

ROTATING EQUIPMENT LOSS PREVENTION—AN INSURER'S VIEWPOINT

by

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ABSTRACT

Accidents involving rotating equipment in chemical, petrochemical, petroleum, and gas plants can result in damage to other process equipment and catalysts along with lost production. Conversely, process upsets, process instrumentation failure, or failures of other process equipment can result in damage to rotating equipment. An effective rotating equipment loss prevention program will be an integral part of an effective plantwide loss prevention program, since all aspects of plant operation and maintenance affect rotating equipment.

Specific rotating equipment loss prevention recommendations of the chemical, oil, and gas business unit of one insurance company are presented. Rotating equipment loss statistics of one insurance company are also presented.

INTRODUCTION

Rotating equipment loss prevention is of vital interest to insurance companies. One insurance company's experience has been that, when losses for all industries are ranked by the size of an average loss paid, rotating equipment accounts for seven of the ten largest averages (Figure 1). In a study of losses paid in the chemical, oil, and gas industries from 1980 through 1995, about 36 percent of all losses paid involved damage to rotating equipment; results of this study are shown in Figure 2. (All loss history studies mentioned herein are based on the Claims Department database of one insurance company. For a description of how this data is obtained and classified, refer to the *Incident Investigation And Loss Mitigation* section later.)

Insurers of the petroleum refining, chemical, petrochemical, and natural gas transmission industries see a wide range of loss

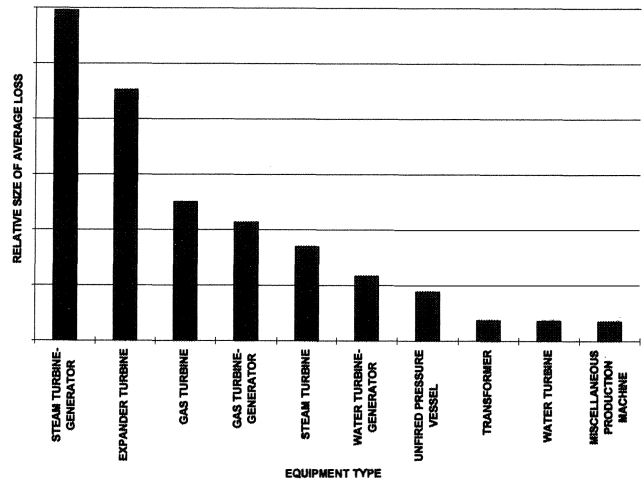


Figure 1. Relative Size of Average Loss for Ten Equipment Groups. Data include all industries for the time period 1986 through 1994.

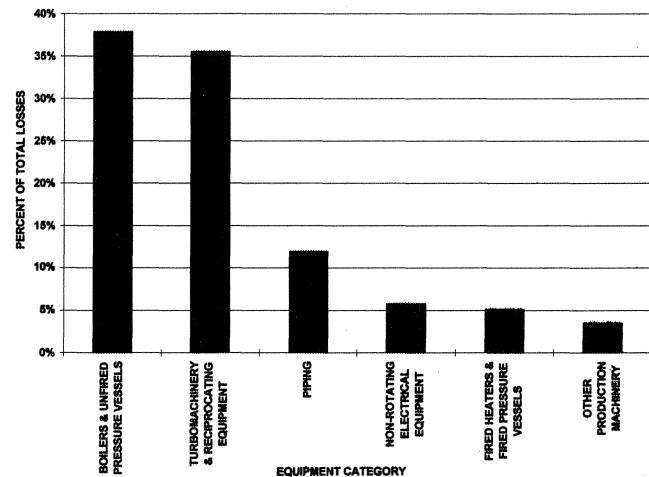


Figure 2. Losses Represented by Six Equipment Categories. Data are for the chemical, oil, and gas industries during the time period 1980 through 1995.

prevention tools and techniques applied to prevent rotating equipment damage and resultant lost production. Through accident and incident investigations, they also see what loss prevention tools and techniques work, which ones fail, and the reasons for success or failure. Based on their experience, insurance companies develop internal guidelines and standards for rotating equipment loss prevention that they recommend to their customers. Insurance companies can be a valuable, unbiased resource for plant rotating equipment engineers trying to maximize rotating equipment safety and reliability at minimum cost.

Some of the rotating equipment loss prevention recommendations of one insurance company are presented. The chemical, oil, and gas business unit of this insurance company currently insures more than 60 companies in the petroleum refining, chemical, petrochemical, and natural gas transmission industries; in recent years, more than 100 companies in these industries were insured. Rotating equipment loss prevention recommendations presented herein were developed through many years of insurance experience at hundreds of plants and through lessons learned by investigating accidents and incidents at those plants.

References/More Information

The rotating equipment loss prevention recommendations presented are based entirely on one insurance company's experience in the chemical, oil, and gas industries. However, the author has referenced technical papers or articles by independent experts that support most recommendations and opinions presented. For those interested in chemical, oil, and gas plant loss prevention in general, the referenced papers and articles provide detailed discussion and can be a valuable loss prevention resource.

INSURANCE PROCEDURES AND PRACTICES

Risk Selection—Evaluation Of Potential New Chemical, Oil, and Gas Accounts

The business of insuring rotating equipment in the chemical, oil, and gas industries has changed significantly in the last few years. Previously, most accidents involving rotating equipment were covered under a mechanical breakdown policy; this policy was also called Boiler and Machinery insurance. The most common type of insurance purchased today by companies in the chemical, oil, and gas industries is All Risk insurance. All Risk insurance covers virtually all process equipment in a plant for a wide range of perils including fire and explosion along with mechanical breakdown. Catalyst and similar materials may also be covered. With All Risk insurance, the insurance company (just like plant personnel) is interested in a loss prevention program that protects all process equipment including catalyst and similar materials. This was true to a certain extent when separate fire and mechanical breakdown policies were common, but it is much more evident today. Problems with rotating equipment can result in damage to other process equipment and/or catalyst, and process upsets or failures of other process equipment can result in damage to rotating equipment. Therefore, from the insurance company's point of view, the rotating equipment loss prevention program must address all aspects of plant operation and maintenance.

Studies have shown that approximately 20 percent of serious chemical, oil, and gas plant incidents are directly caused by human error, and human error is a contributing factor in up to 90 percent of serious plant incidents [1]. While rotating equipment and other process equipment can be protected to a certain extent through engineering means (inspection, nondestructive examination (NDE), vibration, and overspeed trips, etc.), other loss prevention tools are required to reduce the number of incidents related to human error. The following is a partial list of items the insurance company evaluates when assessing the potential insurance risk represented by a new chemical, oil, or gas account:

- **Management**—This is the single most important element of any loss prevention program. If a loss prevention program is to be successful, it must have the support of senior management. Senior management drives the loss prevention program through policies and procedures and through the budget process. When evaluating most of the items listed below, the insurance company is actually evaluating management.
- **Company/Plant History**—Including insurance losses, major incidents, OSHA Incident Rates, and plant/equipment history

- **Process Safety Management (PSM) Programs**—Since most chemical, oil, and gas operations fall under requirements of OSHA's Process Safety Management Program (CFR 1910.119), the prospective customer's PSM program is evaluated in some detail. Most of the PSM elements, if successfully implemented, are excellent tools for reducing the number of incidents caused by human error along with incidents related to process design/engineering deficiencies. In addition to reviewing the overall PSM program, audit results and the status of changes/corrections recommended in the audit(s) are noted. If the prospective customer is a member of the Chemical Manufacturers Association, the plant's progress in meeting the goals and requirements of the Responsible Care program are reviewed and evaluated. As with CFR 1910.119, Responsible Care program elements can be excellent loss prevention tools.

Evaluation of PSM elements includes detailed evaluation of maintenance and predictive maintenance practices and procedures, reliability programs, operator and craftsman training programs, operating instructions, etc.

- **Feedstock Source/Redundancy**
- **Storage Capacities**—Feedstock, intermediate, and finished product
- **Unit Interdependencies**
- **Redundant Equipment**—Installed spare machines or spare machines available inplant or elsewhere
- **Critical Spare Parts**—For large or unique critical, unspared rotating equipment and reciprocating machines, the following spare parts are normally required for business interruption insurance:
 - Two complete sets of bearings and seals
 - Spare rotating element (two or more machines may share a common spare)
 - Spare diaphragms may be required in some instances depending on several factors including the type of machine and the business interruption potential represented by the machine
 - Spare set of stator blades for axial flow compressors and expander turbines
 - Spare coupling(s)
 - Spare gears for enclosed gearsets (or at least gear material with drawings for final machining)
 - Spare copper or windings for induction motors—depending on the type of wire and its availability
 - Spare stator for some synchronous motors
 - Spare armature for some DC motors
 - Spare cylinder of each size, piston, bearings, valves, and connecting rod (or at least a rod forging) for reciprocating equipment.

It is important that spares are stored properly and are properly maintained [2]. Critical spares are routinely inspected by insurance loss prevention specialists to evaluate condition and fitness for service.

Loss Prevention Activities For Existing Chemical, Oil, and Gas Insurance Accounts

The above described risk evaluation process is conducted by the insurance company's technical specialists. The specialists' report is reviewed by engineering and underwriting personnel. If the risk appears acceptable, an insurance premium is calculated based on

the risk represented. The premium is quoted to the prospective customer.

If the account is insured, the insurance company's engineering and technical specialists develop a loss prevention service plan. The service plan specifies minimum amounts and types of loss prevention activities required to protect the insurance company's interests; these activities will be performed by the insurance company's loss prevention specialists. Most of the insurance company's loss prevention resources are focused on the plants, units, and specific equipment that represent significant physical damage and/or business interruption insurance exposure.

Insurance Recommendations

During risk evaluations, accident investigations, and loss prevention inspections, the insurance company's loss prevention specialists are comparing conditions observed to the insurance company's internal guidelines and standards, to common industry practices the loss prevention specialists observe at other insured plants, and to well known industry standards such as ASME, API, and NFPA. In addition, the loss prevention specialist is observing how the customer's own loss prevention policies, procedures, and standards (including PSM/Responsible Care where applicable) are being implemented in practice.

The insurance loss prevention specialist may make informal, verbal suggestions for improvement to plant personnel. However, when significant conditions are observed that should be reviewed, particularly if changing or correcting the observed condition(s) would require expenditure of significant funds, a formal recommendation is made. Each insurance company has its own recommendation classification system, but most systems are similar. The classification system used by one insurance company for rotating equipment and process related recommendations has the following definitions:

- **Code.** This classification applies only to boilers, pressure vessels, and other equipment that falls under the jurisdiction of a governmental authority. Code recommendations apply only to violations of the applicable Code and are made only when the insurance loss prevention specialist is a representative of the jurisdictional authority.
- **Advisory.** These are suggestions for improvement based on industry practice, insurance company experience, and industry guidelines. Advisory recommendations are primarily made for the benefit of the customer, and noncompliance with an Advisory recommendation will usually not affect insurance coverage.
- **Priority.** These are recommendations for conditions that represent a significant risk to the insurance company. Noncompliance with a Priority recommendation could have an effect on insurance coverage.

Since the recommendation type is based on risk to the insurance company, the same recommendation could be "Advisory" or "Priority" based entirely on the insurance coverage in effect. This is an important point that is often misinterpreted. The recommendation is not more valid if it is "Priority" rather than "Advisory;" both are equally important in preventing losses.

A different classification system is usually used for fire protection-related recommendations.

Incident Investigation and Loss Mitigation

Investigation of incidents involving equipment damage or near misses represents an opportunity not only to learn how to avoid repeating the same type of incident in the future, but also to diagnose potential problems with management systems before a more serious event occurs [3, 4]. Insurance companies can be a valuable member of the incident investigation team; in addition,

investigation of incidents that could result in an insurance claim is usually a condition of insurance specified in the insurance policy.

