CHAPTER 10
The Role of Mechanical Integrity in Chemical Process Safety

When handling significant quantities of highly hazardous chemicals, common sense and the OSHA Process Safety Management standard require there must be a formal method for effectively dealing with “mechanical integrity.” Gaining a working understanding of the requirements of the mechanical integrity element of the OSHA Process Safety standard has been troublesome to many companies. Compliance has been and continues to be an exhausting challenge to some organizations.

The sections that follow offer a comprehensive view of mechanical integrity, complete with beneficial insights and practical details. Look forward to a chapter that:

- Gives a working definition of mechanical integrity
- Provides key regulatory excerpts from the standard
- Highlights regulatory enforcement efforts and numerous OSHA citation statistics for failure to comply with mechanical integrity regulations
- Offers an industry view of mechanical integrity and details on inspections and tests
- Defines vital hazard classifications of equipment
- Covers mechanical integrity programs for pumps and compressors, including vibration-monitoring programs
- Covers mechanical integrity programs for piping, pressure vessels, storage tanks, and process piping, including corrosion under insulation problems
- Covers mechanical integrity programs for safety critical instruments and safety relief devices
- Provides numerous photos to illustrate various mechanical integrity activities
- Supplies a comprehensive listing of effective supplemental references if additional resources seem desirable.

Mechanical Integrity in a Chemical Plant

What does mechanical integrity mean in a chemical plant? One definition would be using generally accepted and recognized good engineering practices to confidently contain all the hazardous chemicals within the equipment and piping systems. This is achieved via strong management support, written procedures, and practices.
200 Chemical Process Safety

- By designing to meet or exceed standards
- By fabricating with proper materials, using proper construction and installation techniques and confirming equipment suitability with tests
- By ensuring that the equipment remains fit for service.

It is elementary that the equipment can only remain fit for service through effective periodic inspection, testing, documentation and restoration programs.

The Chemical Manufacturers’ Association defines mechanical integrity as “the establishment and implementation of written procedures to maintain the ongoing integrity of the process equipment.” Mechanical integrity of process equipment is ensured through a documented program of procedures, training, inspections, and tests and through preventive/predictive maintenance based upon good engineering practice, applicable codes, standards, specifications, and manufacturers’ recommendations.

A Regulatory View of Mechanical Integrity

The term mechanical integrity became popular as a result of its use by the U.S. Occupational Safety and Health Administration (OSHA) in the 1992 standard on Process Safety Management of Highly Hazardous Chemicals. [1] The law, OSHA 1910.119, provides requirements for preventing or minimizing the consequences of catastrophic releases of toxic, reactive, flammable, or other listed “highly hazardous” chemicals. The regulation requires inspection and testing of equipment using written procedures and trained employees.

Marcel Decker, Inc., New York, granted their kind permission to use major selections from Chapter 12 of the Handbook of High Toxic Materials Handling and Management (1995), entitled “Mechanical Integrity” by Roy E. Sanders. [2]

The federal standard regulates facilities that handle nearly 140 specifically listed, highly-hazardous chemicals (above a threshold quantity which is different for different substances) and certain processes involving flammable liquids or gases in excess of 10,000 pounds (4,540 Kg). While the law may not cover some highly toxic materials and flammables in quantities less than their threshold or 10,000 pounds for flammables, it does present a good benchmark for examining programs to ensure containment. The techniques discussed in this chapter are not new, yet they are not universally used at this time.

The Occupational Safety and Health Administration, OSHA, Compliance Directive [3] identifies the intent of a “Mechanical Integrity” program:

*is to assure that equipment used to process, store or handle highly hazardous chemical is designed, constructed, installed and maintained to minimize the risk of releases of such chemicals. This requires that mechanical integrity program be in place to assure the continued integrity of process equipment. The elements of a mechanical integrity program include the identification and categorization of equipment and instrumentation, development of written maintenance procedures, training for process maintenance activities, inspection and testing, correction of deficiencies in equipment that are outside acceptable limits defined by the process safety information, and development of a quality assurance program.*
Mechanical Integrity Programs Must Be Tailored to the Specific Site

An insightful Ian Sutton, in *Process Safety Management,* states, “The topic of mechanical integrity is a very broad one. In spite of the fact that the title contains the word ‘mechanical,’ it covers much more than mechanical engineering issues.” The element requires input from a wide range of engineering, maintenance, process safety, and reliability disciplines.

Good mechanical integrity programs are usually very resource intensive to develop and represent an ongoing expense to maintain. Although the law has been in effect for nearly a decade, some organizations are still struggling to develop specific mechanical integrity programs or are redeveloping their programs.

Mechanical integrity programs are “site specific.” OSHA defines the requirements of this element of the Process Safety Management Law in about 350 words and yet, for most companies, many years of engineering and maintenance work have been consumed trying to properly define and achieve the requirements. The procedures ought to be tailored to the size of the facility, the management structure, the specific chemical processes, the specific equipment, as well as the engineering and maintenance resources. Some organizations have in-house specialists such as certified safety relief valve technicians, qualified metals inspectors, and experienced vibration technicians, and other facilities rely on the part-time services of contractors.

Mechanical Integrity in Design and Installation

The term *Quality Assurance* appears in this section of the regulation. Quality Assurance specifically refers to new equipment. Mechanical integrity issues related to the initial design of equipment, piping, and instrumentation design, as well as the construction and installation of equipment, is beyond the scope of this book and requires a library of references. If you need an overview look at design, consider reviewing the 1995 publication *Handbook of Highly Toxic Materials Handling and Management.* [2] The handbook devotes a chapter to design and operating considerations for process equipment. There is practical information on codes, corrosion basics, containment, inerting, as well as specific information on various classes of equipment. The handbook also looks at design considerations for piping and instrumentation, providing good information on the basics covering valves, gaskets, expansion joints, and design awareness concepts on instrumentation. Finally, it addresses the storage of toxic materials and provides a comprehensive look at the assessment of risk, “inherently safer” design, and other information vital to a safe design.

In addition, the American Institute of Chemical Engineers publishes *Guidelines for Safe Storage and Handling of High Toxic Hazard Materials.* [5] “Design of Storage and Piping Systems,” one of the chapter titles, provides information on vessel design, low-pressure tank guidelines, piping design, and other pertinent design considerations. It also presents over six pages of valuable references. Over 200 individual codes and standards are listed—a valuable resource for new engineers. [5]

Equipment Covered by Mechanical Integrity

OSHA 1910.119 specifies that a mechanical integrity program must cover the following equipment:
The language of this element of the standard seems too stiff and vague—perhaps more useful to a courtroom lawyer than a practicing engineer working within a chemical plant. No doubt, the standard was intended to cover all components that handle highly hazardous materials. When the standard mentions pressure vessels and storage tanks, it no doubt included much more. Surely the standard meant to include reactors, filters, furnaces, boilers, other heat exchangers, surge bottles, knock-out pots, and other smaller miscellaneous containers common within the industry even if they were designed below 15 psig (104 kPa gauge) or not a storage tank. When piping is mentioned, it no doubt meant the associated expansion joints, hoses, tubing, supports, and so forth. When the standard mentions relief and vent systems, it no doubt meant ancillary equipment such as scrubbers, flare stacks, incinerators, and similar equipment found on such headers.

Assuming that the original equipment design was acceptable, then the requirement for inspection, testing, and correction of the deficiencies is the heart of the mechanical integrity standard. Any inspection and testing procedures used must follow the applicable manufacturer’s recommendations and/or the generally accepted good engineering practices, guides, codes, as well as internal standards. The standard also specifies documentation of each inspection and test performed.

The Nonmandatory Appendix C provides compliance guidelines of the OSHA PSM standard [1] that are much easier to understand than the standard itself. See page 6414 in the Federal Register. Here is an extended quotation:

*The first line of defense an employer has available is to operate and maintain the process as designed, and to keep the chemicals contained. This line of defense is backed up by the next line of defense which is the controlled release of chemicals through venting to scrubbers or flares, or to surge or overflow tanks which are designed to receive such chemicals, etc. These lines of defense are the primary lines of defense or means to prevent unwanted releases. The secondary lines of defense would include fixed fire protection systems like sprinklers, water spray, or deluge systems, monitor guns, etc., dikes, designed drainage systems and other systems which would control or mitigate hazardous chemicals once an unwanted release occurs. These primary and secondary integrity lines of defense are what the mechanical integrity program needs to protect and strengthen these primary and secondary lines of defenses where appropriate.*

*The first step of an effective mechanical integrity program is to compile and categorize a list of process equipment and instrumentation for inclusion in the program. This list would include pressure vessels, storage tanks, process piping, relief and vent systems, fire protection system components, emergency shutdown systems and alarms and interlocks and pumps. For the categorization of instrumentation and listed equipment the employer would prioritize which pieces of equipment require closer scrutiny than others. Meantime to failure of various instrumentation and equipment failure of various instrumentation and equipment parts would be known from the manufacturers data or the employer’s experience with the...*
parts, which would then influence the inspection and testing frequency and associated procedures. Also, applicable codes and standards such as the National Board Inspection Code, or those from the American Society for Testing and Material, American Petroleum Institute, National Fire Protection Association, American National Standards Institute, American Society of Mechanical Engineers, and other groups, provide information to help establish an effective testing and inspection frequency, as well as appropriate methodologies.

Many of the detailed engineering aspects of mechanical integrity are covered by codes and standards generated by a wide variety of associations. Useful references not mentioned in the OSHA excerpt above include those published by organizations such as the American Institute of Chemical Engineers, the Chemical Manufacturers Association, the Chlorine Institute, the Compressed Gas Association, and publications from various property insurance associations.

The OSHA Law, a performance-oriented standard, allows employers to determine testing criteria and to set criteria to judge the acceptance or failure of test results. If a test detects a potentially hazardous condition, prompt corrective action is required.

Regulatory Enforcement of Mechanical Integrity

In 1995, OSHA issued more citations for mechanical integrity than for any other PSM element. In 1996, the mechanical integrity was a close second to operating procedures and just ahead of process hazards analysis. The May 1997 Chemical Process Safety Report [6] quoted Mr. John Miles, the Director of OSHA’s Compliance Programs, as saying, “Operating procedures and mechanical integrity are two of the more important parts of the standard, and our people are looking for those violations.”

The Chemical Process Report reviewed the 1296 citations issued under the OSHA Process Safety Management Standard in 1996. Oddly enough, chemical manufacturing plants were not the usual target of the citations. The analysis showed more that 75 percent of the companies cited for alleged PSM violations were not from the areas (or Standard Industrial Classifications Codes-SIC Codes) assigned to chemical producers or chemical users. Operating Procedures, Process Hazards Analysis, and the Mechanical Integrity elements of the standard had the highest number of citations in 1996.

