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Mechanical and Metallurgical Failures

Lesson 18
General Damage mechanisms

General Damage mechanisms are divided into the following categories:

a) Mechanical and Metallurgical Failure
b) Uniform or Localized Loss of Thickness
c) High Temperature Corrosion
d) Environment Assisted Cracking
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Temper Embrittlement

Description of Damage

• Temper embrittlement is the reduction in toughness due to a metallurgical change that can occur in some low alloy steels as a result of long term exposure in the temperature range of about 650 °F to 1100 °F (343°C to 593°C).

• Although the loss of toughness is not evident at operating temperature, equipment that is temper embrittled may be susceptible to brittle fracture during start-up and shutdown.
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Temper Embrittlement

**Affected Materials**

- Primarily 2.25Cr-1Mo low alloy steel, 3Cr-1Mo (to a lesser extent), and the high-strength low alloy Cr-Mo-V rotor steels.
- Older generation 2.25Cr-1Mo materials manufactured prior to 1972 may be particularly susceptible. Some high strength low alloy steels are also susceptible.
- The C-0.5Mo and 1.25Cr-0.5Mo alloy steels are not significantly affected by temper embrittlement.
Affected Units or Equipment

• Equipment susceptible to temper embrittlement is most often found in:
  • Hydroprocessing units, particularly reactors.
  • Hot feed/effluent exchanger components, and hot HP separators.
  • Catalytic reforming units (reactors and exchangers), FCC reactors, coker and visbreaking units.
• Welds in these alloys are often more susceptible than the base metal and should be evaluated.
Temper embrittlement is a metallurgical change that is not readily apparent and can be confirmed through impact testing. Damage due to temper embrittlement may result in catastrophic brittle fracture.

Temper embrittlement can be identified by an upward shift in the ductile-to-brittle transition temperature measured in a Charpy V-notch impact test, as compared to the non-embrittled or de-embrittled material.
Brittle Fracture

Description of Damage

• Brittle fracture is the sudden rapid fracture under stress (residual or applied) where the material exhibits little or no evidence of ductility or plastic deformation.

Affected Materials

• Carbon steels and low alloy steels are of prime concern, particularly older steels. 400 Series Stainless Steels are also susceptible.
Brittle Fracture

Affected Units or Equipment

• Equipment manufactured to the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, prior to the December 1987 Addenda, were made with limited restrictions on notch toughness for vessels operating at cold temperatures.

• This does not mean that all vessels fabricated prior to this date will be subject to brittle fracture. Many designers specified supplemental impact tests on equipment that was intended to be in cold service.
Brittle Fracture

Affected Units or Equipment

• Equipment made to the same code after this date were subject to the requirements of UCS 66 (impact exemption curves).
• Most processes run at elevated temperature so the main concern is for brittle fracture during startup, shutdown, or hydrotest/tightness testing. Thick wall equipment on any unit should be considered.
Brittle Fracture

Affected Units or Equipment

• Brittle fracture can also occur during an auto refrigeration event in units processing light hydrocarbons such as methane, ethane/ethylene, propane/propylene, or butane. This includes alkylation units, olefin units and polymer plants (polyethylene and polypropylene). Storage bullets/spheres for light hydrocarbons may also be susceptible.

• Brittle fracture can occur during ambient temperature hydrotesting due to high stresses and low toughness at the testing temperature.
Brittle Fracture

- Cracks will typically be straight, non-branching, and largely devoid of any associated plastic deformation (no shear lip or localized necking around the crack)
- Microscopically, the fracture surface will be composed largely of cleavage, with limited intergranular cracking and very little microvoid coalescence.
• Inspection is not normally used to mitigate brittle fracture.
• Susceptible vessels should be inspected for pre-existing flaws/defects.
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Brittle Fracture

20-inch carbon steel pipeline that failed during hydro test at gouges on the O.D.
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Brittle Fracture During Hydro Test
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Brittle Fracture During Hydro Test
Thermal Fatigue  
*Description of Damage*

• Thermal fatigue is the result of cyclic stresses caused by variations in temperature. Damage is in the form of cracking that may occur anywhere in a metallic component where relative movement or differential expansion is constrained, particularly under repeated thermal cycling.