Insurance companies want to be involved early in incident investigations primarily for three reasons:

- To have the opportunity to help mitigate business interruption losses—Insurance companies have experience in mitigating losses, and they can be a valuable resource to the customer's staff following an incident. Some insurance companies maintain databases of firms that stock used equipment, firms that provide materials, and firms that specialize in repairs to various types of equipment.
- To detect trouble prone models or types of equipment—Some insurance companies have design engineers that regularly meet with the original equipment manufacturer (OEM) to discuss failure rates of particular components and to follow changes/modifications to those components.
- To develop incident/loss data—By analyzing this data, the insurance company identifies priorities for allocation of its loss prevention assets.

During investigations, the insurance company's loss prevention specialists classify and code various types of information such as industry, type of equipment, first part to fail, type of failure, and root cause.

At one insurance company, rotating equipment failure root causes are categorized in seven broad categories: design, construction, repair, application, maintenance, operation, and external. Failures are further classified within categories. As an example, in each of the design, construction, repair, maintenance, and operation categories, there are four lubrication-related subcategories: contamination of lubrication, excessive, lubrication, insufficient or loss of lubrication, and unsuitable type of lubrication. Using this classification system, lubrication related failures can be grouped into lubrication failures due to the design of the system, improper operation of the lubrication system, inadequate maintenance of the lubrication system, etc.

All of the insurance loss statistics referenced herein were derived from a database populated with incident investigation information using the above described classification and coding system.

Rotating Equipment Nonroutine Repairs

It is particularly important that the insurance company be involved in the investigation of mechanical damage to large or critical rotating equipment that requires substantial and/or unusual repairs. The insurance company will want to be sure all factors related to the failure are addressed so that the repaired equipment will represent the best possible insurance risk during future operation.

Nonroutine repairs to large, critical rotating equipment are of particular interest to the insurance company. A nonroutine repair can be defined as a repair that significantly deviates from the original design of the machine. Examples include extensive case repairs, welding repairs to rotors, and welding repairs to crankshafts in reciprocating equipment. The repair firm performing these types of repairs will normally state that the repair will be done on a "best effort" basis; that is, the repair firm will not guarantee the results of the repair since the proven OEM machine design has been altered to an unproven design. Even if the repair firm does guarantee the repair, the guarantee will not cover lost production if the repaired machine fails. Since most, if not all, of the physical damage and business interruption deductibles are likely to be consumed while performing the repair, most of the financial risk involved with operation of the repaired machine will be borne by the insurance company. If a repaired rotor fails and destroys the case, or if a case repair fails and severely damages the

only remaining rotor, a catastrophic business interruption loss may be incurred. Therefore, the insurance company will normally provide its own design engineers, metallurgists, etc., to serve on the repair team to ensure the highest probability of success in the repair design.

It should be noted that the repair firm and the customer's engineers are certainly capable of designing and performing successful nonroutine repairs; successful nonroutine repairs are performed regularly without input from insurance companies. However, if the equipment is insured, all parties concerned will benefit if the insurance company's engineers participate in the design and monitoring of the repair. The primary reasons are:

- The insurance company's design engineers are experts in non-routine repairs and are usually provided at no cost to the customer. In every nonroutine repair the author is familiar with, the insurance company's design engineers and metallurgists brought good ideas to the table that were used in the final repair design. Rather than being simply the "repair police," the insurance company's engineers were a valuable part of the repair team, and the final design of the repair was enhanced by their participation.
- If the insurance company's engineers are used in the design of the repair, the repaired machine is likely to be insurable when it is returned to service; there will be no second guessing or doubts about fitness for service from an insurance point of view.
- When the insurance company's engineers are involved in the repair design, there is a greater likelihood of the repair being considered permanent, rather than temporary, from an insurance point of view.

One insurance company has classified turbomachinery rotor welding repairs and issued repair guidelines for each classification. Details of this classification/repair guideline system are available free of charge from the insurance company [5].

PREVENTING CATASTROPHIC LOSSES RELATED TO ROTATING EQUIPMENT

From the insurance company's point of view, a catastrophic rotating equipment loss is a failure that results in a large physical damage or business interruption insurance loss in excess of the deductible. It is possible for an incident involving rotating equipment to result in a large insurance loss even though the rotating equipment itself is not damaged or is only slightly damaged. For example, a process gas compressor could surge resulting in a process upset. Even though the compressor may have been undamaged by the surge event, the process upset may result in reactor catalyst damage, pressure vessel or fired heater damage, or worse [6, 7, and 8].

A catastrophic rotating equipment loss or incident may involve a severe personnel hazard in addition to financial loss.

Some specific recommendations for preventing serious rotating equipment incidents follow. The following lists of recommendations for various rotating equipment, and various rotating equipment-related practices, are not intended to be all inclusive. On the contrary, the author has attempted to list only those recommendations that:

- When not followed have caused, or have the potential to cause, serious accidents.
- In the author's experience are not always followed by all plants.
- In the author's experience are controversial; there is wide disagreement between industries or between companies in the same industry.
- The author thought would be of interest or value to rotating equipment users.

The following recommendations are based solely on the experience of the chemical, oil, and gas business unit of one insurance company, and some recommendations may not be applicable to other industries. Due to the wide range of rotating equipment applications in the chemical, oil, and gas industries, some of the following recommendations may not be applicable to every application in those industries.

The Incident "Chain of Events"

Studies have shown that serious accidents or "near misses" are almost always the final event in a series of lesser events and/or errors [9]. If any event in the chain of events is eliminated, the catastrophic event will be avoided. A typical chain of events involving a steam turbine overspeed accident is shown in Figure 3; this simplified series of events is based on an actual catastrophic loss involving a steam turbine.

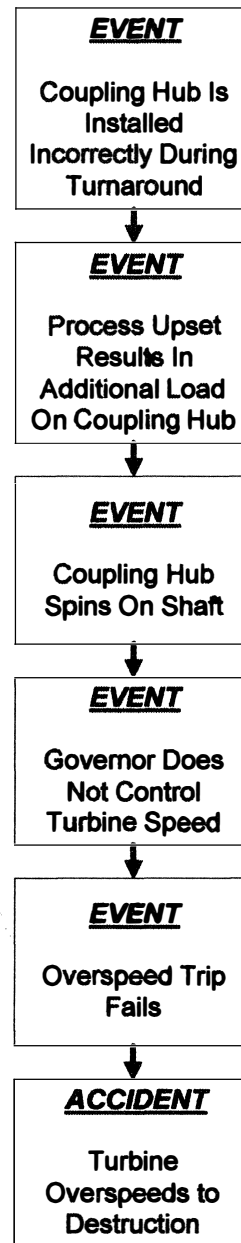


Figure 3. Typical Sequence of Events Leading to a Catastrophic Rotating Equipment Accident.

If any single “event” shown in Figure 3 had been prevented, the accident would not have occurred. Effective loss prevention programs reduce the number of “events,” which in turn reduces the probability of catastrophic losses. A broad approach that reduces the frequency of all events is more effective than concentrating on preventing a single event such as failure of the overspeed trip system.

The following are specific rotating equipment loss prevention tools, techniques, and recommendations:

Steam Turbine Overspeed Wrecks

A catastrophic overspeed wreck of a steam turbine used to drive a large process compressor represents one of the most serious business interruption exposures encountered in the chemical, oil, and gas industries. In a large refinery fluid catalytic cracking unit (FCC), or in a large ethylene unit, methanol unit, or similar unit, the catastrophic wreck of a large steam turbine could result in a business interruption loss of \$300,000 to more than \$1,000,000 per day, and the replacement time for a large industrial drive steam turbine case could be six to 15 months. In addition, fragments produced by the centrifugal explosion of a steam turbine can puncture process vessels and/or piping resulting in a large fire and/or explosion.

The average cost of a steam turbine overspeed accident is greater than the average costs of all other steam turbine incidents (Figure 4). In the chemical, oil, and gas industries, the average cost of a steam turbine overspeed loss greatly overshadows the average costs of losses due to other causes (Figure 5). Based on one insurance company’s experience, most large steam turbine damage is caused by improper operation, improper repair, or inadequate maintenance as opposed to faulty materials or design deficiencies (Figure 6). Within these broad categories, the leading specific loss causes were excessive vibration, fatigue or corrosion, water induction, and overspeed (Figure 7).

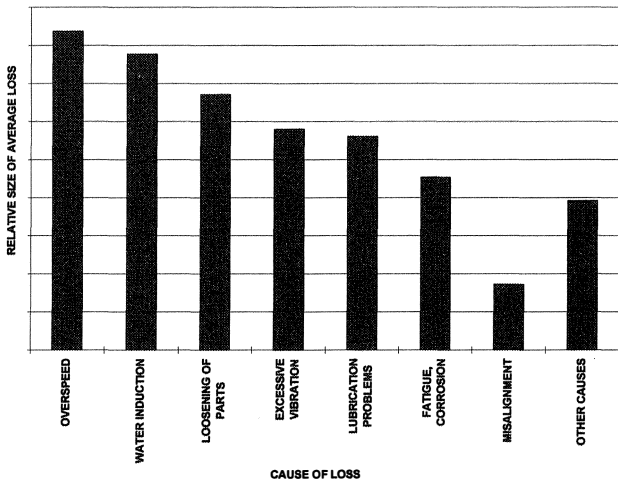


Figure 4. Relative Size of Average Loss for the Seven Most Common Causes of Steam Turbine Damage. Data include all industries for the time period 1980 through 1995.

Generally speaking, three events must occur before a steam turbine used to drive a process compressor or pump can overspeed to the point of a rotor burst that destroys the case:

- There must be a sudden, large loss of load on the steam turbine.
- The governor valve must fail to control the speed of the turbine.
- The overspeed trip system must fail to function properly.

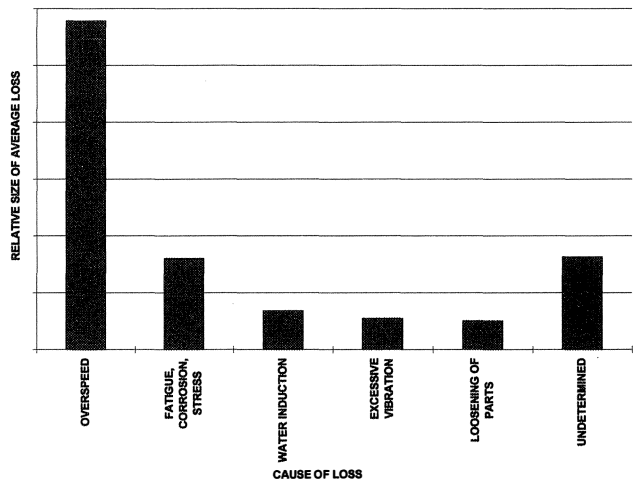


Figure 5. Relative Size of Average Loss for the Five Most Common Causes of Steam Turbine Damage. Data are for the chemical, oil, and gas industries during the time period 1980 through 1995.

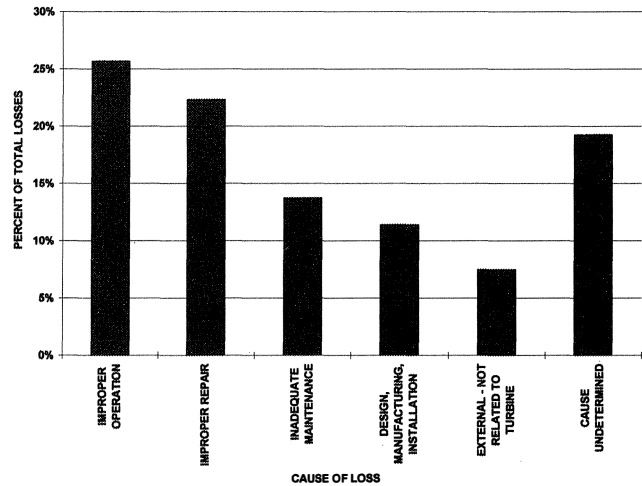


Figure 6. Losses Represented by Five Categories of Steam Turbine Damage Causes. Data are for the chemical, oil, and gas industries during the time period 1980 through 1995.