The mechanical integrity element received 211 citations. Sub-section j-2 (“establish and implement written procedures to maintain mechanical integrity of process equipment”) received the highest number (95) of citations followed by 39 citations in subsection j-4-i (“perform inspection and testing on process equipment within that element”). Having readily available procedures is one of the main focal points for OSHA. Even if you are doing the right things in regard to mechanical integrity, if you don’t have a written procedure, you can expect citations during an OSHA visit. Well-written procedures help with consistency as people move around in the organization.

An Industry View of Mechanical Integrity

Mr. Ken Robertson, President of Exxon Chemical Americas, discussed “protective programs” or “mechanical integrity” programs in a keynote address at the Chemical Manufacturer Association’s Plant Inspection and Maintenance Forum in 1990. Indicating
that public expectations are increasing, Mr. Robertson noted there is less tolerance for oil and chemical spills as well as tragic plant safety incidents. [7]

The Exxon president reviewed some of his company’s process safety management practices relating to maintenance:

*First, safety critical systems must be reliable. These systems control releases in the event of accidents. It’s necessary to have a critical analyzer, instrument and electrical system test program. This should consist of preventive maintenance and alarm and trip device testing for panel alarms, emergency isolation valves and other critical components.* [7]

*Also, procedures must be in place to control defeating safety critical systems. Before taking these systems out of service for any length of time, there must be proper authority, communication and detailed contingency planning.*

*Regular, comprehensive inspections to ensure the safe condition of site equipment is another important consideration. There must be clear lines of responsibility for inspection and maintenance of crucial containment systems. A formal system must be in place for documenting recommendations and communicating them clearly and quickly to the appropriate managers in the organization.*

*We’re doing away with our traditional maintenance mindset of using heroic measures to fix something . . . our approach is to take ownership, to use predictive tools to get ahead of problems. . . .* [7]

In the past, some managers may have given mixed signals by praising actions taken to keep production units on-stream in the face of critical alarms being activated. All supervisors and managers must be careful not to praise actions that allow production to continue while in violation of recognized safe procedures.

**Written Procedures and Training**

Mechanical integrity procedures must be written in adequate detail to assure that the equipment receives prudent, appropriate, and periodically scheduled maintenance. It was noted above that OSHA issued a large number of citations for failure to have the written procedures.

The mechanical integrity procedures must also embody the safe work practices as well as the detailed equipment procedures. Safe work practices include “Lock and Tag,” “Confined Space Entry,” “Welding, Burning and Open Flame,” and similar essential personnel safety procedures. Detailed equipment procedures include generic procedures, equipment specific procedures, and manufacturers’ procedures.

Employees involved in maintaining the ongoing integrity of process equipment must be trained in an overview of the chemical process and its hazards. Employees must be also trained in the procedures applicable to the employees’ job tasks, such as the safe work practices discussed above.

**Classification of Equipment by Hazard Potential**

Chemical plant equipment—including tanks, pressure vessels, piping, rotating equipment, vent systems, and safety instrumentation—should be identified and categorized into different degrees of hazard potential. Classification systems could be simple or very complex. A complex system could be a matrix of increasing severity ratings on one axis and the
frequency of occurrence on the other axis. A simple identification system could consist of three priorities such as:

**Critical Consequence Class 1.** Containment equipment or the critical instruments serving that equipment whose failure would result in uncontrolled releases of dangerous materials, situations resulting in accidental fires or explosions, reportable environmental releases including closing of nearby highways or “shelter in place” for community members, personal injury, death, or major property or major production loss.

Tanks, pressure vessels, piping or rotating equipment containing highly hazardous or flammable chemicals are easily identified by experienced operations personnel as “Class 1” equipment. These containment systems must be inspected in some effective manner on a priority basis.

Critical instruments assigned a “Class 1” include those necessary to avoid a failure which may cause the perils listed above or instruments which fail to inform of upset conditions which may result in perils. Testing of these instrument systems may be mandated by regulatory agencies, in-house technical safety review committees, HAZOP studies, or designated as critical by operations supervisors. All of these shutdown systems and alarms must be proof tested in accordance with a proper schedule. [8]

**Serious Consequences—Class 2.** Equipment or the critical instruments serving whose failure could possibly cause, or fail to warn of upset conditions, uncontrolled releases of dangerous materials, situations that could result in accidental fires and explosions. Furthermore these failures could result in serious conditions involving environmental releases, property or production losses, or other non-life-threatening situations. These particular pieces of equipment, the safety shutdown systems and the alarms that serve this equipment are given a slightly lower priority. However, they are also inspected, tested, or proof tested on a regular schedule, but may be allowed to have some leniency in compliance.

A Class 2 list might include equipment that typically does not contain highly-hazardous chemicals, but may under abnormal conditions contain such chemicals. It may also include utility systems such as cooling tower operations, compressed air or refrigeration systems whose failure could create significant upsets.

**Normal Consequence—Class 3.** All other containment equipment or instrumentation serving the operation whose failure could result in minor environmental releases, property or production losses, or injury to personnel or reduced economic life. It may include less critical refrigeration systems, turbine overspeed trips, lubrication system alarms and similar important, but not crucial items.

These classifications should be considered when defining the level and frequency of inspection and testing. There could also be some built-in tolerance or leniency for some overdue “Class 2” and “Class 3” tests and inspections.

**Mechanical Integrity Programs for Pumps/Compressors**

When handling highly hazardous or flammable materials, it is obvious that the reliability of critical rotating equipment such as blowers, compressors, and pumps is of high importance. Rotating equipment with the highest consequence if a failure would occur (Class 1
and Class 2 equipment) must have qualified personnel inspecting and testing in accordance with written procedures. Mechanics may require specific skill training.

Rotating Equipment Invites Various Inspection Approaches

Inspections of rotating equipment could be accomplished by “Preventive Maintenance Programs,” which assures that equipment and machine behavior follow some sort of statistical average based upon weeks of operation or throughput in the process stream. Preventive maintenance (PM) programs—the planned, periodic inspection of equipment—reduces the occurrence of unexpected problems. Preventive Maintenance Programs are much more efficient to conduct than the old-fashioned breakdown maintenance programs of previous years in which failures often occur at undesirable times, interfere with production, and may prove to be more costly to correct. [2]

PM programs require the equipment to be shut down at regular intervals and inspected for wear, cleanliness, and conformance to assembly and performance tolerances. PM programs should detect small flaws before they grow into equipment problems which interfere with operation of the unit. The method can be satisfactory but can be expensive if no flaws are detected. Despite having a good PM program, an abnormally premature part failure may not be detected before serious damage occurs. In addition, the PM inspection process occasionally results in mistakes during the reassembly process. [2, 9]

Successful rotating equipment “Predictive Maintenance Programs” require several elements. Typical elements include an effective lubrication program with oil analysis to detect residual metal particles, thermography, machine monitoring instrumentation, repair specifications, repair history records, advanced training of mechanics, and the use of data management computers. [10]

Studies in the early 1980s reported predictive maintenance programs were more cost effective than the preventive maintenance programs. These studies showed that PM programs cost about $11–$13 per horsepower of a machine, while a predictive maintenance program cost $7–$8 per horsepower. [11]

Proactive and predictive maintenance programs were discussed in a Spring 1992 telephone survey of over 200 individuals from large industrial plants. Plant Services magazine published the results in a handbook in October 1992. [12] This survey established that vibration analysis and oil analysis were the most frequently used predictive maintenance monitoring techniques. Thermography was the third most popular approach. Ultrasonics and wear particle analysis (ferrography) were used regularly, although less frequently.

Effective predictive maintenance programs incorporate multiple features. However, the key to rotating equipment predictive maintenance is a comprehensive vibration surveillance and analysis program. A change in a machine’s health or operation nearly always causes an easily detectable vibration change long before the machine fails.

Chemical Process Operators’ Role

Chemical process operators routinely perform inspections during their regular rounds. They visually inspect equipment. Operators typically also use sound and feel to determine the operating condition of their pumps and compressors. In most organizations, operators
**The Role of Mechanical Integrity in Chemical Process Safety**

receive training to efficiently take appropriate actions including: adding lubricants, collecting vibration readings, calling for specialists or taking the equipment out of service.

**Maintenance and Inspectors Role**

Rotating equipment sets considered “Class 1” and “Class 2” equipment are candidates for a predictive maintenance program. By the OSHA Standard, the employer must train each employee involved in maintaining the on-going integrity of process equipment. Only qualified personnel can perform maintenance (in accordance to written procedures) on “Class 1” and “Class 2” pumps and compressors. The procedures used to assure the mechanical integrity of pumps and compressors should be written at the normal reading level of journeyman mechanics. Follow-up reports must be written providing the results of the inspection or test including: the name or serial number of the equipment, the date, the name of the mechanic/inspector, and any deficiencies.

The OSHA audit guidelines state that the following questions will be asked: [3]

1. Are inspections and tests performed on each item of process equipment included in the program?
2. Are inspection and test frequencies consistent with the manufacturer’s recommendation and good engineering practice? Are inspections and tests performed more frequently if determined necessary by operating experience?

**FIGURE 10–1** A chemical plant Compliance Coordinator supports an effective Mechanical Integrity Program to protect the employees, the process, and the surrounding community.
3. Are deficiencies in equipment that are outside limits (as defined in process safety information) corrected before further use or in a safe and timely manner when necessary means are taken to assure safe operation?

Important mechanical integrity concerns, such as the manufacturer’s recommendations and lubrication programs, need very specific treatment depending upon the equipment and the service. Although this subject is beyond the scope of this chapter and will not be addressed, we will examine an in-house vibration program and briefly review the use of thermography.

An Overview of One Chemical Complex’s Vibration Program

John Hawkins’s feature article, in Vibrations, June 1992, describes a predictive maintenance program covering over 2,100 rotating sets of equipment on a 250-acre site at PPG Industries in Lake Charles, Louisiana. [9] This vibration program, which had its start in 1971, is based on the principle that subtle changes in the operating condition of a machine generate distinctive vibration patterns long before any failures occurs. PPG equipment sets range in size from small process pumps to large compressors and also includes steam turbines and large gas turbine-driven generators rated for loads in excess of 80 megawatts.

Process pumps convey a variety of liquids required in processes involving acids, caustics, liquid chlorine, liquid vinyl chloride, and other hazardous fluids. Compressors at this location convey gaseous chlorine, anhydrous hydrogen chloride, refrigerants, and compressed air.

