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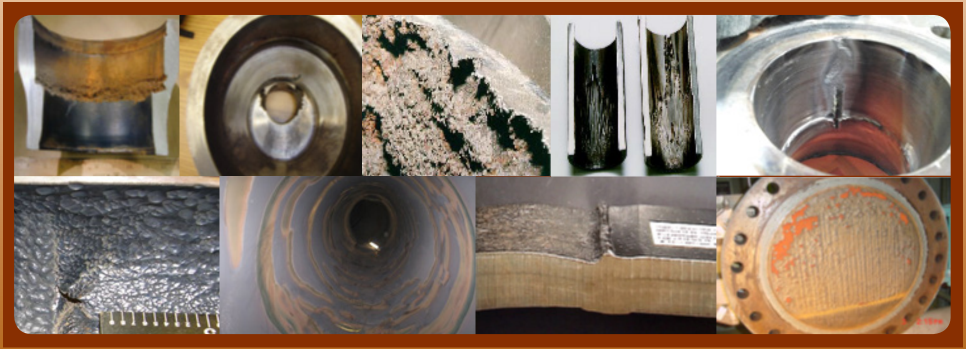
Field Guide: Flow-Accelerated Corrosion and Erosion

3002008124



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EPRI Project Manager
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All or a portion of the requirements of the EPRI Nuclear Quality Assurance Program apply to this product.

YES ✓ NO

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Altran US Corp

NOTE

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Abstract

Nuclear power plant systems that are susceptible to flow-accelerated corrosion (FAC) may also be susceptible to other forms of degradation such as erosion. Erosion is a mechanical degradation mechanism that may be caused by cavitation, flashing flow, liquid droplet impingement (LDI), solid particle erosion (SPE), or steam cutting. These erosive mechanisms have distinctive characteristics relative to the predominant forms of FAC: single-phase FAC, two-phase FAC, entrance/leading edge effect FAC, and low temperature FAC. This research was conducted to assist power plant engineers in correctly identifying the corrosion mechanism in degraded components of FAC-susceptible systems so that appropriate countermeasures may be taken. The report is provided in the format of a spiral-bound field guide to aid in its deployment during inspections. The field guide is organized by degradation mechanism and by plant system to aid the user in the application of the results. This field guide provides practical information describing the various wear mechanisms that are likely to affect plant systems and equipment using clear, concise language and helpful photographs. The field guide is expected to help utilities in accurately identifying the degradation mechanism for components in FAC-susceptible systems which will enable appropriate countermeasures and reduce the likelihood of future erosion-related leaks and ruptures.

Keywords

Cavitation Erosion
Entrance Effect/Leading Edge Effect
Flashing Flow Erosion
Liquid Droplet Impingement Erosion (LDI)
Low Temperature Flow Accelerated Corrosion (FAC)
Solid Particle Erosion (SPE)

Contents

1. Introduction to Wear Mechanisms

1.1 Introduction

This Field Guide addresses both Flow Accelerated Corrosion (FAC) and erosion degradation mechanisms. FAC is a well understood chemical degradation phenomena and can be characterized by different operating conditions. This field guide examines the following subcategories of FAC; single-phase FAC, two-phase FAC, low temperature FAC, and the FAC entrance/leading edge effect. With respect to mechanical degradation mechanisms, this field guide covers cavitation, flashing flow, liquid droplet impingement, solid particle erosion, and steam cutting/steam erosion.

FAC is a form of material degradation that, under certain flow, temperature, and chemistry conditions, results in thinning of the inside pipe wall in carbon steel piping and fittings. Erosion is a mechanical degradation that affects any piping material: carbon steels, stainless steels, and other alloys.

Most nuclear utilities worldwide have formal programs in place to protect against FAC. However, formal programs to address erosion degradation as a result of cavitation, flashing flow, liquid droplet impingement, solid particle erosion, and steam cutting erosion are much less common.

For each degradation mechanism studied, this field guide provides background information in tabular form as well as extensive photos. The background information quickly and effectively documents how the mechanism develops, the surface conditions associated with the mechanism, likely areas for the development of the degradation mechanism, mitigation options, any relevant notes, and references to the EPRI reference material. Examples of each mechanism in the form of photographs were compiled from EPRI technical reports, CHECWORKS™ Users Group (CHUG) conference materials, and operating experience provided by a survey of utility members. Bulleted relevant notes are included with each photograph.

Also included in the field guide is an appendix which provides a list of the operating experience examples cross referenced by plant system and degradation mechanism. This field guide provides program engineers, system engineers, and plant staff with a useful tool to assist in the identification of the degradation mechanisms across a variety of plant systems.

2. Cavitation Erosion

2.1 Cavitation Erosion Requirements

- Water system
- Pressure drop across valve or orifice with formation of bubbles downstream. Bubbles collapse when the downstream pressure is greater than vapor pressure. If the collapsing bubbles are near a solid surface, they can cause damage. This may occur when butterfly and gate valves are throttled to control flow.
- Affects components constructed of any material: carbon steel, carbon steel with trace chrome, chrome-moly, and stainless steel

Affected Surface Characteristics	Susceptible Locations	Mitigation Techniques	Additional Notes	References
• Pock-marked • Very rough and irregular • Cratered	• Pump impellers • Components downstream of butterfly valves, control valves, and orifices • Areas of significant pressure drop	• Modify valve style • Install anti-cavitation devices • Redesign of local area • Multi-hole orifice plates	• Pressure drop related mechanism • Noise and vibration are usually present • Non-linear damage rate	• 2, 3, 4, 5, 8, 9, 31

2.2 Cavitation Erosion Examples

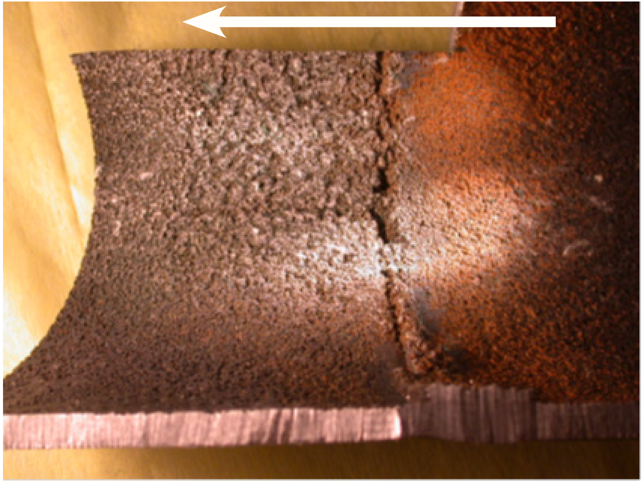


Figure 2-1 High Pressure Core Injection Flush Line to Torus (intrados) – Cavitation Erosion [10]

Items of Note

- Line tested periodically
- Fluid velocity ~126 feet/second (38.4 m/s) during full flow testing
- Total operating time of line ~200 hours
- Fluid flow is right to left
- Backing ring is gone between intrados of elbow and downstream pipe
- Leak in pipe wall
- Pipe surface is rough and pock-marked
- Low temperature testing
- Plant was placed in cold shutdown for repairs
- See next photo for extrados of elbow

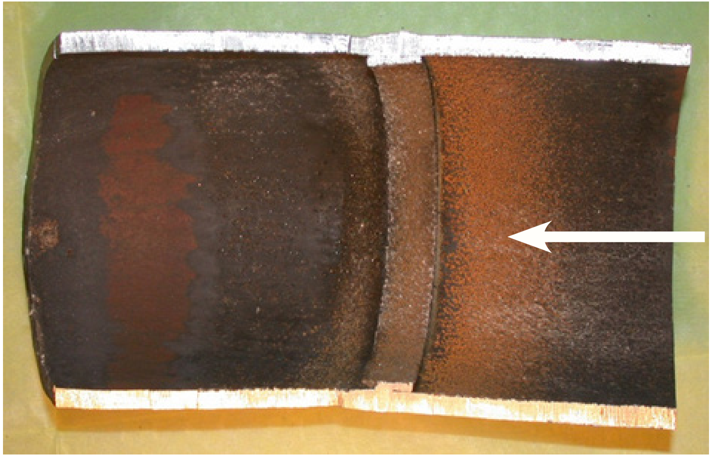


Figure 2-2 High Pressure Core Injection Flush Line to Torus (extrados) – Cavitation Erosion [10]

Items of Note

- Surface damage immediately downstream of backing ring on extrados of elbow
- Rough and pock-marked
- Note wall loss downstream of backing ring
- Fluid flow is right to left
- Full flow testing

Figure 2-3 Profile of Pipe Surface Damage from Cavitation Erosion [11]

Items of Note

- The center of the image shows the pock-marked appearance with jagged edges, while the left half of the image is out of focus due to pipe curvature.
- Surface is very rough
- Can appear porous

Figure 2-4 Fire Protection Downstream of Orifice - Cavitation Erosion [14]

Items of Note

- Piping downstream of orifice
- Surface is rough and cratered
- Installed in a line used for periodic testing
- Low temperature line
- Oxygen concentration is high
- Erosion locations in FAC systems: locations of extreme flashing flow, downstream of orifices, location of pressure drop
- Erosion locations in non-FAC systems: fire protection test lines, safety relief valve (SRV) tail pipes, throttling gate valves, stainless steel tank liners, chrome-moly components

Figure 2-5 Pipe Downstream of Control Valve - Cavitation Erosion [14]

Items of Note

- Pipe downstream of control valve
- Surface is rough, cratered, and irregular
- Significant pipe wall loss

Figure 2-6 Reducer Constructed of P22 Material on 8" (20.3 cm) Feedwater Recirculation Line - Cavitation Erosion [3, 18]

Items of Note

- Reducer downstream of an orifice
- Surface is rough and cratered
- Constructed of FAC-resistant ASTM A234 WP22 material
- Large pressure drop across orifice
- Future modification eliminated the reducer
- See next photograph for close-up of surface damage

Figure 2-7 Close-Up View of Degraded Surface of P22 Fitting - Cavitation Erosion [3, 18]

Items of Note

- Surface is degraded with craters into the fitting wall
- Very rough and irregular surface

Figure 2-8 Close-Up View of Degraded Surface of WP22 Fitting - Cavitation Erosion [3, 18]

Items of Note

- Closer view of degraded surface
- Surface has craters, extremely rough and porous looking

Figure 2-9 Control Valve Trim - Cavitation Erosion [8, 19]

Items of Note

- Valves are susceptible to erosion mechanisms
- Surface appears rough and pock-marked
- Significant loss of control valve trim metal
- Non-linear damage rate

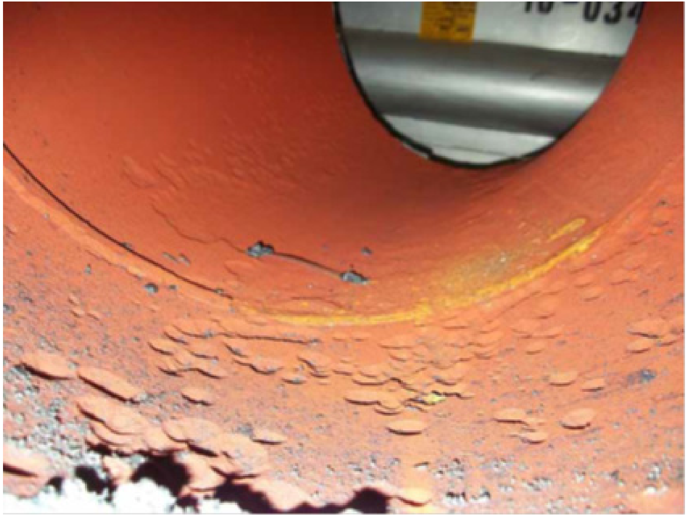


Figure 2-10 Heater Drains - Cavitation Erosion [20]

Items of Note

- Wear mechanism in feedwater heater cascading drain
- Operating temperature ~174°F (~79°C)
- 18″ (45.7 cm) nominal pipe size (NPS) carbon steel elbow
- 0.375″ (9.53 mm) nominal thickness
- Surface degradation has craters and pits

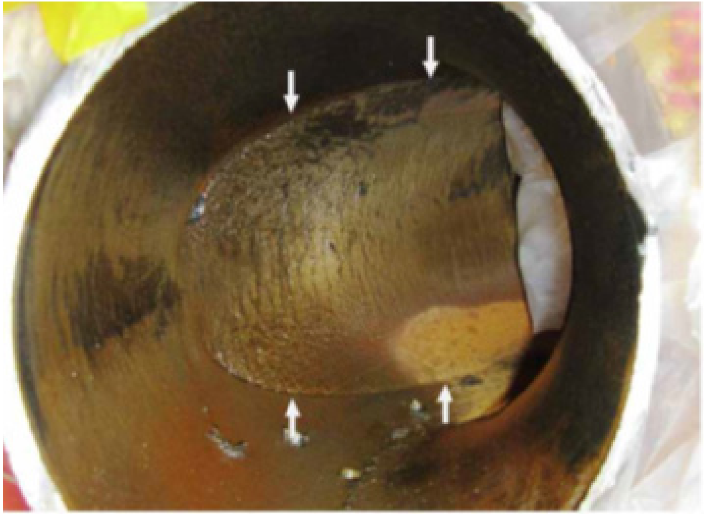


Figure 2-11 High Pressure Core Spray - Cavitation and Flow Curvature Erosion [3, 20]

