3 THE TRIPLE THREAT

Derrick Bauer, Matthew Konek and Brian Stewart, Elliott Group, USA, discuss the impacts of corrosion, erosion and fouling upon rotating equipment in petrochemical and other refinery processes, and the latest prevention and mitigation measures that have proven most effective.

Corrosion, erosion and fouling are common challenges for rotating equipment in petrochemical and refining services, and can affect performance and reliability, or even result in premature equipment failure. If left unchecked, they can cost a company millions of dollars over time.

Corrosion, the gradual wearing away of metal material, is a result of a chemical and/or electrochemical process. Impurities, such as chloride and hydrogen sulfide (H_2S), found in process gas cause corrosion. The presence of liquids can also cause corrosion, as well as some gases that are naturally corrosive. The damage caused can be general or localised, such as pitting. Corrosion reduces efficiency and damages the structural integrity of the equipment. Fatigue cracking, and ultimately catastrophic failure, can result.

Erosion is a wear process, brought about by repeated impacts, causing localised stresses in the material. It is the result of a mechanical reaction caused by liquids and/or solids entrained in the gas stream. In compressors, the liquids/solids normally come from the upstream process. In steam turbines, liquids form at the transition zone and beyond.

Eroded surfaces adversely affect material properties by increasing roughness. Surface roughness decreases efficiency and can act in combination with corrosion to increase the rate of material degradation. As with corrosion, erosion can lead to integrity damage, fatigue cracking, and potentially, catastrophic failure.

Fouling is the undesirable accumulation of material on the rotating or stationary parts inside the rotating equipment. In compressors, this usually starts as a solid substance adhering to the internal surfaces. With cracked gas, polymers usually adhere to the compressor's internal rotating and stationary surfaces that are in contact with the process gas. In steam turbines, silica and salts can deposit on latter stage blading. The deposits tend to build up faster with time, and are more difficult to remove with each cleaning.

Fouling blocks the aero path, increases rotor weight, and increases vibration due to the resulting unbalance. It also decreases clearances in the eye and interstage seals. In steam turbines and hydrogen recycle compressors, hydroscopic salt on outer surfaces can cause local pitting corrosion underneath the deposits.

All three damaging conditions – corrosion, erosion and fouling – can lower efficiency, which means lost productivity or yield, and wasted power.

Corrosion

In rotating equipment, corrosion effects are service specific, and vary depending on the equipment and the environment in which it is used, including H_2S, hydrogen, chlorides, and wet/charge/cracked gas. In steam turbines, the rotors (which are made of a low-alloy steel) and the rotating blades (which are 12% chromium stainless steel) are continuously exposed to steam and the impurities that condense out of the steam, including chlorides, phosphates, and silicates. The result is corrosion pitting, which reduces fatigue life.

Compressors experience sulfide-induced stress corrosion cracking (SCC) if all of the following elements are present at the same time: H_2S, moisture, threshold applied tensile stress, certain temperatures, and susceptible material. The rotor shafts, which are in a H_2S environment, need high strength at the drive ends. Stress at the main body, however, must be low (less than 10 ksi [70 MPa]) to avoid cracking. The rotor shafts are constructed of low-alloy steel and the impellers of low-alloy steel, martensitic stainless steel (400 series), and nickel-based alloy. Both low-alloy steels and martensitic stainless steels can be susceptible to SCC.

Wet/charge/cracked gas compressors are made of carbon and low-alloy steels and so are also susceptible to SCC. Hydrogen recycle compressors experience harsh corrosion pitting as their stainless steel impellers are not always effective. Ideally, chlorine compressors should not experience SCC as dry chlorine should not be corrosive. Any amount of moisture (more than 200 ppm), however, can lead to corrosion. Use of nickel-based materials is effective but comes with a high cost and is only really needed in critical areas.

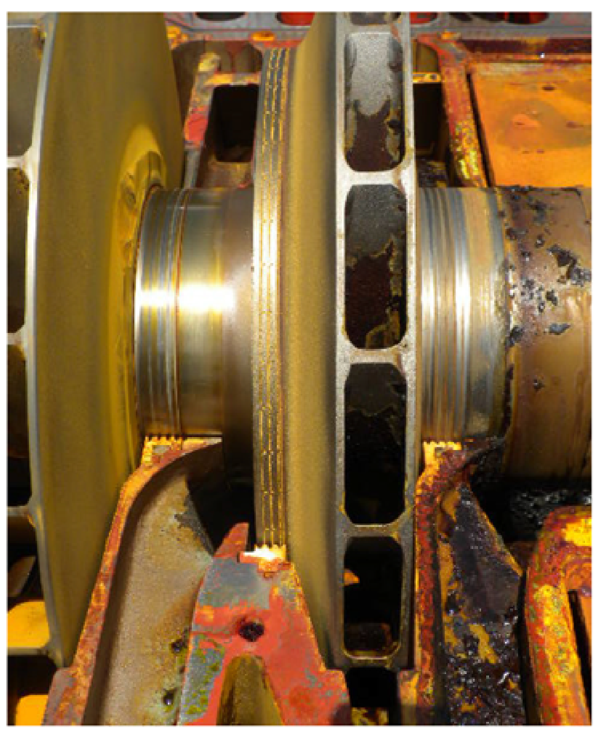

Figure 1. Corrosion on a chlorine compressor.