**Affected Materials**

• All materials of construction.
Examples include the mix points of hot and cold streams such as locations where condensate comes in contact with steam systems, such as de-superheating.
Thermal Fatigue
Thermal fatigue cracks on the inside of a heavy wall Stainless Steel pipe downstream of a cooler H2 injection into a hot hydrocarbon line.
Thermal Fatigue

**Affected Units or Equipment**

- Thermal fatigue cracking has been a major problem in coke drum shells. Thermal fatigue can also occur on coke drum skirts where stresses are promoted by a variation in temperature between the drum and skirt.
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Thermal Fatigue
Bulging in a skirt of a Coke Drum
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Thermal fatigue cracking in the bulged coke drum skirt
Thermal Fatigue

• In steam generating equipment, cracks usually follow the toe of the fillet weld, as the change in section thickness creates a stress raiser. Cracks often start at the end of an attachment lug and if there is a bending moment as a result of the constraint, they will develop into circumferential cracks into the tube.

• Water in soot blowers may lead to a crazing pattern. The predominant cracks will be circumferential and the minor cracks will be axial.
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Thermal fatigue crack indicates origin (here at the toe of an attachment weld) and shape.
Thermal Fatigue

*Inspection and Monitoring*

- Since cracking is usually surface connected, visual examination, MT and PT are effective methods of inspection.
- External SWUT inspection can be used for non-intrusive inspection for internal cracking and where reinforcing pads prevent nozzle examination.
- Heavy wall reactor internal attachment welds can be inspected using specialized ultrasonic techniques.
Erosion/Erosion – Corrosion

Description of Damage

• Erosion is the accelerated mechanical removal of surface material as a result of relative movement between, or impact from solids, liquids, vapor or any combination thereof.

• Erosion-corrosion is a description for the damage that occurs when corrosion contributes to erosion by removing protective films or scales, or by exposing the metal surface to further corrosion under the combined action of erosion and corrosion.
Erosion/Erosion – Corrosion

Affected Materials

• All metals, alloys and refractory.
All types of equipment exposed to moving fluids and/or catalyst are subject to erosion and erosion-corrosion. This includes piping systems, particularly the bends, elbows, tees and reducers; piping systems downstream of letdown and block valves; pumps; blowers; propellers; impellers; agitators; heat exchanger tubing; device orifices; turbine blades; nozzles; ducts and vapor lines etc.
Erosion/Erosion – Corrosion

Affected Units or Equipment

• Erosion can be caused by gas borne catalyst particles or by particles carried by a liquid such as a slurry.

• In refineries, this form of damage occurs as a result of catalyst movement in FCC reactor/regenerator systems in catalyst handling equipment.
Erosion/Erosion – Corrosion

Affected Units or Equipment

• Hydroprocessing reactor effluent piping may be subject to erosion-corrosion by ammonium bisulfide. The metal loss is dependent on the ammonium bisulfide concentration, velocity and alloy corrosion resistance.

• Crude and vacuum unit piping and vessels exposed to naphthenic acids in some crude oils may suffer severe erosion-corrosion metal loss depending on the temperature, velocity, sulfur content and TAN level.
Erosion/Erosion – Corrosion

Appearance of Damage

• Erosion and erosion-corrosion are characterized by a localized loss in thickness in the form of pits, grooves, gullies, waves, rounded holes and valleys. These losses often exhibit a directional pattern.
• Failures can occur in a relatively short time.
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Erosion/Erosion – Corrosion
Erosion of a 9Cr coker heater return bend.
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Erosion/Erosion – Corrosion

*Inspection and Monitoring*

• Visual examination of suspected or troublesome areas, as well as UT checks or RT can be used to detect the extent of metal loss.
• Specialized corrosion coupons and on-line corrosion monitoring electrical resistance probes have been used in some applications.
• IR scans are used to detect refractory loss on stream.
Mechanical Fatigue

Description of Damage

• Fatigue cracking is a mechanical form of degradation that occurs when a component is exposed to cyclical stresses for an extended period, often resulting in sudden, unexpected failure.
• These stresses can arise from either mechanical loading or thermal cycling and are typically well below the yield strength of the material.