Three well-trained, full-time, energetic analysts comprise the surveillance crew of the PPG Industries Vibration Group. The technicians develop their skills through self-study, peer support, periodic out-of-plant training, years of experience and participation in the Vibration Institute. The program has three fundamental components: Surveillance, Analysis, and Correction.

Automated Vibration Surveillance

With significant management encouragement and over 25 years of experience, PPG created a model cost-efficient vibration program. Engineering provides fixed vibration-monitoring sensors, alarms, and shutdown systems for major critical rotating equipment (including large turbo-generator sets and critical large centrifugal compressors). Modern, commercially-available, hand-held vibration data collector modules provide a cost-effective path to acquire information from smaller units and make the program successful. (In earlier times, PPG had to use pencil and pad to gather data from hand-held instruments.)

After the initial programming of the state-of-the-art data collector units, a display window on the module provides a description of each piece of equipment on the surveillance route in sequence. The vibration inspector, prompted by the instrument readout, walks up to the operating equipment described on the display and thrusts a probe on the indicated bearing or other data point. When the analyst presses a button, the module captures the vibration level and any required analysis data. The data collector automatically identifies troubled sets based upon preset alarm values and collects spectrum data. Once the data col-
lection is completed on an equipment point, the program automatically advances to prompt data collection at the next point.

Built-in features to the surveillance module include the ability to scroll up and down through the list of equipment sets and the ability for the technician to provide useful comments. The technician can select comments from a preprogrammed list such as: needs alignment, base requires anchoring, or piping strain. The technician can also enter any descriptive short phrase.

Vibration inspectors take readings on each operating piece of rotating equipment. Vibration monitoring can detect “unbalance,” the most common cause of vibration. Proper monitoring allows misalignment to be checked while the machine is operating. Causes of misalignment include wear and tear, temperature, and improper maintenance. Routine surveillance can also detect looseness, advanced wear and cracking, damaged gears, and failing bearings.

**FIGURE 10–2** A vibration technician taking readings on a cooling water pump.
Computerized Reports and Program Benefits

Technicians require minimal effort to generate surveillance and summary reports, once the vibration data is collected. The vibration signals from the operating equipment is computer classified using proprietary computer programs into three levels of operation: (1) Smooth, (2) Marginal, and (3) Rough.

The team generates reports for two management reports. Vibration inspectors generate and distribute detailed surveillance reports to the equipment owners and the area maintenance supervisor so that corrective action can be planned. The inspectors also provide a summary report for middle management.

The Vibration Inspectors at PPG—Lake Charles collect data on 27,000 data points from 2,100 equipment sets. The vast amount of data requires a Pentium computer with a 2-gigabyte hard disk to manage it. R. W. LeBlanc described the benefits of a proactive
vibration program by citing a number of case histories. His list of success stories of a vibration surveillance and analysis includes: [10]

- Postponing maintenance when it can be delayed safely. Certain costly steam turbine/generator units outages were scheduled every six years. With the data obtained through vibration surveillance and analysis methods, the intervals between overhauls were extended with the concurrence of the property insurance carrier.
- Focusing repair efforts to the source of the machine problems via vibration diagnoses so that repairs are effective and efficient. One service request for the vibration technicians involved a 200-H.P. motor-driven, induced-draft fan. An area maintenance crew considered sending the large motor to a repair shop because they were unable to get the system to operate smoothly. The vibration technician diagnosed the problem as a simple imbalance in the fan, which was corrected easily with balance weights.
212 Chemical Process Safety

- Evading extensive damage and safety hazards by planning and scheduling machine repairs as necessary, before complete failure.
- Verifying the quality of a machine overhaul. The vibration program can provide assurances that the rotating equipment has been repaired correctly and that there are no residual problems.
- Identifying and communicating problems and solutions that are common throughout the plant complex.

Thermography Techniques for Rotating and Stationary Equipment

As recently as 1960, commercial thermography was very limited for plant operations. An instrument that weighed 85 pounds, required 110 volt power supply, and was cooled by liquid nitrogen was the best equipment to produce a useful thermal picture. [13]

Significant technological advances made in infrared imaging systems over the past decade have made thermography a useful predictive maintenance tool. Nowadays, some infrared camcorder cameras weigh less than ten pounds.

Quoting from a 1995 Plant Services magazine article:

The real power of thermography is that it allows us to quickly locate and monitor problems, and present critical decision-making information in visual form making it easy for management to understand. Infrared imaging systems, as they are generally called, produce a picture . . . of the invisible thermal pattern of a component or process. These thermal patterns, when understood, can be used to monitor operating conditions of equipment or processes. [14]

All equipment, most processes, and most buildings have components at different temperatures that radiate invisible thermal or infrared energy. You can feel the heat in the near vicinity of boilers, hot transformers, and hot motors. Thermography is a technique of producing pictures, called thermograms, from invisible infrared heat emissions. Good imaging systems in today’s cameras can see small temperature differences as small as 1/2˚ F or less. Thermography is a noncontact means of quickly identifying electrical and mechanical components that are hotter than the expected normal temperature. [13, 14]

It is a unique experience to raise the sensitivity of the camera and see your fellow employees on the screen with their temperature profiles. The instrument is so sensitive that even a thermal handprint on the wall will remain visible after a minute or so after the hand has been removed.

Thermography is useful in finding problems in electrical systems, mechanical equipment, refractory/insulation, steam distribution systems, and building and roofing surveys. The technique can help find frozen or plugged lines and can also determine the liquid level in a tank. Some companies are now trying to use thermographic techniques on furnace tubes to locate hot spots with the aim of better predicting tube failures.

Thermography has been used on electrical distribution systems for years by various corporations. Its use on rotating equipment is not as widespread, but it can be used to pinpoint the areas with friction problems. Excessive heat can be generated from friction due in part to faulty bearings, inadequate lubrication, misalignment, aging components and other reliability sacrificing problems. [13]
Out-of-limit temperatures for rotating mechanical components and systems are usually based on values established by the manufacturers. Pump and compressor equipment that could benefit from an infrared thermography inspection program include motor gears, bearings, shafts, couplings, V—belts, pulleys, compressors, vacuum pumps, and clutches.

Thermography offers similar benefits of a vibration program. It can assist in the timing and planning of scheduled repairs. It is a valuable tool in protecting capital investment, speeding inspections and diagnosis, and checking repair work.

How do you start? One suggestion is to hire a consulting thermographer to make a survey. You may be surprised at the valuable information, and will thus be able to evaluate the need for an on-sight thermographic team. Plant Services stated, “The thermographer and the structure of the program, rather than the equipment, have the greatest influence on the success of programs. Beginning thermographers often report solving problems that more than paid for the imaging equipment within a few weeks of startup. Not a bad return on investment.” [14]

Mechanical Integrity Programs for Piping, Pressure Vessels, Storage Tanks, and Process Piping

The mechanical integrity focus of this section covers stationary existing chemical processing plant equipment and piping. “Equipment” includes storage tanks, pressure vessels, dryers, heat exchangers, reactors, incinerators, columns, filters, knock-out pots, and so forth. As previously stated, this section assumes the equipment is designed and fabricated to
appropriate codes, standards, plant specifications, and good engineering practices. It is also assumed that the craftsmen were qualified, fabrication materials were certified (where necessary), and documentation of tests and inspections are retained.

“Appropriate codes” for new tank construction include: ASME Section VIII Pressure Vessel Code, API 650 for Atmospheric Tanks, API 620 for Low-Pressure Storage Tanks. “Appropriate codes” for other aspects include: ANSI/ASME B31.3 Code for Pressure Piping, the National Fire Protection Association Codes, Tubular Exchanger Manufacturers Association standards, property insurance guidelines, and any local or federal requirements.

Corrosion under Insulation—A Legacy of Yesteryear

During the 1960s and 1970s, many plant designers were not concerned with the potential problems of corrosion under insulation. As a result, today’s troublesome pitting or lamellar rusting of carbon steel, chloride stress corrosion cracking of austenitic stainless steels, and other concealed metal loss can be found beneath insulation. This hidden metal loss may result in drips, spills, or ruptures, leading to environmental insults, releases of toxic materials, or conditions that allow significant quantities of flammables to escape and could result in fires or explosions.

Intruding water, ingress of acid vapors, and process spills are some of the menaces that encourage corrosion problems on insulated equipment. Very few, if any, thermal insulation systems are completely waterproof, and the steel or alloy material covered by insulation is
intermittently wet and dry. Brackets that support insulated vessels or brackets on insulated vessels to support piping, ladders, or walkways can act as traps to collect water.

Engineers must take special care during the design stages and over the life of metallic equipment to reduce or eliminate the intrusion of water into the insulation by direct openings or by capillary action. The weather/vapor jacket covering the insulation provides the primary barrier to rain, drips, and operator wash down activities. This barrier can be destroyed by walking on piping, by poor maintenance, and by weathering.

In early designs, it was common to install thermal insulation over bare steel or over a single coat of oil base primer. According to the National Association of Corrosion Engineers, NACE [15], the most serious corrosion problems seemed to be most prevalent in plants with chloride-containing or sulfide-containing environments. These corrosion problems were further aggravated in high rainfall, high humidity, and salt air locations.

NACE studies determined that the most severe corrosion problems occurred under thermal insulation at temperatures between 140˚ and 250˚ F (60˚ to 120˚ C) where the temperatures were too low to quickly boil off any intruding water. At temperatures higher than the boiling point of water, other corrosion problems can occur. The intruding water can carry chlorides and other corrosive elements that can concentrate and result in stress corrosion cracking. [15]

When serious corrosion was first noted, many engineers decided that better surface preparation and primer were needed. Inorganic zinc was then often selected and used to prime carbon steel, which was to be covered with thermal insulation. In the 1970s some U.S. Gulf Coast Corrosion Engineers noted that the presence of inorganic zinc seemed to accelerate corrosion.

A NACE task group reported [15]:

- Inorganic zinc primers did not perform well under insulation, even if they were topcoated.
- Catalyzed epoxy coatings lacked sufficient high-temperature resistance to soaked insulation for the long-term exposure.
- The best generic coatings for carbon steel that may be surrounded by wet insulation in the 140˚ to 250˚ F (60˚ to 120˚ C) range are the epoxy phenolic and the amine-cured coal tar epoxy formulations.

Chloride stress cracking corrosion was also a problem when austenitic stainless steels were covered with thermal insulation. The NACE Paper also discusses the protective coatings for stainless steels and provides sandblasting and coating application guides for stainless and carbon steels.