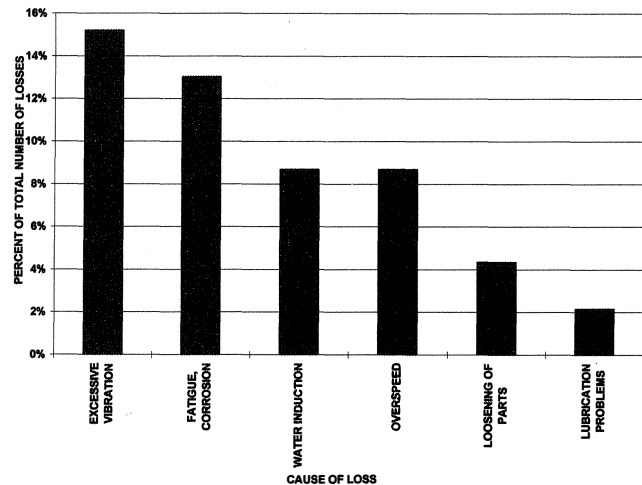


Figure 7. Six Most Common Specific Causes of Steam Turbine Damage. Data are for the chemical, oil, and gas industries during the time period 1980 through 1995. Combined percentages do not total 100 percent because less common causes are not shown.

If any of the three events are eliminated, the steam turbine likely will not overspeed to the point of a centrifugal explosion that destroys the case.

The greatest probability of success in preventing a catastrophic steam turbine overspeed accident lies in proper coupling installation and condition monitoring to ensure excessive stress is not applied to the coupling while the turbine is in operation. While steam turbines driving process compressors can certainly overspeed without coupling or shaft failure, the probability of losing the steam turbine case is relatively low unless the coupling or shaft fails thereby reducing the driven load very quickly. Most steam turbines driving process gas compressors or pumps will not overspeed to complete destruction if they are still under a 20 percent to 30 percent load, and turbines driving a cavitating pump or surging compressor generally still operate under 20 percent to 30 percent of full load. In addition, when a pump is cavitating or a compressor is in surge, the load on the steam turbine is reduced slowly compared to the rate of load loss if the coupling or shaft fails. The relatively slow loss of load provides more time for the governor system and/or overspeed trip system to function; it also provides more time for a component failure to occur, such as a blade failure or rotor rub, that might limit the speed of the turbine or produce enough vibration to cause the trip/throttle valve to close. Of course, the same cannot be said for steam turbines driving generators; those turbines can lose a very large percentage of load very quickly without coupling failure. [10, 11] Also, it should be noted that a pump with a completely blocked suction may not put even a 20 percent load on a driving steam turbine, and the turbine can overspeed to complete destruction [12].

If a component fails or the rotor rubs, the turbine may be severely damaged, but the diaphragms and case will likely be repairable. Assuming a spare steam turbine rotor is in stock, the business interruption loss might only be three to eight weeks to repair the case and diaphragms as opposed to six to 15 months if the case is destroyed.

The above is not intended to imply that steam turbine governor systems or overspeed trip systems are not important; in fact, they are critically important. However, the frequency of governor system failures and overspeed trip system failures is very high relative to the frequency of coupling failures. With proper procedures and diligence, correct coupling installation is relatively straightforward. With proper vibration analysis, misalignment and other causes of coupling distress can be detected and corrected prior to coupling failure. Coupling failure can be prevented relatively easily compared to preventing governor and overspeed trip system failures. Preventing governor and overspeed trip system failures is more difficult because those failures are often related to steam purity problems; steam purity is discussed in the *Steam Turbine Rotor Disk Failure* section later. Of course, every effort should be made to ensure the overspeed trip system and governor system are functioning properly by following the manufacturer's recommendations for periodic exercising and testing.

The previous discussion on steam turbine overspeed wrecks concerns steam turbines in normal operation. A large percentage of steam turbine overspeed wrecks occur while performing an overspeed trip test with the turbine uncoupled from the driven load or operating at a very low load. Due to the increased risk during an uncoupled, or low load, test of the overspeed trip system, one insurance company has long had a specific exclusion in its standard policy for damage incurred during maintenance or testing of steam turbines.

Frequency Of Steam Turbine Overspeed Wrecks. Overspeed wrecks of large steam turbines are relatively rare; however, they do occur. One insurance company's loss data for all industries includes 24 overspeed incidents in the time period of 1980 through 1995; 15 of the 24 involved industrial steam turbines as opposed to large steam turbine-generators used in the utility industry.

In the chemical, oil, and gas industries, the same insurance company's data includes four large steam overspeed wrecks; one was in an ammonia plant, two were in chemical plants, and one was in an ethylene plant. The primary cause of two incidents was improper coupling installation; in all four incidents, governor and overspeed trip systems also failed to function properly. Numerous other overspeed wrecks of large steam turbines are detailed in the referenced literature [12]. A gas turbine used to drive a pipeline gas compressor also oversped to complete destruction in recent years.

The financial and safety implications of a large turbine overspeed wreck are such that even one accident is too many.

The frequency of overspeed wrecks involving smaller steam turbines is higher than the frequency of large steam turbine overspeed wrecks. Smaller steam turbines usually have less sophisticated governor systems and overspeed trip systems, and they usually do not have continuous condition monitoring instrumentation. Small steam turbines are often spared, so lost production resulting from an accident is usually not significant. The financial consequences of a small steam turbine overspeed wreck are small enough that these wrecks may not get entered into an insurance loss database. Therefore, reliable insurance statistics are scarce regarding the frequency of small steam turbine overspeed wrecks. Subjectively, the author is personally aware of numerous small steam turbine overspeed wrecks; turbine repair shops can verify that small steam turbine overspeed incidents are not uncommon.

Recommendations To Prevent Small Steam Turbine Wrecks. Although the replacement cost of a small steam turbine may not be a serious concern, the risk of damage to nearby piping and vessels and a resulting fire or explosion are very significant concerns. Of course, personnel safety implications of a small steam turbine overspeed wreck are very serious. The following are specific recommendations for small steam turbines:

- Governors and overspeed trip systems should be tested and maintained on a regular basis; generally, they should be tested and maintained at least annually and more frequently if steam quality is poor [11, 13].
- Vibration monitoring and/or alignment checks should be performed often enough to detect excessive stresses being applied to the coupling so that corrections can be made well in advance of coupling failure [13].
- Where practical, mechanical governors should be upgraded to hydraulic governors or electronic governors [11, 13].
- Where practical, mechanical overspeed trip systems should be replaced with, or supplemented by, electronic overspeed trip systems [13]. Advantages of electronic governors and electronic overspeed trip systems are discussed in the next section: *Recommendations To Prevent Large Steam Turbine Overspeed Wrecks.*
- Some small steam turbines are designed to overspeed to destruction with the case intact. On these turbines, upgrading governor or overspeed trip system protection would not be justified solely for safety reasons; upgrading may be justified for reliability reasons depending on the specific application.
- Lube oil and hydraulic oil coming into contact with any component in the governor system or overspeed trip system must be clean, in good condition, and free of water [8, 11].

Recommendations To Prevent Large Steam Turbine Overspeed Wrecks. The following are specific recommendations to prevent overspeed wrecks of large industrial steam turbines:

- Design of couplings should be carefully reviewed, and a liberal safety factor should be used in the design of couplings; high stresses can be transmitted to the coupling due to problems in connected machines [14].

- Specific, detailed, written procedures should be in place for coupling inspection and repair. Critical steps in coupling installation should be witnessed by someone other than the craftsmen installing the coupling. Coupling installation steps and witnessing should be documented. Craftsmen should receive very thorough training in coupling installation practices; this training should be periodically repeated as refresher training, and all training should be documented [15].
- Couplings should be inspected at every opportunity. Excessive forces applied to couplings will result in specific failure modes; unusual coupling wear or damage should be thoroughly investigated and the root cause corrected [16, 17, 18].
- Large steam turbines and driven equipment should be equipped with adequate continuous condition monitoring systems. The term "large steam turbines and driven equipment" cannot be accurately defined in regards to the level of condition monitoring instrumentation needed; the level of sophistication required for machinery train condition monitoring systems should be determined primarily by safety considerations and business interruption exposures. Large turbomachinery trains in units such as refinery FCC and reformer units, ethylene units, ammonia plants, and methanol plants should have state-of-the-art condition monitoring systems including the capability for very fast, automatic data acquisition during periods of unusual/transient operation [19, 20]. The author is aware of numerous "saves" of large rotating equipment at customers' plants where advanced vibration analysis, in conjunction with a conservative operating philosophy by plant management and operators, enabled large machines to be shutdown before a serious wreck occurred. Advanced condition monitoring systems have also repeatedly proved valuable in diagnosing the cause of a trip so that the probability of serious damage during a restart of the machine is greatly reduced. State-of-the-art condition monitoring systems are not "bells and whistles;" they are tools that, when properly used by well trained rotating equipment engineers, can significantly reduce rotating equipment failures and lost production. Condition monitoring systems on critical machinery trains that represent large business interruption exposure should be upgraded when significant advances are made in technology.

Having said all of the above, there may be instances where upgrading condition monitoring systems is impractical. One example might be very old equipment that may be replaced in the near future. Whatever condition monitoring system is used, every effort should be made to diagnose and correct conditions that create excessive stress on couplings well in advance of coupling failure.

The following interlocks (trips) are recommended for large, critical machines equipped with reliable continuous condition monitoring instrumentation:

- Excessive axial vibration trips as a minimum—Excessive radial vibration trips are also preferred, but they are usually optional from an insurance viewpoint. Severe thrust damage can occur relatively quickly; an operator usually cannot manually trip the machine fast enough to prevent severe thrust damage [21]. The time required to repair excessive thrust damage to the diaphragms or case can be costly from a business interruption viewpoint. Repairing damage following excessive radial vibration often can be done more expeditiously; of course, this damage can still be quite extensive. Vibration monitoring and trip systems should be installed in accordance with API Standard 670.

- Excessive bearing temperature trips—Bearing temperature probes should be imbedded in the bearing metal. A trip on high rate of increase in the bearing temperature may offer more protection than a specific temperature trip point—particularly with thrust bearings.

- Vibration analysis and/or alignment checks should be performed often enough that conditions such as misalignment, which can produce excessive stress on the coupling, are detected well in advance of coupling or shaft failure [16, 22, 23]. It should be noted that detection of excessive misalignment forces using vibration analysis is more difficult, or at least the type of vibration produced is different, on machines with flexible disc type couplings [16, 24].

- Electronic governors and electronic overspeed trip systems are highly preferred. Electronic systems have several significant advantages compared to mechanical governor and overspeed trip systems; these include:

- Much of an electronic overspeed trip system can be tested while the equipment is in normal operation [11]. Online testing of electronic overspeed trip systems should be performed at least annually; more frequent testing is desirable.

- Electronic governors generally respond more quickly to load changes [11].

- Electronic governors can be mounted off the turbine eliminating the need for governor drives [11].

- Electronic governors can provide control over a wide speed range [11].

- With electronic governors, process controls can input to the turbine speed setting [11]; this may reduce the probability of process upsets in some applications.

- Automated turbine operation, including startup and shutdown sequences, is easier with electronic governors [11].

- Control of turbine variables other than speed is possible with electronic governors [11].

- Electronic overspeed trip systems are redundant; the failure of any single component will not result in a lack of overspeed protection or a nuisance trip. Use of triple redundant components and two-out-of-three voting logic can increase reliability even further. With mechanical overspeed trip systems, the failure of a single component can result in loss of overspeed protection or a nuisance trip [11].