Most petrochemical process gases contain impurities, which may dissolve into the water and become corrosive. For example, H_2S is a common constituent in cracked gas, while carbon dioxide may exist in natural gas. Usually these impurities are not corrosive in a dry condition, but when moisture is present, they dissolve into the water and form a hazardous acidic vapour or droplets. So, while water injection may combat fouling, water may also induce corrosion.

Process treatments are one way to address corrosion issues. In steam turbines, boiler feedwater treatments are used. Corrosion can be minimised by keeping the steam purity within the National Electrical Manufacturers Association (NEMA) SM 24 guidelines (for land-based steam turbine generator sets 0 – 33 000 kW), and there are a number of different proprietary methods for doing so. In compressors, water or oil injection treatments are options, but have not proven particularly effective in preventing corrosion.

Careful base metal choices, in adherence with National Association of Corrosion Engineers (NACE) specifications, can provide some corrosion protection. Coatings can also help minimise corrosion impacts. For steam turbines, chromising or titanium nitride (TiN) coatings are recommended. Chromising is a diffusion coating applied by pack process or chemical vapour deposition (CVD) that increases the chromium content at the surface. TiN is a hard ceramic, physical vapour deposition (PVD) coating that offers both good corrosion and erosion protection. For compressors, there are polymeric coatings such as phenolic and polytetrafluoroethylene (PTFE), and weld overlays/cladding. Polymeric coatings are applied by spray or dip-and-bake processes that provide excellent chemical resistance at a low cost. Weld overlays/cladding made of stainless steel or nickel alloys increase the corrosion resistance of critical areas such as the O-ring and diaphragm grooves and seal teeth.

Erosion

Solid particle erosion (SPE) affects both compressors and turbines. Coatings containing chromium and boron can provide compressors with good resistance to SPE. These coatings are commonly used on single-stage compressors in harsh service. For turbines, boriding, the process of diffusing boron atoms into the surface of a metal, is used on the front end stationary blading to address SPE. A coating depth of up to 2 mils and a hardness of up to 80 rockwell hardness (HRC) provides protection against SPE.

Turbines are also affected by liquid particle erosion (LPE). This occurs when an impact creates a shock wave, and the shock wave compresses existing liquid, causing a stress wave in the turbine material. The shock wave then detaches and creates a lateral jet. With LPE, the effects increase over time. Laser welding and stellite weld overlays provide resistance.

In compressors, erosive particles come from outside processes. Liquid particles are due to improperly atomised liquids or undersized demisters prior to the inlet. Solid particles come from the upstream process, and may include hydrogen gas (H_2), rust, and recycle ammonium chloride carryover contaminants such as submicron dirt and organic or inorganic pollutants. The best method of prevention is to keep liquids and solids out of the compressor. If that is not possible, there are other alternatives.

Hard face coatings containing chromium and boron can be effective in preventing SPE. To reduce LPE, atomisation is essential when injecting liquids. Demister pads should be appropriately sized. Material changes to

Figure 2. A charge gas compressor with erosion damage.

Figure 3. A H_2 recycle compressor with chloride fouling.

Table 1. Comparison of removable and fixed nozzle assemblies

Removable nozzle assembly	Fixed nozzle assembly
Can be moved for maintenance while compressor is operating	Results in lost production time due to compressor shutdown during system installation or repair
Eliminates the need for unnecessary outages	Incurs costs associated with unplanned outages for fixed nozzle system repairs
Higher up-front costs; more components	Lower up-front cost; simpler design
Requires extra axial space for installation and removal	Fits in areas with space limitations

17-4 precipitation hardened (PH) stainless steel and Inconel can slow progression but will not stop LPE. Stellite overlays, unfortunately, are not practical for impellers.

Fouling

Fouling impacts are usually service specific for cracked gas compressors, steam turbines, and other services.

Centrifugal compressors play an important role in ethylene production. Usually, a cracked gas compressor train in an ethylene plant consists of two, three, or four compressor bodies driven by a steam turbine. The plant typically has turbine-driven propylene refrigeration as well as ethylene refrigeration compressors, but due to the low temperature service and the cleanliness of the compressed gas, these compressors do not normally experience fouling or corrosion problems.