Items of Note

- Flow-Curvature Cavitation
- Horizontal 6" (15.2 cm) NPS elbow in High Pressure Core Spray (HPCS) minimum flow line
- Operating temperature < 100°F (38°C)
- Elbow located downstream 17 feet (5.2 m) from orifice
- Pressure drop of ~1,300 psi (89.63 bar) across the orifice
- Generated a fluid velocity of ~270 feet/second (82.3 m/s)
- Three to four pin hole leaks in extrados of elbow
- Tested quarterly
- Next photograph provides close-up of surface degradation

Figure 2-12 High Pressure Core Spray – Close-Up of Degraded Surface - Cavitation and Flow Curvature Erosion [3, 20]

Items of Note

- Rough, pitted surface degradation
- Findings indicated cavitation and flow curvature erosion

Figure 2-13 Steam Generator Blowdown - Cavitation/Liquid Droplet Impingement Erosion [21]

Items of Note

- Low Capacity Steam Generator Blowdown System used for Start-Up
- FAC-resistant stainless steel SA403 WP304 1″ x 2″ (2.54 cm x 5.08 cm) expanding elbow downstream of manual angle valve
- Photograph shows previous weld overlay on the extrados of the expanding elbow
- Elbow replaced every five years
- Cavitation/Liquid Droplet Impingement surface degradation very rough and porous in the previously repaired area
- See Figure 2-14 for close-up view of surface damage

Figure 2-14 Steam Generator Blowdown – Close-Up of Degraded Surface - Cavitation/Liquid Droplet Impingement Erosion [21]

Items of Note

- Cavitation/Liquid Droplet Impingement surface degradation very rough and porous in the previously repaired area
- The smooth grooves surrounding the area of significant attack are indicative of solid particle erosion
- Large amounts of copper were detected in the area of heavy wall loss, which also suggests some contribution from solid particle erosion by particles in the blowdown stream

Figure 2-15 Heater Drains Downstream of Check Valve – Cavitation Erosion and Flow Accelerated Corrosion [22]

Items of Note

- 8″ (20.3 cm) NPS pipe section
- Upstream check valve disc nut was very loose/worn, allowing it to float in the flow stream
- Significant wall loss from Flow Accelerated Corrosion and Cavitation between the 4 o’clock and 6 o’clock positions
- Surface degradation shows single-phase scallop wear pattern (left side of pipe) and rough surfaces pits (right side)
- Internal surface of the check valve also indicated wear.

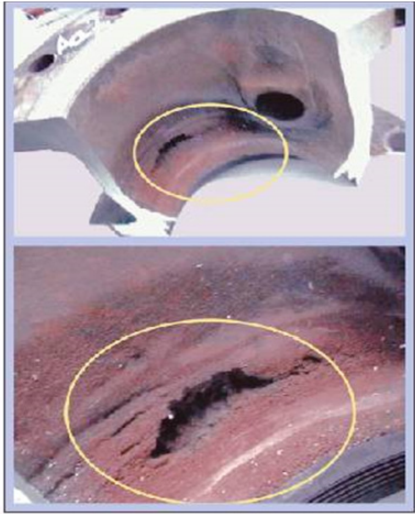


Figure 2-16 Body of Plug Valve - Cavitation Erosion [2, 3, 8]

Items of Note

- Damage in the body of a plug valve
- Very rough and irregular surface
- Damage is rapid and localized

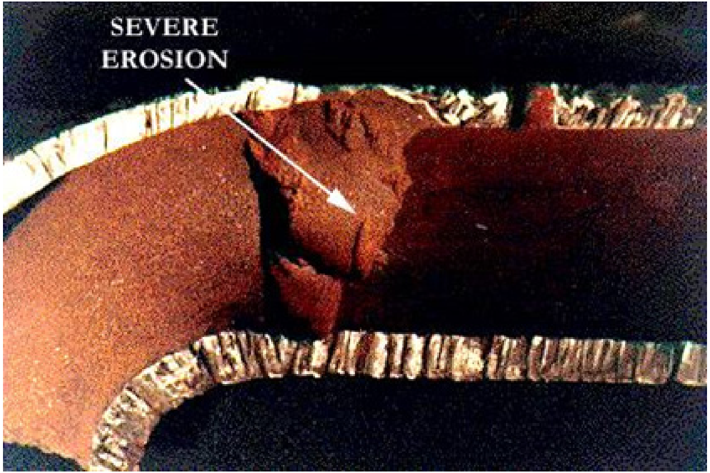


Figure 2-17 Elbow – Cavitation Erosion [3, 8]

Items of Note

- "Flow Curvature" or Re-circulation Cavitation in an elbow
- Typically occurs in elbows and tees installed in low pressure lines with turbulent flow
- A pressure gradient is developed as the fluid flow passes through a tee or an elbow. The pressure gradient generates different velocity streams which generate secondary flows. This results in bubbles impacting the inside surface of the component.
- Next photograph shows a tee exhibiting "Flow Curvature" or Re-circulation Cavitation

Figure 2-18 Tee and Downstream Pipe – Cavitation Erosion [3, 8]

Items of Note

- Flow directions shown by arrows on photograph
- Tee exhibiting “Flow Curvature” or Re-circulation Cavitation with elongated sweeping hole in sidewall of tee

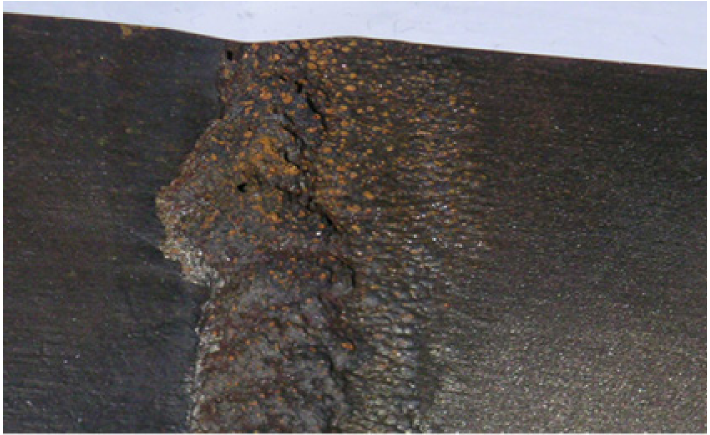


Figure 2-19 Feedwater Recirculation Line to Condenser – Cavitation Erosion [3, 8]

Items of Note

- Damage ~1 foot (30.48 cm) downstream from vendor supplied, stainless steel orifice
- Surface degradation is rough and irregular with pits
- Line operated only when the feedwater pump was in recirculation mode (less than 1% of plant operating time)

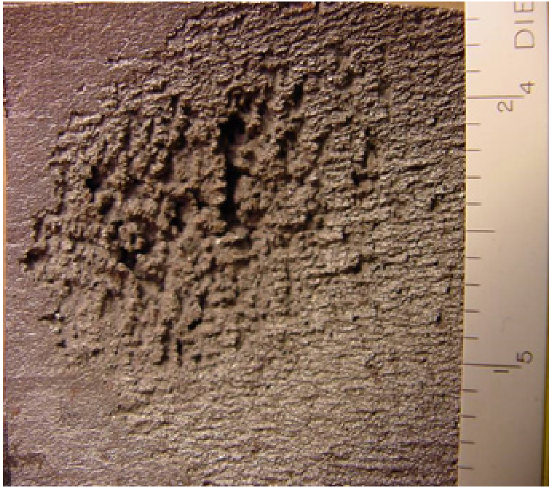


Figure 2-20 Moisture Separator Reheater Drain Line Cavitation Erosion [3, 8]

Items of Note

- FAC resistant A234 WP22 chrome-moly, short radius 90° elbow
- 6″ (15.24 cm) NPS
- 0.432″ (11 mm) nominal thickness
- Downstream of restriction device
- Surface degradation is rough, irregular, and pitted
- Led to pinhole leak after four years of service

Figure 2-21 Pump Impellor – Cavitation Erosion [2, 8]

Items of Note

- Localized damage on pump impellers
- Low pressure side of impeller vane tops and close tip clearance regions more likely to be damaged by cavitation.
- Items that can increase pump cavitation: piping modifications, increase operating temperature, fouled inlet strainers, increasing pump speed

Figure 2-22 Steam Generator Blowdown – Downstream of Throttled Gate Valve – Cavitation Erosion [5]

Items of Note

- Throttling of gate valve
- Cavitation erosion to valve body
- Rough, pitted, and irregular surface degradation
- Downstream pipe damage is shown in the next photograph

Figure 2-23 Steam Generator Blowdown – Downstream of Throttled Gate Valve – Cavitation Erosion [5]

Items of Note

- Cavitation erosion to pipe downstream of gate valve
- Upstream gate valve was throttled
- Pipe surface degradation lines up with location of valve damage
- Rough, pitted, and irregular surface degradation

Figure 2-24 Feedwater Regulating Valve Body – Cavitation Erosion [3]

Items of Note

- Cavitation erosion to valve body
- Surface degradation is rough and pitted
- Wall loss of 0.500 inches (12.7 mm)

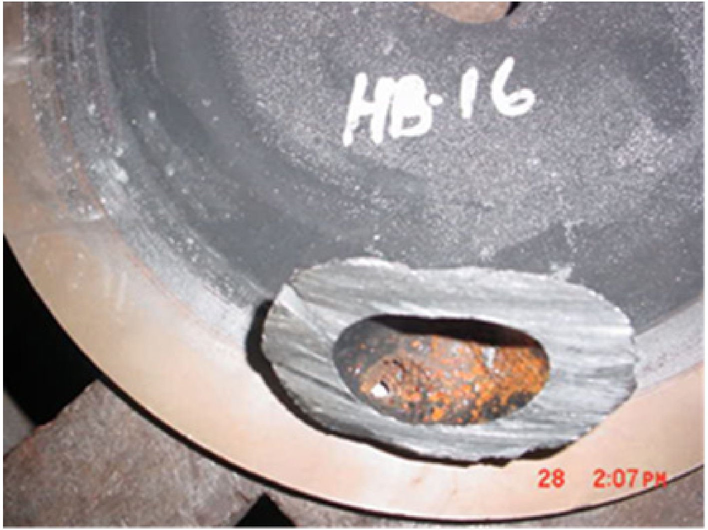


Figure 2-25 Condensate Pump Equalizer Line Downstream of Orifice – Cavitation Erosion [3]

Items of Note

- Cavitation damage
- Surface degradation is rough and pitted
- Damage downstream of flow orifice
- Operating temperature is 100°F (38°C)
- Damage after four years of service

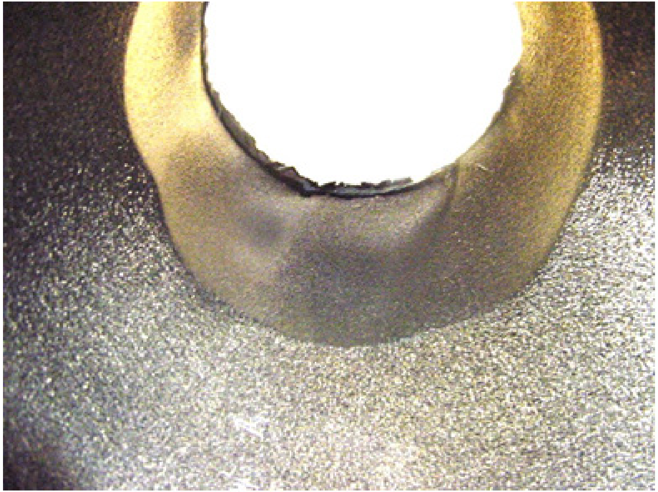


Figure 2-26 Moisture Separator Reheater Drains Downstream of Control Valve – Cavitation Erosion [3]

Items of Note

- Carbon steel expander 3″x 8″ (75 mm x 200 mm) downstream of control valve
- Pressure drop across the valve ~410 psi (28 bars)
- Surface is pitted
- Damage was found at three similar valve locations for each of the MSR's

Figure 2-27 Core Spray System Component – Cavitation Erosion (Photo Courtesy of Taiwan Power)

