the release of flammable or combustible liquids, combustible gas, or potentially toxic material. An EIV can be either hand-operated or power-operated (air, hydraulic, or electrical actuation). EIVs can be actuated either by an ESD system or by a local and/or remote actuating button, depending on the design of the facility

Emergency Shutdown a method to rapidly cease the operation of a process and isolate it from incoming and outgoing connections or flows to reduce the likelihood of an unwanted event from continuing or occurring

Ergonomics the study of the design requirements of work in relation to the physical and psychological capabilities and limitations of human beings

Executive Action a control process performed to initiate critical instructions or signals to safety devices

Explosion the sudden conversion of potential energy (chemical or mechanical) into kinetic energy with the production and release of gases under pressure, or the release of gas under pressure

Explosionproof a common term characterizing an electrical apparatus designed so that an explosion of flammable gas inside the enclosure will not ignite flammable gas outside the enclosure. Nothing is really considered technically "explosionproof"

Extrinsically Safe used to describe conditions where safety is built in by adding instrumentation, controls, alarms, interlocks, equipment redundancy, safety procedures, etc., for engineering designs, construction, operation, maintenance, inspection, etc., for a component, system, process, or facility

Fail Safe a system design or condition such that the failure of a component, subsystem, or system or input to it will automatically revert to predetermined safe static condition or state of least critical consequence for the component, subsystem, or system

Fail Steady a condition wherein the component stays in its last position when the actuating energy source fails. May also be called fail in place

Fail to Danger a system design or condition such that the failure of a component, subsystem, or system or input to it will automatically revert to an unsafe condition or state of highest critical consequence for the component, subsystem, or system

Failure Mode the action of a device or system to revert to a specified state upon failure of the utility power source that normally activates or controls the device or system. Failure modes are normally specified as fail open (FO), fail close (FC), or fail steady (FS), which will result in a fail safe or fail to danger arrangement

Failure Modes and Effects Analysis (FMEA) a systematic, tabular method for evaluating and documenting the causes and effects of known types of component failures

Fault Tree a logic model that graphically portrays the combinations of failures that can lead to a specific main failure or accident of interest

Fire a combustible vapor or gas combining with an oxidizer in a combustion process manifested by the evolution of light, heat, and flame

Fireball the atmospheric burning of a fuel-air cloud in which the energy is mostly emitted in the form of radiant heat. The inner core of the fuel release consists of almost pure fuel whereas the outer layer in which ignition first occurs is a flammable fuel-air mixture. As buoyancy forces of the hot gases begin to dominate, the burning cloud rises and becomes more spherical in shape

Fireproof resistant to a specific fire exposure. Essentially nothing is absolutely fireproof, but some materials or building assemblies are resistant to damage or fire penetration at certain levels of fire exposures that may develop in the petroleum, chemical, or related industries

Fireproofing a common industry term used to denote materials or methods of construction used to provide fire resistance for a defined fire exposure and specified time. Essentially nothing is fireproof if it is exposed to high temperatures for extended periods of time

Fire Retardant in general a term that denotes a substantially lower degree of fire resistance than fire resistive. It is frequently used to refer to materials or structures that are combustible but have been subjected to treatment or provided with surface coatings to prevent or retard ignition to prevent the spread of fire

Fire Resistive properties of materials or designs that are capable of resisting the effects of any fire to which the material or structure may be expected to be subjected

Flame the glowing gaseous part of a fire

Flame Arrestor a device used to prevent the propagation of a flame front initiated on its unprotected side through the device into a vessel or piping system

Flame Resistant Fabric material that is self-extinguishing after removal of an external ignition source. Material can be flame resistant because of the inherent properties of the fiber or the presence of flame retardants. Also different yarn properties and fabric construction may contribute to an increase in flame resistance

Flammable in general sense refers to any material that is easily ignited and burns rapidly. It is synonymous with the term inflammable that is generally considered obsolete, due to its prefix, which may be incorrectly misunderstood as not flammable (e.g., incomplete is not complete)