To diminish the problems of corrosion under wet insulation within chemical plants, the design engineer, operator supervisor, and the maintenance foreman must focus on certain practices, which include:

- Providing an appropriate coating system for all new installations.
- Providing a periodic inspection of the piping or equipment in areas around potential points of moisture intrusion by removal of insulation.
- Repairing mechanical damages to weather barriers and thermal insulation quickly.
- Avoiding the use of zinc, cadmium, or zinc rich coatings on austenitic stainless steels.
- Even stainless systems operating at low temperatures can accidentally be heated by fire or welding repairs and can cause stress cracking.
- Becoming familiar with NACE Publication 6H189.
The degree and frequency of external inspection of equipment and piping under insulation is site specific. The API 570 Piping Inspection Code has added this note of caution: “The extent of a ‘Corrosion Under Insulation Inspection’ program may vary depending on the local climate; warmer, marine locations may require a very active program, whereas cooler, drier, mid-continent locations may not need as extensive a program.” [16]

Inspecting Pressure Vessels, Storage Tanks, and Piping

In some chemical plants, early inspection programs primarily addressed the corrosion and weld repairs of steels and alloys. However, inspections should also focus on the equipment’s foundation, the connecting piping, exterior coatings, and insulation. When such equipment is available, inspectors must also be capable of inspecting plastic (fiberglass, ABS, PVC, Teflon-lined, etc.) vessels and piping. Specialty metal liners and Teflon, rubber, glass, or ceramic linings within reactors or tanks also need attention from qualified inspectors. The inspection function should be conducted and managed by personnel who are independent of production, not unduly influenced by limited maintenance budgets, and still have management’s ear.

It is not the intent of this chapter to review in detail the types of inspection tools, techniques, and procedures. Recent American Petroleum Institute publications, available at moderate costs, do an excellent job in that respect.

Inspection of Pressure Vessels and Storage Tanks

The intent of the mechanical integrity section of the OSHA Process Safety Law is to prevent or reduce catastrophic releases. [1] An equipment classification system is a requirement of the law. Earlier in the chapter, a simple system involving three classes was previously defined. Here are the highlights of that section specifically for pressure vessels and storage tanks.

Critical Consequence—Class 1. Containment equipment whose failure would result in uncontrolled catastrophic releases of dangerous materials resulting in accidental fires or explosions. Failures of such equipment would include the potential for reportable environmental releases including closing of nearby highways or “shelter in place” for community members, personal injury, death, or major property or major production loss. “Class 1” pressure vessels and storage tanks are those which contain highly toxic or highly hazardous chemicals. These containment systems must be routinely inspected in some effective manner on a priority basis.

Serious Consequences—Class 2. Containment equipment whose failure could possibly cause uncontrolled releases of dangerous materials, situations which could result in accidental fires and explosions, with minimal off-site problems. Such a failure could have resulted in serious conditions involving environmental releases, property or production losses, or other non-life-threatening situations. This equipment is given a slightly lower priority. However, the equipment is also inspected and tested on a regular schedule, but may be allowed to have some leniency in compliance.

Normal Consequences—Class 3. All other containment equipment serving the operation whose failure could not create serious conditions involving recordable environmental
The Role of Mechanical Integrity in Chemical Process Safety  217

releases, or injury to personnel. However, such a failure could create some property losses or production interruptions.

API 510 Pressure Vessel Inspection Code—Maintenance, Inspection, Rating, and Alteration, June 1989, is an “owner/user” code and an excellent inspection reference. [17] Some countries, provinces, and states require pressure vessels to be inspected by government agents. In those cases, the governing agency rules should be the standard reference.

External Inspections of Vessels

Visual external inspections (or in-service inspections) should be made regularly to operating vessels to help ensure the integrity of the vessel. The frequency of this inspection should

![Well-maintained pressure vessels (over 30 years old) still safely handling hazardous materials.](image)
be site specific between semi-annually and once every three years for most chemical plant processes, depending on the aggressiveness of the chemical plant atmosphere. However, API 510 will accept intervals up to once every five years.

Visual external inspections are often made with the normal physical limitations of accessibility and visibility that exists at the time of the inspection. Normally, for the removal of insulation, scaffolds or man-lifts are not employed during frequent external inspections unless “tell-tale” conditions warrant a closer examination. In those cases, the difficulty of access to any portion of the tank should not be permitted to prevent a thorough inspection.

Consider the following items during an external inspection, whenever applicable:

1. *Anchor Bolts.* These important but sometimes neglected bolts should be painted and free of corrosion; this is especially important on tall towers.

2. *Foundations.* Concrete pads, base rings, and piers should show no signs of serious spilling, cracking, or uneven settling. Any such conditions, including uneven settlement and exposure of reinforcement, should be noted.

3. *Supports and skirts.* These should be free of corrosion and signs of deflection or buckling; ideally, skirts and supports should be accessible for inspection, sandblasting, and painting.

4. *Tank accessories.* Ladders, walkways, pressure gauges, sight glasses, and associated piping (including supports, pipe hangers, etc.) should be serviceable. Ladder rungs, stair treads, and handrails should be carefully examined as the tank is being climbed.

5. *Coatings.* Paint on metals should be intact to reduce corrosion potentials.

6. *Grounding.* Grounding cables should be securely attached to the tank and the grounding grid in the foundation.

7. *Heads and shell of exchangers and pressure vessels.* These containment elements should be free of corrosion, distortion, obvious cracks, dents, bulges, blisters, and signs of threatening conditions or pending leakage.

8. *Low-pressure tanks.* The shell of the tank should be checked for leaks, buckles and bulges and other conditions listed above in item 7. Thickness measurements must be taken at points where corrosion is evident. Special attention should be given to the shell near the bottom on low pressure tanks. Inspectors sometimes find advanced corrosion in that area caused by corrosive soils or trapped water. Tank roofs also require detailed inspections. For safety’s sake the inspector must exercise extra care to first establish that the roof will support his weight.

9. *Fireproofing or insulation.* Such barriers must be weather-sealed and intact to prevent collection and retention of moisture against metal surfaces that could corrode.

10. *Nozzles, flanges and valves.* These components must be free of signs of corrosion and leakage. All flange bolts should be installed and be of the correct diameter and length.

11. *Relief devices/safety relief valves.* Safety relief valves should be mounted in the vertical position. The ASME Code requires that the space between a combination rupture disc mounted below an SRV must have a pressure gauge or other device to warn if the rupture disc is leaking.

In the event of detection, or suspicion of some form of corrosion or deterioration that needs further investigation, the inspector is encouraged to recommend more extensive inspections or a different form of inspection.
Internal Inspections of Vessels

There is no good substitute for an internal inspection. Assuming the hazardous chemical residues can be easily removed, the internal inspection is easily accomplished and relatively inexpensive. Internal inspections are essential to determine possible weakening of the vessel or any conditions that may develop into unwanted leaks, because very few vessels experience uniform corrosion. Typically, internal inspections are established with frequencies between semi-annually and once every ten years. The exact frequency is best determined by the corrosive nature of the chemical being processed or stored, including the effect of trace components and the past history of this equipment.

Some companies are now using Risk-Based Inspections (RBI), especially for the costly preparation efforts for internal inspections. RBI is a method that is gaining credibility and

![Figure 10-8](image-url) An operations foreman checks for blinding and samples the vessel's atmosphere before tank entry.
popularity. Organizations calculate a proposed inspection frequency by considering the consequences of failure (as described above) and the likelihood of failure based upon the anticipated internal corrosion rates. The method employs a risk matrix.

An internal inspection provides a global view of the vessel. Visually “eye-balling” a vessel can be much more revealing than any of the limited judgments based upon thickness readings from the outside of the tank. Visual examination is usually the single most important and universally accepted method used to ensure fitness of service of a vessel. A good internal visual inspection should include examination of the shell and heads for cracks, blisters, bulges, operating deposits, corrosion products, erosive patterns, and other deterioration. In various aggressive chemical services, it is important to examine the welded joint and the heat-affected zone for accelerated corrosion, cracks, and other metal
loss. Often the use of a bright flashlight placed parallel to the internal walls of a vessel shining away from the inspector will help to visually identify metal loss or distortion of the walls.

If the vessel is not insulated or does not have a liner, the wall thickness may be tested from either the outside or from within using a D-Meter. This tool can quickly and easily measure the thickness of piping or a vessel wall. D-meters are generally the inspector’s favorite tool. The name “D-Meter” is the technician’s lingo for the simple hand-held digital ultrasonic thickness meter. Often corrosion patterns on vessels and equipment are not uniform, so it is often best to check the thickness from the inside. Other inspection methods to ensure mechanical integrity of vessels may include: magnetic-particle examination for cracks at or near the metal surface; dye penetrate examination for disclosing cracks or

Figure 10–10 A pressure vessel inspector enters the confined space after the vessel is blinded, tested, and cleared, but still relies on a manway watch.
pin holes that extend to the surface; radiographic examination; acoustic emission testing; and pressure testing.

**Pitfalls of Metal Ultrasonic Thickness Detectors**

Many organizations rely heavily upon the use of a D-Meter. A D-Meter is a relatively inexpensive handheld digital display ultrasonic thickness gauge for determining the remaining thickness of vessel walls and piping. Ultrasonic wall-thickness measurements resemble radar or sonar in technique. A burst of ultrasound is emitted via a probe into a material and bounces off the rear wall. The time interval measured for this reflection to return is a measure of wall thickness.

The D-Meter probe (usually called a transducer) sends the signal and recaptures it. Since sound travels poorly in air, a couplant (water, grease, glycerin, etc.) is used to displace the air between the transducer and material to be sampled.

Gary Waggoner, a talented code specialist from southwest Louisiana and long-time vessel inspector for fabricators, plant owners, and insurance companies, provided these tips:

- Light coatings of paint are of little consequence when using a D-Meter. However, heavy multiple coatings of paint can cause inaccurate readings by artificially increasing the thickness indication even greater than the actual paint thickness.
- Pitting on the surface of metal on the side the probe set can hinder sound transmission into the surface if it is too rough.
Pitting on the opposite side of the probe location can sometimes deflect sound waves preventing return to the transducer. Varied readings can confuse the user, making decisions of true thickness difficult and error prone.

Measuring a wall thickness on the exterior of a vessel near a weld may not yield an accurate measurement. It is not uncommon for the worst internal corrosion to occur in weld or heat-affected zones.

The search for small isolated sites of erosion or corrosion can sometimes become like looking for the needle in the haystack. An isolated thin area can be easily missed or skipped over depending on the density of the examination pattern.