Items of Note

- Orifice is located upstream of the component
- Component shows wall loss between the 10 o'clock to 12 o'clock position
- Surface is very rough and irregular with several craters
- System tested every 92 days for pump reliability and flow test for a duration lasting < 2 hours
- System test temperature is between 90°F (32°C) to 110°F (43°C)
- Component was replaced with stainless steel material
- Sister unit had similar issues

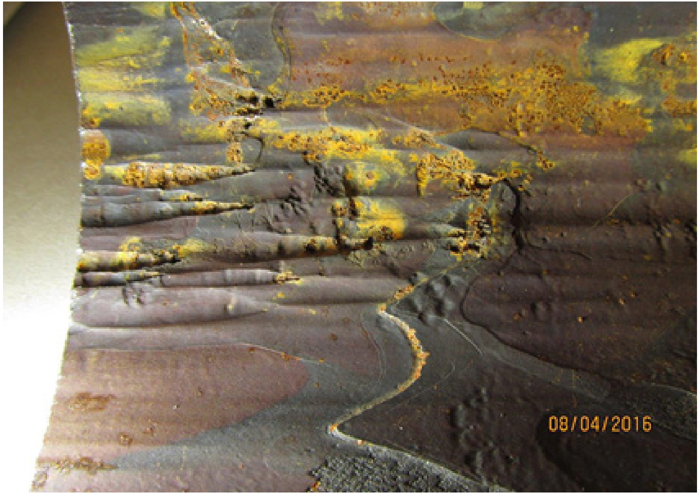


Figure 2-28 Condensate Cooling Water – Cavitation Erosion (Photo Courtesy of PG&E)

Items of Note

- Condensate cooling water from steam generator blowdown (SGBD) coolers
- Orifice is located upstream of the component
- Operating pressure is 150 psig (10.3 bar)
- Operating temperature is 135°F (57°C)
- Flow rate ~450 gpm (1,703 l/min)
- Surface is very rough and irregular with craters
- Carbon steel component was replaced with carbon steel material
- See related Figures 2-29 through 2-31

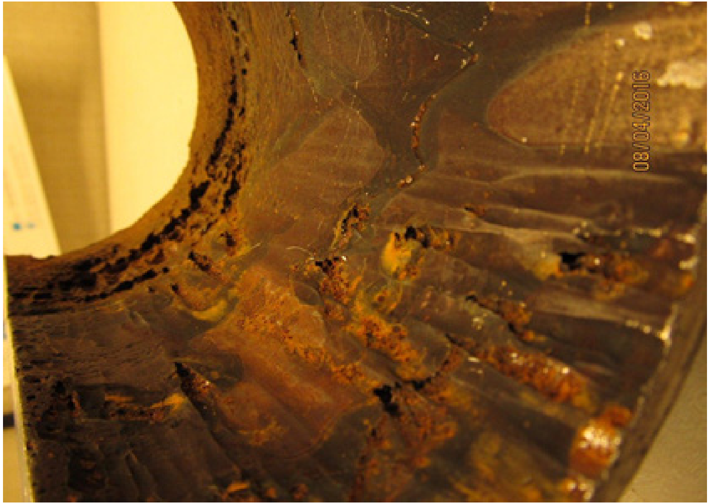


Figure 2-29 Condensate Cooling Water – Cavitation Erosion (Photo Courtesy of PG&E)

Items of Note

- Lower section of pipe
- Flow into picture
- Condensate cooling water from SGBD Coolers
- Orifice is located upstream of the component
- Operating pressure is 150 psig (10.3 bar)
- Operating temperature is 135°F (57°C)
- Flow rate ~450 gpm (1,703 l/m)
- Surface is very rough and irregular with craters
- Carbon steel component was replaced with carbon steel material
- See related Figures 2-28, 2-30, and 2-31

Figure 2-30 Condensate Cooling Water – Cavitation Erosion (Photo Courtesy of PG&E)

Items of Note

- Top section of pipe
- Flow is from the left
- Condensate cooling water from SGBD Coolers
- Orifice is located upstream of the component
- Operating pressure is 150 psig (10.3 bar)
- Operating temperature is 135°F (57°C)
- Flow rate ~450 gpm (1,703 l/m)
- Surface is very rough and irregular with craters
- Carbon steel component was replaced with carbon steel material
- See related Figures 2-28, 2-29, and 2-31

Figure 2-31 Condensate Cooling Water – Cavitation Erosion (Photo Courtesy of PG&E)

Items of Note

- Condensate cooling water from SGBD Coolers
- Orifice is located upstream of the component
- Operating pressure is 150 psig (10.3 bar)
- Operating temperature is 135°F (57°C)
- Flow rate ~450 gpm (1,703 l/m)
- Surface is very rough and irregular with craters
- Carbon steel component was replaced with carbon steel material
- See related Figures 2-28 through 2-30

3. Flashing Flow Erosion

3.1 Flashing Flow Erosion Requirements

- High pressure liquid flows through a valve or orifice to region of low pressure
- Two-phase mixture is developed downstream
- High velocity liquid portion creates damage
- Affects components constructed of any material: carbon steel, carbon steel with trace chrome, chrome-moly, and stainless steel

Affected Surface Characteristics	Susceptible Locations	Mitigation Techniques	Additional Notes	References
• Smooth • Polished • Fine sand blasted	• Downstream of control valves, including low-usage emergency lines to the condenser • Orifices • Condenser lines with valves leaking by • Malfunctioning steam traps	• Redesign of local area	• Pressure drop related mechanism • Noise and vibration are usually present • Non-linear damage rate • Mostly liquid with some steam downstream	• 2, 3, 4, 5, 8, 9, 31

3.2 Flashing Flow Erosion Example

Figure 3-1 Reactor Feedwater Pump Minimum Flow Line to Condenser – Flashing Flow Erosion [2, 3, 11]

Items of Note

- Liquid filled line upstream of orifice
- Large pressure drop across orifice with ~1,100 psi (75.84 bar) differential
- Surface appears smooth or polished
- Issues are still possible with multi-hole orifice plates

Smooth or Polished Surface Downstream of Orifice

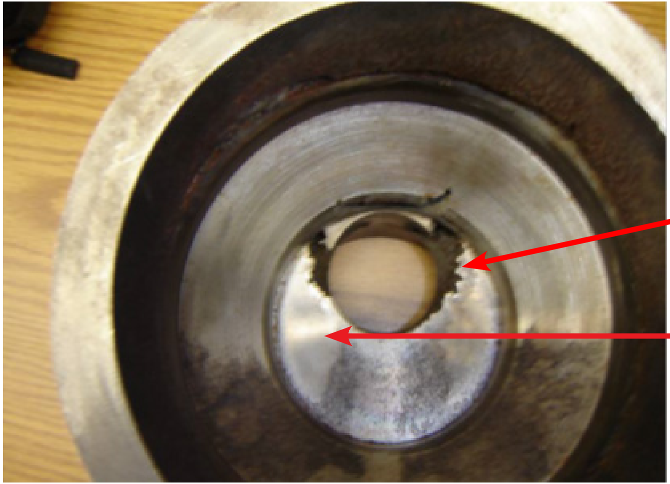
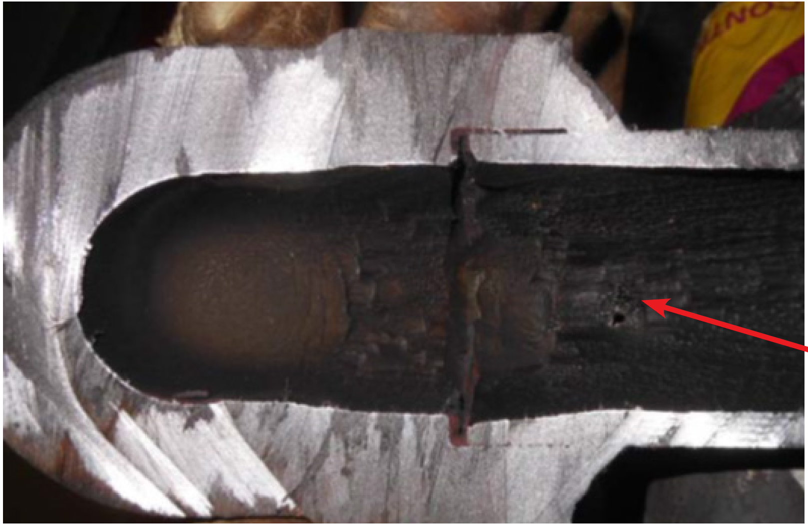


Figure 3-2 Feedwater Minimum Flow Recirculation Line – Flashing Flow Erosion [2, 9, 11]

Items of Note

- Liquid filled line upstream of orifice
- Large pressure drop across orifice
- Surface appears smooth or polished
- Rough edges possibly from Liquid Droplet Impingement



Hole in Chrome-Moly Socket-Welded Pipe

Figure 3-3 Reactor Feed Pump Turbine (RFPT) Main Steam Supply Drain Line – Flashing Flow Erosion [18]

Items of Note

- During an earlier outage, line replaced with FAC-resistant chrome-moly material
- Socket welded pipe now has hole
- Socket welded elbow has erosion wear and was replaced
- Lower section of socket welded joint shows wall loss

Figure 3-4 Heater Drain System – Flashing Flow Erosion (Photo Courtesy of Taiwan Power)

Items of Note

- Surface degradation appears both smooth in some areas and rough in other regions
- Combination of flashing flow erosion and possibly some cavitation erosion

4. Liquid Droplet Impingement Erosion

4.1 Liquid Droplet Impingement Erosion Requirements

- Two-phase systems experience a high pressure drop at an orifice or valve
- Steam and liquid droplets accelerate
- Elevated velocity (> approximately 300 ft/s (90 m/s)) liquid droplets impact and damage the metal surface
- Affects components constructed of any material: carbon steel, carbon steel with trace chrome, chrome-moly, and stainless steel

Affected Surface Characteristics	Susceptible Locations	Mitigation Techniques	Additional Notes	References
• Very rough and irregular • Cratered	• Downstream of control valves, including low-usage emergency lines to the condenser • Orifices • Lines to condenser with normally closed valves leaking by	• Redesign of the local area	• Pressure drop related mechanism • No noise or vibration • Non-linear damage rate • Mostly steam with some liquid downstream	• 2, 3, 4, 5, 8, 9, 31

4.2 Liquid Droplet Impingement Examples

Figure 4-1 Feedwater Recirculation Line to Condenser Downstream of Control Valve [11]

Items of Note

- Liquid Droplet impingement (LDI) on extrados of elbow
- Surface degradation typical of LDI wear mechanism
- Large pressure drop across the control valve
- Previously installed temporary enclosure to allow re-start operation until permanent modification is implemented

Figure 4-2 Magnified View of Surface Degradation from Liquid Droplet Impingement [11]

Items of Note

- Liquid Droplet Impingement wear mechanism surface degradation
- Surface very rough, irregular, and crater-like features

Figure 4-3 Heater Shell Surface Damage from Liquid Droplet Impingement [15]

Items of Note

- Plant equipment is susceptible to Liquid Droplet Impingement
- Surface degradation on Feedwater Heater Shell
- Rough surface
- Dominant mechanism for heater shells is flow–accelerated corrosion

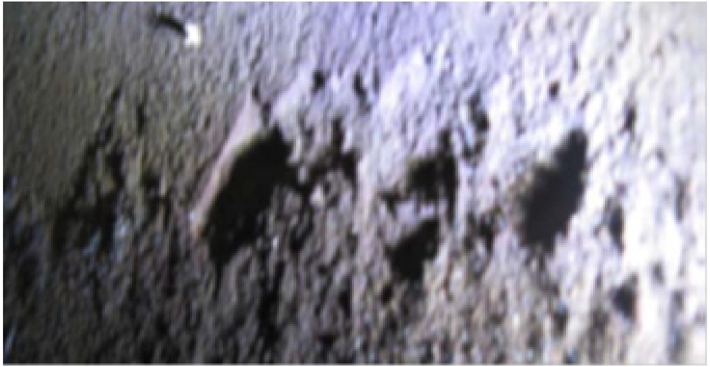


Figure 4-4 Bleed Steam Line Downstream of High Velocity Separators [17]

Items of Note

- Carbon steel pipe
- Steam quality ~87%
- Water droplet impact
- Degraded surface is rough and irregular

Figure 4-5 Feedwater Heater Operating Vent Line [18]

Items of Note

- Feedwater Heater Vent line downstream of orifice
- Red color indicates hematite
- Wall loss between 11 o'clock to the 12 o'clock position
- Liquid Droplet Impingement degradation along the pipe wall surface along the 12 o'clock position

