Damage Mechanism Reviews and Mitigation Methodology for Ammonia Equipment

This paper presents a methodology for conducting damage mechanism reviews (DMRs) that can help operating companies maintain equipment integrity by providing a foundational basis on which to manage and mitigate common damage mechanisms that may affect plant equipment. The DMR methodology allows ammonia-related industries to draw on recent API recommended practices to provide a holistic management resource for the plant's Mechanical Integrity Process Safety Management programs. The assessment methodology is demonstrated for typical process unit equipment in an ammonia plant. BakerRisk's Asset Mechanical Integrity Plan identifies the potential damage mechanisms based on known process parameters, selects the appropriate inspection methods, and communicates relevant factors and possible mitigation options as a resource for the site.

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Reliability in operating companies depends heavily on the mechanical integrity of the equipment and piping.

In an ideal world, materials would be chosen that would be impervious to deterioration effects from process conditions. In the real world, this is either impossible or cost-prohibitive, so various types of equipment damage continues to occur. For the refining industries, American Petroleum Institute (API) has identified some common damage mechanisms for typical refinery and chemical process units along with proper inspection techniques in developing API RP 571, *"Damage Mechanisms Affecting Fixed Equipment in the Refining Industry,"[1]* followed by the soon to be released new edition of API RP 970, *"Corrosion Control Documents."* [2]

The ammonia-related industries can utilize these resources and methodology with specific industry knowledge to manage and mitigate the consequences of the knowns and unknowns in their Asset Mechanical Integrity (MI) programs. An example of damage mechanism reviews for ammonia equipment is presented in this paper along with an example of BakerRisk's Asset Mechanical Integrity Plan as a preferred option for generating an overall foundation document and plan for improving equipment reliability.

Damage Mechanism Review (DMR):

It's easier to find something if you know what you are looking for. While the MI programs for some process areas of a plant are easily managed, others are complex and can be affected by changing operating conditions. For the ammonia equipment and piping industries, potentially life-limiting damage mechanisms include high temperature mechanisms, high temperature hydrogen attack (HTHA), stress corrosion cracking (SCC), general corrosion, and brittle fracture, to name a few. [3, 4, 5, 6, 7]

Awareness of mechanisms that can damage equipment is essential in developing the solution to inspect the equipment properly, mitigate damage, and prevent failure. The pertinent damage mechanisms are also input for evaluations regarding fitness-for-service, and rate of attack needs to be understood to determine the remaining life. For a proper risk-based inspection (RBI) program or during a hazards analysis, the appropriate mechanisms are identified so that the probability of failure can be determined when addressing reliability issues. While API RP 571 is targeted for refineries, it does provide a good resource for other industries in identifying the characteristics of damage mechanisms and their proper inspection techniques.

API RP 571 provides general guidance as to the most likely damage mechanisms affecting common alloys used in the refining and petrochemical industry and is intended to introduce the concepts of service-induced deterioration and failure modes. These guidelines provide information that can be utilized by plant inspection personnel to assist in identifying likely causes of damage, to assist with the development of inspection strategies, and to help identify monitoring programs to ensure equipment integrity.

Identifying the damage mechanisms by the site's MI subject matter expert (SME) is not enough for proper management, as MI interacts with many plant functions such as operations and equipment design. A damage mechanism review (DMR) requires a multi-disciplined team that includes a process engineer and the inspection/reliability SME working with the damage mechanism SME. Operations personnel are also utilized for operating conditions, such as startup and shutdown.

Reviewing trended failures or life-limiting damage or near misses should be included in the DMR. [8]

API RP 970 outlines a document with information on the process unit, damage mechanisms, and inspection plan. The format of the Asset Mechanical Integrity plan draws on variety of additional sources — such as a facility siting study for consequence evaluation — to provide broad perspective that generates a process safety foundation for operations management. Team input is recommended to provide a foundational document for the site that represents plant functions that can impact the mitigation plan.