- With electronic overspeed trip systems, an overspeed trip test can be performed while the turbine is operating at, or less than, normal operating speed. Using proper equipment and procedures, an electronic overspeed signal is used to simulate overspeed and actuate the overspeed trip system [11]. This greatly reduces the danger associated with overspeed trip testing with the turbine uncoupled or under very low load. A large percentage of steam turbine overspeed wrecks occur during uncoupled/low load overspeed trip testing. In the author's opinion, this single advantage should be sufficient to justify upgrading to electronic overspeed trip systems.

- Electronic overspeed trip systems can be adjusted easily. Adjustment of mechanical overspeed trip systems is sometimes very difficult and time consuming [11]; the adjustment often occurs at a time when the steam turbine is needed to get the plant back into operation.

- Upgrading some steam turbines to electronic governors may eliminate various linkages and gears that are sources of mechanical problems [2].

- Most of the above listed advantages of electronic governors and electronic overspeed trip systems that increase steam turbine safety also increase reliability and increase process control. Economic advantages of electronic overspeed trips and electronic governors alone may be sufficient to justify system upgrades; the

author is aware of several upgrades to electronic governors that were made primarily for economic reasons.

- As a general rule, mechanical overspeed trip systems should be tested at least annually. More frequent testing may be needed if steam purity is questionable. The overspeed trip should be tested as soon as the machine is taken out of service and before any cleaning or adjustments are made; this test is the best indication of whether the testing frequency is adequate. If the overspeed trip fails to function properly during this test, the test frequency should be shortened if the reason for the failure cannot be positively identified and corrected [25]. Items to consider if the overspeed trip frequency is extended beyond one year include:

- Steam purity must be adequately controlled and monitored. Refer to the *Steam Turbine Rotor Disk Failure* section later for details on steam purity monitoring and control.

- Previous overspeed trip tests, conducted prior to cleaning and adjustment, should have been successful indicating the testing frequency could safely be extended.

- If unscheduled unit outages occur, the opportunity should be taken to test the mechanical overspeed trip system.

- Each time the steam turbine is shutdown for a scheduled outage after being in service for an extended period, the turbine should be stopped by tripping the trip/throttle valve. The closing time of the trip/throttle valve should be accurately measured during this trip. The closing time of the trip/throttle valve should also be accurately measured during overspeed trip tests. If the closing time is excessive, the cause should be determined and corrected [25].

- Steam turbine trip/throttle valves should be exercised at least monthly [26, 27, 28]; more frequent exercising and testing may be desirable depending on the application [27]. For most industrial drive steam turbines in the chemical, oil, and gas industries, one insurance company recommends weekly exercising. Manufacturers of the steam turbine, governor, and trip/throttle valve should be consulted regarding proper testing, exercising, inspection, and maintenance frequencies and procedures. More frequent exercising is necessary if steam purity is questionable. Generally speaking, governor valves and trip/throttle valves should be cleaned, inspected, and repaired during each major turnaround of the unit; more frequent cleaning, inspection, and repair may be required depending on the application and steam purity [11].

Most large trip/throttle valves are designed to be exercised without affecting the speed of the turbine and without producing a nuisance trip of the turbine; however, it is common for operations personnel to be reluctant to exercise governor valves and trip/throttle valves for fear of a process upset or nuisance trip. It is important that operators have confidence in the systems so that exercising is performed regularly. Operator training sessions during commissioning or other opportune times, during which each operator actually exercises the governor valve and trip/throttle valve while the turbine is online, can be effective in instilling confidence that the systems can be exercised without incident [26]. These training sessions should include detailed explanations of why exercising is critical to ensure reliability of the valve.

- Specific, detailed, written procedures should be developed for overspeed trip tests [25].

- When performing an uncoupled or low load overspeed trip test, turbine speed should be controlled with a hand operated block valve; the speed should not be controlled with the governor valve or with another type of control valve [12, 25]. Some control system designs may not permit speed control with a hand operated block valve [12].

- Electronic overspeed trip systems should have at least two independent speed sensing systems [10]. In addition, the governor system should have its own speed sensing system [11]. The overall protection system design should ensure that both the governor valve and trip/throttle valve close when overspeed is detected [11, 25].

- Regardless of the redundancy of other components in the overspeed trip system, most large steam turbines in the chemical, oil, and gas industries have only one trip/throttle valve, and this valve is notorious for becoming inoperable due to steam purity problems or incorrect maintenance. From a mathematical probability viewpoint, two trip/throttle valves in series would increase safety; however, both valves could fail to operate properly due to poor steam quality (common mode failure), so the net increase in safety is debatable.

The author is aware of one petrochemical plant that has installed two trip/throttle valves in parallel on large, critical steam turbines. During normal operation, only one valve is in service. (If both valves were in continuous service in parallel, the mathematical probability of turbine overspeed would be increased.) Each trip/throttle valve is sized to handle the full steam requirements of the turbine so that one valve at a time can be tested without affecting production. This arrangement allows full stroking of trip/throttle valves rather than partial exercising. Also, by electronic simulation of an overspeed condition, the entire overspeed trip system can be tested while the process unit is in normal operation. The valves are tested monthly; each quarter, valve closing time is checked to ensure steam contaminants are not affecting closing time. Obviously, the cost is greater than the cost for a single trip/throttle valve; however, increased safety and reliability, along with no lost production solely for overspeed trip system testing/maintenance, help justify the increased cost.

- Most steam turbine overspeed accidents involve governor valve and/or trip/throttle valve sticking, and most governor valve and trip/throttle valve sticking is caused by impure steam [10]. Every effort should be made to ensure steam turbines operate on good quality steam. Steam purity is discussed further in the *Steam Turbine Rotor Disk Failure* section below.

Steam Turbine Rotor Disk Failure

Failure of a steam turbine rotor disk can also result in a catastrophic steam turbine wreck. From an insurance viewpoint, financial consequences of steam turbine rotor disk failure are similar to financial consequences of a catastrophic steam turbine overspeed wreck. The turbine case will likely have to be replaced, and objects around the turbine can be punctured or damaged by rotor blades or disk fragments. The following quote from the Twelfth Turbomachinery Symposium paper by Rogers, Wells, and Johnson [29] describing a large steam turbine wreck due to stress corrosion cracking in a rotor disk is an example of the damage potential in this type of accident:

"The last stage disk had an 80 in OD and a 36 in ID, and it was 17.5 in wide at the bore. ...Piece A-13 exited the turbine casing with a trajectory sloping upwards at about 15 degrees. Exiting the building, the segment sheared through a 12 in steel beam and perforated a 6 in thick reinforced concrete wall. The segment then struck a 55,000 lb transformer, whose end was displaced about 6 feet, deflecting the segment's trajectory slightly to one side. The segment came to rest 355 feet away from and 60 feet above the turbine axis.

Piece C-3 separated from the shaft on a slightly downward trajectory, producing extensive damage to structural members in the lower turbine casing and to the edge of a massive concrete wall that forms a part of the foundation. The segment ricocheted up from this area, denting the side of the cowling on the adjacent

IP turbine, damaging the insulation on piping beneath the cawling and producing a 3 foot deep dent in a steel beam in the wall of the building before coming to rest on the floor."

The above described accident involved a very large rotor disk in a 138 MW turbine in a utility plant; damage from rotor disks in turbines 50 MW and smaller typically found in refining, chemical, and petrochemical plants would be less but still very serious. Most importantly, blades or disk fragments resulting from a process plant steam turbine wreck could rupture vessels and/or piping resulting in a serious fire and/or explosion.

Prevention of steam turbine rotor disk failure is more difficult than preventing steam turbine overspeed wrecks because:

- A single event, disk cracking, can result in an accident. There are only two ways to prevent the accident; one is to prevent the disk cracking—the other is to detect the disk cracking prior to failure of the disk.
- Vibration analysis or other condition monitoring will not reliably detect steam turbine disk cracking. Disk cracking can progress undetected by routine vibration analysis [29].

Frequency of Steam Turbine Rotor Disk Failures. The author is not personally aware of any catastrophic insurance losses in the chemical, oil, and gas industries due to steam turbine rotor disk failure caused by cracking. Catastrophic failures of this type have occurred in other industries.

In spite of the fact no catastrophic chemical, oil, and gas plant losses have been experienced due to steam turbine rotor disk failure, stress corrosion cracking of steam turbine rotor disks is relatively common. The author is personally familiar with the following steam turbine rotor disk cracking incidents involving large steam turbines in the chemical, oil, and gas industries:

- **Chemical Plant A:** A rotor in a steam turbine driving a process air compressor suffered disk stress corrosion cracking due to carryover from a boiler steam drum. The spare rotor also experienced disk stress corrosion cracking while the original rotor was being repaired.
- **Chemical Plant B:** Several steam turbines driving process gas compressors in the same unit suffered rotor disk stress corrosion cracking due to excessive carryover from waste heat boiler steam drums. One steam turbine had disks cracked almost to the point of failure after only three weeks of operation (Figure 8).
- **Petroleum Refinery:** Two steam turbines were opened for routine inspection after the first few years of what was thought to be normal operation. Eight or nine disks on each rotor had stress corrosion cracks. Due to cracking at the bore, one disk had moved axially on the shaft resulting in rub damage to diaphragms. Carryover from waste heat boilers in one unit of the refinery was suspected; impure desuperheating medium was also thought to be a contributing cause. In addition, metallurgical analysis of rotor material indicated the material would be very susceptible to stress corrosion cracking. The rotors were repaired (with upgraded material), and steps were taken to minimize boiler carryover and correct the desuperheating medium purity problem. After another couple of years operation, one of the turbines was opened for routine inspection, and stress corrosion cracking was again found on the rotor disks.
- **Ammonia Plants:** A study conducted of steam turbine failures in the ammonia industry found 45 occurrences of stress corrosion cracking type failures [30].
- **Ethylene Unit:** The rotor from an approximately 30,000 hp steam turbine was sent to the shop for repair of foreign object damage. In the shop, NDE found stress corrosion cracking in one disk. The plant was aware of at least one incident involving severe carryover from a waste heat boiler in the unit. The repaired rotor was

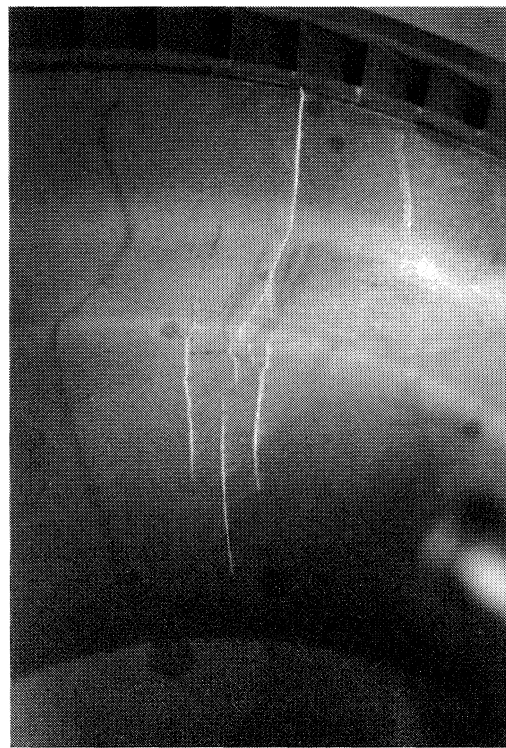


Figure 8. Photograph of Steam Turbine Rotor Disk Cracked Almost to the Point of Failure After Only Three Weeks Operation with Impure Steam.

installed during the next turnaround. The rotor removed during that turnaround was found to also have stress corrosion cracking in one disk.

In addition to the steam turbine disk cracking noted above in the chemical, oil, and gas industries, the power generation industry also experiences the problem. Rogers, Wells, and Johnson quote an Electric Power Research Institute (EPRI) report that included data on 120 cracked steam turbine disks over a several year period [29].