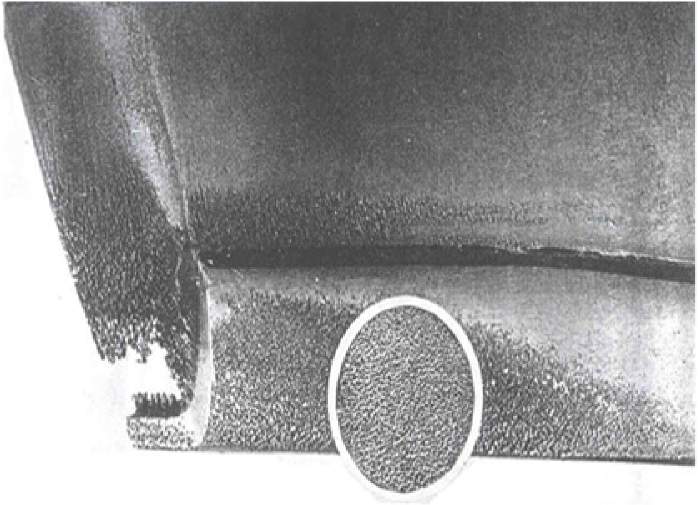


Figure 4-6 Eroded Turbine Blade – Impingement [2, 3, 18]

Items of Note

- Small pock marks/craters on blade surface
- Very rough
- Inset image is a laboratory test sample, demonstrating that LDI can be duplicated by lab testing

Figure 4-7 Liquid Droplet Impingement on High Pressure Coolant Injection Steam Line Drain Pot Valve Body and Internals [19]

Items of Note

- ASME Section III Class 2 line
- Two leaks in body of valve
- Liquid Droplet Impingement damage to valve body and internals
- Valve seat is missing as a result of the wear mechanism

Figure 4-8 Reactor Water Clean-Up (RWCU) Valve Body Leak and Internals LDI [20]

Items of Note

- ASME Section III Class 3 Valve
- Carbon steel body
- Leak in valve body just downstream of seat
- Liquid Droplet Impingement surface degradation (craters and rough surface) on bottom of valve body
- Valve disassembled
- Significant plug and seat damage identified
- Missing seat and base metal material not recovered

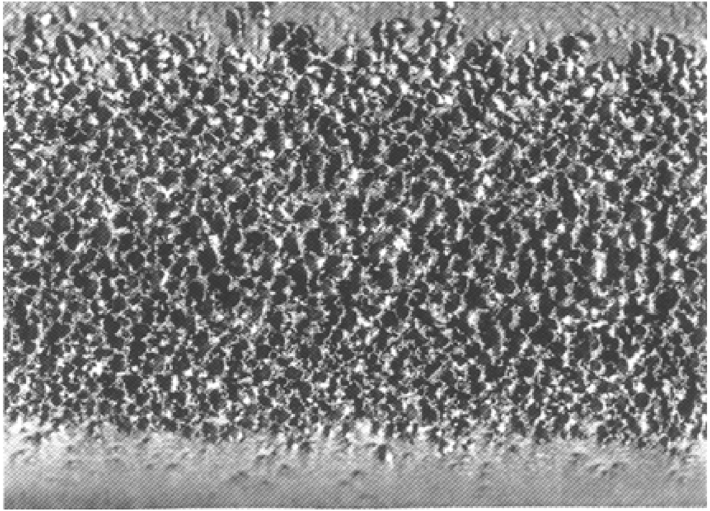


Figure 4-9 Damage to Copper Alloy Condenser Tube [3, 19, 20]

Items of Note

- Liquid Droplet Impingement on outside diameter surface
- FAC resistant copper alloy material
- Rough, crater-like surface degradation

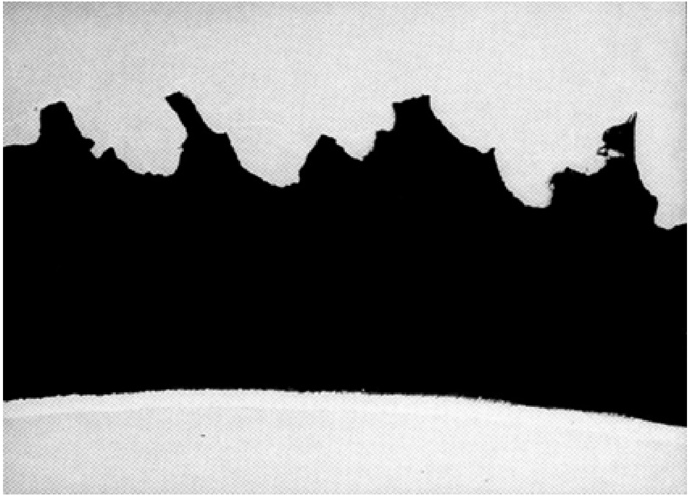


Figure 4-10 Profile of Copper Alloy Condenser Surface Degradation from Liquid Droplet Impingement [3, 8]

Items of Note

- Liquid Droplet Impingement surface degradation on outside diameter surface
- Profile view of copper alloy condenser tube
- Very rough, crater-like, irregular

Figure 4-11 Turbine Stop Valves and 'B' Moisture Separator Re-heater (MSR) cross-under piping drains to the Condenser [23]

Items of Note

- Drain line normally used during outage startup activities
- Liquid Droplet Impingement attributed to seat leakage from upstream isolation valves
- Fitting is a 2" x 4" (50.8 mm x 101.6 mm) tee
- Branch piping is constructed of chrome-moly material
- Main run pipe is constructed of carbon steel material
- Hole in tee directly opposite of the drain line connection is ~2" (50 mm) in diameter

Figure 4-12 Main Steam End Cap Liquid Droplet Impingement [25]

Items of Note

- End cap installed on long 30″ (76.2 cm) NPS Main Steam Header
- A234 WPB carbon steel material
- Liquid Droplet Impingement
- Deep craters on degraded surface are approximately 0.500″ (12.7 mm) to 0.650″ (16.5 mm) deep
- End cap to be replaced at a later date using super duplex stainless steel

Figure 4-13 Piping Downstream of a Normally Closed Bleed Line Valve which was Leaking By [3, 8]

Items of Note

- Leak in Low Pressure Bleed Line from Liquid Droplet Impingement
- Line is normally closed
- Surface around hole is jagged, rough, and crater-like

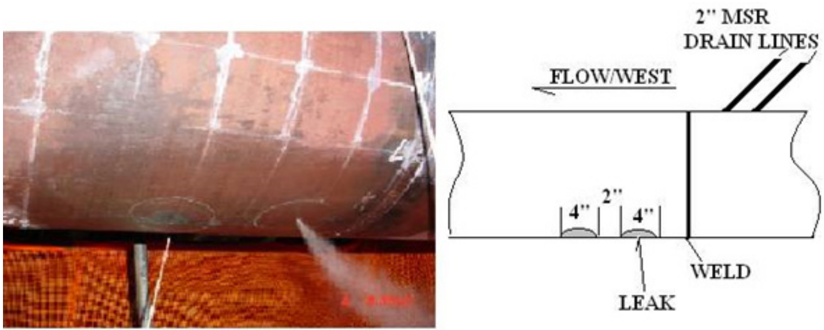


Figure 4-14 Through Wall Leak in Chrome-Moly Extraction Steam Header Diagonally Opposite to MSR Drain Lines [3, 8]

Items of Note

- FAC resistant chrome-moly material
- Two leaks directly opposite the drain line connections
- Liquid Droplet Impingement from water droplets impacting header pipe wall

Figure 4-15 MSR Vent Line Liquid Droplet Impingement [3]

Items of Note

- Liquid Droplet Impingement damage located downstream of orifice
- Moisture Separator Reheater Vent Line
- 6″ (15.2 cm) NPS, carbon steel material
- Rough and small craters located in degraded areas

Figure 4-16 Extraction Steam Line Combinations of LDI and FAC [3]

Items of Note

- Combination of (rough) liquid droplet impingement and two-phase flow accelerated corrosion

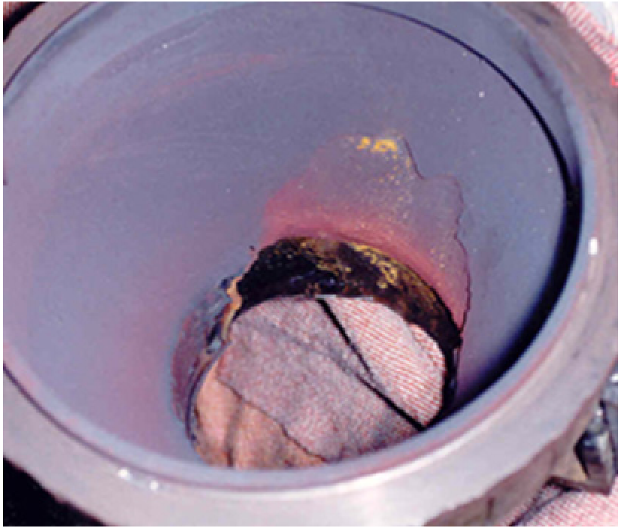


Figure 4-17 Moisture Separator Drain Tank Line LDI Downstream of Control Valve [3]

Items of Note

- Moisture separator drain tank normal drain to low pressure feedwater heater
- 4″ x 8″ (10.2 cm x 20.3 cm) Expander downstream of control valve
- Liquid Droplet Impingement surface degradation immediately downstream of weld
- Edges of degraded areas are rough and jagged

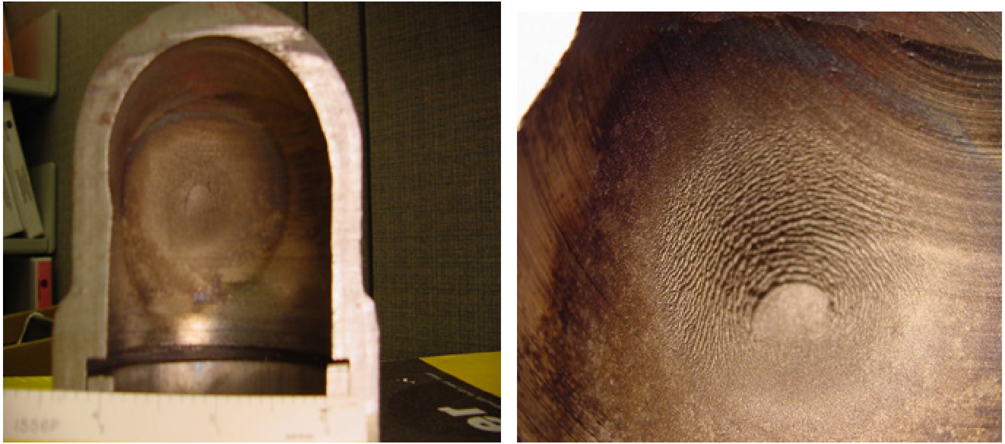


Figure 4-18 Feedwater Heater Vent Line P22 Socket Welded Elbow Downstream of an Orifice [3]

Items of Note

- Through-wall leak in the extrados of the elbow
- Liquid Droplet Impingement wear mechanism
- Socket welded elbow constructed of FAC-resistant material
- Elbow installed downstream of restriction orifice

Figure 4-19 Low Pressure Extraction Steam Line Degradation from Liquid Droplet Impingement [26]

Items of Note

- Cutout section of 24″ (61.0 cm) NPS Tee in Low Pressure Extraction Steam line
- Surface degradation is rough with crater-like excavations
- Liquid Droplet Impingement wear mechanism

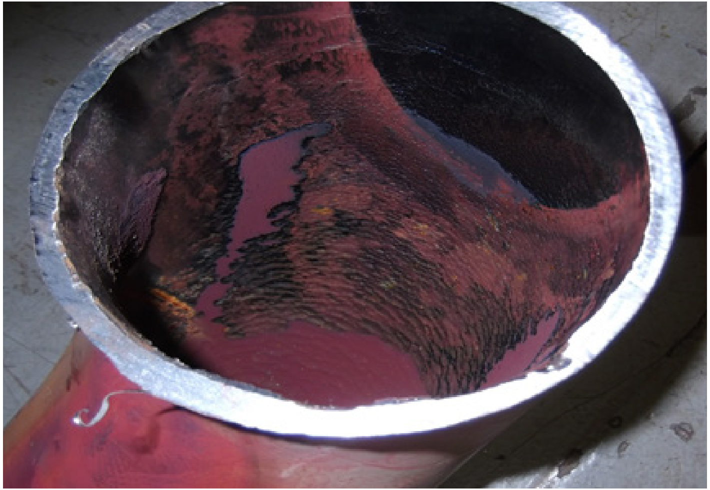


Figure 4-20 Miscellaneous Equipment Drain Header Elbow Degradation from Liquid Droplet Impingement (Photo Courtesy of TVA)

Items of Note

- Surface degradation at the left side (9 o'clock position) and lower right quadrant of cut elbow is cratered and irregular
- Internal surface is very rough, cratered, and irregular

Figure 4-21 Low Pressure Extraction Steam Line to Condenser Degradation from Liquid Droplet Impingement (Photo Courtesy of Entergy)