Testing the thickness of higher temperature metals over approximately 180°F usually requires special transducers and couplants (liquid or gels between the probe and the metal used to bridge the air gap).

Despite these inherent shortcomings, the D-Meter will remain very popular due to its ease of use, low initial cost, low maintenance costs, and quick results.

Global Testing—Pressure Testing of Vessels

One popular method of testing for structural integrity is the use of the hydrotest. Typically, any newly constructed vessel or a vessel with major repairs is hydrotested using water pressure at 150 percent of its maximum allowable design pressure. In many cases the ASME Code requires a hydrotest.
Testing for structural integrity and testing for tiny leaks sometimes require two different approaches. Sometimes it is necessary to find leaks in systems such as a heat exchanger, which has hundreds of tubes rolled into a tube sheet. Water drips from a hydrotest may be hard to see or correct. At other times you may need to test gasketed systems that will not tolerate moisture.

A pneumatic test may be the answer. But be very cautious! Inspectors often use a spray solution of one part liquid dishwashing soap mixed in ten parts of water to check for leaks on certain systems that can be pneumatically pressurized. For safety’s sake, pneumatic testing ought to be limited to 5 or 10 psig and not greater than 25 percent of the maximum allowable working pressure of the weakest component being tested. The inspector’s eyes and a soap-water-filled garden sprayer can be an effective inspection tool on a zero-leak tolerance heat exchanger.

Tank fabricators and tank inspectors check new and repaired welds on floors of low-pressure tanks using soap suds. They commonly use a vacuum box to check tank floor seams. The inspection team coats a short section of weld seam with soapy water. An inspector places a custom-built rectangular box that has a clear window on the top of the soapy weld seam. A specially designed air eductor, which uses compressed air, evacuates the box. If soap bubbles appear in the box, the inspector marks the defective weld for repairs.

The inspection of low-pressure tanks is amply covered in *API Standard 653 Tank Inspection, Repair, Alteration, and Reconstruction*, January 1991. [18] This short, practical booklet covers such items as inspector qualifications, concerns for tank bottom corrosion,
and related topics. Appendix C of API 653 offers a four-page checklist for tank inspection of a tank while in service and seven pages of checklists for internal inspections.

**One Chemical Plant’s Pressure Vessel Management Program**

The Freeport, Texas, Dow Chemical Plant shared details of their pressure vessel management program several years ago. [19] The Dow Texas pressure vessel program had evolved over 25 years and covered about 12,000 pressure vessels. No doubt with today’s PSM Mechanical Integrity element, Dow’s program has far exceeded the excellent efforts discussed here.

**Vessel Design Review and Registration**

The Dow Chemical Texas Division Pressure Vessel Review Committee determines if a vessel meets the requirements of the ASME Code and/or Dow’s Engineering Specification. If a pressure vessel meets those requirements, Dow assigns a unique index number. Such a pressure vessel is either fabricated in a commercial fabrication shop, is received as a part of a package unit (like a refrigeration unit or an air compressor skid), or is built within a Dow fabrication shop. [19]

If a vessel is to be fabricated outside the Dow Chemical Company, the requisition must be routed to a Dow buyer who is familiar with engineering specifications. This buyer works under the guidance of a Custom Fabrication Purchasing Agent. Procedures require that all
specifications, drawings, and requisitions be approved by a pressure vessel “designer” who is also responsible for reviewing vendor calculations and fabrication drawings.

These procedures insure that each vessel is reviewed by at least two Dow employees, plus employees of the fabrication shop, prior to the start of construction. A pressure vessel inspector follows the fabrication and insures that the company specifications are met and that ASME Code considerations are achieved. The inspector also arranges to have a set of wall-thickness measurements made to be a base line for any corrosion studies. Therefore, before a vessel is put in service, at least three Dow employees have examined various aspects of the quality of the job. [19]

The Pressure Vessel Review Section (PVRS) is a service organization that assigns index numbers and maintains current records and inspection status on all vessels. The PVRS files include:

- Manufacturer’s Data Report
- Registration Form
- Actual thickness measurement reports
- Minimum Allowable Thickness Calculations
- Relief System Design Calculations.

In addition, the typical owner files include:

- Vendor Calculations
- Mill Test Reports
- Shop Drawings
- Visual Inspection Reports.

Routine Vessel Inspections

The Dow Freeport inspection program included an annual visual inspection while the vessel is in operation. Dow schedules the initial out-of-service (or internal) inspection within the first five years a vessel is in service and subsequent internal inspections are performed at least every five years thereafter. If either the owner or the inspector believe it is necessary for more frequent in-service and out-of-service inspections, the schedule is adjusted to accommodate that need. The Pressure Vessel Review Section (PVRS) can extend the frequency of internal inspections up to once in ten years, if sufficient data support this conclusion. [19]

The Dow Freeport in-service inspection procedures are similar to those reported earlier in this chapter. The Dow out-of-service (internal) inspection includes ultrasonic thickness measurements at all benchmark locations. Other test methods include shear wave ultrasonics, eddy current, and radiography. Engineers use ultrasonic thickness readings to project the remaining useful life of the vessel and to determine when the next internal inspection should be scheduled.

Repairs, Revisions, and Other Status Changes on Vessels

Under this system, Dow equipment owners are required to report a change of status when any of the following occur:
Rerating of the vessel
Change in emergency relief requirements
Change in service
Return to service after being idle for a prolonged period
Repair or modification to a pressure-containing part

If pressure-containing parts of a vessel corrode or erode to a thickness less than the minimum allowable, something must be done. The deficient parts must be reconditioned or the equipment will be assigned a lower pressure rating consistent with the new conditions. When a vessel is rerated, engineers review the relief system. [19] The Dow Chemical system for vessels, as reported over a decade ago, seemed to be a very practical method to meet today’s OSHA Mechanical Integrity requirements.

Inspection of Above-Ground Piping

API 570 Piping Inspection Code: Inspection, Repair, Alteration and Rerating of In-Service Piping Systems [16] was developed to establish requirements and guidelines for owners and users to maintain the safety and integrity of piping systems. Such important topics as frequency and extent of inspections, repairs, alterations, and rerating of piping systems are covered.

In Section 4 of API 570 the concept of Piping Service Classes is introduced. The classification was developed to allow extra inspection efforts to be focused on piping systems that may have the highest potential consequences, if failure or loss of containment should occur.

The API 570 categories are as follows: [16]

- Class 1 Piping Systems are services with the highest potential of an immediate emergency if a leak were to occur.
- Class 2 Piping Systems are an intermediate class and includes the majority of unit process piping and some off-site piping.
- Class 3 Piping Systems are defined as flammable service systems that do not significantly vaporize from a release and are not located in high activity areas.

Using this “class” system, the API recommends maximum inspection interval between three and ten years. See this valuable reference for details.

Some companies make piping service evaluations. These evaluations are used to categorize piping systems and determine the initial piping inspection intervals and degree of inspections for critical piping systems. A team determines which inspection tasks are needed to lower the likelihood of failure occurrence. A matrix is established to determine the type of inspection and the interval between inspections. This service evaluation is beyond the scope of this chapter.

The inspection of piping is very well covered in the practical American Petroleum Institute’s (API) Recommended Practice 574, Inspection of Piping, Tubing, Valves, and Fittings. [20] The recommended practice addresses the description of piping components, causes of deterioration, frequency of inspection, inspection tools, inspection procedures, and record keeping.
The API-574 guide is full of sensible, easy-to-use information including piping inspection procedures with these hints:

- Inspect in areas in which the piping is anticipated to have experienced metal loss because it was affected by velocity or turbulence. Prime inspection areas include the outer surfaces of piping bends and elbows, areas around tees, piping around reducers, orifice plates, and throttling valves and the piping downstream from them.
- Inspect areas of piping at which condensation or boiling of water or acids can occur.
- Pay attention to slurry piping and piping conveying catalyst or other abrasive materials.
- Examine piping conditions in areas involving dead-ends subject to turbulence, condensation, or areas in which freezing is likely to occur.
- Piping areas just downstream of a corrosive chemical injection point should receive particular examination.
- In high humidity areas, examine for corrosion beneath piping as it rests on beams, if pipe shoes are omitted.

In many cases, corrosion under piping insulation is a substantial threat. Corrosion is found adjacent to pipe supports, on small bore piping for the vents or relief valves as the small diameter piping protrudes from the top of an insulated larger line or protrudes beneath the pipeline. Water can enter and accumulate in these locations.

Corrosion under insulation, as generally discussed in the previous pages is a genuine concern, because it can be so easily concealed. The “Safer Piping—Awareness Training for the Process Industries” module [21] discusses a survey of 13-year-old carbon steel piping. The thermally insulated piping that was examined carried liquids at temperatures between 14˚ F and 280˚ F (−10˚ C and 140˚ C). Initially, about a third of the pipes in a 6.2-mile (10 km) network were inspected and the following was observed:

- 10 percent of the piping had greater than a 50-percent wall thickness decrease
- 10 percent of the piping had 25- to 50-percent wall thickness decrease
- 30 percent of the piping had 10- to 25-percent wall thickness decrease
- 50 percent of the piping had less than a 10-percent wall thickness decrease.

The “Safer Piping” module sums up the corrosion on piping under insulation as a problem of water ingress on piping with poor surface protection. Engineering, construction, and maintenance recommendations parallel those presented in the heading “Corrosion under Insulation” offered earlier in the chapter.

Many plant employees do not appreciate the need for inspection and maintenance of piping systems as well as they should. As many chemical plants grow older, more piping corrosion problems will occur in plants that do not utilize proper inspection and renewal programs.

**Mechanical Programs for Safety-Critical Instruments and Safety Relief Valves**

Safety relief valves (SRVs) and safety critical alarms and critical shutdown systems can be modified easily by aging or tampering. The local environment surrounding the device including cycles of freezing and thawing, moisture, corrosive contact with equipment inter-
nals, localized corrosive emissions, general atmospheric corrosion, dirt, sandblasting, painting, and tampering can alter the ability of these process safeguards to properly function.

McGraw-Hill Publications has granted special permission to use excerpts from my article entitled “Don’t Leave Plant Safety to Chance,” Chemical Engineering Vol. 98 no. 2, February 1991. [8] Many paragraphs will be used verbatim in the rest of this section on safety relief valves without being shown as quotes or without further reference.

All of the effort expended in designing plant-safety systems is of little value unless accompanied by an adequate “prooftest” program and regular maintenance. These safety systems—consisting of such components as safety-relief valves, tank vents, critical alarms, and protective isolation and shutdown devices—do not operate on a continuous basis. Rather, they are only called into service periodically to warn of, or to prevent, conditions that could lead to plant accidents. [8]

After just a few years of neglect, many protective devices and preventive process loops could become ineffective. Unfortunately, these safety-system failures may go undetected until a crises occurs.