Recommendations To Prevent Catastrophic Steam Turbine Disk Failure. The following are specific recommendations to prevent catastrophic steam turbine disk failure accidents:

- Operate steam turbines with good quality steam. A common cracking mechanism in steam turbine rotor disks is stress corrosion cracking. A complete discussion of stress corrosion cracking is beyond the scope of this paper; however a listed reference describes the mechanism in detail [31]. Generally speaking, steam turbine disk cracking will not be experienced with good quality steam. There is no single definition of good quality steam; however, technical papers cover the subject in considerable detail [32, 33].
- In the author's experience, most steam quality problems are caused by changes in the steam system rather than the original design of the steam system. Most plants, or units in plants, operate without steam purity problems for many years before suddenly experiencing a steam quality change and resultant steam turbine disk cracking. The following are some causes of steam quality problems; this list does not include all of the causes of poor steam quality—only the most common:
 - Impurities enter the steam system, boiler feedwater system, attemperating or desuperheating system, or condensate system through leaks in heat exchangers, valves leaking through, improper regeneration of water softener resins, etc. Corrosion products and impurities migrate through the systems to steam turbines.

- A steam boiler(s) is operated at higher capacity, due to changes in unit operation, debottlenecking projects, etc. Operating at higher capacity, steam drum carryover is experienced.
- Steam drum carryover from a waste heat boiler(s) is experienced due to process upsets; process upsets result in operating the waste heat boiler at a higher steaming rate, an abnormally high water level in the steam drum, or in widely fluctuating steaming rates. Carryover from conventional fired boilers can also be experienced under the same conditions.
- Carryover from a steam drum is experienced due to mechanical failure of steam separation equipment in the steam drum or due to a design error involving steam separation equipment.
- It is important that impurities entering the steam system, boiler feedwater system, condensate system, and attemperating/desuperheating system be detected quickly so that corrective measures can be taken and damage to steam turbines minimized or prevented. Stress corrosion cracking can progress quickly [34]; severe disk cracking that resulted after only three weeks operation with very poor quality steam is shown in Figure 8. The following are a few items that can help quickly detect impurities in steam, boiler feedwater, and condensate systems:
 - Conductivity and/or pH analyzers should be used to continuously monitor boiler feedwater and condensate systems so that impurities entering the systems will be quickly detected. Other types of monitors may be needed depending on the potential impurities that can enter feedwater and condensate systems at individual plants. Appropriate alarms should be used for early detection of impurities in the systems [32, 33].
 - Steam purity should be continuously monitored with sodium analyzers and/or cation conductivity analyzers. Design and installation of sampling nozzles is critical for reliable results. Refer to ASTM, ASME, and EPRI Standards for correct sampling nozzle design and location information [32, 33].
 - Operators must have proper training, including periodic refresher training, on maintaining steam purity. Operators should receive training in the consequences of a loss of steam quality. Operators should understand that steam purity excursions may occur very infrequently, but equipment can be severely damaged after operation with poor quality steam for a short time. Specific operator actions required should be documented in the Operating Instructions [32].

Even with good systems in place to detect impurities entering water and steam systems, steam turbine rotors may still be susceptible to cracking. Continuous monitoring of steam purity using isokenetic nozzles in steam lines and continuous analyzers is not done in every plant, and where it is done, it has not always prevented rotor cracking. In the author's opinion, the lack of catastrophic steam turbine disk failures in the chemical, oil, and gas industries has been due, primarily, to the frequency of dismantled inspections. In the author's experience, every plant that experienced disk cracking thought steam quality was satisfactory prior to the discovery of cracks in steam turbine disks. If each plant had not performed a dismantled inspection of the steam turbine, the disk cracking could have progressed to the point of a catastrophic failure. Dismantled inspections of turbines and rotor NDE have been the "safety net" to catch disk cracking prior to catastrophic failure.

Many plants are either increasing the time between dismantled inspections, or they are considering increasing the time, due to significant cost savings possible with extended production runs between turnarounds. The following are some specific recommendations for items to consider before extending dismantled inspection frequencies of steam turbines:

- Extension of steam turbine dismantled inspection frequencies must receive formal multidisciplinary reviews and approvals

equivalent to a process safety management (PSM) management of change procedure. Rotating equipment engineers cannot ensure, and are not responsible for, steam quality; therefore, other plant departments should be involved in the extension decision.

Some plants have a PSM management of change procedure that includes changes that are not strictly design related; this type of procedure is highly preferred [35, 36].

- History and design of the turbine(s) involved should be carefully reviewed. Some steam turbine rotor designs are more susceptible to disk cracking than other designs [30, 34]. Metallurgical properties of the rotor disk are an extremely important factor in a rotor's susceptibility to all types of cracking; metallurgical properties will also affect the rate of crack progression. Actual metallurgical properties of the rotor disk may not be known without detailed metallurgical analysis.
 - Plant/unit steam system design, control, and reliability should be carefully reviewed; a process hazards analysis (PHA) may be needed. Typical questions to answer include:
 - Will operators know if adverse water, boiler feedwater, attemperating/desuperheating, condensate, or steam purity conditions develop, and if so, how quickly?
 - What will be the result of instrumentation failure? What backup systems are in place?
 - Operator training in steam quality.
 - What will be the course of action if steam quality becomes suspect during the period of operation between turnarounds; will the extended run time between turnarounds be continued? How will the decision be made, and who will make it? This course of action should be agreed on prior to extending the turnaround frequency.
 - Reliability of boiler steam drum level control systems should be carefully reviewed. Loss of control of boiler steam drum levels is a common cause of carryover that leads to rotor disk cracking [33]. Boiler steam drum level control is discussed further in the *Steam Turbine Water Induction* section later.
- The above comments are not intended to imply that operating intervals between steam turbine dismantled inspections cannot be increased; the comments are intended to point out potential risks involved and measures that should be taken to reduce the risk.
- Improving steam quality, or improving steam quality control, in a large refinery, chemical, or petrochemical plant is a major undertaking that requires a multidisciplinary, plantwide effort. However, the benefits of pure steam, boiler feedwater, and condensate will usually more than justify the effort. In addition to reducing probabilities of steam turbine rotor cracking and steam turbine overspeed due to sticking governor valves or trip/throttle valves, improved steam quality can result in lower maintenance costs for a wide range of equipment; a few examples include:
- Reduced corrosion in piping and vessels that handle steam, condensate, or boiler feedwater.
 - Reduced cleaning costs for heat exchangers, boilers, economizers, superheaters, etc.
 - Reduced steam trap maintenance costs and energy savings by eliminating wasted steam.
 - Reduced costs, and reduced risks, associated with cleaning steam turbines. Though steam turbines can be safely cleaned online, there are inherent risks in the operation, and turbines have been damaged in the past during cleaning operations. Even if steam turbines are not damaged during cleaning, overall maintenance costs and lost production can be minimized if the root problem, poor steam quality, is reduced or eliminated [2, 37].

Steam Turbine Water Induction

Steam turbine damage due to water induction is relatively common in the chemical, oil, and gas industries (Figure 7). During one several-year period in the mid-1980s, most of the medium to large oil refineries insured by one company had at least one large steam turbine damaged by water induction. In addition to wrecking the steam turbine, water induction can result in a severe process upset resulting from rapid slowing of the steam turbine and driven equipment. A process upset following water induction in a large steam turbine in an ethylene unit, ammonia plant, refinery FCC unit or reformer unit, methanol unit, and various other processes, could have very serious consequences.

Preventing Process Upsets and Steam Turbine Damage Due To Water Induction. Various methods of detecting water carried over into steam lines are available; most of these use conductivity probes. There is an ANSI/ASME Standard (ANSI/ASME TDP-1-1985) related to protecting steam turbines from water induction.

Based on one insurance company's experience in the chemical, oil, and gas industries, the best means of preventing water induction to steam turbines is to have adequate control of the water level in boiler steam drums. Due to the thermodynamics involved, boiler steam drum level control is quite complicated. Boiler steam drum level instrumentation must be reliable and redundant. In addition to offering the best water induction protection to steam turbines, reliable boiler steam drum level instrumentation is critical in reducing steam carryover that can render governor valve and trip/throttle valves inoperable and cause cracking in steam turbine rotor disks. The following are some specific recommendations:

- Equip boiler steam drums, particularly process waste heat boiler steam drums, with reliable, redundant level instrumentation systems. The best system design the author is aware of uses three steam drum level transmitters in a two-out-of-three voting system for level control, indication, alarms, and trips [38]. Although Waltz's [38] paper specifically addressed utility power boilers, the same general control system design would provide very reliable control for process waste heat boiler steam drum levels. The control system described by Waltz allows the failure of any single component without loss of control of the steam drum level and without loss of interlock protection. In addition, the probability of nuisance trips is minimized.
- Regardless of steam drum level control system sophistication, the most reliable means of determining the level in a boiler steam drum is a direct indicating sightglass. Displaying images of one or more sightglasses at the point where the steam drum level is controlled (usually the central control room) is highly recommended. The best means of displaying a boiler sightglass image in the control room is through the use of fiber optic systems [7, 38, 39]. Of course, boiler steam drum sightglasses must be kept clean and in good condition if they are to be relied on.
- There should be a high-high level interlock on each boiler steam drum to protect steam turbines from water induction. If a high-high steam drum level interlock is impractical for some reason, boiler steam drum level indication and control instrumentation becomes even more critical; redundancy and reliability must be ensured, and operators should clearly understand the actions required if the boiler steam drum level becomes excessively high.

Preventing Catastrophic Losses Related To Critical Compressors

In the chemical, oil, and gas industries loss experience of one insurance company, centrifugal, axial, and rotary compressors represent the largest portion of rotating equipment losses (Figure 9). In the event of rotor separation, steam turbines represent a larger risk to surrounding equipment than do compressors. However, production loss due to severe case damage can be as

great with compressors as with steam turbines, since replacement times for large compressor cases are roughly equal to replacement times for steam turbines cases up to approximately 60,000 hp. Also, damage to other process equipment such as fired heaters, catalyst, and pressure vessels can be caused by problems related to compressors [8].

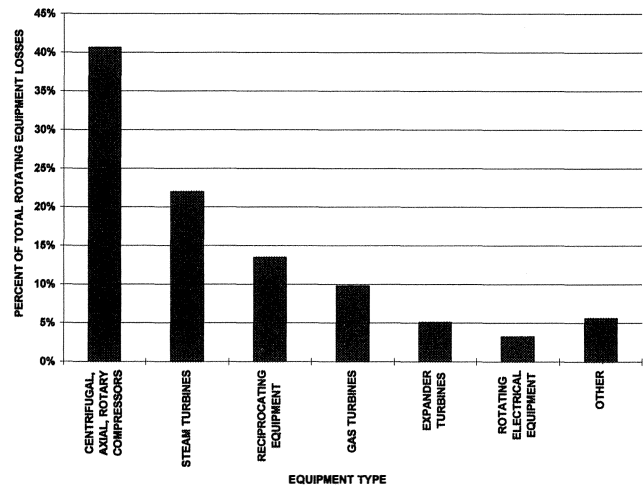


Figure 9. Portion of Total Losses Represented by Six Types of Rotating Equipment. Data are for the chemical, oil, and gas industries during the time period 1980 through 1995.

A study by one insurance company of centrifugal, axial, and rotary compressor accidents in the chemical, oil, and gas industries indicated most losses were due to inadequate maintenance or improper operation as opposed to design or construction problems (Figure 10). Fatigue and vibration, water or foreign object induction, surge, and lubrication problems accounted for the greatest portion of total losses (Figure 11). The average loss size was greatest for liquid or foreign object induction, surge, and fatigue/vibration related accidents (Figure 12).