Items of Note

- Cutout section of 36″ (91.4 cm) NPS Tee in Low Pressure Extraction Steam line
- Surface degradation is rough with crater-like excavations
- Low quality two-phase steam

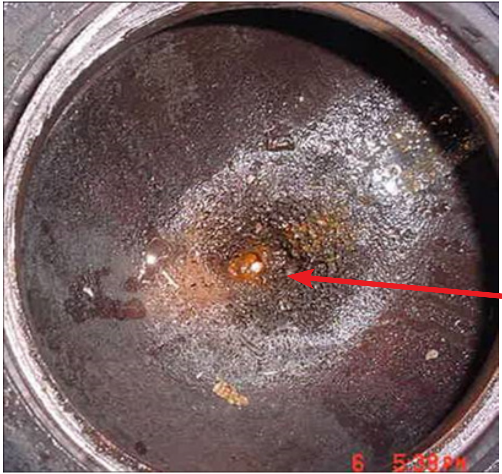


Figure 4-22 Seat Leakage in Dump Valve Resulted in Hole in Valve Body – Cavitation Erosion [2, 8]

Items of Note

- Normally closed valve
- Valve had seat leakage
- Hole in bottom of valve seat
- Surface is rough, pitted, and irregular

Hole in Valve Seat of Normally Closed Valve

5. Solid Particle Erosion

5.1 Solid Particle Erosion Requirements

- Single and two-phase systems with solid particles carried in the fluid stream
- Can occur at low velocities
- Affects components (pipe, valves, pumps, etc.) constructed of any material

Affected Surface Characteristics	Susceptible Locations	Mitigation Techniques	Additional Notes	References
• Varies depending on size of particle, shape, hardness of particle, velocity, and angle of incidence at impact to surface	• Pipes, elbows, valves, equipment • Steam turbines	• Replace with stainless steel material which may only slow down the rate of damage • Installation of filters, strainers, or separators for removal of particles from fluid stream	• No Noise or Vibration • Linear damage rate • Raw water systems • Steam Generator Blowdown system	• 2, 3, 4, 5, 8, 9

5.2 Solid Particle Examples

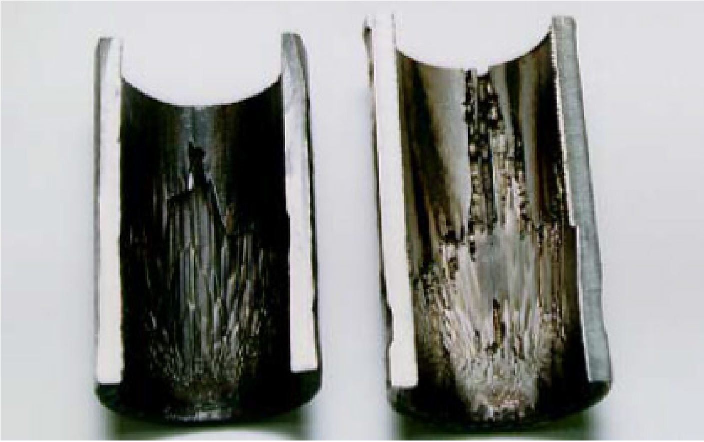


Figure 5-1 Carbon Steel and Stainless Pipe – Solid Particle Erosion [11]

Items of Note

- Carbon steel pipe component on left
- Stainless steel pipe component on right
- Deep grooves on both surfaces along flow path
- No benefit in substituting FAC resistant material
- Side view of stainless steel pipe provides an indication of the approximate depth of the grooves

Figure 5-2 Feedwater Heater Shell – Solid Particle Erosion [15]

Items of Note

- Inside surface of Feedwater Heater Shell
- Small channels on the surface
- Surface is also rough

Figure 5-3 Boiler Blowdown Valve Body – Solid Particle Erosion [3, 19]

Items of Note

- Solid Particle Erosion damage to valve body
- Grooves on surface
- Side view provides an indication as to the approximate depth of the grooves into the valve body

Figure 5-4 Boiler Blowdown Valve Body – Solid Particle Erosion [3, 20]

Items of Note

- Solid Particle Erosion damage to valve body
- Grooves on surface
- Side view provides an indication as to the approximate depth of the grooves into the valve body

Figure 5-5 Steam Generator Blowdown Valve Internal – Solid Particle Erosion [2, 3, 8]

Items of Note

- Solid Particle Erosion damage to valve internal stem
- Grooves on the surface of the stem
- Large pieces of the stem material have been removed

Figure 5-6 Turbine Blade Damage – Solid Particle Erosion [8]

Items of Note

- High velocity impact to turbine blade
- Blade surface is rough and shiny

Figure 5-7 Steam Generator Blowdown System – Solid Particle Erosion [3, 8]

Items of Note

- Solid Particle Erosion downstream of stainless steel angle control valve in Steam Generator Blowdown System
- Pipe is lined with P11 material
- Damage appears as a rippled surface due to small impingment angle

6. Steam Cutting/Steam Erosion

6.1 Steam Cutting/Steam Erosion Requirements

- Steam systems that are not superheated
- Affects mainly carbon steel components

Affected Surface Characteristics	Susceptible Locations	Mitigation Techniques	Additional Notes	References
• Rough • Gouged/Groove	• Steam traps • Heater shells • Components downstream of normally closed valves with leak-by related issues	• Replace valve internals • Monitor normally closed boundary valves and traps though Thermography Performance Program	• Seen in steam leaks through failed gaskets at flanged connections	• 8, 15, 16

6.2 Steam Cutting/Steam Erosion Examples

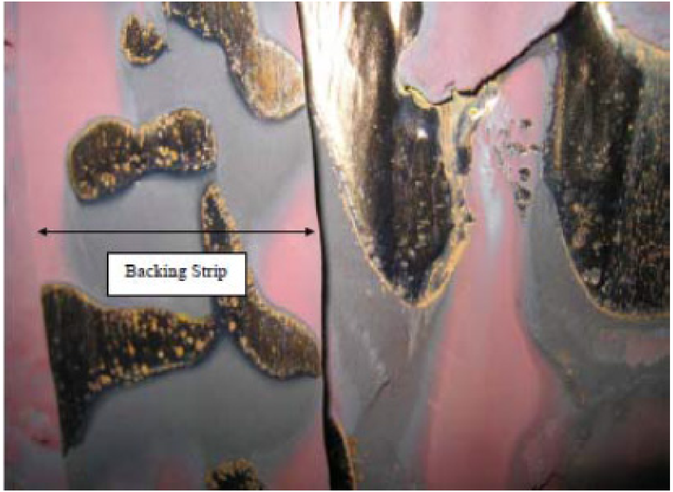


Figure 6-1 Feedwater Heater Shell – Steam Cutting Erosion [15]

Items of Note

- Localized section of Feedwater Heater Shell
- Backing strip installed when a section of heater shell was previously replaced
- Grey areas show lack of protective hematite
- Steam Cutting/Erosion partially eliminated the backing strip in the vicinity of the nozzle
- Two-phase FAC was also determined to be present on the heater shell

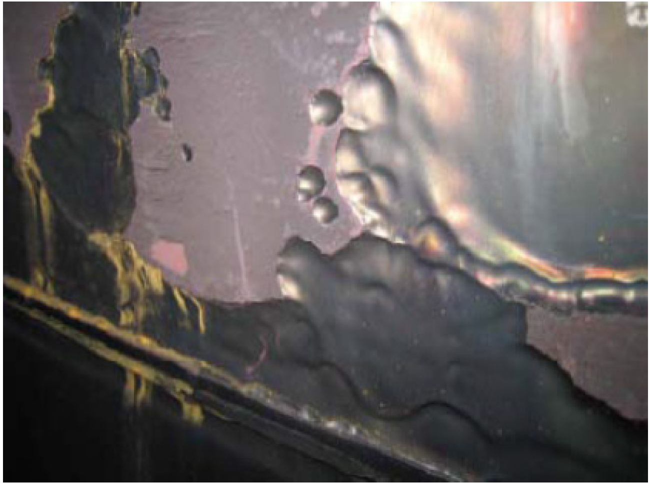


Figure 6-2 Feedwater Heater Shell – Steam Cutting Erosion [16]

Items of Note

- Steam Cutting/Erosion on Feedwater Heater Shell
- Smooth shiny surface
- Hemispherical pits are created by the steam eroding the metal surface
- With time the pits will connect and form a trough

Figure 6-3 Pipe Flange – Steam Cutting Erosion [8]

Items of Note

- Sliced through the entire thickness of the flange
- High velocity steam created narrow path in the flange

Figure 6-4 Steam Trap Body – Steam Cutting Erosion [8]

Items of Note

- Steam jet eroded the steam trap body in the 12 o'clock position
- Steam trap may not have been functioning normally

Figure 6-5 Stainless Steel Expander – Steam Cutting Erosion (Photo Courtesy of TVA)

Items of Note

- Steam jet eroded the stainless steel expander
- Located downstream of normally closed moisture separator emergency drain control valve
- The damage occurred within a five (5) month period

7. Single Phase Flow Accelerated Corrosion

7.1 Single Phase Flow Accelerated Corrosion Requirements

- Water systems operating at 200°F or higher
- Affects carbon steel components with less than 0.1% chromium content

Affected Surface Characteristics	Susceptible Locations	Mitigation Techniques	Additional Notes	References
• Scalloped • Fish scales • Orange peel • Interlocking horse-shoe pits	• Pipes, elbows, tees • Components downstream of a valve (check, angle, control, gate) • Equipment inlet and exit nozzles • Equipment internals	• Replace component with FAC resistant material • Modify plant chemistry (higher pH, dissolved oxygen)	• None	• 1, 7, 9, 26, 32

7.2 Single Phase Flow Accelerated Corrosion Examples

Figure 7-1 Surface Damage – Single Phase Flow Accelerated Corrosion [11]

Items of Note

- Single-phase FAC described as:
  - "Orange Peel"
  - "Scalloped"
  - "Fish Scale"
  - "Interlocking Horseshoe Pits"

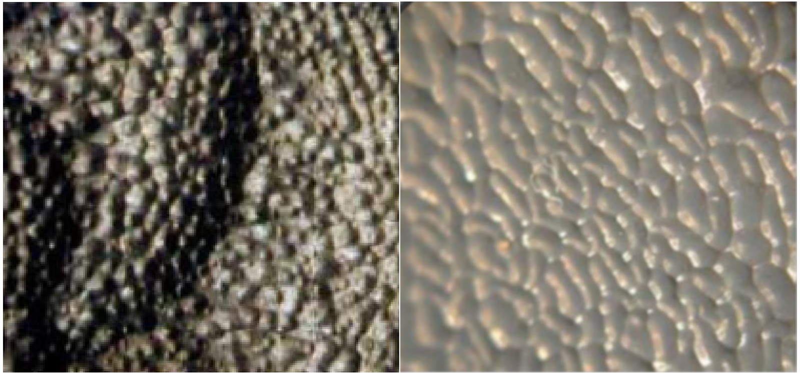


Figure 7-2 Surface Damage – Single Phase Flow Accelerated Corrosion [9]

Items of Note

- Low temperature FAC is displayed in the photo on the left.
- Single-phase FAC is on the right
- Low Temperature FAC shows undulating surface with rounded bumps

Figure 7-3 Socket Welded Connection Downstream of Normally Closed Valve – Single Phase Flow Accelerated Corrosion [13]

Items of Note

- Socket welded elbow and pipe downstream of normally closed valve
- Valve leaking by in drain line
- Surface damage appears scalloped shape
- Erosion mechanism may also be present
- Wear on back side of socket welded elbow
- Wear at socket welded elbow-to-pipe connection

Figure 7-4 Reactor Water Clean Up – Single Phase Flow Accelerated Corrosion [20]

Items of Note

- Heat exchanger interconnecting piping
- Carbon steel SA234/WPB material
- Operating temperature 230°F (110°C); Operating pressure 1253 psi (86.39 bar)
- Fluid velocity 11.6 feet/second (3.5 m/s)
- Oxygen concentration is 2.50 PPB
- Surface degradation appears scalloped

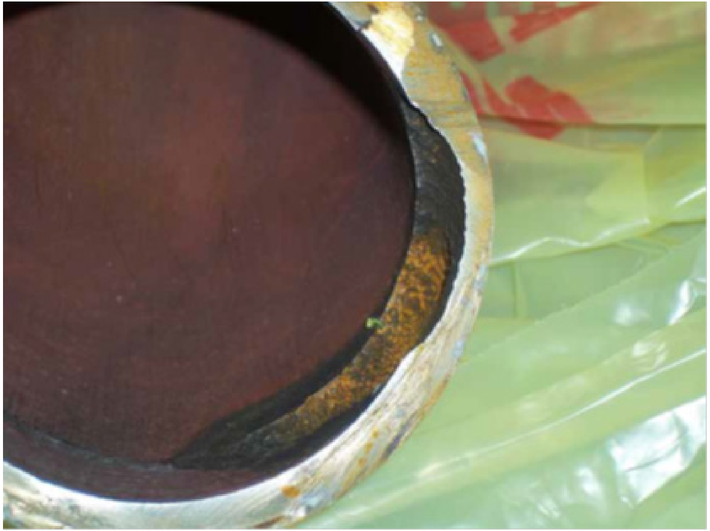


Figure 7-5 Reactor Water Clean Up – Close Up View of Wall Loss - Single Phase Flow Accelerated Corrosion [20]