The Asset Mechanical Integrity plan includes the following:

- A description of the unit.
- Process flow and corrosion loop diagrams
- A list of probable damage mechanisms and failure modes, along with information on each.
- Guidance for operations and process support, such as operating conditions that may impact damage mechanisms and walk-around field observations such as vibration or insulation damage.
- Equipment limits/applicable integrity operating windows (IOW's).
- Recommended inspection practices.
    - The critical damage mechanism circuits, their potential for failure, and the failure consequence.
    - Critical operational, process, or inspection mitigating factors, and the responsible parties for taking action.
    - Guide to the report's location for additional operational, process, safety, and inspection actions and input.

Developing an Asset Mechanical Integrity Plan:

The process of analyzing damage mechanisms and creating an equipment and piping plan begins with identifying a process unit of interest for damage mechanism assessment; in this example, a Selexol unit was considered that

removes and concentrates CO_2 and H_2S discharged from a petcoke gasifier.

Unit Description: Selexol is an acid gas removal solution comprised of dimethyl ethers produced from polyethylene glycol. It is a physical solvent rather than a chemical absorption solvent. Figure 1 shows a Process Flow Diagram for the unit. The consequence of failure is high on an unmitigated basis due to the H_2, CO_2, CO, and H_2S content of the gas. The green highlight is the Flash Gas Type circuit. The blue highlight is the Lean Cold Selexol circuit. Both are discussed later in the paper.