For compressors in cracked gas service, fouling begins when the gas stream temperature reaches the polymerisation temperature (typically 194 – 220˚F/90 – 104˚C), and increases as the temperature increases. Fouling tends to be worse at the back end of the compressor, which experiences the highest temperatures. Typically, fouling does not cause catastrophic failures but can gradually reduce the efficiency of cracked gas compressors. Because the compressor trains are driven by steam turbines, when fouling occurs, the operator may be forced to increase the speed of the driver to maintain the desired compressor discharge pressure. A cracked gas compressor with a fouling problem may also have a worn impeller eye, worn interstage shaft, and worn balance piston labyrinth seals because of the erosive effect of the foulant.

Fouling in steam turbines comes from silica and salts in the steam. The best prevention is to control the impurities per NEMA SM 24 and original equipment manufacturer (OEM) guidelines, as applicable.

Fouling or buildup can also be detrimental in other services. Sampling the foulant can determine whether the source is the feedstock or contamination. Changing the feedstock in an ethylene process can affect the amount of fouling that occurs within the cracked gas compressors. However, careful planning is needed before a change is made. The process licensor and/or the OEM can help to determine the best protection programme.

There are a number of process treatments to mitigate fouling including oil injections, water injections, and coatings. Wash oil injection wets the compressor surfaces and mechanically removes or dissolves foulant. Wash oils include petroleum-based solvents, such as naphtha, and water with various additives, such as detergents. The process licensor can recommend the best treatments to use.

Liquid injection treatments to mitigate fouling

The water injection process typically uses boiler feedwater to cool the process gas. The process licenser provides the maximum temperature, and the OEM determines the injection type, quantities, and location. Water injection works through the evaporative cooling process. Water is injected into the gas stream and vaporises. The energy required to induce the phase change from liquid to vapour is taken from the process gas. The net effect is a reduced temperature. The liquid injection locations for both oil and water injections are in the compressor inlet piping or in between stages. Ideally, inlet injection points are placed as close as possible to the inlet nozzle. The interstage injection nozzles are located at the diffuser-to-return channel crossover point. Both removable and fixed nozzle assemblies are used; Table 1 compares them.

For liquid injections, an atomising spray nozzle tip is used as the smaller droplet size minimises erosion. Caution must be taken to ensure the nozzle does not enter the casing and cause damage. A mechanical stop can be used to avoid this or the nozzle tip can be tack welded to the nozzle body. Casing drains are also required to remove any excess liquid that builds up on the bottom of the casing. Most of the injection will pass through as entrained liquid or gas, but a small amount will fall to the bottom of the casing.

In oil injection, the OEM specifies safe flow limits as a percentage of gas flow to minimise erosion. The inlet volute provides better mixing of the wash oil with the process gas so more injection is allowed at the inlet and less at the interstage locations.

In water injection, the maximum amount of water injected is based on the theoretical saturation point of the gas. A factor of safety is applied to ensure the gas is not oversaturated. The more the droplet size is minimised, the greater the evaporation efficiency and, therefore, the greater the cooling effect.

Figure 4. Compressor rotor with protective coating.

Figure 5. Compressor with a removable wash system.

Anti-fouling coatings

The use of anti-fouling coatings is another option. These create a non-stick surface that does not let the foulant adhere. They may not be compatible with liquid or chemical injections. Types of coatings include multi-layer organic/inorganic composite and electroless nickel. Composite coatings can be either two or three layers and are applied by a spray and brake process.

Organic composites do have some limitations. Some organic resins require an inorganic base layer. Organic coatings offer limited erosion resistance as they are susceptible to degradation from liquid injections and solid/liquid erosion. They can absorb some chemicals, which can vaporise, causing blisters, and only have a pH range of 4 – 9. The coating often degrades over time, typically 12 – 18 months, and thus must be reapplied at each overhaul.

More durable and chemically resistant coatings have been used to try to minimise foulant buildup during service. Composite coatings with a corrosion-resistant base coat and a ceramic top coat have been used in centrifugal compressors. While these coating systems do not have the same anti-foulant characteristics as organic top coat systems, they are more likely to withstand liquid and chemical injections. Electroless nickel is a very strong and tough metallic coating that has been successful in minimising foulant buildup, working well in conjunction with a liquid injection system. Electroless nickel coatings have also been used as a preventive measure in corrosive atmospheres containing high partial pressures of H_2S. The selection of the most appropriate coating system should be reviewed for each compressor application.

Conclusion

Corrosion, erosion and fouling negatively impact rotating equipment. There are mitigation and prevention measures to address each issue but no one answer fits every situation. Corrosion is best handled with selected overlays and coatings. For example, stellite overlays are very effective for latter stage turbine blades. SPE can be minimised by applying hard surface coatings, and fouling may be minimised by coatings and/or liquid injections. Operators should work with the OEM to help identify the cause of the problem, whether corrective action should be taken, and what that action should be.

Best practice to avoid the impacts of all three is effective process control. Maintaining a clean environment at all times results in cleaner rotors, compressors, and turbines, with minimal corrosion, erosion, and fouling. Tight control of steam and process purity is required, and proper material selections can help, as well as inclusion of coatings and/or injections.