Affected Materials

• All engineering alloys are subject to fatigue cracking.
• The stress levels and number of cycles necessary to cause failure vary by material.
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Mechanical Fatigue

Affected Units or Equipment

Thermal Cycling Failures

• Equipment that cycles daily in operation such as coke drums.
• Equipment that may be auxiliary or on continuous standby but sees intermittent service such as auxiliary boiler.
• Quench nozzle connections that see significant temperature deltas during operations such as water washing systems.
Affected Units or Equipment

Mechanical Loading Failures

• Rotating shafts on centrifugal pumps and compressors that have stress concentrations due to changes in radii and key ways.
• Components such as small diameter piping that may see vibration from adjacent equipment and/or wind.
• High pressure drop control valves or steam reducing stations can cause serious vibration problems in connected piping.
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Appearance of Damage

• The signature mark of a mechanical fatigue failure is a “clam shell” type fingerprint that has concentric rings called “beach marks” emanating from the crack initiation site.
• This signature pattern results from the “waves” of crack propagation that occur during every cycle above the threshold loading. These concentric cracks continue to propagate until the cross-sectional area is reduced to the point where failure due to overload occurs.
Appearance of Damage

Schematic of a fatigue fracture surface showing “beach marks”.

[TYPICAL FATIGUE FRACTURE Schematic Image]
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Appearance of Damage
Fatigue fracture surface of a carbon steel pipe.
Appearance of Damage

• Cracks nucleating from a surface stress concentration or defect will typically result in a single “clam shell” fingerprint.
• Cracks resulting from cyclical overstress of a component without significant stress concentration will typically result in a fatigue failure with multiple points of nucleation and hence multiple “clam shell” fingerprints. These multiple nucleation sites are the result of microscopic yielding that occurs when the component is momentarily cycled above its yield strength.
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Appearance of Damage

Fatigue crack in a 16-inch pipe-to-elbow weld in the fill line of crude oil storage tank after 50 years in service.
Appearance of Damage
The surface of the fracture faces of the previous pipe to elbow crack.
Appearance of Damage

- Cracks resulting from cyclical overstress of a component without significant stress concentration will typically result in a fatigue failure with multiple points of nucleation and hence multiple “clam shell” fingerprints. These multiple nucleation sites are the result of microscopic yielding that occurs when the component is momentarily cycled above its yield strength.
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*Inspection and Monitoring*

- NDE techniques such as PT, MT and SWUT can be used to detect fatigue cracks at known areas of stress concentration.
- VT of small diameter piping to detect oscillation or other cyclical movement that could lead to cracking.
- Vibration monitoring of rotating equipment to help detect shafts that may be out of balance.
- In high cycle fatigue, crack initiation can be a majority of the fatigue life making detection difficult.
Uniform or Localized Loss of Thickness
Atmospheric Corrosion

Description of Damage

• A form of corrosion that occurs from moisture associated with atmospheric conditions. Marine environments and moist polluted industrial environments with airborne contaminants are most severe. Dry rural environments cause very little corrosion.

Affected Materials

• Carbon steel, low alloy steels and copper alloyed aluminum.
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Atmospheric Corrosion

**Affected Units or Equipment**

- Piping and equipment with operating temperatures sufficiently low to allow moisture to be present.
- A paint or coating system in poor condition.
- Equipment may be susceptible if cycled between ambient and higher or lower operating temperatures.
- Equipment shut down or idled for prolonged periods unless properly mothballed.
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Atmospheric Corrosion

Affected Units or Equipment

• Tanks and piping are particularly susceptible. Piping that rests on pipe supports is very prone to attack due to water entrapment between the pipe and the support.
• Bimetallic connections such as copper to aluminum electrical connections.
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Atmospheric Corrosion

Appearance

• The attack will be general or localized, depending upon whether or not the moisture is trapped.
• If there is no coating or if there is a coating failure, corrosion or loss in thickness can be general.
• Localized coating failures will tend to promote corrosion.
• Metal loss may not be visually evident, although normally a distinctive iron oxide (red rust) scale forms.
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Atmospheric Corrosion

*Inspection and Monitoring*

- VT and UT are techniques that can be used.
Corrosion Under Insulation (CUI)

Description of Damage
Corrosion of piping, pressure vessels and structural components resulting from water trapped under insulation or fireproofing.

Affected Materials
Carbon steel, low alloy steels, 300 Series SS and duplex stainless steels.
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Corrosion Under Insulation (CUI)

Affected Units or Equipment

• Carbon and low alloy steels are subject to pitting and loss in thickness.
• 300 Series SS, 400 Series SS and duplex SS are subject to pitting and localized corrosion.
• 300 Series SS are also subject to Stress Corrosion Cracking (SCC) if chlorides are present, while the duplex SS are less susceptible.
Common areas of concern in process units are higher moisture areas such as those areas down-wind from cooling towers, near steam vents, deluge systems, acid vapors, or near supplemental cooling with water spray.
Corrosion Under Insulation (CUI)

Affected Units or Equipment

Design Issues

• CUI can be found on equipment with damaged insulation, vapor barriers, weatherproofing or mastic, or protrusions through the insulation or at insulation termination points such as flanges.