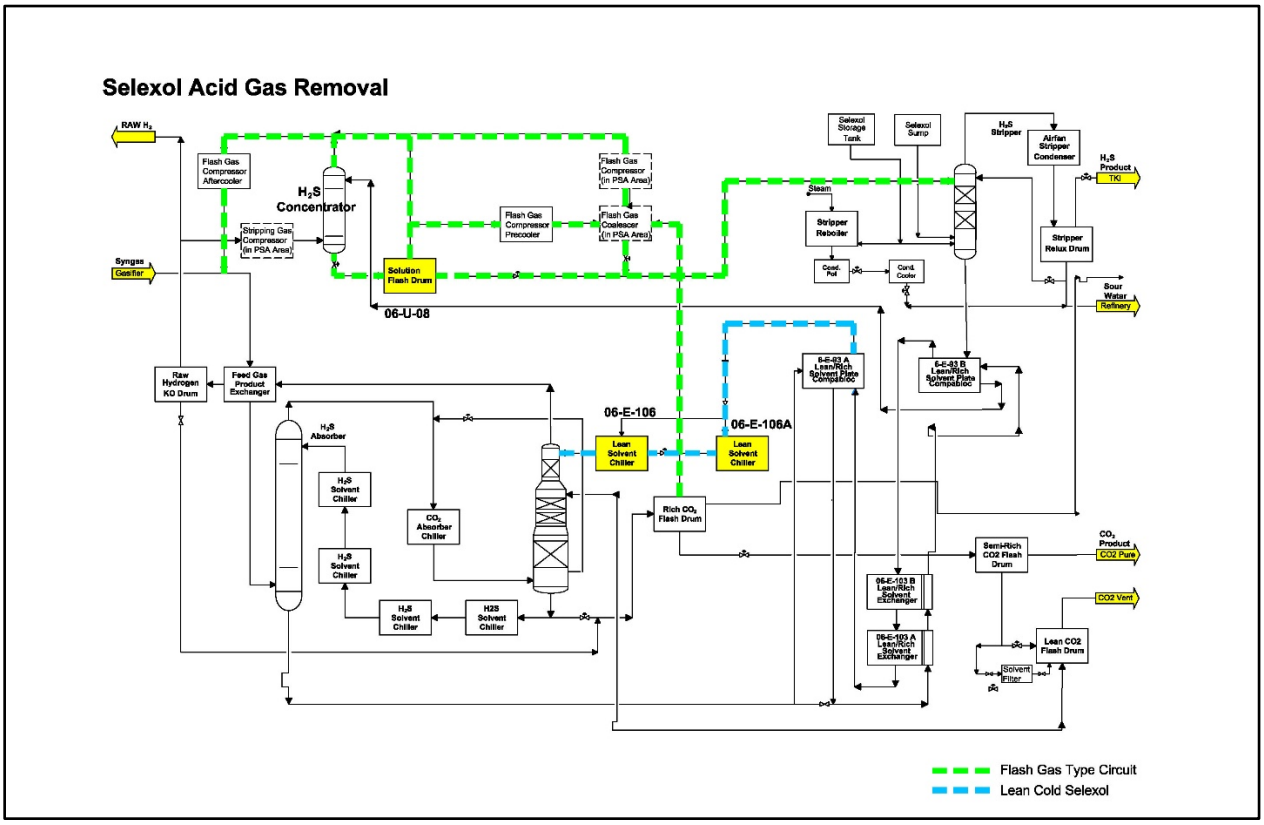

Figure 1. Process flow diagram for the Selexol Unit

In the Selexol unit, the cooled gasifier discharge is treated with chilled Selexol solvent in several absorption and flashing steps to clean the feed gas. The CO_2 and H_2S streams are concentrated and the Selexol is regenerated in a steam-driven stripping tower.

The equipment parameters and operating conditions are compared to the damage mechanisms that could potentially cause life-limiting damage. In the damage mechanism review, the scenarios / mechanisms considered were given a qualitative likelihood rating based upon the known conditions. The following rating was used:

- *No likelihood to occur:* Conditions are not present or possible.
- *Low likelihood to occur:* Condition is theoretically possible; but judged unlikely to occur.
- *Medium likelihood to occur:* Condition is judged likely to occur in the lifetime of the plant.
- *High likelihood to occur:* Condition has been observed in the facility or a similar facility.

As part of a damage mechanism and mitigation review, equipment in two different damage circuits denoted with different damage characteristics were examined: the H_2S Concentrator Circuit and the Lean Selexol Chilling Circuit. The exchanger (06-E-106) and the Solution Flash Drum (06-U-08) were assessed.

Lean Selexol Solvent Source:

The 06-E-106/106A Lean Solvent Chillers, shown in Figure 2, are the final exchangers in chilling the unit's stripped Selexol solution to 15ºF (-9 ºC) prior to feeding the top section of the CO_2 absorber 06-U-107. The chillers can be operated in series or in parallel.

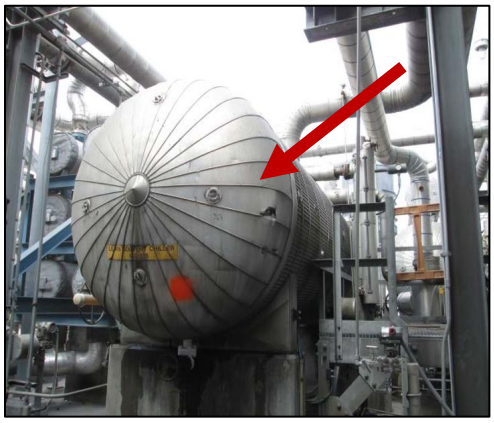

Figure 2. Lean solvent chillers 06-E-106 / 106A

Like most acid gas removal solvents, lean Selexol is relatively noncorrosive. Unlike potassium carbonate or amine based systems, Selexol has no added water, which potentially reduces some active corrosion mechanisms.

Selexol leaves the bottom of the H_2S Stripper 06-U-105 which uses a steam-driven Stripper Reboiler 06-E-08 to bring the solution temperature up to 301ºF (149 ºC) at 23 psig (0.16 MPa) in order to remove H_2S from the Selexol stream. This stripping process should maintain the "Lean Solvent" relatively free of water and dissolved gases, including CO_2 and H_2S. The flow then passes through a series of Lean/Rich Solvent Exchangers (06-E-93B plate exchanger, 06-E-103A&B) prior to the 06-E-106 A/B Lean Solvent Chillers.