Flammable Limits the minimum and maximum concentrations of a flammable vapor or gas/air mixture that will propagate a flame (flash) when ignited. The currently accepted test method for determining flammability limits is ASTM E 681. Note: lower flammable limit (LFL) and upper flammable limit (UFL) are often used interchangeably with lower explosive limit (LEL) and upper explosive limit (UEL)

Flammable Liquid as defined by NFPA 30, a liquid having a flash point below 37.8°C (100°F) and having a vapor pressure not exceeding 2068 mm Hg (40 psia) at 37.8°C (100°F) as determined under specific conditions

Flash Fire the combustion of a flammable gas or vapor and air mixture in which the flame propagates through that mixture in a manner such that negligible or no damaging overpressure is generated

Flash Point (FP) the minimum temperature of a liquid at which it will give off sufficient vapors to form an ignitable mixture with air immediately above the surface of the liquid or within the vessel used, on the application of an ignition source, under specific conditions

Foam a fluid aggregate of air filled bubbles formed by chemical means that will float on the surface of flammable liquid or flow over solid surfaces. The foam functions to blanket and extinguish fires and/or prevent the ignition of the material

Foam Concentrate fire suppression surfactant material used to seal the vapors from the surface of combustible liquid, once it has been proportioned into water and aspirated to form a bubbly assembly that can be applied rapidly to the hazard

Foam Solution fire suppression foam concentrate mixed in proper proportion to water as required by specification of the foam concentrate

Foolproof so plain, simply, or reliable as to leave no opportunity for error, misuse, or failure

Fusible Link a mechanical release device activated by the heat effects of a fire. It usually consist of two pieces of metal joined by a low melting solder. Fusible links are manufactured as various incremental temperature ratings and are subjected to varying normal maximum tension. When installed and the fixed temperature is reached, the solder melts and the two metal parts separate, initiating the desired actions

Hazard Analysis the systematic identification of chemical or physical characteristics and/or processing conditions and/or operating conditions that could lead to undesired events

Hazardous Area, Electrical a US classification for an area in which explosive gas/air mixtures are, or may be expected to be, present in quantities such as to require special precautions for the construction and use of electrical apparatus

HAZOP an acronym for Hazard and Operability study, which is a qualitative process risk analysis tool used to identify hazards and evaluate if suitable protective arrangements are in place if the process were not to perform as intended and unexpected consequences were to result

Heat Flux the rate of heat transfer per unit area normal to the direction of heat flow. It is the total heat transmitted by radiation, conduction, and convection

HIPS an acronym for High Integrity Protective System. Is a set of components, such as sensors, logic solvers, and final control elements (e.g., valves), arranged for the purpose of reverting a process to a safe state when predetermined conditions are violated. Sometimes also referred to as HIPPS, High Integrity Pressure Protective System

Human Factors a discipline concerned with designing machines, operations, and work environments to match human capabilities and limitations

Hydrocarbons an organic compound containing only hydrogen and carbon. The simplest hydrocarbons are gases at ordinary temperatures, but with increasing molecular weight, they change to liquid form and finally to the solid state. They form the principle constituents of petroleum and natural gas

Ignition the process of starting a combustion process through the input of energy. Ignition occurs when the temperature of a substance is raised to the point at which its molecules will react spontaneously with an oxidizer and combustion occurs

Incident an event or sequence of events or occurrences, natural or man-made, that results in undesirable consequences and requires and emergency response to protect life and property

Independent Protection Layer (IPL) protection measures that reduce the level of risk of a serious event by 100 times, which have a high degree of availability (greater than 0.99) or have specificity, independence, dependability, and auditability

Inerting the process of removing an oxidizer (usually air or oxygen) to prevent a combustion process from occurring, normally accomplished by purging

Inflammable identical meaning as flammable, but the prefix "in" indicates a negative in many words and can cause confusion, therefore the use of flammable is preferred over inflammable