The following are specific recommendations related to centrifugal and axial flow process compressors:

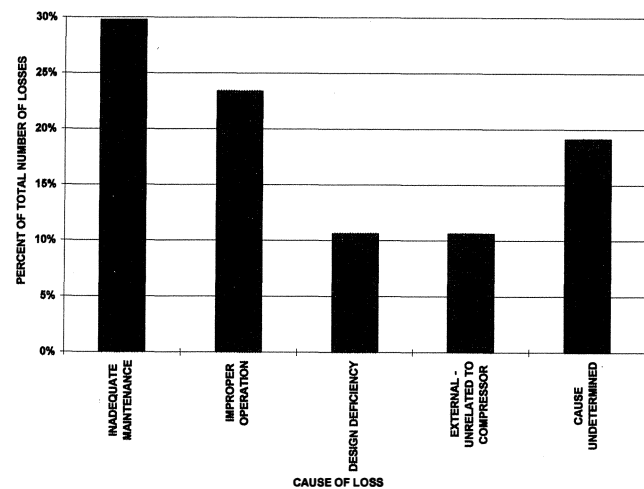


Figure 10. Losses Represented by Five Categories of Centrifugal, Axial, and Rotary Compressor Damage Causes. Data are for the chemical, oil, and gas industries during the time period 1980 through 1995. Combined percentages do not total 100 percent because smaller categories are not shown.

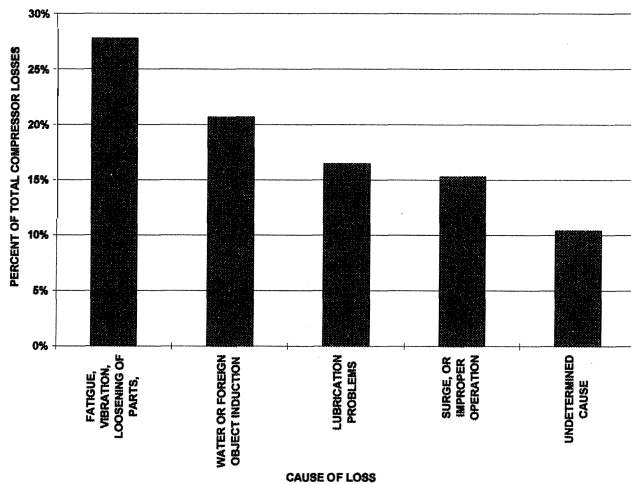


Figure 11. Most Common Specific Causes of Centrifugal, Axial, and Rotary Compressor Damage. Data are for the chemical, oil, and gas industries during the time period 1980 through 1995. Combined percentages do not total 100 percent because less common causes are not shown.

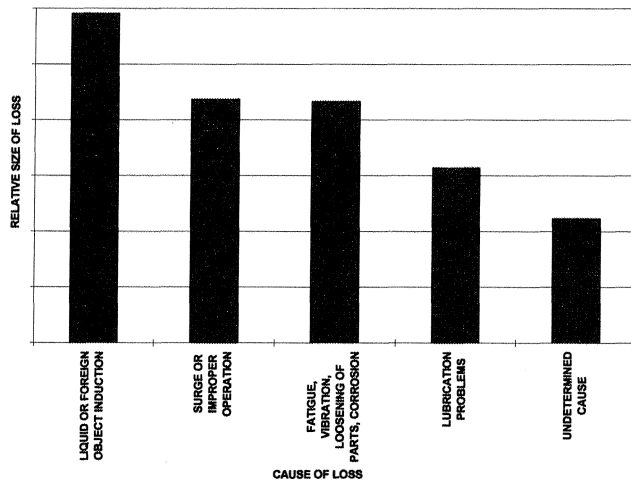


Figure 12. Relative Size of Average Loss for the Four Most Common Causes of Centrifugal, Axial, and Rotary Compressor Damage. Data are for the chemical, oil, and gas industries during the time period 1980 through 1995.

- Compressors should have surge control systems adequate to protect the compressor and other process equipment. The required sophistication of the surge control system depends on the size and type of compressor and on the consequences of compressor surge on the compressor, the compressor driver, and other process equipment. In some applications, instrumentation that provides input to a surge control system may need to be redundant.

In most applications, an operator cannot manually prevent compressor surge.

Conventional instrumentation may not respond fast enough to detect surge; high speed sensing and recording equipment may be required to detect surge and diagnose surge problems [6]. Surge control technology is available to meet the demands of any application [40]; however, in the author's experience, the correct level of surge protection is often applied only after a surge related accident or "near miss" occurs. Older, or simpler, surge control systems should be upgraded if justified by the potential

consequences of a severe surge event; a history of operation without surge related damage, by itself, does not justify an inadequate surge control system if the consequences of a surge event are potentially very serious.

Generally speaking, axial flow compressors are more vulnerable to surge damage than centrifugal compressors, and they require more sophisticated surge control instrumentation. Steam turbines used to drive compressors can also be damaged during a surge event [34]. One particular application usually requires the best available surge control system regardless of the type of compressor used; this application is the main air compressor in a refinery FCC unit. There may be exceptions based on the design of a specific FCC process, but this compressor usually should be equipped with the most redundant and most reliable surge control system available, since the consequences of surge can be especially severe [8].

- In some applications, check valves are very critical in protecting compressors. Malfunctioning check valves can result in compressor damage due to reverse rotation or due to backflow of process materials into the compressor [8]. In the past, several very large losses involved compressor discharge check valves that did not function properly; these accidents involved the main air compressor in refinery FCC units.

The correct type of check valve must be used, and two check valves in series may be required to achieve the necessary level of reliability. In some applications, such as the cracked gas compressor in an ethylene unit, check valves may be required on the suction of a compressor along with the discharge [41].

Check valves must receive proper inspection and maintenance. Large check valves with external counterweights are usually equipped with an exercising system and/or an assist system to help the check valve open and/or close properly. These systems must receive proper maintenance and inspection to ensure the check valve will properly close and protect the compressor following a trip.

Check valves should be exercised frequently enough to prevent binding or seizing of the shaft that can prevent closing. (Of course, some check valves have no external access to the main shaft and cannot be exercised.) As is the case with steam turbine governor valves and trip/throttle valves, Operations personnel are often reluctant to exercise check valves for fear of creating a process upset or nuisance trip of the compressor. However, if proper procedures are developed and followed, exercising check valves will not result in enough change in the compressor discharge flow or pressure to cause a process upset or nuisance trip of the compressor. Large check valves with external counterweight assemblies are usually designed to be exercised while in service; the check valve manufacturer should be consulted regarding specific exercising, inspection, and maintenance procedures. Operator training sessions during commissioning or other opportune times, during which each operator actually exercises the check valve while the compressor is online, can be an effective method of instilling confidence that check valves can be exercised without incident [26].

- Temperature instruments with alarms should be supplied for each bearing on the compressor. Temperature sensing probes should be imbedded in the bearing metal [42]. The compressor should trip on high thrust bearing temperature; this provides a backup to the axial thrust trip. It may be preferable to have the compressor trip on a high rate of increase in the thrust bearing temperature rather than trip at a specific temperature.

- Instrumentation should be provided, with alarms, to monitor compressor discharge pressure, temperature, and flow. In some applications, the compressor should trip on high discharge temperature. There is a well known problem with detonation/fires in piping on the discharge of air compressors in some applications,

and limiting the compressor discharge temperature is the primary means of preventing detonation/fires in these applications [43, 44]. The detonations and fires are caused by oil mist and/or a carbonaceous buildup in the piping. In the case of oil mist or vapor, the ignition source can be a spark due to mechanical failure in the compressor such as a broken valve. At elevated temperatures, the carbonaceous material can chemically react and self-heat to ignition.

- Large, critical compressors should be equipped with continuous radial vibration monitoring instrumentation on each journal bearing and axial movement instrumentation with alarms [2, 42]. This instrumentation should be designed and installed in accordance with API Standard 670. The compressor should trip on excessive axial movement of the rotor [21, 42]. Preferably, the compressor should also trip on excessive radial vibration, but radial vibration trips are usually optional from an insurance viewpoint. Radial vibration alarms must be provided and kept in good operating condition.

- The main and auxiliary oil pumps should be equipped with discharge pressure and temperature instruments with alarms. The auxiliary oil pump should start automatically on low oil pressure. The auxiliary oil pump should have a power source independent of the main oil pump. The compressor should trip on low-low oil pressure. A compressor rundown oil system not dependent on any power source is highly preferred. If the compressor and its driver are not equipped with an emergency rundown oil system using gravity or another nonpower system for pressurization (for example, nitrogen pressure), the auxiliary oil system becomes even more critical. The following items are preferred for an auxiliary oil system that also serves as the rundown oil system after a compressor train trip:
 - Pressure switches used in the lube oil systems should be redundant.
 - The auxiliary oil pump motor overload protective device should alarm only; it should not trip the motor (the philosophy being: it is well worth sacrificing a small electric motor to get a few more minutes of lubrication for a large compressor train).
 - Circuit protective devices for the auxiliary oil pump motor should be in the form of a magnetic type circuit breaker rather than fuses. The trip setpoint should be at least 50 percent greater than the maximum measured motor starting current. The maximum starting current may be up to five times the rated motor full load amps in some cases.
 - An energized type starter should be used for the auxiliary oil pump motor rather than a nonenergized type.

There should be provision for testing the auxiliary oil pump while the compressor is in operation. The three position "Manual-Off-Automatic" switch routinely used on standby equipment designed to start automatically should not be used for critical auxiliary oil pumps, because if the switch is inadvertently left in the "Off" position after a test, the pump cannot start automatically [42]. If this type of switch is used, there should be an alarm in the control room to indicate when the switch is in the "Off" position.

If the main lube oil pump is shaft driven, and if there is even a remote chance the compressor can be rotated backwards after a trip, the auxiliary oil pump should start on low main oil pump discharge pressure rather than low shaft speed [41].

- Instrumentation may need to be provided to monitor gas molecular weight and/or gas composition with alarms. In some applications, the compressor should trip if gas composition or molecular weight exceed design parameters.
- Level monitoring instrumentation with alarms should be provided for all suction, interstage, and aftercooler separator

drums. The compressor should trip on high-high separator level [8].

- For air compressors, the inlet air filter differential pressure should be monitored and an alarm provided. In some applications, the inlet filter can become restricted relatively quickly (sandstorms, refinery FCC catalyst dust, etc.), and filter cleaning based on hr of operation may be insufficient.

Preventing Catastrophic Wrecks of Gas Turbines

A study by one insurance company concluded that gas turbine failures are usually model-specific and related to the design of the specific machine (Figure 13). Because of this fact, design engineers on the staff of one insurance company regularly meet with gas turbine OEMs to stay abreast of actions in progress to address design related problems. In the study, specific causes of inadequate material properties and inadequate design accounted for almost half of all gas turbine losses; improper operation and bypassed controls represented 29 percent of all losses. The study indicated gas turbines in the chemical, oil, and gas industries receive excellent maintenance; as a specific loss cause, inadequate maintenance accounted for only three percent of gas turbine losses (Figure 14).

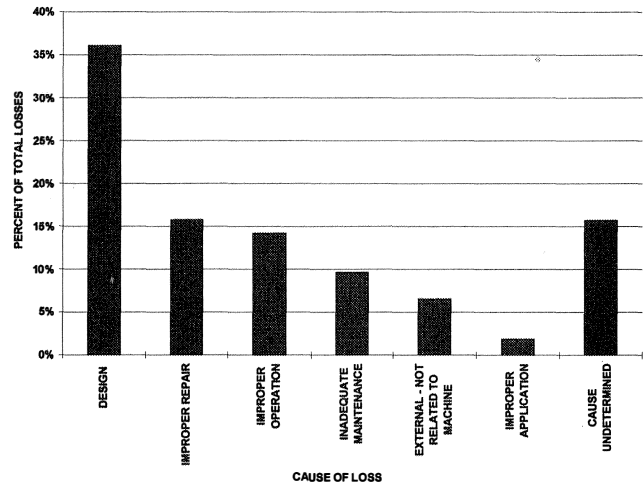


Figure 13. Losses Represented by Six Categories of Gas Turbine Damage Causes. Data are for the chemical, oil, and gas industries during the time period 1980 through 1995.