The Selexol enters the tube side of the horizontal exchanger and is chilled by ammonia refrigerant on the shell side. The final temperature is controlled by the temperature on the shell side for a given flow of Selexol.

Table 1 summarizes the materials of construction and operating conditions for the 06-E-106 exchanger. These materials of construction parameters and conditions were compared to the possible damage mechanisms that could potentially cause damage. Only the most reasonable damage mechanisms were considered based on experience and known parameters that could limit the life of the cooler. These damage mechanisms are described further in Appendix A.

Condition	Description
Date fabricated (U1)	1998
Time in service	Since 2000
Materials of Construction	Shell: SA 516 70N (0.75-inch thick) (19mm) PWHT Head: SA 516 Grade 70N (11/16-inch thick) (17mm) PWHT Channel: SA 516 Grade 70N (1.125-inch thick) (29mm) PWHT Nozzles: SA 105/SA106 Tubes: SA334-1 welded Tube Sheet: SA350-LF2
Insulation	Yes, vessel painted
Design Temperature	Shell: 200 to (-20)ºF (93 to -28 ºC) Tube: 150 to (-20)ºF (66 to -28 ºC)
Design Pressure	Shell: 250 psig (1.7 MPa) Tube: 700 psig (4.8 MPa)
Typical Temperature	Shell: 6ºF (-14 ºC) Tube: 75ºF inlet to 40ºF outlet (24 to 4 ºC) (Outlet 15ºF on original PFD)
Typical Pressure	Shell: 18 psig (0.12 MPa) Tube: 630 (4.3 MPa) inlet-600 outlet, psig (4.1 MPa)
Process Stream	Shell side: Ammonia refrigerant Tube side: Selexol 100%
Inspection/ Repair History	See Inspection Report
Process Upset (thermal shock)	As this exchanger is preceded by several other exchangers, hydraulic shock should be low.

Table 1. Materials of Construction and Operating Condition for Exchanger (06-E-106)

Table 2 summarizes the potential damage mechanism assessment. Damage mechanisms that could apply are listed with their probability of occurrence.

Scenario/ Mechanisms	Carbon Steel Shell (Probability)	Carbon Steel Tubes (Probability)	Comments
Welding/Fabrication failure from repairs	Low	Low	No repairs, welds PWHTed
General wall thinning (Acid attack)	Low	Low	Verify corrosion rates
Flow-assisted Corrosion (FAC)	Low	Low	Flow rates are from 3 to 5ft. (0.9 to 1.5 M) /sec– not high enough to cause metal loss.
High Temperature Degradation (creep, HTHA)	No	No	Low to ambient temperature operations - not a concern
Low Temperature Exposure (brittle fracture)	Low	No	Low pressure and normalized and PWHTed material should not present a concern on the shell. Tubes and tube sheet are low temp materials.
Ductile Overload Failure (High Pressure)	No	No	No high pressure conditions
Ice freezing in a line (<32˚F)	No	Low	Water is not normally present, excepting at washout for turnarounds.
Solution Freezing	No	Medium	Selexol with water will become slushy at 0ºF (-18ºC)
Corrosion Under Insulation (CUI)	Medium	No	Vessel is painted and the carbon vessel shell operates at about 6ºF, which is below the maximum corrosion rate at a temperature of 150ºF to 250ºF (66 to 121ºC)
Internal Environmental Cracking Degradation (SCC)	Low	No	Ammonia SCC possible in high hardness or non-PWHT welds. Welds are PWHT. Welding Procedure OW-483 - Hardness below BHN 225.
Mechanical Fatigue (high cycle vibrations)	Low	Low	Steady state operation
Thermal or High Stress Fatigue (low cycle fatigue)	Low	Low	Equipment cycled upon shutdowns and could be subject to sudden temperature swings.
Thermal Shock	No	No	Temp -29ºF (-34 ºC), but at low pressure.