Determining the methods and frequencies of testing for critical instrument loops must be tailored to each plant’s needs and resources. No matter how often testing is carried out, the facility must be committed to checking all plant safety devices regularly. Testing programs must be impervious to all the other demands taxing a plant’s resources, including key personnel changes. Periodic in-house audits should be conducted to ensure that testing methods are effective.

The Critical Role of Safety Relief Valves

SRVs are critical elements to the overall process safety of a chemical plant. The decisive functions of these safeguards are described in Valve Magazine [22], which begins with this attention-getting paragraph:

Perhaps no one valve plays as critical a role in the prevention of industrial accidents as the pressure relief valve. This “silent sentinel” of industry, sometimes referred to as the “safety” or “safety relief” valve, is essential in helping us minimize industrial accidents caused by the overpressurization of boilers and pressure vessels.

Relief valves serve the unique function of providing the last line of defense against the dangerous accumulation of excessive pressures within pressure vessels, tanks, and piping. They are self-contained and self-operating when other warning and control systems fail to provide the necessary protection.

The following observations were reported by Bruce Van Boskirk at an AIChE Meeting in Southeast Texas: [23]

Relief valves are very deceiving in appearance. Because they look like pipe fittings, they are often handled and stored in the same manner. This misconception can lead to significant abuse and damage. RELIEF DEVICES ARE DELICATE INSTRUMENTS AND MUST BE TREATED AS SUCH.

It is reasonable to draw an analogy between a shotgun and a relief valve. Both are made from high quality materials. Both contain parts machined to extremely close tolerances. Both are expected to operate accurately and reliably when called upon. Both are
"In-House" Testing Safety Relief Valves

Undetected corrosion, fouling of SRVs, or fouling in the inlet or outlet piping of the SRV can adversely affect the setpoint and the relieving flow rate. Standby equipment that has been improperly specified, installed, or maintained is particularly susceptible to undetected corrosion and fouling.

One major chemical complex, PPG Industries, in Lake Charles, Louisiana, relies on about 2,200 individual safety relief valves and conservation (pressure/vacuum) vents for overpressure protection. This large complex has a number of unique materials and corrosion challenges. On a typical day, huge quantities of saturated brine (NaCl) enter the complex, and several thousand tons of chlorine are produced. In the humidity of southern Louisiana, the salt, chlorine, co-product caustic soda, and hydrogen chloride gas circulating throughout the plant can attack process equipment. Other products such as vinyl chloride monomer and chlorinated solvents require unique elastomers for “O”-rings and gaskets.

PPG Lake Charles was one of the first chemical plants to openly discuss problems that users experience by improperly specifying and testing safety relief valves. Expertise on new safety valves could be obtained from manufacturers; sizing methods were documented by various designers and users, but no one published practical SRV testing and SRV corrosion problems.

Over the years, PPG Lake Charles has shared its findings with a number of organizations. A series of technical papers [8, 24, 25] has documented the progress and problems. The late Warren H. Woolfolk, Inspector, became PPG’s first SRV Test Program Coordinator in 1974. His prime responsibility was to ensure that SRVs were properly specified, installed, tested, and that there was sufficient record keeping. He gathered information from SRV manufacturers, helped develop centralized record keeping, and improved engineering specifications.

Woolfolk became concerned over the adequacy of the SRV test facilities, which were commonly used by many commercial SRV test and repair shops and most chemical plants. The typical test stand consisted of a clamp-down table connected to a compressed air cylinder by a 1/4-inch (0.6 cm) tubing. Woolfolk experimented with surge accumulators for testing relief valves, using a substantial volume of air to mimic actual process conditions.

In 1983, after some years of testing SRVs with significant volumes of gas, Woolfolk presented “Process Safety Relief Valve Testing” [24] to the Loss Prevention Symposium of the American Institute of Chemical Engineers. The resulting published article generated a lot of interest; he published an updated version for the Chemical Manufacturing Association in 1986. [25] However, a number of U.S. chemical plants were still using the primitive clamp-down table connected to a compressed air cylinder in the late 1980s.

Selection of Safety Relief Valve Testing Equipment

The American Society of Mechanical Engineers (ASME) understands the need for a sufficient volume of gas to properly test a safety relief valve. Until the ASME provides some well-defined guides, a concerned chemical plant may wish to develop its own criteria for
volume testing or gather current data from various SRV manufacturers. Limited-volume testing often fails to result in a distinct “pop.” (A “pop” is defined as the rapid opening of the SRV with its associated audible report.) If a valve only “simmers” instead of an actual “pop,” internal parts can be misaligned on some SRVs, resulting in leakage. [25]

The simmer point is seldom at the same pressure as the “pop” pressure. Most spring-loaded safety relief valves simmer at 90–95 percent of the set or popping pressure. In other words, some SRVs could be set 5 to 10 percent too high, and in cases where springs were faulty, larger errors of up to 20 percent or more could occur. Simmering does not guarantee that the SRV will fully open to discharge name plate flow capacity.

Woolfolk performed limited testing to estimate the required accumulator volume for PPG’s needs. He used several salvaged vessels as accumulators to test various SRVs and determine the optimum-sized accumulator. An oversized accumulator could be costly in compressed air usage, while an undersized tank would not provide the necessary volume to allow the SRV to properly respond.

Woolfolk estimated a 3 cubic ft. (85 L) test tank (or accumulator) rated at 500 psig (3450 kPa gauge) would provide a representative pop action for an SRV with a normal blown-down ring setting up to and including a 3-inch “L” orifice SRV. For larger SRVs up to and including a “T” orifice valve, Woolfolk selected a 15 cubic ft. (425 L) test tank also

FIGURE 10–15 A cartoon of a safety relief valve being tested on a test-stand without sufficient volumetric flow rate.
rated at 500 psig (3450 kPa gauge). He chose a 4.4 cubic ft. (125 L) tank with a 3,000 psig (20,700 kPa) rating for this plant’s higher pressure SRV testing. He also selected a smaller, 1/3 cubic ft. (9.4 L) tank rated at 5,000 psig (34,500 kPa) that can be used to pneumatically or hydraulically test SRVs for some special cases. Later an additional 6.5-cubic ft. (184 L) tank was engineered and installed for vacuum and low-pressure applications. Any plant considering installation of their own test facilities should carefully study the specific needs of their unique situation for the number and size of the accumulator tanks.

All test accumulators (pressure vessels) were mounted directly below the test table. These vessels were mounted vertically with 2:1 ellipsoidal heads on top and bottom. The top head has a well-rounded outlet nozzle sized equal to the SRV inlet to be tested. To test smaller-orifice SRVs, ring-shaped adapter plates having an opening equal to the SRV inlet are used. This arrangement reduces the possibility of starving the flow to the valve.

Mr. Woolfolk designed the accumulator depressurization piping to ensure that the momentum of the exiting air expelled any moisture, pipe scale, or other foreign material after each SRV test on each tank depressurization. The depressurization piping is connected to the low point in the accumulator. [25]

PPG Industries learned firsthand that testing SRVs with a large volume test stand had many advantages. The larger pneumatic energy supply allowed a gradual pressure rise, easier reading on the test gauges and more “cushioned” reseating conditions. Finely lapped nozzles and seats are better protected from slamming together during tests on larger volume stands. The higher volume test equipment better simulated actual operational situations, allows a measurable lift of the seats, and assures that the moving parts are properly aligned.

With a volume-pneumatic test, mechanics can detect defects in the parts due to incorrect replacement parts, incorrect machining, corrosion, or weak springs. Each of these problems can be discovered by such characteristics as early simmer, only a partial lift or leakage after the test. Defects such as inadvertently installing a spring too strong for the set pressure can be detected by short blow-down or chatter. Competent SRV test craftsmen can pinpoint defects with this type of test equipment.

Figure 10–16 A safety relief valve test-stand for dynamic testing.
Safety Relief Valve Testing and Repair Procedures

Small chemical plants with just a few dozen SRVs should rely on the local SRV test and repair shops for help. The larger chemical plants must decide if they want to invest in equipment and factory training for the mechanics and approve the capital for an inventory of spare parts to properly maintain the SRVs.

If a chemical plant decides to operate an in-house SRV test and repair program, it must have the necessary resources. Essential resources include test equipment with a sufficient volume of gases to simulated process conditions, factory-trained mechanics, a supply of spare parts, an up-to-date Quality Control Manual, and perhaps the approval of local or

Figure 10–17 A mechanic is removing an SRV from a unit. The mechanic records the condition of the inlet and outlet piping components on the tag before the valve is sent for testing.
state authorities. Certain localities may require an accreditation and certification via the National Board of Boiler and Pressure Vessel Inspectors.

A good Quality Control Manual should include specific actions to accommodate testing requirements. The SRVs should be pretested and the appropriate data on the initial pop pressure and blow-down observed and recorded. This procedure is for all valves removed from process service as well as for brand new valves. [8]

The safety valve is disassembled and examined, and all internal parts are blasted with glass shot to remove rust and surface accumulations. The valve body is then sandblasted and repainted, both internally and externally. During this stage, all defective parts are replaced or reconditioned to the manufacturer's specifications. Metal seats are machined to the desired flatness. All moving or guiding surfaces and all pressure-bearing surfaces are lightly lubricated. [8]

Once the valve is reassembled, the SRV is performance tested and adjusted to the correct set pressure, and the blow-down is set. All bellows-type and spring-loaded valves
exposed to back pressure are back-pressure tested to ensure the integrity of the bellows and gaskets on the exhaust side of the SRV.

Tamper-proof seals are added to discourage unauthorized or undetected field adjustments. Once testing is complete, a metal identification tag (of soft lead, which is easy to imprint, yet impervious to corrosion) is attached to the SRV. The tag records the location number, set pressure, and test date.

Safety relief valves must be kept clean during transit and storage so valve openings are sealed with tape and cardboard. If lifting levers are present they are tied down to protect the SRV’s seats in route to the user. The valve must be transported and stored in an upright position.

Mechanics document SRV test results and observations on a checklist. This information includes initial test pressure, and the condition of seats, stems, guides, springs, and inlet and outlet piping upon arrival at the plant. The appropriate second-level supervisor receives these results and a copy is maintained in the central SRV records. [8]

How Often Is Often Enough When Testing Safety Relief Valves?

PPG Lake Charles has established different test cycles for different process-safety equipment. Some are tested as frequently as every six months; some are tested as infrequently as once every three years. SRVs operating in dirty, fouling or highly corrosive conditions may require more-frequent testing to ensure reliable service.