• Equipment designed with insulation support rings welded directly to the vessel wall (no standoff); particularly around ladder and platform clips, and lifting lugs, nozzles and stiffener rings.
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Corrosion Under Insulation (CUI)

Affected Units or Equipment

Design Issues

- Piping or equipment with damaged/leaking steam tracing.
- Localized damage at paint and/or coating systems.
- Locations where moisture/water will naturally collect (gravity drainage) before evaporating (insulation support rings on vertical equipment) and improperly terminated fireproofing.
- The first few feet of a horizontal pipe run adjacent to the bottom of a vertical run is a typical a CUI location.
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Appearance of Damage

• After insulation is removed from carbon and low alloy steels, CUI damage often appears as loose, flaky scale covering the corroded component. Damage may be highly localized (Figure 4-38 and Figure 4-39).
• In some localized cases, the corrosion can appear to be carbuncle type pitting (usually found under a failed paint/coating system).
• For 300 Series SS, specifically in older calcium silicate insulation (known to contain chlorides), localized pitting and chloride stress corrosion cracking can occur.
• Tell tale signs of insulation and paint/coating damage often accompany CUI.
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Appearance of Damage

CUI of CS level bridle
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Appearance of Damage
Profile RT of the level bridle
Corrosion Under Insulation (CUI)

Inspection and Monitoring

An inspection plan for corrosion under insulation should be a structured and systematic approach starting with prediction/analysis, then looking at the more invasive procedures. The inspection plan should consider operating temperature; type and age/condition of coating; and type and age/condition of insulation material. Additional prioritization can be added from a physical inspection of the equipment, looking for evidence of insulation, mastic and/or sealant damage, signs of water penetration and rust in gravity drain areas around the equipment.
Inspection and Monitoring

Utilize multiple inspection techniques to produce the most cost effective approach, including:

- Partial and/or full stripping of insulation for visual examination.
- UT for thickness verification.
- Real-time profile x-ray (for small bore piping).
- Neutron backscatter for identifying wet insulation.
- Deep penetrating eddy-current inspection.
- IR thermography looking for wet insulation and/or damaged and missing insulation under the jacket.
- Guided wave UT.
Cooling Water Corrosion

Description of Damage

• General or localized corrosion of carbon steels and other metals caused by dissolved salts, gases, organic compounds or microbiological activity.

Affected Materials

• Carbon steel, all grades of stainless steel, copper, aluminum, titanium and nickel base alloys.

Affected Units or Equipment

• Cooling water corrosion is a concern with water-cooled heat exchangers and cooling towers in all applications across all industries.
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Appearance of Damage

• Cooling water corrosion can result in many different forms of damage including general corrosion, pitting corrosion, MIC, stress corrosion cracking and fouling.
• General or uniform corrosion of carbon steel occurs when dissolved oxygen is present.
• Localized corrosion may result from under deposit corrosion, crevice corrosion or microbiological corrosion.
• Deposits or crevices can lead to under deposit or crevice corrosion of any of the affected materials.
Appearance of Damage

• Wavy or smooth corrosion at nozzle inlets/outlets and tube inlets may be due to flow induced corrosion, erosion or abrasion.
• Corrosion at ERW weld areas will appear as grooving along the weld fusion lines.
• Metallurgical analysis of tube samples may be required to confirm the mode of failure.
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Appearance of Damage

Cooling water corrosion on the I.D. of a CS heat exchanger tube operating at 86°F (30°C).
Cooling Water Corrosion

*Inspection and Monitoring*

- Cooling water should be monitored for variables that affect corrosion and fouling.
- Ultrasonic flow meters can be used to check the velocity of water in the tubes.
- EC or IRIS inspection of tubes.
- Splitting representative tubes.
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Boiler Water Condensate Corrosion

Description of Damage

• General corrosion and pitting in the boiler system and condensate return piping.

Affected Materials

• Primarily carbon steel, some low alloy steel, some 300 Series SS and copper based alloys.