Table 2. Possible Failure Scenarios/Mechanisms for Exchanger (06-E-106)

- CUI is a concern because of insulation discontinuity and damage. Figure 3 shows a location where water can ingress under the insulation.

Figure 3. Potential area of CUI on lean cooler

- Ammonia SCC is also a potential concern, especially at welds. Therefore, it should be verified that welds are of sufficiently low hardness.

Brittle fracture is a potential mechanism for refrigeration systems, particularly where high pressures and cold temperatures are present. The drawings for this vessel indicated that the proper material specifications for cold service were used.

The Selexol Solvent Flash Drum

The 06-U-08 Selexol Solvent Flash Drum, shown in Figure 4, receives a high flow of Selexol with dissolved and two-phase gases after absorbing CO_2 and H_2S from the bottom exit of the 06-U-02 H_2S Concentrator operating at 245 psig (1.7 MPa) and 226ºF (108ºC).

Figure 4. The flash drum 06-U-08

In the Solution Flash Drum, a two-phase flow enters and the temperature reduces as the pressure drops by 30 psig (0.21 MPa), allowing gases to flash and be separated from the Selexol solvent, still rich in H_2S in the flash drum. The flash gases pass on to the flash gas system for recovery.

The Selexol solution is rich in CO_2 and H_2S, and contains water at ~0.2% (as absorbed from the main Feed Gas Stream). The Selexol leaving the flash drum is fed to the top inlet feed of the H_2S stripper.

Table 3 summarizes the materials of construction and operating conditions for the 06-U-08 Flash Drum. The parameters and conditions of the materials of construction were compared to the possible damage mechanisms that could potentially cause damage. Only the most reasonable damage mechanisms were considered based on experience and known parameters that could limit the life of the cooler. These mechanisms are described further in Appendix A.

Condition	Description		
Date fabricated (U1)	1982		
Time in service	Fabricated in 1982. Inspected before use.		
Materials of Construction	Shell: SA 516 70 (1.45 inch thick) (37mm) (PWHT uncertain) Head: SA 516 Grade 70 Nozzles: SA106B No impact testing		
Insulation	Yes		
Design Temperature	425 to (-20)ºF (93 to -28 ºC)		
Design Pressure	485 psig (3.34 MPa)		
Typical Temperature	200ºF (93 ºC)		
Typical Pressure	215 psig (1.48 MPa)		
Process Stream	H2	33.33	mol%
	CO_2	63.12	mol%
	O2/Ar	0.21	mol%
	N2	0.34	mol%
	CH4	0.39	mol%
	CO	1.59	mol%
	H_2S	0.98	mol%
Inspection/ Repair History	Clam shell repair at the bottom. Inspection in 2015 found excessive corrosion/pitting under deposits at the bottom drain valve area which was not characterized – appeared as likely acid attack.		
Excursion concerns	Water, oxygen, or chloride contamination and cooler temperatures will accelerate corrosion rates.		
Shutdown/Start-up concerns	On shutdown—cooler temperatures promote CO_2 and H_2S absorption in residual liquids. Contamination with water and oxygen in the presence of CO_2 and/or H_2S greatly increases corrosion rates for carbon steel. This could occur on shutdowns, in conjunction with a water flush.		

Table 3. Materials of Construction and Operating Condition for Solution Flash Drum 06-U-08

Table 4 summarizes the potential damage mechanism assessment. Damage mechanisms that could apply are listed with their probability of occurrence.