State laws, corporate policies, insurance regulations, and any other appropriate mandates should be considered when establishing regular testing cycles. Additionally, any SRV that

![Figure 10-19 A crane is lifting a recently tested and reconditioned safety relief valve to reinstall on a reactor.](image)
pops or discharges a corrosive or tar-like fluid should be removed and reworked as soon as
the discharge is detected.

At the PPG Lake Charles facility, in 1990, about 30 percent of the overpressure devices
are tested annually; another 60 percent are tested every two years and the remainder are
tested at other frequencies. Typically, SRVs on the following types of equipment are tested
at the corresponding intervals. [8]

- Positive-displacement pumps or compressors—every 12 months
- Vessels processing corrosive chemicals—every 12 months
- Processing vessels with heat sources, including stills, kettles, hot-oil systems, and low-
  pressure, refrigerated storage tanks—every 12 months
- Boilers—every 12 months (Louisiana law requires boiler SRVs to be tested, set, and
  sealed annually)

FIGURE 10–20 A mechanic is reinstalling an SRV after it was tested in the shop and
raised into position by a crane.
Keeping the Safety Relief Valve Records Straight

A simple, sequential numbering system to identify SRVs may be acceptable for a small plant such as a batch-chemical processing facility with only a few dozen SRVs. However, for PPG’s Lake Charles plant, a dual numbering system is used to keep up with 2,000 SRVs in service and several hundred additional SRVs in storage. The devices kept in storage on-site are used as spares or can be cannibalized for parts. Spare safety valves for critical equipment must be available. [8]

In the dual-numbering system, one number refers to the valve design-type, and the other refers to its location and service. The first number, identifying the equipment, is unique to the SRV and is retired once the valve is taken out of service. Equipment records include information on the orifice size, set pressure, manufacturer, model number, serial number, and inlet and outlet flange sizes and ratings.

Test results are entered into the mainframe computer according to each device’s identification number. Employees have “read” access to the records at over 500 terminals and personal computers throughout the complex.

The Importance of Proper Safety Relief Valve Identification

The importance of proper identification of the safety relief valve cannot be overstated. Without a strict numbering system, the risk of incorrectly joining the wrong SRV to the right vessel after testing is too great to accept. For example, a 1-inch threaded valve can have an effective orifice area from 0.06 to 0.314 square inches (a five-fold difference), yet both could fit the same installation. Similarly, a 1-inch threaded-type SRV set at 100 psig (690 kPa) may look identical to another valve with the same description but set at 200 psig (1380 kPa). Likewise, a 4-inch valve with 300 psi style flange could be equipped with either an “L” orifice (2.85 square inches) or a “P” orifice (6.38 square inches). The “P” orifice is 2.24 times larger than the “L” orifice.

The location portion of the numbering system indicates the SRV’s specific site. Site records include a description of the location, temperature, set pressure, product, and the presence or absence of a rupture disc.

Communications to Equipment Owners and Management

A mainframe computer system has data on each SRV. Every other month, a computer-generated inspection schedule is sent to the second-level supervisor of each process unit. The report serves as a reminder of all SRV and conservation vent locations, recommended
service, and frequency of inspection. The report provides last test date and results (satisfactory, changed, or unsatisfactory) and the correct set pressure, back-pressure, operating temperatures, and equipment number of each SRV and conservation vent. This schedule is intended to highlight those valves due for testing.

Brief, statistical SRV Test Compliance Summaries are prepared and are provided to higher levels of management. Compliance reports list the total number of SRVs in the area and the total number (and total percentage) that are overdue for testing, if any. They serve as a periodic report card, signifying which process areas are in compliance and which are delinquent. [8]

**Mechanical Integrity Program for Process Safety**

**Interlocks and Alarms**

Alarms, process safety interlocks, and safety instrumented systems can be modified easily by aging or tampering and such critical safeguards are just too vital to neglect. Each organization must develop an effective way to ensure that process safety systems will properly function when the process demands protection.

Whereas numerous safety relief valves share many similarities, process safety interlocks are each individually tailored to the unique requirements of the process. The final parts of this chapter will discuss the critical process shutdown systems and the process safety alarms management systems used by three different major chemical plants.

**Protective Process Safety Interlocks at a DuPont Plant**

The Sabine River Works of the DuPont Company Plant in Orange, Texas, shared their process interlock classification and test program in 1988. [26] At that time, this large DuPont chemical complex employed about 2,500 individuals and consists of large single-train processing units. Most of the units are continuous processes for the manufacture of olefins, polyolefins, and chemical intermediates for nylon.

Process materials range from mild-mannered substances such as water and air to highly-toxic chemicals and very large inventories of hydrocarbons. Process temperatures were reported to range from −180˚ F (−118˚ C) to 1,000˚ F (540˚ C). Process pressures were reported to range between a low vacuum and over 30,000 psig (207 MKa). [26]

The DuPont Sabine River Works had reported between 35,000 and 40,000 instrument installations and more than 5,000 safety interlocks and alarms in 1988. The interlocks and alarms are divided into two classifications: the *operator aid* is used to alert the operator of a nonhazardous abnormal condition that might otherwise be undetected; the *safety interlock* or *alarm* refers to any equipment whose proper functioning is essential to prevent or signal hazardous process conditions that may threaten personnel or equipment. [26]

DuPont’s Sabine River Works experience shows that it is crucial to segregate the more critical interlocks from the others. A few well-understood, respected interlocks are said to be better than an overwhelming number of interlocks with the critical ones scattered amongst the others. DuPont’s system allows a range of required authorizations. At DuPont, a supervisor may bypass less critical interlocks such as lubrication alarms for up to 24 hours for testing and repairs, but some of the more critical alarms may not be bypassed by anyone.
Testing Safety Critical Process Instruments at a DuPont Plant

Interlock testing is performed on a periodic basis, usually every 12 months, following detailed written test procedures. The test procedure for each safety interlock defines the actions, including the approval system and the mechanical work required to ensure reliability. These procedures cover the testing activity from the process measurement device to the final element, which is often a control valve. [26]

Due in part to the complexity of the instrument systems, there are two first-to-final testing methods. These methods are labeled “actual tests” and “simulated tests.”

The “actual test” is performed by operating the process to the trip point, and ensuring that the intermediate relays and instruments respond properly. The “simulated test” is used in circumstances in which the instruments are of a nature that create a forced shutdown or startup in a very hazardous process. The “simulated test” is also used if the instrument schemes are so complicated that the interlocks cannot be checked on a single-trip shutdown. [26]

The technical paper described the interlock testing program to consist of more than merely verifying that the interlock works. There is also inspection of the interlock equipment for deterioration. The “function test” on instrumentation is required following mechanical work on one or more of the safety system elements. In short, all devices or systems that have been disturbed enough to affect their normal function will be function tested prior to being restored to service. [26]

Another Company—A Different Emphasis on Safety Critical Instrument Systems

Gregory McMillan, formerly an engineering fellow in process control for the Monsanto Chemical Company, approached the subject differently. His very entertaining presentation entitled, “Can You Say ‘Process Interlocks’?” at an AIChE Loss Prevention Symposium was written as a parody of a popular youngster’s TV show. [27]

Monsanto felt there were some real benefits to separate the economic issues from the safety issues and focus on the interlocks that really require special attention. Prior to this separation, human life was grouped with major property protection and formed a large class for which it was difficult to enforce stringent design and test requirements. [27]

In earlier times, costs associated with business interruption (which can exceed property losses) after an interlock failure were largely ignored and those interlocks were often placed with the so-called “operational interlocks.” McMillan’s approach was a system that grouped the protection instrument loops into four classes. These are the classes and a rough idea of the number of affected loops:

- 100 Class I Community Protection (Safety) Loops
- 1,000 Class II Employee Protection (Safety) Loops
- 5,000 Class III Major Property and Production (Economic) Loops
- 100,000 Class IV Minor Property and Production (Economic) Loops.

McMillan reveals alarms and interlocks can proliferate to the point where they detract from the most critical loops. To be effective, a logical cause-and-effect approach to interlock classification is required. It must be determined which events are the direct and distinct causes of hazardous events.
Mr. Fellow, the process control engineer—in the script of this satirical article—explains that in the past, interlocks would have been placed on many but not all of the indirect causes of a release. In McMillan’s example, a steam-heated chlorine vaporizer would have only two direct chemical process causes of a release. These direct causes are high pressure, which can open a relief device, and high temperature. The high temperature can accelerate corrosion.

In the past, this company’s process control design would have placed interlocks on many of the indirect causes of releases. The indirect causes include: a wide-open steam control valve, a closed chlorine gas valve downstream of the vaporizer, or a wide open upstream nitrogen regulator. Unfortunately with the large number of interlocks with similar test requirements, there was not sufficient time and money to assure the integrity of all of the interlocks.

Gregory McMillan suggests that the most direct and distinct cause for a potential release from this steam-heated chlorine vaporizer is high pressure; high temperature is the second most likely cause. Thus, the high pressure and high temperature interlocks should receive the most severe classification and the most testing attention.

The author points out statistics that suggest 80 percent of all interlock failures are due to failures of the field device. Those statistics show 45 percent of the interlock failures are measurement device failures and the other 35 percent are caused by valve or valve actuator failures. [27]

Another Approach—Prooftesting at a Louisiana Plant

At PPG Industries in Lake Charles, Louisiana, numerous instrument loops provide critical safety, alarm, and shutdown functions. These protective instruments are located on reactors, oil heaters, incinerators, cracking furnaces, compressors, steam-heated vaporizers, kettles, distillation columns, boilers, turbines, and other critical equipment. Process analyzers and flammable vapor detectors also enhance the overall process safety environment. [8]

Instrument loops serving equipment described above can function in either an on-line or a standby manner; both types can fail. Failure of an on-line loop, such as a failure of level control valve, becomes known rather quickly when the operation deviates either gradually or drastically from the normal. Depending on the type of failure, this may place a demand on the standby loop.

After all, failure of a standby instrument loop, such as an alarm or safety interlock, will not become evident until a potential hazard is detected. Potential defects developing in these loops must be discovered by periodic prooftesting.

A prooftest program cannot be left to someone’s memory. It must follow a well-structured format to accomplish the essential steps, regardless of the myriad of other activities and distractions that tend to absorb all the supervisors’ and mechanics’ time.

What Instruments Are Considered Critical?