Inherently Safe an essential character of a process, system, or equipment that makes it without or very low in hazard or risk. Usually accomplished by removal of the hazard rather than being designed for them

Interlock a device or group of devices arranged to sense a limit or off-limit condition or an improper sequence of events and to shut down the offending or related piece of equipment or to prevent proceeding in an improper sequence in order to avoid a hazardous condition

Intrinsically Safe (IS) a circuit or device in which any spark or thermal effect is incapable of causing ignition of a mixture of flammable or combustible material in air under prescribed test conditions

Intumensent a fireproofing material (e.g., epoxy coating, sealing compound, or paint) that foams or swells to several times it volume when exposed to heat from a fire and simultaneously forms an outer char covering that together form an insulating thermo layer against a high temperature fire

Local Emergency Planning Committee (LEPC) groups mandated by the Superfund Amendment and Reauthorization Act (SARA) that are responsible for planning responses to emergency incidents. They typically include individuals from industry, emergency responders, and the local community

Liquefied Natural Gas (LNG) natural gas that has been converted to a liquid though cooling to approximately −162°C (−260°F) at atmospheric pressure

Liquefied Petroleum Gas (LPG) hydrocarbon factions lighter than gasoline, such as ethane, propane, and butane, kept in a liquid state though compression or refrigeration, also commonly referred to as "bottled" gas

Lower Explosive Limit (LEL) the minimum concentration of combustible gas or vapor in air below in which propagation of flame does not occur on contact with an ignition source

Naptha straight-run gasoline distillate, below the boiling point of kerosene. Napthas are generally unsuitable for blending as a component of premium gasoline, hence they are used as a feedstock for catalytic reforming in hydrocarbon production processes or in chemical manufacturing processes

Natural Gas a mixture of hydrocarbon compounds and small amounts of various non-hydrocarbons (such as carbon dioxide, helium, hydrogen sulfide, and nitrogen) existing in the gaseous phase or in solution with crude oil in natural underground reservoirs

Natural Gas Liquids (NGL) the portion of natural gas that is liquefied at the surface in production separators, field facilities, or gas production plants, leaving dry natural gas. NGLs include, but are not limited to, ethane, propane, butane, natural gasoline, and condensate

Operational Excellence (OE) Operational Excellence (OE) is an element of organizational leadership that stresses the application of a variety of principles, systems, and tools toward the sustainable improvement of key performance indexes. The process involves focusing on customer needs, keeping employees positive and empowered, and continuous improvement of activities in the workplace

Overpressure is any pressure relative to ambient pressure caused by an explosive blast, both positive and negative

PFD acronym for Process Flow Diagram. A facility engineering drawing depicting the process without showing instrumentation and minor isolation valves. Used to show flow quantities and conditions at various points in the process

P&ID acronym for Piping and Instrumentation Drawing. A facility engineering drawing depicting the process piping and equipment schematic arrangements and their associated control monitoring instrumentation devices

Pre-Startup Safety Review (PSSR) audit check performed prior to equipment operation to ensure adequate PSM activities have been performed. The check should verify (1) Construction and equipment is satisfactory, (2) Procedures are available and adequate, (3) A PHA has been undertaken and recommendations resolved, and (4) The employees are trained

Probability of Failure on Demand (sometimes called unavailability) a value indicating the probability of a system failing to respond to a demand. Probability of failure on demand equals one minus availability

Process any activity or operation leading to a particular event

Process Hazard Analysis (PHA) an organized formal review to identify and evaluate hazards with in industrial facilities and operations to enable their safe management. The review normally employs a qualitative technique to identify and access the importance of hazards as a result of identified consequences and risks. Conclusions and recommendations are provided for risks that are deemed at a level not acceptable to the organization. Quantitative methods may be also employed to embellish the understanding of the consequences and risks that have been identified

Process Safety Management (PSM) comprehensive set of plans, policies, procedures, practices, administrative, engineering, and operating controls designed to ensure that barriers to major incidents are in place, in use, and are effective