Items of Note

- Significant single-phase FAC wall loss
- Operating temperature 230°F (110°C)
- Operating pressure 1253 psi (86.39 bar)
- Fluid velocity = 11.6 feet/second (3.5 m/s)

Figure 7-6 Condensate Line Downstream of Flow Measuring Orifice – Mihama Unit 3 Single-Phase Flow Accelerated Corrosion [20]

Items of Note

- Condensate line catastrophic failure immediately downstream of orifice
- 22″ NPS (560 mm)
- Nominal thickness of 0.394″ (10 mm)
- Operating temperature 284°F (140°C);
- Operating pressure 135 psia (0.93MPa)
- Fluid velocity = 6.4 feet/second (2 m/s)
- Five fatalities

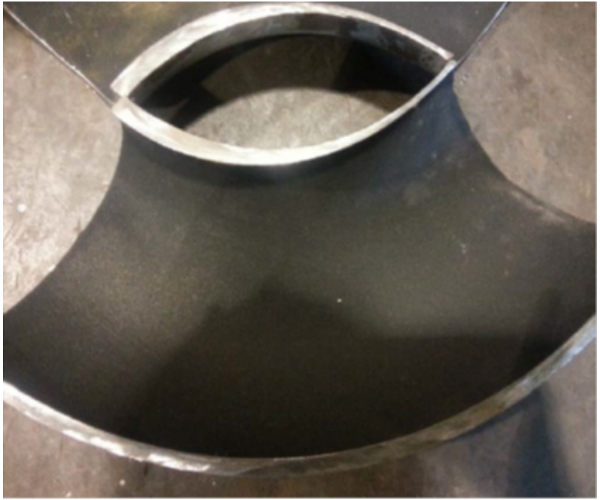


Figure 7-7 Elbow in Main Feedwater Bypass Line Downstream of Flow Control Valve – Single Phase Flow Accelerated Corrosion [22]

Items of Note

- Single-phase FAC Wear on intrados of 6″ (15.2 cm) NPS elbow; 0.562″ (14.3 mm) nominal thickness
- Carbon steel A234/WPB material
- Operating Temperature 427°F (219°C)
- Operating Pressure 864 psig (59.57 bar)
- Fluid velocity = 5.68 to ~8.68 meters/second
- Localized wear attributed to a weld bead defect and an increase of the inside diameter going from the upstream component to the elbow

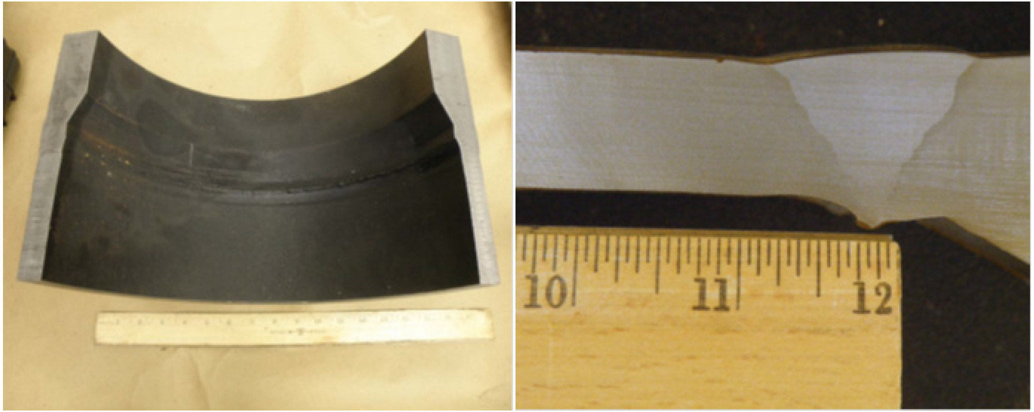


Figure 7-8 Pipe Downstream of Feedwater Regulating Valve – Single Phase Flow Accelerated Corrosion [23]

Items of Note

- Upstream reducers FAC resistant material
- Pipe is carbon steel
- Laboratory findings of pipe show single-phase FAC with "orange peel" morphology

Figure 7-9 Socket Welded Fitting in Drain Line – Single Phase Flow Accelerated Corrosion [23]

Items of Note

- Single-phase wear at several locations
- Socket welded coupling connection wear
- Pipe wall thinning immediately downstream of the coupling connection
- Wall thinning on extrados of elbow

Figure 7-10 Reactor Water Clean Up Heat Exchanger Nozzle and Pipe – Single Phase Flow Accelerated Corrosion [25]

Items of Note

- RWCU interconnecting piping
- Single-phase FAC damage
- Additional influences expected based on rough and crater-like surface damage

Figure 7-11 Carbon Steel Feedwater Elbow Downstream of Carbon Steel Pipe with Trace Chrome – Single Phase Flow Accelerated Corrosion [25]

Items of Note

- Upstream pipe contains 0.08% trace chrome
- Weld and elbow contain no trace chrome
- Single-phase FAC in 16″ (40.6 cm) NPS carbon steel elbow
- "Entrance Effect" may also be present

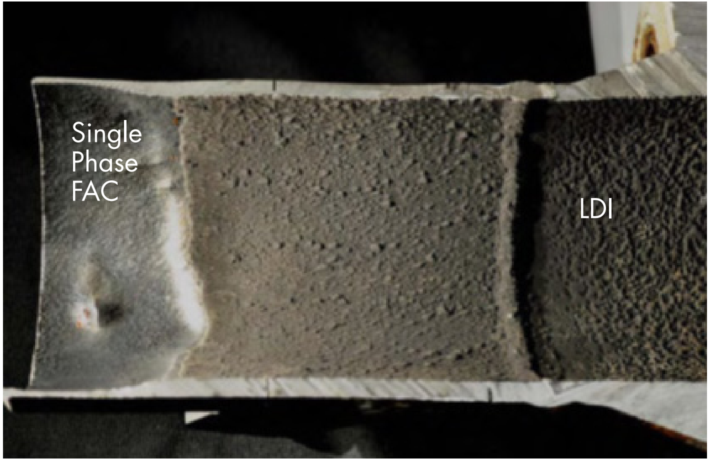


Figure 7-12 Pipe with Two Damage Mechanisms – Liquid Droplet Impingement Erosion and Single Phase Flow Accelerated Corrosion [25]

Items of Note

- Liquid Droplet Impingement erosion on pipe immediately downstream of orifice
- Surface pits were shallow and smooth
- Single-phase FAC at location of through wall leak
- Magnified surface showed scalloped features

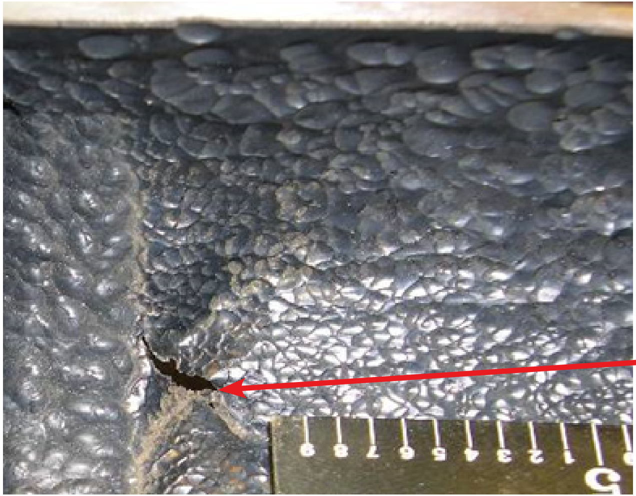


Figure 7-13 Pipe Damage – Single Phase Flow Accelerated Corrosion [8]

Items of Note

- Single-phase FAC
- "Scalloped" surface
- Through-wall leak at lower left in photograph

Figure 7-14 Damaged Pipe Wall at Thermowells – Single Phase Flow Accelerated Corrosion [7]

Items of Note

- Single-phase FAC
- Thermowells protrude into fluid stream
- Local velocities increase around and downstream of the obstructions
- Scalloped surface

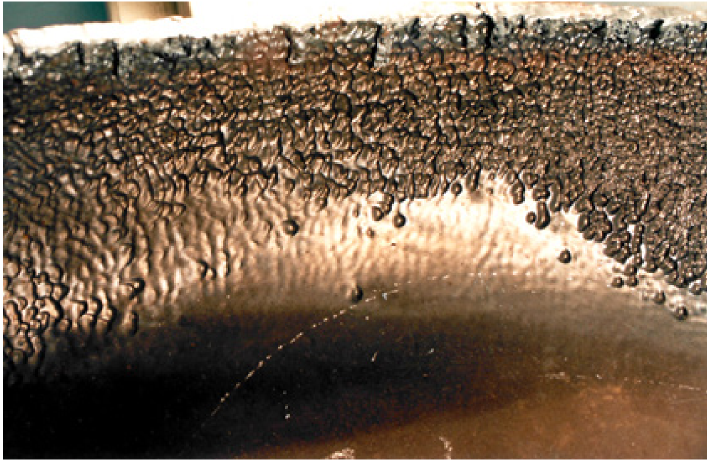


Figure 7-15 Moisture Separator Reheater Drain Line – Single Phase Flow Accelerated Corrosion [26]

Items of Note

- Scalloped surface on extrados of elbow

8. Two Phase Flow Accelerated Corrosion

8.1 Two Phase Flow Accelerated Corrosion Requirements

- Steam systems that are not superheated
- Affects carbon steel components with < 0.1% chromium content

Affected Surface Characteristics	Susceptible Locations	Mitigation Techniques	Additional Notes	References
• Tiger striping • Plateaus and valleys	• Pipes, elbows, tees • Components downstream valves (check, angle, control, gate) • Equipment inlet and exit nozzles • Equipment internals	• Replace component with FAC-resistant material • Modify plant chemistry (higher pH, dissolved oxygen)	• None	• 1, 7, 9, 26, 32

8.2 Two Phase Flow-Accelerated Corrosion Examples

Figure 8-1 Pipe Damage – Two Phase Flow Accelerated Corrosion [11]

Items of Note

- Two-phase FAC "Tiger Striping" in piping component
- Plateaus and valleys

Figure 8-2 Turbine Crossunder Pipe Damage – Two Phase Flow Accelerated Corrosion [11]

Items of Note

- Crossunder piping
- Two-phase FAC "Tiger Striping"
- Swirling of steam and water vapor as it travels down the flow path
- Plateaus and valleys

Figure 8-3 Pipe Damage – Two Phase Flow Accelerated Corrosion [12]

Items of Note

- 9th Stage Extraction Steam
- Two-phase FAC "Tiger Striping"
- Plateaus and valleys
- Low Pressure Extraction Steam line
- Line located inside condenser
- Line had through wall leak
- Surface degradation was noted on outside surface of pipe

Figure 8-4 Feedwater Heater Shell Wear – Two Phase Flow Accelerated Corrosion [14]

Items of Note

- Two-phase FAC "Tiger Striping" in heater shell
- Plateaus and valleys

Figure 8-5 Feedwater Heater Shell – Two Phase Flow Accelerated Corrosion [15]

Items of Note

- Two-phase FAC "Tiger Striping" in heater shell
- Plateaus and valleys

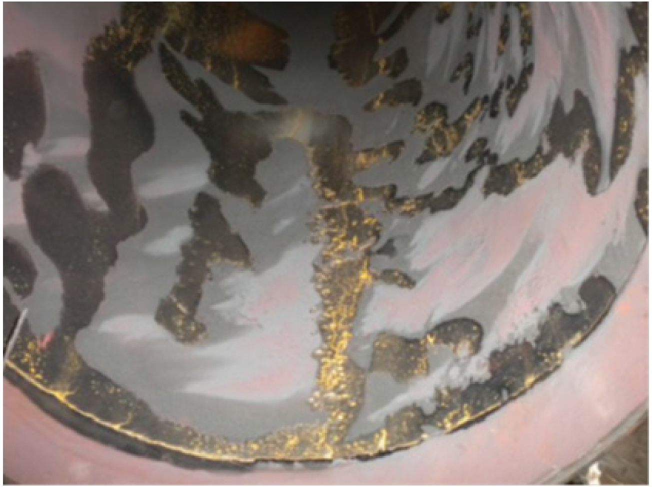


Figure 8-6 Extraction Steam Equalizing Header Pipe Leak – Two Phase Flow Accelerated Corrosion [17]