When PPG Lake Charles first initiated its prooftest program, efforts to classify which safety devices were truly “critical” were not defined specific enough. Hence, the original program allowed too many instruments into the test system which created a top-heavy burden. To prevent this from happening, the following information should be developed for critical loops: [8]
A listing of critical alarms and safety interlocks essential to safe plant operations must be made.

The criteria by which the truly "critical instrument" system can be characterized as such, and distinguished from other important (but not critical) systems should be documented.

The test procedure for complex interlocks should be developed with engineering help and, for consistency and compliance with OSHA 1910.119, should be documented in writing. Any proposed additions or deletions should be screened by a third party group or committee. An appropriate authorization path should be in place to assist in making changes in classified instrument alarms and shutdown setpoints.

Test results must be recorded systematically, and must be easily accessible to all who need them for analysis. Defective or worn components should be identified and repaired immediately.

Management must take an active role in the stewardship of this program. High levels of compliance with stringent test schedules should be urged and rewarded.
It takes years to develop and fine-tune a prooftest program. Time is required to identify all of the instrument loops that need to be included, and more time is needed to systematically collect or develop data sheets containing basic operational information for each device or loop. During the development stage, test methods need to be defined, and the appropriate personnel responsible for testing must be identified and trained. Finally, test frequencies must be decided.

In 1998, the PPG Lake Charles facility has about 3,200 loops in its prooftest program. Over the past 20 years the prooftesting definitions have been revised, refined, rewritten, and revised again. There are still three classes in the prooftest program.

**Classifying Critical Loops**

Some process safety instrument loops are more critical than others. The “importance class” and test frequency are initially assigned by the group(s) directly associated with the origin and the reason for the required test. Input is received from a variety of in-plant departments such as...
The Role of Mechanical Integrity in Chemical Process Safety

Class 1 Critical Consequence Instrument Loops

These are instrument loops that are necessary to avoid perilous situations. These critical consequence instrument loops are those whose failure would either cause, or fail to inform of, situations resulting in accidental fire, explosion, uncontrolled release of dangerous materials, personal injury, or death. The OSHA Process Safety management loops fall within this group.

The Safety Instrumented Systems (SIS) and critical alarms assigned a “Class 1” include those that have been mandated as such by: state or federal agencies; an in-house technical safety review committee; HAZOP studies; and specific alarms deemed critical by operations supervisors. All of these Safety Instrumented Systems and alarms are on a regular prooftesting schedule.

In 1998, the PPG Lake Charles facility had about 1325 “Class 1” critical consequence instrument loops that required prooftesting. These include alarms and trips on storage tanks containing flammable or toxic liquids, devices to control high temperature and high pressure on exothermic-reaction vessels, and control mechanisms for low-flow, high-temperature fluids on fired heaters. Other Class 1 instruments include alarms that warn of flame failure on fired heaters, high level and high pressure of toxic or flammable storage tanks, and flammable vapor detectors for emergency valve isolation and sprinkler-system activation. All of the safeguards on the large diesel-driven fire-water pumps, battery failure, low lubrication pressure, and high cooling water temperature are also included. In 1997, there was a review to revisit all instrument loops in this classification, because it seems that a significant number of instrument loops were previously rated as too high in some units.

At PPG, Class 1 Prooftesting also covers 250 Safety Instrumented System loops in the PSM Safety Systems. A Safety Instrumented System (SIS) is composed of sensors, logic solvers, and final control elements for the purpose of taking the process to a safe state when predetermined conditions are violated. SISs are normally controlled by a PLC with the sole function of monitoring a process to insure operation is maintained within the safe operating envelope.

Class 2 Serious Consequence Instrument Loops

These serious consequence instrument loops are those instrument systems whose failure could cause, or fail to inform of, serious conditions involving environmental releases, major property or production losses, or other non-life-threatening situations. These alarms are given a slightly lower priority but are also prooftested on a regular schedule. These prooftests may be required by many of the originators listed for Class 1 Prooftests.

There are about 1500 “Class 2” alarms at PPG Lake Charles. Examples include those alarms or trips systems on refrigeration compressors (low freon pressure, high freon discharge pressure, high vibration) rectifiers, cooling towers (water level or high fan vibration), high- and low-operating liquid, pressure, or temperature levels or flow rates on and stills and some storage tanks, alarms, and instrument air compressors on the gaseous supply pressures of feedstock material.
Class 3 Normal Consequences Instrument Loops

These are instrument system loops that are necessary to avoid a failure which could result in nonreportable environmental releases, equipment or production losses, or reduced economic life, plus all other systems and alarms that assist operations that require prooftesting. These alarms and shutdown systems include refrigeration units that have less impact or safety or environmental issues than the Class 2 units, important pump shutdown alarms, low pressure utility alarms (well water, cooling tower water, natural gas, instrument air, nitrogen), and numerous low-pressure lubrication alarms.

Prooftest Frequencies

Assigning prooftest frequencies for complex, safety-instrumentation loops requires “sound engineering judgment” for simple systems. For more complex, interlock systems, the frequency is a function of the tolerable hazard rates. For example, DuPont Sabine River Works (Orange, Texas) reported it had 35,000 instruments in service. Every safety interlock is
tested on a periodic basis, usually every 12 months, following a detailed written test procedure. Once a test frequency is established by DuPont for a particular interlock, a significant review and multiple approvals are required to permanently remove the interlock or change its test frequency. [26]

Many of PPG’s high-pressure and high-temperature alarms are tested every six months. A significant number of the PPG Lake Charles Complex test frequencies have been developed using detailed reliability studies that consider the “hazard rate” (the acceptable probability of a process accident) and the “demand rate” (the number of times the critical alarm or shutdown function is required in service). [8]

Several years ago, within PPG’s chlorinated-hydrocarbon complex—which comprises a major portion of the Lake Charles facility and produces eight different product lines—26 percent of the loops were on a one-year test frequency; 42 percent were on a six-month frequency; 15 percent were tested every four months; 11 percent every three months; and the remaining 6 percent at various other frequencies from weekly to every two years.

Test-frequency changes to shorten or lengthen the test cycle at PPG are based upon evaluations of proof-test results, performance of the components in the loop, or changes in equipment or service. When the desired test pass rate (100-percent pass rate for Class 1 loops) is not met, causes of failure are evaluated. If warranted, a corrective action (such as a design change, test frequency change or request for further study) is initiated.

A request to lengthen a test frequency may result from a long record of no failed test and good maintenance records. The request is reviewed and documented by the Loss
Prevention Engineer. Any resulting changes are documented and retained five years in the Loss Prevention Engineering “Prooftest Change” file.

Prooftest Methods at PPG

Many of PPG—Lake Charles control loops and shutdown systems are very complicated and it is difficult to prooftest the systems without interrupting production, unless well-planned methods are developed. In the mid-1990s, the importance class and the availability was used to help specify one of the following four methods of prooftesting.

Method 1: Complete Loop Test

This method is the ideal dream test. For processes that allow complete loop prooftesting, the maintenance mechanics test all components in the loop by inputting a signal at the primary field element or sensor and performing three-point calibration check of the respective component. During the calibration span the prescribed setpoints are verified. The output is monitored through the Programmable Logic Controller (PLC) (or recorder, indicator, controller, enunciating devices, Distributed Control Systems, process computers) to the final trip or control element in the process. The trip function is included in the test. All components in the loop are visually inspected for physical condition.

Method 2: Split Test

This is the more “normal” test situation. For processes where prooftesting the final trip or control element cannot be made available (such as: testing a furnace shutdown system), the maintenance mechanics perform a prooftest as described above (complete loop test) with the exception of testing the final trip or control element. All components in the loop including the final element are visually inspected for physical condition. Maintenance takes test credit for the portion of the loop prooftested.

In the case where the final element is not tested, Operations performs a functional check of that loop’s final trip element during the next routine startup or shutdown of the process unit. Operations then takes test credit for the final element prooftest, which is listed separately as their responsibility on the Prooftest Program.

Method 3: Trip Test

Operations are also assigned independent prooftests (in addition to the split test above) which are functional trips or visual checks of controls and emergency shutdown systems.

Method 4: Routinely Monitored Tests

Importance Class 2 and 3 loops that are routinely monitored and have backup indication only require periodic verification of the listed criteria that follows:

- The loop does not have a PLC in the safety shutdown system
- The loop is routinely monitored (at least once per 24-hour period) and recorded by operations
- Performance and accuracy of the loop is verbally acknowledged between maintenance and operations
The loop’s primary device has backup indication with separate impulses sources
A satisfactory visual cross check of the backup indication or recorder printout has been made
Each component in the loop is physically inspected and found/ left in good condition.

Administering the PPG Critical Instrument Prooftest Program

Six independent groups of technical personnel provide prooftesting services. Prooftesting is performed by electricians, critical-metering mechanics, refrigeration mechanics, analyzer-repair technicians, instrument-maintenance personnel, and chemical process operators.

Once a loop has been prooftested, the results are entered into the mainframe computer, along with the date tested and the condition found. Many employees have “read” access to this data on many terminals throughout the complex, but only authorized personnel have

![An instrument mechanic prooftests a critical instrument panel.](image)

**FIGURE 10–25** An instrument mechanic prooftests a critical instrument panel.
access to the actual database. Keeping track of other aspects of the system is also done on computer. For example, if a setpoint on a particular instrument needs changing, the request and approval (both approved by the second-level supervisor) are done at the computer terminal. Loops that are no longer in service can be deleted by the authorized personnel. New loops can be added by an individual designated by the technical safety committee, who reviews all new and modified installations. Finally, monthly compliance reports are issued to top plant management. Particularly critical to the success of the program is management’s full support and commitment to compliance with process-safety administration.

Additional Information on Mechanical Integrity

In 1992, the Center for Chemical Process Safety (CCPS), a section of the American Institute of Chemical Engineers, released a “how-to” book [28] which contains practical appendices on inspection and test procedures. These appendices comprise the practices at major chemical manufacturing facilities. Chapter 8 should be consulted for specific information and actual plant programs.

Appendix 8-B of the CCPS book is entitled, “Example of Test and Inspection Equipment and Procedures.” This appendix covers minimum testing and inspection requirements of all classified equipment. “Classified” equipment is equipment identified in operational safety standards and governmental regulations.

Appendix 8-C is called “Example of Field Inspection and Testing of Process Safety Systems.” Appendix 8-E is named “Example of Criteria for Test and Inspection of Safety” and in 17 pages, it covers safety relief valves, rupture disks, control loop/manual actuated emergency vent devices and explosion vents. These AIChE guidelines should be consulted if the reader desires more information while building or improving a mechanical integrity program.

References

The Role of Mechanical Integrity in Chemical Process Safety