Programmable Logic Controller (PLC) a digital electronic controller that uses computer based programmable memory for implementing operating instructions through digital or analog inputs and outputs

Reid Vapor Pressure (RVP) the pressure caused by vaporized part of a liquid, the enclosed air and water vapor as measured under standard conditions in standardized apparatus. The result is given in psi at 100°F, although normally reported as RVP in lbs. RVP is not the same as the true "vapor pressure" of the liquid, but provides a relative index of the volatility of a liquid

Reliability the probability that a component or system will perform its defined logic function under the stated conditions for a defined period of time

Risk the combination of expected likelihood or probability (e.g., events/year) and consequences or severity (effects/event) of an incident, i.e., $R = f\{P, C\}$

Risk Analysis a procedure to identify and quantify risks by establishing potential failure modes, providing numerical estimates of the likelihood of an event in a specified time period and estimating the magnitude of the consequences

Risk Assessment the use of risk analysis results to make business decisions

Root Cause the most basic cause of an incident that can reasonably be identified which management has control to fix and for which effective recommendations for preventing reoccurrence can be generated. Sometimes it is also referred to as the absence, neglect, or deficiencies of management systems that allow the "causal factors" to occur or exist

Safety a general term denoting an acceptable level of risk of, relative freedom from, and low probability of harm

Safeguard a precautionary measure or stipulation. Usually equipment and/or procedures designed to interfere with incident propagation and/or prevent or reduce incident consequences

Safety Integrity Level (SIL) the degree of redundancy and independence from the effects of inherent and operational failures and external conditions that may affect system performance

Safety Instrumented System system composed of sensors, logic solvers, and final elements for the purpose of bringing a process to a safe state when predetermined conditions are violated. Other terms commonly used included emergency shutdown system (ESD, ESS), safety shutdown system (SSD), and safety interlock system

Shelter-in-Place (SIP) a method of protection in which instead of escaping from a fire risk, toxic vapors, radiation, etc. (because avenues of escape are unavailable or time consuming to reach) an individual protects themselves in the immediate vicinity to avoid injury such as in an adequately protected structure or building. Shelter-in-place cannot be utilized where available oxygen supplies are insufficient or cannot be isolated from contaminants

Single Point Failure (SPF) a location in a system in which if failure occurs it will cause the entire system to fail, because backup or alternative measures to accomplish the task are not available

Smoke the gaseous products of the burning of carbonaceous materials made visible by the presence of small particles of carbon; the small particles that are of liquid and solid consistencies are produced as a byproduct of insufficient air supplies to a combustion process

Snuffing Steam pressurized steam (water vapor) used to smother and inhibit fire conditions in the process industries

Sprinkler a water deflector spray nozzle device used to provide distribution of water at specific characteristic patterns and densities for purposes of cooling exposures, suppression of fires, and to air in vapor dispersions

Triple Modular Redundant (TMR) a system that employs a 2 out of 3 (2oo3) voting scheme to determine the appropriate output action. It is based on the application of three separate operating systems running in parallel

Vapor Cloud Explosion the explosion resulting from the ignition of a cloud of flammable vapor, gas, or mist in which flame speeds accelerate to sufficiently high velocities to produce significant overpressures

Vapor Pressure (VP) the pressure exerted by a volatile liquid as determined by ASTM D 323, Standard Method of Test for Vapor Pressure of Petroleum Products (Reid Method)

Voting Logic 1oo1, 1oo2, 2oo2, 2oo3 one out of one, one out of two, etc., is shorthand expressing the number of inputs that must be in agreement to effect an executive action, e.g., shutdown. For example, in a 2oo3 failsafe switch configuration, two of the three switches must be open to produce a shutdown

What-If Analysis (WIA) a safety review method by which "What-If" investigative questions (i.e., brainstorming and/or checklist approach) are asked by an experienced and knowledgeable team of the system or component under review where there are concerns about possible undesired events. Recommendations for the mitigation of identified hazards are provided

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