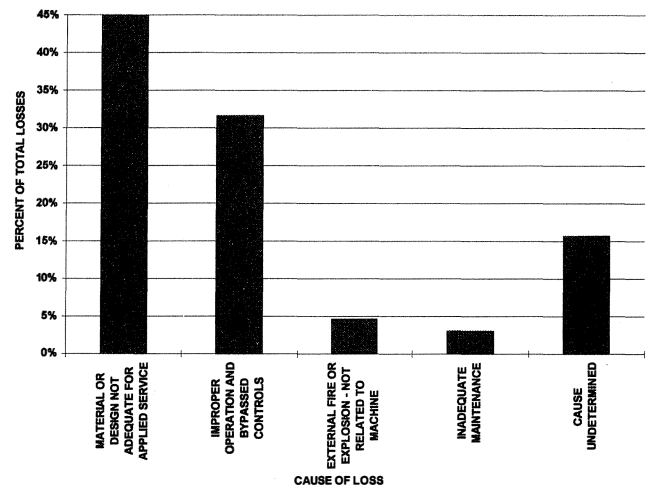


Figure 14. Most Common Specific Causes of Gas Turbine Damage. Data are for the chemical, oil, and gas industries during the time period 1980 through 1995.

OEMs of smaller gas turbines often keep complete spare gas turbines in stock that can be used to replace failed units; this greatly reduces business interruption exposure. OEMs of larger gas turbines may stock a spare rotor(s) for some models, but availability may not be guaranteed.

In addition to serving as the prime mover for a compressor or generator, gas turbines used in process plants are often a primary heat source. Gas turbine exhaust may be directly injected into the process, or it may be used to generate steam or heat a hot oil system. Therefore, abnormal gas turbine operation has increased potential to generate process upsets. However, in the author's experience, gas turbines have been reliable heat sources and have not resulted in excessive losses related to process upsets. One reason for gas turbine reliability may be the control systems; generally speaking, gas turbine control systems have been very automated for many years. Newer, solid state systems are also very redundant.

The following are some specific recommendations for gas turbines used in process applications:

- Fuel systems should be very reliable; it is particularly important to avoid introducing the wrong fuel to a gas turbine. If process off gas is used as fuel, the btu content may need to be continuously monitored and trips provided. It is also important to ensure liquid fuel is not accidentally introduced into a machine operating on a gas fuel.
- If two or more gas turbines exhaust into the same system and dampers or valves of some type are used to isolate a gas turbine from the system when the turbine is down, it is important to have an interlock that trips the turbine, or prevents it from starting, when the damper or valve is in the closed position.
- One common failure mode is overheating in the power turbine. It is important to accurately monitor temperatures in various parts of the power turbine. In some gas turbine applications, upgrading temperature monitoring systems when significant advances are made in technology may be advisable.

Expander Turbines

The expander turbine loss experience of one insurance company has been poor. Although a relatively small number of losses occurred (18 losses in nine years), the average cost of each loss was exceeded only by the average cost of losses involving steam turbine-generators (Figure 1); the category of steam turbine-generators includes large power generation units up to hundreds of megawatts in size, whereas most expander turbines are roughly 30 mw or less in size.

In spite of insurance loss statistics, expander turbines are reliable machines. Some expander turbines have operated for many years with no significant problems. In a study conducted by one insurance company of expander turbine losses in the chemical, oil, and gas industries, all of the losses were related to improper operation or improper maintenance; no losses were related to the design or construction of the machine. The following are specific expander turbine recommendations:

- In refinery FCC units, there should be an interlock to stop oil feed to the reactor riser any time the riser temperature is too low to properly vaporize the oil. Unvaporized oil entering the reactor can result in a severe process upset. Catalyst "burped" out of regenerators has wrecked several expander turbines over the years. Severe damage to other equipment has also been experienced; one explosion is documented in the literature [8]. In spite of the history of this type of process upset, many FCC units have not utilized a low riser temperature interlock.
- In refinery FCC units and nitric acid units, the normal operating temperature of expander turbines is close to the maximum design

temperature of the machine; during process upsets, the design temperature of the expander turbine can quickly be exceeded. Process control instrumentation systems should be state-of-the-art to ensure process upsets are minimized. Operator training is critical; refer to the section *Other Rotating Equipment Loss Prevention Recommendations* later for recommendations related to operator training.

- Refinery FCC unit power recovery trains should have state-of-the-art condition monitoring instrumentation including the capability for very fast data collection during abnormal/transient conditions [19, and 22]. Alignment of the train is critical. Some expander turbines, particularly older expander turbines, may not have overspeed protection capable of saving the turbine in the event of coupling failure. It is imperative that coupling stresses due to misalignment are minimized.
- In refinery FCC units, expander turbines should not be operated for extended time periods with excessive vibration due to catalyst buildup in the turbine. Also, expander turbines should not be excessively "thermal cycled" to dislodge catalyst buildup. While occasional thermal cycling is acceptable, the root cause of excessive catalyst carryover from the regenerator should be corrected rather than thermal cycling the expander turbine on a daily or weekly frequency for an extended period.

Preventing Catastrophic Wrecks of Large Reciprocating Compressors and Internal Combustion Engines

From an insurance point of view, a catastrophic reciprocating compressor or engine wreck includes crankshaft breakage, severe case damage, or loss of the case. Depending on the size of the machine involved, a broken crankshaft can result in repair costs of \$400,000 to \$2 million; repairs can take many months if a forging for a new crankshaft has to be ordered from the foundry. Major case repairs can take six weeks or longer; delivery of a new case could take six to twelve months or longer.

A spare crankshaft is normally not required from an insurance standpoint.

Case damage can often be repaired, but a case can also be damaged beyond repair; two recent accidents involved very large machines with cases that could not be repaired. In one accident, the case had to be replaced; in the other accident, the entire machine had to be replaced. Replacement of the case for a very large reciprocating machine can cost several million dollars.

In spite of the fact that reciprocating compressors and internal combustion engines have been in industrial use for a very long time, practices and procedures involving reciprocating equipment vary greatly from industry to industry and from company to company in the same industry.

Recommendations To Prevent Failures Of Reciprocating Equipment. It has been the experience of one insurance company that catastrophic wrecks of large reciprocating equipment are most often caused by excessive bending stresses on the crankshaft. Excessive bending stresses on the crankshaft, in turn, are most often caused by misalignment and/or uneven cylinder loads. Taken together, improper operation and inadequate maintenance accounted for almost 80 percent of reciprocating equipment losses in a study conducted by one insurance company (Figure 15). In the same study, specific causes of overloading, liquid or foreign object induction, lubrication problems, and fatigue/excessive stress accounted for most losses (Figure 16). The following are specific recommendations for preventing catastrophic wrecks of large reciprocating equipment:

- Foundations must be properly designed and structurally sound. Grouting, baseplates, and chocks or shims must be properly installed and in good condition. Anchor bolts must be securely anchored to the foundation; the bolts should secure the base of

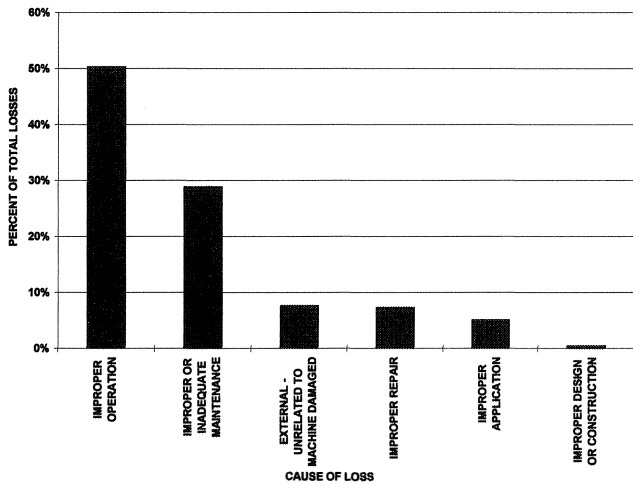


Figure 15. Losses Represented by Six Categories of Reciprocating Equipment Damage Causes. Data are for the chemical, oil, and gas industries during the time period 1980 through 1995.

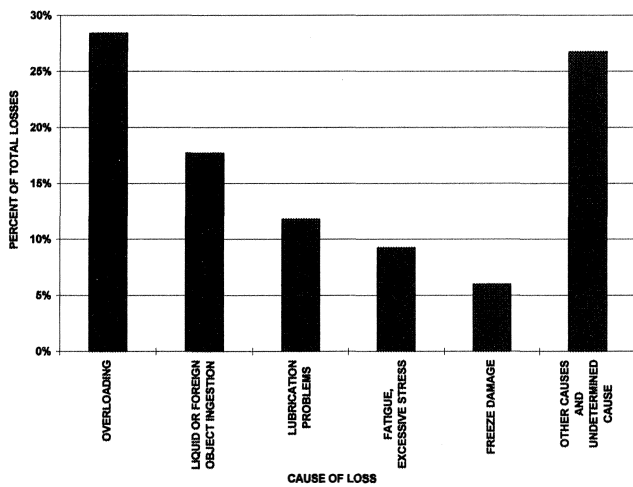


Figure 16. Most Common Specific Causes of Reciprocating Equipment Damage. Data are for the chemical, oil, and gas industries during the time period 1980 through 1995.

the machine to the baseplate or chocks so that, during operation, the case does not move relative to the chocks or baseplate [45]. Tightening with a torque wrench may not apply the correct load to a large anchor bolt; hydraulic tensioning may be required [45, 46]. Foundation, grout, and anchor bolt technology has changed significantly over the last 30 to 50 years; upgrades should be considered when machines are undergoing major overhauls and/or grout is being replaced [47]. The quality of foundation and grout work is often highly dependent on the skill and experience of the contractor, and the contractor's employees, performing the work; specific instructions and procedures should be provided for these projects, and adherence to instructions and procedures should be closely monitored.

Loosening and retightening anchor bolts should not produce case movement; if it does, the grout may be failing. More than 1.0 to 2.0 mil movement indicates the machine may be out of alignment. Case movement while loosening and retightening anchor bolts should be checked at least annually [48].

- If one or more compressor cylinders or engine cylinders are doing significantly less than their share of the total machine work,

uneven stresses and temperatures may be applied to the crankshaft. Compressor valve performance should be monitored closely by monitoring discharge temperatures; all engine temperatures should be closely monitored [49]. Engine analysis is also highly recommended. Prompt detection and correction of weak cylinders and malfunctioning valves will increase efficiency, reduce overall wear of components, and reduce the probability of crankshaft failure and case damage due to bearing failure and/or misalignment.

- Crankshaft web deflection readings should be taken at least annually. Since some crankshaft and/or alignment problems may not result in excessive crankshaft web deflection readings, at least one main bearing shell should be removed and inspected annually. It is important to inspect both sides of the bearing; some problems will produce wear or defects on the back side of the bearing shell [49].

- Protective instrumentation has the potential to detect developing problems and trip the machine before catastrophic damage occurs. The following are some specific recommendations for protective instrumentation on large reciprocating engines and compressors:

- High bearing temperature trip—Bearing temperature probes should be imbedded in the bearing material when practical.

- High vibration trip—Large reciprocating compressors and engines should be equipped with continuous vibration monitoring instrumentation. One design that has worked well utilizes a sensor mounted at a 45 degree angle (pointing towards the crankshaft) on each crosshead and one or more sensors mounted on the case of the compressor near a crankshaft main bearing. The sensors are connected to a vibration analyzer similar to that used with turbomachinery. Properly designed, installed, and maintained systems of this type offer protection against catastrophic failures without nuisance trips. Some companies have also had success using systems of this type for vibration analysis.

- Rod drop monitors—Rod drop monitors monitor the position and deflection of the compressor rod. If the rod moves beyond preset limits, an alarm or trip is actuated. A trip on excessive compressor rod movement is recommended; this can minimize connecting rod and/or crankshaft damage following failures in the compressor cylinder area.