Affected Units or Equipment

• Corrosion can occur in the external treatment system, deaerating equipment, feedwater lines, pumps, stage heaters and economizers as well as the steam generation system on both the water and fire sides and the condensate return system.
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Boiler Water Condensate Corrosion

Appearance of Damage

• Corrosion from oxygen tends to be a pitting type damage and can show up anywhere in the system even if only very small quantities break through the scavenging treatment. Oxygen is particularly aggressive in equipment such as closed heaters and economizers where there is a rapid water temperature rise.

• Corrosion in the condensate return system tends to be due to carbon dioxide although some oxygen pitting problems can occur if the oxygen scavenging treatment is not working correctly. Carbon dioxide corrosion tends to be a smooth grooving of the pipe wall.
Oxygen scavenging treatments typically include catalyzed sodium sulfite or hydrazine depending on the system pressure level along with proper mechanical deaerator operation. A residual of the oxygen scavenger is carried into the steam generation system to handle any oxygen ingress past the deaerator.

If the scale/deposit control/magnetite maintenance treatment scheme does not minimize carbon dioxide in the condensate return system, an amine inhibitor treatment might be required.
• Water analysis is the common monitoring tool used to assure that the various treatment systems are performing in a satisfactory manner. Parameters which can be monitored for signs of upset include the pH, conductivity, chlorine or residual biocide, and total dissolved solids to check for leaks in the form of organic compounds.
There are no proactive inspection methods other than developing an appropriate program when problems such as a ruptured boiler tube or condensate leaks are recognized in the various parts of complex boiler water and condensate systems.

Deaerator cracking problems can be evaluated off-line at shutdowns by utilizing properly applied wet fluorescence magnetic particle inspection.
High Temperature Corrosion
[400°F (204°C)]
Sulfidation also known as Sulfidic Corrosion

**Description of Damage**

Corrosion of carbon steel and other alloys resulting from their reaction with sulfur compounds in high temperature environments. The presence of hydrogen accelerates corrosion.
Sulfidation

Affected Materials

• All iron based materials including carbon steel and low alloy steels, 300 Series SS and 400 Series SS.
• Nickel base alloys are also affected to varying degrees depending on composition, especially chromium content.
• Copper base alloys form sulfide at lower temperatures than carbon steel.
Sulfidation

Affected Units or Equipment

• Sulfidation occurs in piping and equipment in high temperature environments where sulfur-containing streams are processed.
• Common areas of concern are the crude, FCC, coker, vacuum, visbreaker and hydroprocessing units.
• Heaters fired with oil, gas, coke and most other sources of fuel may be affected depending on sulfur levels in the fuel.
• Boilers and high temperature equipment exposed to sulfur-containing gases can be affected.
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Sulfidation

Appearance of Damage

• Depending on service conditions, corrosion is most often in the form of uniform thinning but can also occur as localized corrosion or high velocity erosion-corrosion damage.

• A sulfide scale will usually cover the surface of components. Deposits may be thick or thin depending on the alloy, corrosiveness of the stream, fluid velocities and presence of contaminants
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Sulfidation failure in an elbow
Environment – Assisted Cracking
Chloride Stress Corrosion Cracking

A cracking process that requires the simultaneous action of a corrodent and sustained tensile stress. This excludes corrosion-reduced sections that fail by fast fracture. It also excludes intercrystalline or transcrystalline corrosion, which can disintegrate an alloy without applied or residual stress. Stress-corrosion cracking may occur in combination with hydrogen embrittlement.
Chloride Stress Corrosion Cracking

Description of Damage

Surface initiated cracks caused by environmental cracking of 300 Series Stainless Steel and some nickel base alloys under the combined action of:

- tensile stress
- temperature
- aqueous chloride environment.
- The presence of dissolved oxygen increases chances for cracking.
Affected Materials

a) All 300 Series Stainless Steels are highly susceptible.
b) Duplex stainless steels are more resistant.
c) Nickel base alloys are highly resistant.
Affected Units or Equipment

a) All 300 Series SS piping and pressure vessel components in any process units are susceptible to CUI-SSCC.
b) Cracking has occurred in water-cooled condensers and in the process side of crude tower overhead condensers.
c) Drains in hydroprocessing units are susceptible to cracking during startup/shutdown if not properly purged.
Chloride Stress Corrosion Cracking

*Appearance of Damage*

- Surface breaking cracks can occur from the process side or externally under insulation.
- The material usually shows no visible signs of corrosion.
- Characteristic stress corrosion cracks have many branches and may be visually detectable by a craze/cracked appearance of the surface.
Chloride Stress Corrosion Cracking