Scenario/ Mechanisms	Carbon Steel Shell (Probability)	Comments
Welding / Fabrication failure from repairs	Low	Original weld procedure should provide low hardness in the welds with PWHT.
General wall thinning and pitting (Carbonic Acid attack, H_2S attack)	High	1) Inspection report 15-379-bsm-V1, corrosion at the bottom 0.5"deep 2) Carbonic and H_2S acid potential 3) Under deposit corrosion, dead legs, low flow areas. 4) CO_2/H_2S corrosion-rates are high where cooler temperatures or condensation occurs. This can also impact connections; for example, static level gauges without tracing and insulation.
Flow-assisted Corrosion (FAC)	Medium	Flow rate through bottom nozzle is ~5 ft./sec. at 386,000 lb./hour without entrained gasses. Higher flows and entrained gas would increase this flow rate. Inlet flow is ~3 ft. (0.9M)/sec, excepting surges.
High Temperature Degradation (creep, HTHA)	Low	H_2 present but operating temperature 150ºF (66 ºC) below API 941 curve
Low Temperature Exposure (brittle fracture)	Low	Brittle fracture review performed. Shell: Minimum temperature -15 to -16ºF (-26 ºC). Shell material normalized. No Charpy impact testing (exempt at those temps) Nozzles: minimum temp. -150ºF (-101ºC). Pads: 47ºF (8 ºC)
Ductile Overload Failure (High Pressure)	Low	Vessel re-rated by FFS and PRV pressure changed
Ice freezing in a line (<32ºF)	Low	Verify that no locations for water getting trapped after flushing for inspections.
Corrosion Under Insulation (CUI)	Medium	Insulated. The carbon vessel shell operates in the maximum corrosion rate at a temperature of 150ºF to 250ºF (66 to 121 ºC). CUI can occur.
Internal Environmental cracking Degradation (SCC)	Low	Wet H_2S: H2 cracking a low concern in the weldments. Weld procedure A200 Hardness HAZ HB211 (HRB95), which is below HB 237.
Mechanical Fatigue (high cycle vibrations)	Medium	Piping velocities – enter in and exit piping.
Thermal or High Stress Fatigue (low cycle fatigue (LCF))	Low	Startup/shutdown cycling.
Pressure shock	Low	Sudden surge of flow may damage inlet deflector.

Table 4. Possible Failure Scenarios/Mechanisms for Solution Flash Drum 06-U-08

Review of the inspection reports and process conditions identified some of the following potential concerns:

- Corrosion was the worst on the bottom of a "drain nozzle." During inspections, corrosive attack was found on the bottom near a drain of the vessel, and at least ½-inch (13mm) of metal was removed. Figure 5 shows the attacked region. The inspection report did not identify the damage mechanism, but most likely it was an acid attack due to dissolved CO_2 and H_2S found in collected water or condensation, assisted by under-deposit corrosion.

Figure 5. Observed corrosive attack and pitting on the bottom of the flash drum

- Flow rates are from 3 to 5 ft. (0.9 to 1.5 M)/sec at the inlet and exit nozzle, respectively. Both of these are acceptable and should not accelerate corrosion. There is the possibility of accelerated corrosion occurring underneath deposits.
- Cooler temperatures at upper level gauge nozzles provide an opportunity for condensation corrosion and create localized corrosion with high CO_2 and H_2S levels absorbing on wetted surfaces.

As cooler temperatures promote CO_2 and H_2S absorption, uninsulated areas or areas of low

flow have increased corrosion potential. Contamination with water and oxygen greatly increases corrosion rates for carbon steel. This could occur with process upsets that introduce more water in the incoming feed gas, or during shutdowns in conjunction with a water flush.

Asset Mechanical Integrity Plan for Selexol Unit:

After an initial Damage Mechanism Review (DMR), the Asset Mechanical Integrity plan is developed for the piping circuits with the vessels. This would include supporting detailed analysis tables, along with circuit maps, circuit/equipment-specific mitigation plans for operations/process engineering, and an inspection outline to provide guidance to the inspection group.

Connected equipment, including piping and instrument installations with similar damage mechanism concerns are grouped together in a "damage management circuit." These circuits provide a broader view of potential effects and efficiencies in the effort.

In addition to the damage mechanism input, the unmitigated consequence of failure is provided through HAZOPs or Quantitative Risk Assessments (QRAs).

Knowing the circuit and the potential failure consequences, the unmitigated failure consequence can be assessed as shown in Table 5.