- In one insurance company's experience, preventive type inspection and overhauls of reciprocating equipment, particularly large integral gas engine compressors, has not satisfactorily prevented catastrophic failures. Some machines have operated many years without problems with only routine inspections and overhauls. However, the vast majority of machines that suffered broken crankshafts and/or severe case damage were also receiving regular inspection and overhauls.

Some users have had good success with a philosophy of placing primary emphasis on rapid detection and correction of conditions that result in excessive stresses on the crankshaft (conditions discussed above) rather than routine inspection and overhauls. At least until proven unsuccessful, this philosophy is being accepted by one insurance company. These machines still receive the web deflection checks and bearing spot checks described above; however, major overhaul frequencies are based on indicated need rather than hours of operation.

Other Rotating Equipment Loss Prevention Recommendations

The following are additional rotating equipment loss prevention recommendations. Some of these recommendations will not be applicable for all rotating equipment applications. However, these items are essential components of a comprehensive loss prevention program for most plants.

- Good housekeeping around rotating equipment is important. Excessive accumulation of dirt, debris, and/or leaking oil can obscure leaks and other developing problems. If operators and maintenance craftsmen are slipping and sliding through puddles of oil and water, or having to inspect equipment through a cloud of smoke from hot oil or steam from steam leaks, the quality and quantity of visual equipment inspections will decrease.

- Piping stress has been a contributing factor in some large rotating equipment losses. Piping stress is addressed in the design of rotating equipment installations. However, after the equipment has been in operation, it is important to ensure, on an ongoing basis, that piping stresses have not increased beyond acceptable limits. Piping stress can increase for many reasons; a few include:

- A modification, addition, or deletion of system components
- Corrosion, binding, or failure of hanger systems

- Unusual thermal growth/contraction of high temperature piping systems—Changes in high temperature piping systems can be caused by process upsets, insulation/refractory failure, etc. Routine infrared inspection of large, high temperature insulated or refractory lined piping is recommended.

- Piping vibration—Piping vibration can result in piping failure (a leading cause of fire and explosions in hydrocarbon handling plants) along with turbomachinery and reciprocating equipment problems [50, 51].

- Testing of alarms, interlocks, and instrumentation—Critical instrumentation, alarms, and interlocks should be tested at least annually; more frequent testing may be required [52]. During scheduled outages, machines should be shutdown by testing a trip whenever possible; when possible, the trip should be actuated by actually changing an operating parameter, such as level or pressure, rather than electrically actuating a relay, etc.

- Electric motor failures are usually related to insulation failure—Insulation failure in turn is often caused by overheating. Insulation overheating is often caused by oil and/or dust accumulation in windings that reduces cooling. Electric motors, particularly larger motors (over 1,000 hp), generally should receive thorough inspection and cleaning every three to five years. The frequency of cleaning and inspection will vary greatly according to the design of the motor. Induction motors that are well sealed may need less frequent cleaning. More open designs, particularly some synchronous motors, may need cleaning every one to three years. Cleaning materials and procedures must be chosen carefully to avoid damage to the windings. All mechanical components in the motor should be checked for tightness, proper electrical connections, etc., following cleaning. Electrical insulation tests should be performed regularly to detect weak insulation prior to actual insulation failure.

- Backup power systems for alarm and trip circuits, auxiliary oil pumps, and control systems are very critical. Rotating equipment losses due to the failure of batteries in backup power systems are not uncommon. Battery systems should receive full load capacity testing and connection resistance testing in accordance with ANSI/IEEE Standard 450.

- Commissioning/testing new or modified installations—Typically, rotating equipment is performance tested at the factory. It is important that rotating equipment also be tested, as thoroughly as practical, during commissioning. A thorough performance test during commissioning will usually reveal damage incurred during shipment, design deficiencies related to location specific components such as foundations and piping systems, and installation errors.

One critical component that usually cannot be effectively tested during the factory performance test is a compressor surge control

system; it is impractical to effectively simulate piping/process systems at the factory. Ideally, the calculated surge control line and surge control system effectiveness should be verified during commissioning by actually initiating carefully controlled surges [53, 54]. The ability of the surge control system to handle process system upsets and trips should be verified [6].

Commissioning of new or upgraded equipment is an ideal time for hands-on training for operators and maintenance technicians [2, 26].

- Reliability programs—Reliability programs are highly recommended. Reliability programs reduce the number of “events” as described in the *Incident Chain of Events* section previously; this reduces the probability of a catastrophic loss [55].

Implementing successful reliability programs for rotating equipment usually requires a difficult change in the plant rotating equipment operating and maintenance “culture” [56]. However, the payback for undergoing the cultural change and successfully implementing a reliability program can be well worth the effort. In addition to reducing chances of catastrophic equipment damage and lost production, successfully implemented reliability programs can have a substantial payback in increased efficiency and reduced costs [55].

- Human factors programs—Human factors programs address the human element in loss prevention; human factors are a critical element in any loss prevention program. It is impractical, if not impossible, to make chemical, oil, and gas processes immune to the effects of human error. It is also impractical to design rotating equipment that is immune to damage caused by human error. As the size and complexity of rotating equipment increase—and the size and complexity of chemical, oil, and gas processes increase—the importance of reducing the probability of accidents due to human error increases.

Petroleum refining, petrochemical, and chemical processes, and the rotating equipment in those processes, can be protected to a certain extent through engineering means. For example, processes can be designed more inherently safe by reducing quantities of hazardous materials in the process, and interlocks, such as high temperature and high vibration trips, can be utilized to protect equipment and reduce the probability of uncontrolled reactions. However, history has proven that catastrophic accidents cannot be prevented even with the most sophisticated protective instrumentation systems. The best examples are the Three Mile Island and Chernobyl nuclear power plant accidents. Even though these plants were designed with very sophisticated and reliable protective instrumentation systems, serious accidents occurred in both plants. Both accidents were caused, primarily, by a series of serious human errors [57, 58].

(The author highly recommends the book “The Truth About Chernobyl” by Grigori Medvedev [58] to anyone interested in human factors as they relate to loss prevention. Mr. Medvedev was Chief Engineer during the plant’s construction in 1970, and he returned to the plant to investigate the 1986 accident. He also compares the Chernobyl accident to the Three Mile Island accident; in spite of the difference in design of the two plants, the sequences of events leading to the two accidents were strikingly similar.)

As stated previously, human error is a contributing factor in up to 90 percent of process plant accidents. In process plants, there is a tendency to assume that the only critical human errors are those which occur on the part of operating and maintenance technicians. On the contrary, human error on the part of designers, suppliers, vendors, and technical support staff can all cause accidents. Several loss prevention theories are based on the belief that all industrial accidents are caused, primarily, by failures of management systems [3, 57]; accident prevention therefore must

address management systems and, especially, the interaction of management systems, people, and facilities [1].

Human error "events" in the chain of events leading to rotating equipment failures can be minimized by the following:

- Training—Training is critical in reducing human error. Training must be effective, and it must be repeated on a regular basis; this includes training for managers, technical staff, administrative staff, and supervisors along with operating and maintenance technicians.

Some modern processes operate for many years between major turnarounds, and most modern processes are highly automated. Because of these facts, it is very difficult for operators to obtain experience in dealing with abnormal process situations. The use of computer simulators enables operators to acquire this experience without risk to equipment or product, and the use of computer simulation for operator training is highly recommended [59].

During training, the method of presenting rotating equipment loss prevention information may be as important as the information itself. Audiences will usually apply loss prevention knowledge more effectively if the consequences of rotating equipment accidents are fully understood, and if the audience truly accepts the fact that past accidents not only can be repeated but are likely to be repeated [60]. The complex, automated nature of modern refining, chemical, and petrochemical processes also necessitates specific training in evaluation of, and response to, abnormal process situations; training methods used successfully in the past with less complex processes may no longer be sufficient to prevent catastrophic losses [61, 62].

Regularly repeated refresher training on rotating equipment basic practices and procedures, such as those documented in *Sawyer's Rotating Equipment Maintenance Handbook* [63] should be very valuable.

- Operating instructions and maintenance procedures—Well written operating instructions and maintenance procedures will reduce the frequency of human error. Writing operating instructions for process operators is a specialized task that requires professional skills [64]. However, process operators and maintenance craftsmen should always be involved in the development and review of operating instructions and maintenance procedures; their involvement will help ensure the final document is usable on a day to day basis along with technically correct.

- Corporate downsizing/reengineering—Loss of technical experience following reductions in force is a significant loss prevention concern; this includes experience at the unit, plant, and corporate levels. A formal, multidisciplinary study equivalent to a PSM management of change procedure should be performed to determine effects of reducing experience levels. This includes experience levels of operators, maintenance technicians, and engineering staff [35, 65]. Experience levels in certain units may also be reduced by personnel transfers and promotions during times of rapid expansion [35, 62]. If required, internal or external consultants should be used to supplement existing plant rotating equipment experience.

- Rotating equipment fire protection—Fires involving rotating equipment are not uncommon. Fire protection requirements for rotating equipment will generally be included in company standards and industry guidelines developed for process plants; these are developed by fire protection engineers. The following are a few specific recommendations:

- Large rotating equipment can be damaged by thermal shock, loss of lubrication, etc., during fire fighting. This damage may be far more serious than any damage that would have resulted from a minor fire that was being extinguished. Written preplans should be developed for fighting fires around each large machine in a unit; these preplans should be discussed during plant fire

brigade training sessions and practiced during drills. The objective of the preplan should be to match firefighting efforts to the potential seriousness of the fire so that the fire is quickly extinguished without unnecessary collateral damage to rotating equipment.

- Fixed suppression systems should be carefully designed, installed, and maintained to ensure correct quantities of the proper extinguishing agents are used and the correct type of nozzle is used in the proper orientation. Detection and suppression systems should be properly tested on a regular frequency.

- To minimize the frequency and severity of lube oil fires, open ended lube oil lines should be plugged, or preferably, a blind flange installed; this is particularly important on pressurized lube oil lines, air bleed lines on filters, etc. Lube oil reservoir drain and sample lines should also be protected with blind flanges. If plugs or blind flanges are not used on lube oil sample lines and/or water drain lines, two valves in series should be used. The inside valve should be a screw type valve rather than a quick opening ball type valve. Leaks should be promptly repaired, and large accumulations of oil, or oil soaked dirt/catalyst on foundations and baseplates should be avoided.

- Large quantities (55 gallon drums, etc.) of spare lube oil or solvents should be stored in properly designed flammable storage areas; they should not be stored near machines in the field or in enclosed compressor buildings. A minor rotating equipment lube oil fire that spreads to 55 gallon drums can quickly escalate to a major fire.

SUMMARY

Rotating equipment is an integral part of petroleum refining, chemical, petrochemical, and natural gas production processes. Failures or abnormal operation of rotating equipment can result in process upsets, damage to other process equipment and catalysts, and lost production. Conversely, process upsets and failures of process instrumentation or other process equipment can result in damage to rotating equipment. An effective rotating equipment loss prevention program will address all aspects of plant operation and maintenance activities—activities related to technical issues along with activities related to human factors.

Specific rotating equipment loss prevention recommendations have been presented based on the experience of the chemical, oil, and gas business unit of one insurance company. Technical resources supporting the loss prevention recommendations have been included in the REFERENCES section. Insurance loss statistics for rotating equipment have also been provided.

Due to the wide range of rotating equipment applications in the chemical, oil, and gas industries, not all recommendations presented are applicable at every plant. Some recommendations will not be applicable to rotating equipment in other industries.

Implementation of recommendations presented should result in increased efficiency and profits along with a reduction in the number and severity of plant incidents. Most importantly, implementation of recommendations presented should reduce the probability of catastrophic accidents in the chemical, oil, and gas industries ultimately reducing personnel injuries and financial losses while assuring a reliable stream of products to customers.

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