Appearance of Damage

• Metallography of cracked samples typically shows branched transgranular cracks. Sometimes intergranular cracking of sensitized 300 Series SS may also be seen.
• Welds in 300 Series SS usually contain some ferrite, producing a duplex structure that is usually more resistant to CUI – SCC. Fracture surfaces often have a brittle appearance.
Chloride Stress Corrosion Cracking

Appearance of Damage

External cracking of 304 Stainless Steel instrument tubing
Chloride Stress Corrosion Cracking

Appearance of Damage

Cracking on the shell side of Type 316L SS tubes in steam service at 450°F (232°C), showing tubes after PT inspection. The cracks can be seen in the center tube (arrow).
Chloride Stress Corrosion Cracking

Appearance of Damage

Close-up of the tube in previous picture showing tight cracks with a spider web appearance.
Corrosion Fatigue

Description of Damage

A form of fatigue cracking in which cracks develop under the combined affects of cyclic loading and corrosion. Cracking often initiates at a stress concentration such as a pit in the surface. Cracking can initiate at multiple sites.

Affected Materials

• All metals and alloys.
Affected Units or Equipment

Any equipment subjected to cyclic stresses in a corrosive environment. Some examples include:

• Rotating Equipment
• Deaerators
• Cycling Boilers
Appearance of Damage

• The fatigue fracture is brittle and the cracks are most often transgranular, as in stress-corrosion cracking, but not branched, and often results in propagation of multiple parallel cracks.

• Fatigue cracking will be evidenced by very little plastic deformation except that final fracture may occur by mechanical overload accompanied by plastic deformation.

• In cycling boilers, the damage usually appears first on the water side of buckstay attachments.
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Photograph of a carbon steel boiler tube cut in half lengthwise. Corrosion fatigue cracks initiate at the I.D. of a tube, opposite a buckstay attachment on the O.D.
Caustic Stress Corrosion Cracking
(Caustic Embrittlement)

Description of Damage

Caustic embrittlement is a form of stress corrosion cracking characterized by surface-initiated cracks that occur in piping and equipment exposed to caustic, primarily adjacent to Non-Post Weld Heat Treated welds.
Refinery Industry
Environment – Assisted Cracking
Wet H2S Damage (Blistering/HIC/SoHIC/SSC)\n
*Description of Damage*

This section describes four types of damage that result in blistering and/or cracking of carbon steel and low alloy steels in wet H2S environments.
• Hydrogen blisters may form as surface bulges on the ID, the OD or within the wall thickness of a pipe or vessel.
• The blister results from hydrogen atoms that form during the sulfide corrosion process on the surface of the steel, that diffuse into the steel, and collect at a discontinuity in the steel such as an inclusion or lamination.
• The hydrogen atoms combine to form hydrogen molecules and the pressure builds to the point where blister forms.
• Blistering results from hydrogen generated by corrosion, not hydrogen gas from the process stream.
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Hydrogen blistering and Hydrogen Induced Cracking damage.
Wet H2S Damage (Blistering/HIC/SOHIC/SSC)

Hydrogen Induced Cracking (HIC)

• Hydrogen blisters can form at many different depths from the surface of the steel, in the middle of the plate or near a weld. In some cases, neighboring or adjacent blisters that are at slightly different depths (planes) may develop cracks that link them together. Interconnecting cracks between the blisters often have a stair step appearance, and so HIC is sometimes referred to as “stepwise cracking”
Hydrogen Induced Cracking (HIC)
Cross-section of plate showing HIC damage in the shell of a trim cooler which had been cooling vapors off a HHPS vessel in a hydroprocessing unit.
Hydrogen Induced Cracking (HIC)
High magnification photomicrograph showing stepwise cracking nature of HIC damage.
Stress Oriented Hydrogen Induced Cracking (SOHIC)

- SOHIC is similar to HIC but is a potentially more damaging form of cracking which appears as arrays of cracks stacked on top of each other. The result is a through-thickness crack that is perpendicular to the surface and is driven by high levels of stress (residual or applied). They usually appear in the base metal adjacent to the weld heat affected zones where they initiate from HIC damage or other cracks or defects including sulfide stress cracks.
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Hydrogen blistering that is accompanied by SOHIC damage at the weld.
Wet H2S Damage (Blistering/HIC/SOHIC/SSC)
Sulfide Stress Corrosion Cracking (SSC)