Circuit	Unmitigated Consequence	Unmitigated Failure Risk
H_2S Concentrator Bottoms	High	High
Lean Selexol Chilling Circuit	Medium	Low

Table 5. Unmitigated failure consequence

Mitigation and Inspection Plans:

Critical operational, process, or inspection mitigating factors and the responsible parties for taking action are considered for the circuit.

Flash Gas Type Circuit:

Concerns and mitigation options for a Flash Gas Type Circuit, shown in Figure 1, are described below.

Concern: H_2S concentrator circuits have a high potential for heavy corrosion with pitting in areas where condensation occurs, low flow areas, or in dead legs.

Mitigation: Check deadlegs and thinner wall attachments (Action: Inspection)

Concern: Low potential for Wet H_2S cracking.

Mitigation: Verify that weld hardness is below the recommended minimum; if above, perform inspection for SCC. (Action: Inspection)

Concern: Accelerated corrosion may be linked to startups or shutdowns where acid gases cool and accumulate in Selexol or water to accelerate corrosion rates.

Mitigation: (1) Consider impact of using water flushes without controls to prevent CO_2/H_2S in the atmosphere. (Action: Operations, Process Engineering, Inspection). (2) Consider nitrogen blanket.

Lean Selexol Chilling Circuit:

Concerns and mitigation options for the Lean Cold Selexol Chilling circuit, shown in Figure 1, are described below.

Concern: Brittle fracture is a low potential damage mechanism mitigated by proper materials specifications that must be maintained. (Action: Maintenance, Engineering)

Mitigation: (1) assure pressures are low at very low temperatures. (2) Repair welds require low temperature evaluation for brittle fracture.

Concern: Medium potential for Corrosion under Insulation is possible, report insulation damage. (Action: Operations)

Mitigation: Perform visual inspection and UT of suspected areas.

Concern: Low Potential for Ammonia SCC.

Mitigation: Verify that weld hardness is below the recommended minimum; if above, perform inspection for SCC. (Action: Inspection)

SUMMARY

Damage Mechanism Reviews (DMRs) provide a systematic, proactive method for identifying potential damage mechanisms prior to failures. Having a broad understanding of these damage mechanisms and how operations or process conditions can be used to develop an Asset Mechanical Integrity Plan. When implemented, this plan aids in mitigation and inspection of damage or failures, and will produce more proactive process safety management decision-making when considering plant modifications or new equipment designs.

The development of an overall inspection and mitigation plan with input from impacted groups, such as that provided by the Asset Mechanical Integrity Plan, can provide an efficient method for conveying important actions to mitigate damage and prevent equipment failures.

It is essential that the developed DMR and the Asset Mechanical Integrity Plan be effectively communicated to plant and management staff, and the actions implemented, otherwise the high risks are not mitigated.

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Appendix A - Mechanisms Definition and Key Parameters

Brittle Fracture

Definition:
Carbon steel and alloy materials can undergo a transformation from ductile-to-brittle behavior as the material temperature drops, resulting in low toughness at low temperatures and increasing the hazard of sudden brittle fracture. The ASME B31.3 for piping and ASME Section VIII for Pressure Vessels codes provide extensive rules for carbon steel materials that are subject to cold temperatures. While the codes and standards are available on cold embrittlement, additional steps may be needed to ensure codes and standards are properly utilized and addressed. Examples where cold embrittlement can be a concern:

Key Parameters:

- Piping with water that freezes
- Thick-wall pressure vessels
- Repair-welded equipment that have altered material properties.
- Cryogenic storage systems
- De-pressurized systems
- Materials used with low toughness an no guarantee for low temperature properties.
- Pre-existing cracks

Fatigue

Definition:
High-cycle fatigue (HCF) is often the result of high frequency vibrations and low stress. Low-cycle fatigue LCF is typically due to thermal or high stress cyclic conditions. Corrosion fatigue is fatigue in a corrosive environment. Fatigue is the mechanical degradation of a material under the cyclic loading. Nearly all engineering structures experience some form of alternating stress and are exposed to harmful environments during their service life. The environment plays a significant role in the fatigue of high strength structural materials like steels, aluminum alloys, and titanium alloys.