Items of Note

- Thru wall leak in Extraction Steam Equalizing line
- 16″ (40.6 cm) NPS
- 0.375″ (9.53 mm) nominal thickness
- Two-phase FAC “Tiger Striping”
- Piping replaced with FAC-resistant chrome-moly piping
- Sister units had indicated wear

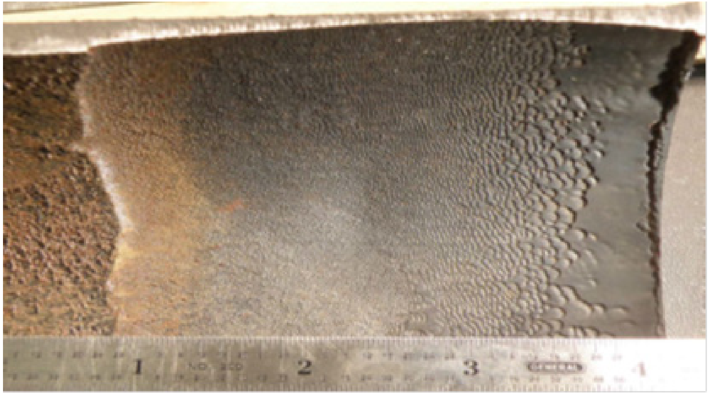


Figure 8-7 Steam Supply to Gland Steam – Two Phase Flow Accelerated Corrosion and Liquid Droplet Impingement Erosion [17]

Items of Note

- 2nd Point Extraction Steam: 210 psig (1.448 MPa), 394°F (201°C), Quality = 0.89 supply to Gland Steam
- Pipe extension located downstream from tee main
- Top section of pipe wall significantly thinned
- Multiple wear mechanisms present: two-phase FAC and Liquid Droplet Impingement

Figure 8-8 Low Pressure Feedwater Heater – Two Phase Flow Accelerated Corrosion [18]

Items of Note

- Low Pressure Feedwater Heater Shell is in the Condenser
- Two-phase FAC "Tiger Striping"

Figure 8-9 Extraction Steam Wear in Non-Return Valve Body – Two Phase Flow Accelerated Corrosion [21]

Items of Note

- 2nd Point Extraction Steam: 43 feet/s (13 m/s); 225 psig (1.55 Mpa); 397°F (203°C); Q = 0.905
- Non-Return Valve body is A216 WCB
- Two-phase FAC on check valve body
- Valve was previously replaced
- Upstream piping is P22 chrome-moly piping

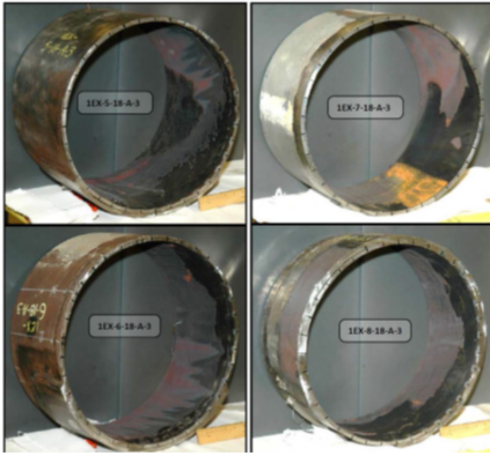


Figure 8-10 Low Pressure Extraction Steam Pipe as Viewed from Nozzle Ends – Two Phase Flow Accelerated Corrosion [22]

Items of Note

- Four separate Low Pressure Extraction Steam lines
- Material of construction is SA106B
- Operating conditions 79 psia (5.45 bar) at 315°F (157°C)
- 18″ (45.7 cm) NPS
- 0.375″ (9.53 mm) nominal thickness
- Two-phase FAC “Tiger Striping”

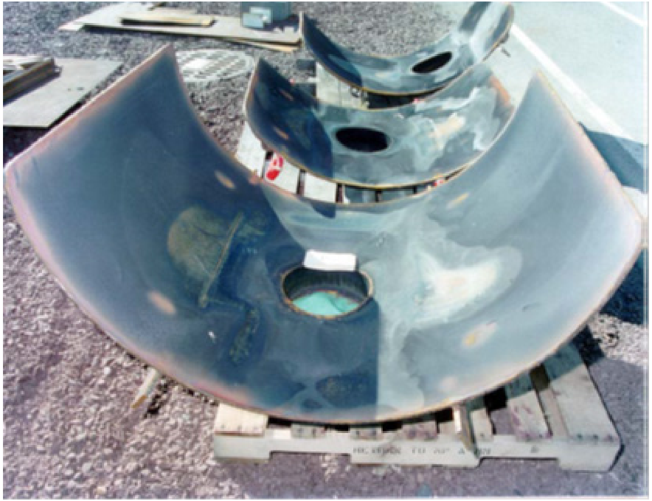


Figure 8-11 High Pressure Extraction Steam Inlet to Feedwater Heater Shell – Two Phase Flow Accelerated Corrosion [22]

Items of Note

- Two-phase FAC "Tiger Striping"
- Shell area damage after hitting impingement plate and deflecting onto heater shell wall on sides of nozzle

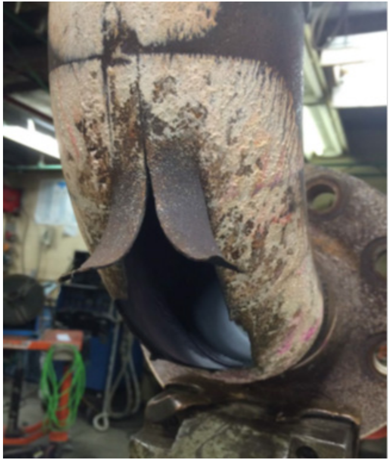


Figure 8-12 Reheat Steam and Moisture Separator System Elbow Downstream of Orifice – Two Phase Flow Accelerated Corrosion [24]

Items of Note

- Rupture in 2015
- 4″ (10.2 cm) NPS
- 0.237″ (6.02 mm) nominal thickness
- Carbon steel elbow A234 WPB
- Operating Conditions 874 psig (60.26 bar) and 529°F (276°C); Q = 0.99
- Flow rate 20,148 lbs/hr (9,139 kg/hr)
- Detailed views shown in Figures 8-13, 8-14, and 8-15

Figure 8-13 Reheat and Moisture Separator System Side View of Failed Elbow – Two Phase Flow Accelerated Corrosion [24]

Items of Note

- Rupture and adjacent wall loss on extrados of elbow
- Lab results indicated "tiger striping"

Figure 8-14 Reheat and Moisture Separator System Magnified View of Failed Section of Elbow – Two Phase Flow Accelerated Corrosion [24]

Items of Note

- Ruptured area and adjacent wall magnified
- Lab results indicate two-phase FAC

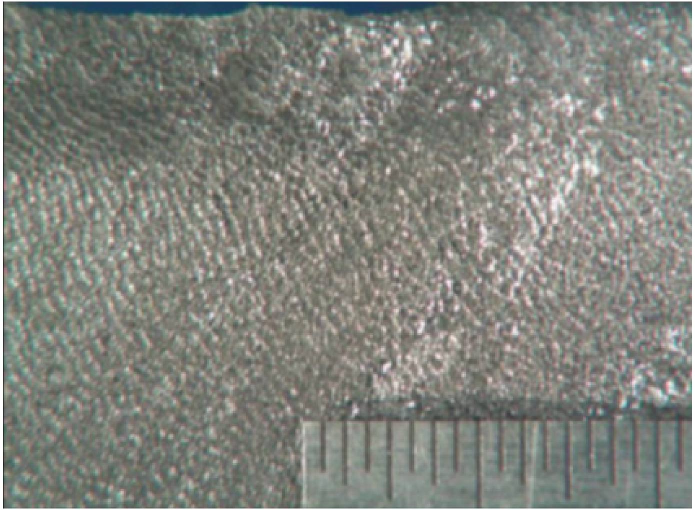


Figure 8-15 Reheat and Moisture Separator System Magnified View of Internal Surface of Failed – Two Phase Flow Accelerated Corrosion [24]

Items of Note

- Detail view of elbow wall showing wear pattern

Figure 8-16 Steam Seal Leak in Elbow – Two Phase Flow Accelerated Corrosion [24]

Items of Note

- Hole in Steam Seal elbow
- Two-phase FAC patter
- Significant wall loss on extrados of elbow beyond hole
- Elbow to pipe weld shows partial loss of weld

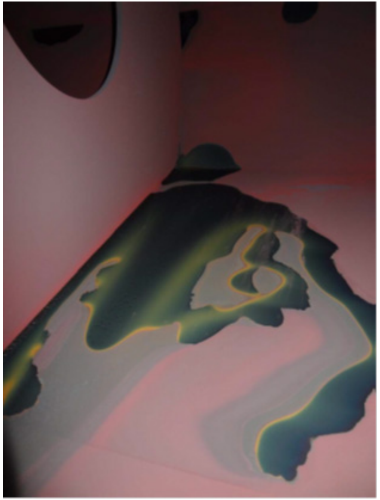


Figure 8-17 Moisture Separator Reheater Internal Wear – Two Phase Flow Accelerated Corrosion [24]

Items of Note

- Inspection of Moisture Separator Reheaters
- Two-phase FAC "Tiger Striping"

Figure 2: MNS 2HA-8 spool piece, as-received (looking in direction opposite to steam flow).

Figure 8-18 High Pressure Extraction Pipe Shown with Clam Shell – Two Phase Flow Accelerated Corrosion [25]

Items of Note

- Pipe is downstream of stainless steel elbow
- Operating conditions about 444°F (229°C), 398 psia (27.44 bar), 0.84 steam quality
- Flow rate about 89 feet/second (27.1 m/s)
- Two-phase FAC pipe wear was in line with the extrados of the stainless steel elbow
- Some wear noted at the 6 o'clock position of the pipe

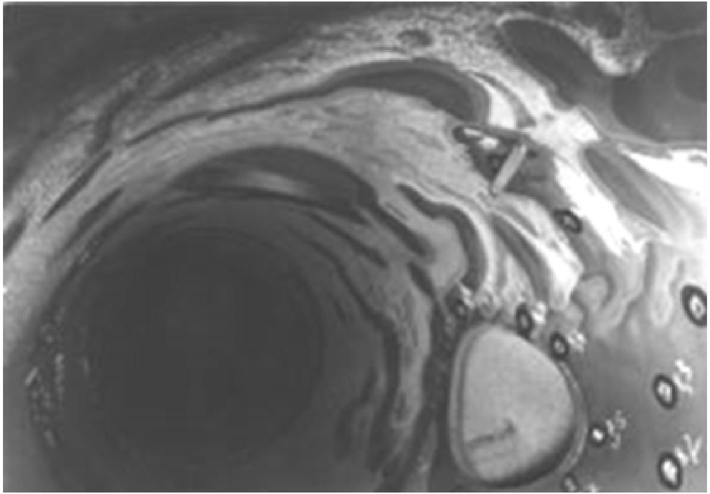


Figure 8-19 Crossover Line – Two Phase Flow Accelerated Corrosion [8, 26]

Items of Note

- Crossover piping
- Two-phase FAC "Tiger Striping"
- Plateaus and valleys

Figure 8-20 High Pressure Extraction Steam Bend Failure – Two Phase Flow Accelerated Corrosion [9]

Items of Note

- Failure of H.P. Extraction Steam Bend or Sweep
- Two-phase FAC "Tiger Striping"

Figure 8–21 Steam Line – Two Phase Flow Accelerated Corrosion [29]

Items of Note

- Inside surface of failed carbon steel flange
- Downstream weld (towards top of photo) appears to be intact

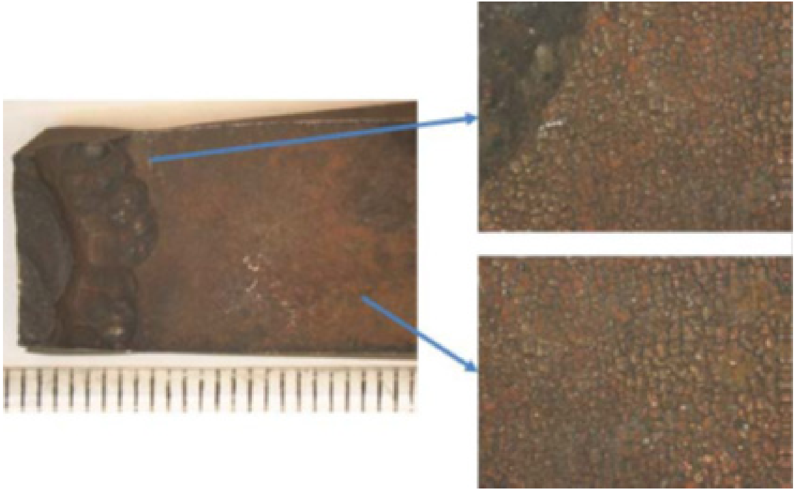


Figure 8–22 Steam Line – Two Phase Flow Accelerated Corrosion [29]