• Sulfide Stress Cracking (SSC) is defined as cracking of metal under the combined action of tensile stress and corrosion in the presence of water and H2S.
• SSC is a form of hydrogen stress cracking resulting from absorption of atomic hydrogen that is produced by the sulfide corrosion process on the metal surface.
• SSC can initiate on the surface of steels in highly localized zones of high hardness in the weld metal and heat affected zones.
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Wet H2S Damage (Blistering/HIC/SOHIC/SSC)
Sulfide Stress Corrosion Cracking (SSC)

• Zones of high hardness can sometimes be found in weld cover passes and attachment welds which are not tempered (softened) by subsequent passes.
• PWHT is beneficial in reducing the hardness and residual stresses that render a steel susceptible to SSC.
• High strength steels are also susceptible to SSC but these are only used in limited applications in the refining industry.
• Some carbon steels contain residual elements that form hard areas in the heat affected zones that will not temper at normal stress relieving temperatures. Using preheat helps minimize these hardness problems.
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SCC Damage of a Hard Weld
Affected Materials

• Carbon steel and low alloy steels.

Affected Units or Equipment

• Blistering, HIC, SOHIC and SSC damage can occur throughout the refinery wherever there is a wet H2S environment present.

• In hydroprocessing units, typical locations include fractionator overhead drums, fractionation towers, absorber and stripper towers, compressor interstage separators and knockout drums and various heat exchangers, condensers, and coolers.
Wet H2S Damage (Blistering/HIC/SOHIC/SSC)

**Inspection and Monitoring**

- Inspection for wet H2S damage generally focuses on weld seams and nozzles.
- Cracks may be seen visually, crack detection is best performed with WFMT, EC, RT or ACFM techniques. Surface preparation is required for WFMT but not for ACFM. PT cannot find tight cracks and should not be depended on.
- UT techniques including external SWUT can be used. SWUT is especially useful for volumetric inspection and crack sizing.
- Grinding out the crack or removal by thermal arc gouging is a viable method of crack depth determination.
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Refinery Industry

Other Mechanisms
High Temperature Hydrogen Attack (HTHA)

Description of Damage

- High temperature hydrogen attack results from exposure to hydrogen at elevated temperatures and pressures. The hydrogen reacts with carbides in steel to form methane (CH4) which cannot diffuse through the steel.
- Methane pressure builds up, forming bubbles or cavities, micro fissures and fissures that may combine to form cracks.
- Failure can occur when the cracks reduce the load carrying ability of the pressure containing part.
Affected Materials

In order of increasing resistance:

1. Carbon steel
2. C-0.5Mo
3. Mn-0.5Mo
4. 1Cr-0.5Mo
5. 1.25Cr-0.5Mo
6. 2.25Cr-1Mo
7. 2.25Cr-1Mo-V
8. 3Cr-1Mo
9. 5Cr-0.5Mo and similar steels with variations in chemistry.
High Temperature Hydrogen Attack (HTHA)

**Affected Units**

- Hydroprocessing units, such as hydrotreaters (desulfurizers) and hydrocrackers, catalytic reformers, hydrogen producing units and hydrogen cleanup units, such as pressure swing absorption units, are all susceptible to HTHA.
- Boiler tubes in very high pressure steam service.
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**High Temperature Hydrogen Attack (HTHA)**

**Appearance of Damage**

- HTHA can be confirmed through the use of specialized techniques including metallographic analysis.
- In the early stages of HTHA, bubbles/cavities can be detected in samples by a scanning microscope.
- In later stages of damage, decarburization and/or fissures can be seen by examining samples under a microscope and may sometimes be seen by in-situ metallography.
- Cracking and fissuring are intergranular and occur adjacent to pearlite (iron carbide) areas in carbon steels.
- Some blistering may be visible to the naked eye.
High Temperature Hydrogen Attack (HTHA)

*Inspection and Monitoring*

- Damage may occur randomly in welds or weld heat affected zones as well as the base metal, making detection of HTHA extremely difficult.
- Ultrasonic techniques using a combination of velocity ratio and backscatter have been the most successful in finding fissuring and/or serious cracking.
- Visual inspection for blisters on the inside surface may indicate methane formation and potential HTHA.
- HTHA may occur without the formation of surface blisters.
- Other forms of inspection, including WFMT and RT, are severely limited in their ability to detect anything except damage where cracking has already developed.