Key Parameters:

- Material, corrosive environment, cyclic stresses and stress risers are critical factors.
- Crack initiation sites include concentrators such as pits, notches, surface defects, and changes in sections or fillet welds.
- Unsupported piping.

Flow-Assisted Corrosion (FAC)

Definition:
Flow-Assisted Corrosion (FAC) is a localized corrosion process that occurs due to high flow rates and removal of protective films on metal surfaces.

Key Parameters:

- Flow rate, piping dimensions

CO_2 Corrosion

Definition:
Carbon dioxide (Carbonic Acid) corrosion is localized aqueous CO_2 corrosion of carbon and low alloy steels in an electrochemical process involving the anodic dissolution of iron and the cathodic evolution of hydrogen. Carbon dioxide in a weakly acidic gas that is corrosive when dissolved in water becomes carbonic acid (H_2CO_3). Often large shallow pits occur.

Key Parameters:

- Carbon dioxide, water concentration, process conditions

Corrosion Under Insulation (CUI)

Definition
CUI is a particularly severe form of localized corrosion. Intruding water or moisture (external) is the key driving mechanism. Special consideration must be taken during design to avoid corrosion by not permitting water to enter a system either directly or indirectly. Corrosion may attack the jacketing, the insulation hardware, or the underlying equipment. For high temperature equipment and piping, water that enters the insulation material will eventually reach a region under the insulation and come in contact with hot piping or process equipment metal walls. A saturated salt solution may then develop in this area, which becomes a problem during shutdown and reheating. Upon reheating, the wall will temporarily be in contact with the saturated solution, and stress-corrosion cracking may begin.

Key Parameters:

- Damaged or partial insulation of piping and equipment.
- Carbon steel with insulation operating within a temperature range of 0º F to 300º F (-18 to 149 ºC) Maximum corrosion rate occurs at a temperature of 150º F to 250º F (65.6 to 121 ºC).
- Shutdowns and Restarting.

Wet H_2S Damage (WHIP)

Definition:
"Wet H_2S Cracking" can occur in carbon steel and alloy due to the effects of aqueous hydrogen charging in "Wet H_2S" process environments. Types of damage that can occur as a result of aqueous hydrogen charging include sulfide stress cracking (SSC) of hard weldments and microstructures, hydrogen blistering, hydrogen induced cracking (HIC) and stress-oriented hydrogen induced cracking (SOHIC). The key characteristic of Wet H_2S cracking mechanisms involve charging of the steel with hydrogen at relatively low temperatures, most often as the result of corrosion process, which evolves hydrogen.

Key Parameters:

- Environmental Conditions (pH, H_2S level, containments and temperature).
- Material Properties (hardness, microstructure and strength).
- Temperature (ambient to 300ºF (149 ºC))
- Welded Steel.
- Carbon steels and low alloy steels above a hardness of 237 Brinell Hardness (BH).
- Containing an aqueous phase with more than 50ppmw (weight) total sulfide content in aqueous phase.
- Containing more than just 1ppmw total surface content in the aqueous phase and a pH less than 4.0.

Ammonia Stress Corrosion Cracking

Definition:
Welded carbon steel in anhydrous ammonia is highly susceptible. Intergranular cracks can occur in heat affected zones. Impurities in liquid ammonia such as air or carbon dioxide can cause stress corrosion cracking of mild steel. Ammonia is highly corrosive towards copper and zinc alloys.

Key Parameters:

- PWHT of carbon steel eliminates susceptibility to Ammonia SCC.
- Weld hardness should not exceed 225 Brinell Hardness (BH).
- Contamination with air or oxygen increases the tendency to crack.
- Anhydrous ammonia with less than 0.2% water may cause cracking in carbon steel.