Items of Note

- Inside surface of failed carbon steel flange

9. Flow Accelerated Corrosion Entrance Effect/Leading Edge Effect

9.1 FAC Entrance Effect/Leading Edge Effect Requirements

- Single or two-phase
- Flow goes from component constructed of FAC-resistant material to a downstream FAC-susceptible carbon steel component

Affected Surface Characteristics	Susceptible Locations	Mitigation Techniques	Additional Notes	References
• Localized circumferential groove downstream of the connecting weld	• Locations where a FAC-susceptible carbon steel component is welded to an upstream FAC-resistant material	• Replace remaining sections of carbon steel pipe with FAC resistant material	• Degradation is usually around the entire circumference of the weld	• 28, 30, 32

9.2 FAC Entrance Effect/Leading Edge Effect Examples

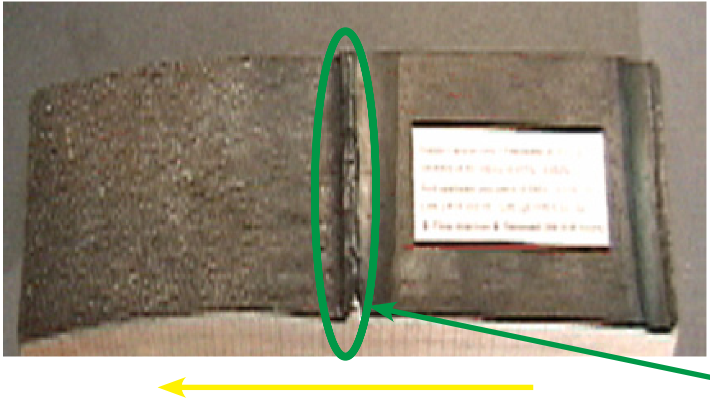


Figure 9-1 Feedwater System with trace chrome upstream pipe component welded to carbon steel elbow [28]

Items of Note

- Trace chrome pipe component to the right of green region (resistant material)
- Carbon steel elbow downstream of green region (non-resistant material)
- Entrance Effect/Leading Edge Effect groove within green region
- Single-phase system
- Groove upstream of weld is in weld prep region

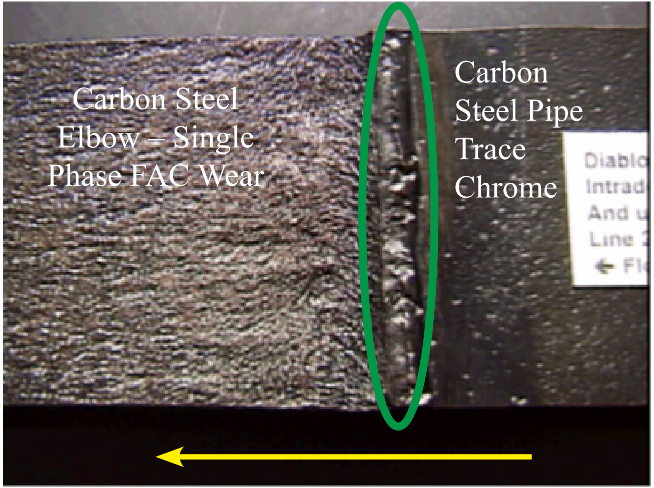


Figure 9-2 Close-Up view of region in vicinity of trace chrome pipe to carbon steel elbow weld [28]

Items of Note

- Region of Entrance Effect/Leading Edge Effect wear is located within green ellipse
- Single-phase FAC Wear downstream of green ellipse
- Pipe section with trace chrome no single-phase FAC wear but some surface pitting present

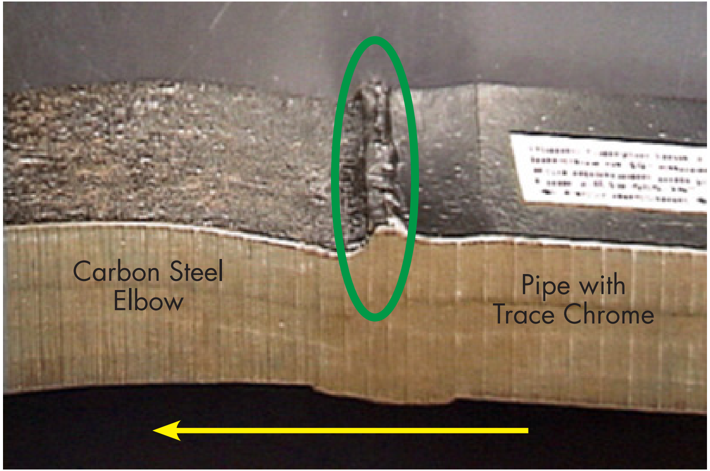


Figure 9-3 Profile view of trace chrome pipe, weld, and carbon steel elbow [28]

Items of Note

- Entrance Effect/Leading Edge Effect groove
- Localized accelerated wear
- Localized wall loss of ~ 0.140″ (3.56 mm)

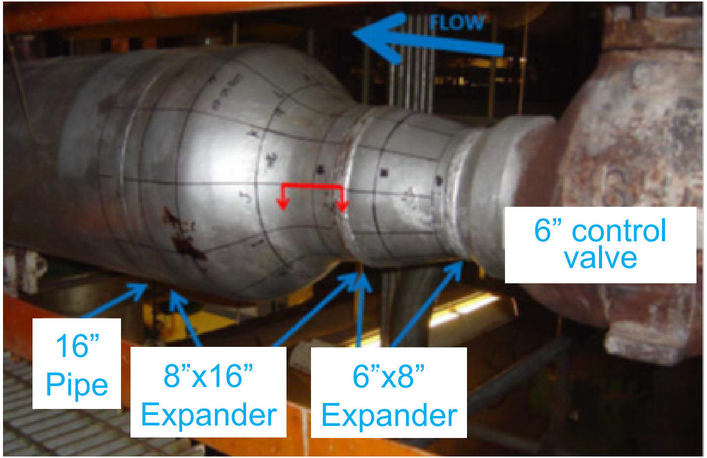


Figure 9-4 Piping layout of Heater Drain line to High Pressure Feedwater Heater Downstream of Control Valve [10, 28]

Items of Note

- Operating temperature of 348°F (176°C)
- Operating pressure of 191 psig (13 bars)
- 6″ x 8″ (15.2 cm x 20.3 cm) expander previously replaced with FAC-resistant A234/WP22 material
- 8″ x 16″ (20.3 cm x 40.6 cm) expander is FAC-susceptible carbon steel
- Six outages later, 8″ x 16″ (20.3 cm x 40.6 cm) expander required replacement due to significant wall loss due to accelerated wear rate on the small end
- Figure 9-5 is a cross section of the area designated by the red arrows

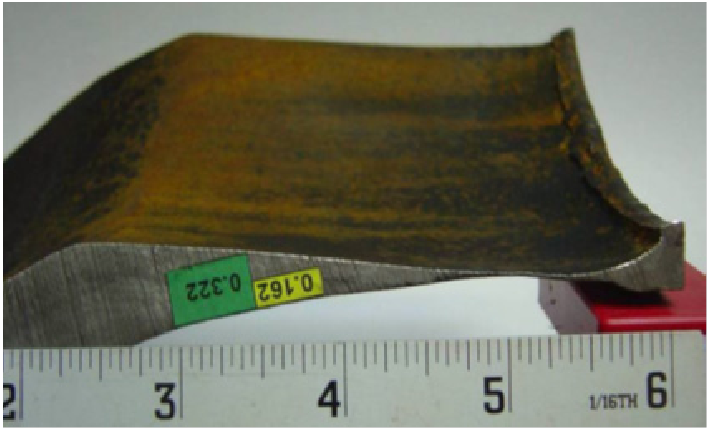


Figure 9-5 Profile view of wall loss on small end of expander [10, 28]

Items of Note

- Small end is 8″ (20.3 cm) NPS with a nominal thickness of 0.322″ (8.433 mm)
- Thickness measurement = 0.015″ (0.381 mm)
- Localized wear immediately downstream from weld
- Historical thickness measurement prior to upstream replacement with chrome-moly was 0.349″ (8.865 mm)
- 8″ x1 6″ (20.3 cm x 40.6 cm) expander replaced with carbon steel containing chrome

Figure 9-6 Ruptured Feedwater line to Economizer at Fossil Power Plant [28]

Items of Note

- Failed section of pipe was on branch side of tee
- 12″ (30.5 cm) NPS; A106 Gr. C; Seamless
- Tee had trace chrome of 0.12%
- Branch pipe had trace chrome of 0.03%
- Difference in chromium content was enough to cause the Entrance Effect downstream of the tee branch to pipe weld

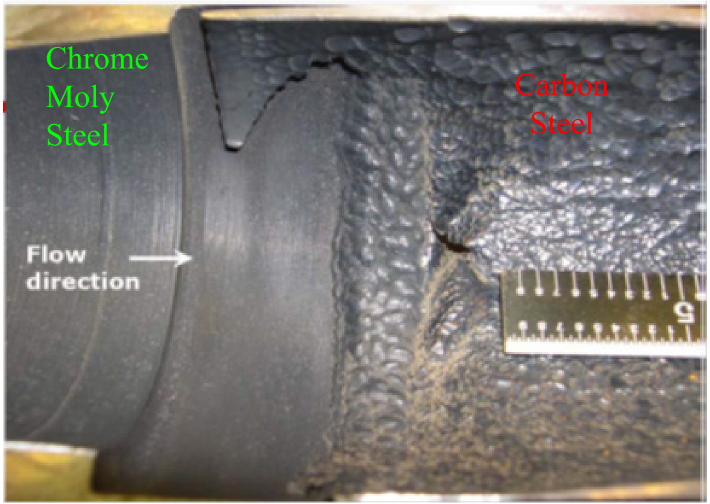


Figure 9-7 MSR Small Bore Vent Line [28]

Items of Note

- Carbon steel pipe component had severe localized wear downstream of the weld
- Socket welded pipe has hole downstream of weld

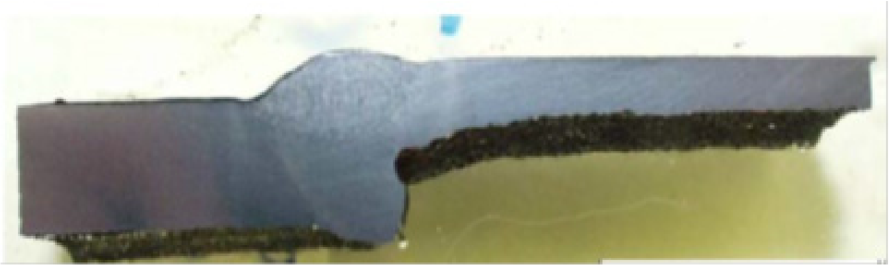


Figure 9-8 Carbon steel weld with trace chromium in upstream component - System Unknown [29]

Items of Note

- Flow is from left to right
- Upstream component contains 0.1% trace chrome
- The weld contains trace chrome > 0.04%
- Downstream carbon steel component contains very little trace chrome
- Visible degradation of the component's pipe wall downstream of the weld

10. Low Temperature Flow Accelerated Corrosion

10.1 Low Temperature Flow Accelerated Corrosion Requirements

- Operating temperature below 200°F (~90°C)
- Neutral pH
- Low oxygen concentration
- Components constructed of carbon steel material;

Affected Surface Characteristics	Susceptible Locations	Mitigation Techniques	Additional Notes	References
• Isolated pits or divots • At microscopic level damage is similar to single-phase FAC	• Resin traps • Piping between polisher discharge and amine injection point in PWR plants • Areas upstream of oxygen injection point in BWR plants	• Relocation of chemistry injection points • Monitor if polishers are bypassed • FAC-resistant material replacements	• Wear rates of ~10 mils/year (0.25 mm/year) have been observed.	• 6, 27

10.2 Low Temperature FAC Examples

Figure 10-1 Low Temperature FAC – Polisher Piping between Isolation Valve and Resin Trap [24]

Items of Note

- Condensate Polisher Piping System
- Low Temperature < 200°F (93°C)
- Damage similar to single-phase FAC
- Surface degradation appears to have some Cavitation wear mechanism also occurring

Figure 10-2 Low Temperature FAC – Reactor Building Closed Loop Cooling Showing Scalloped Surface [6, 25, 27]

Items of Note

- Leaks in Reactor Building Closed Loop Cooling
- Operating temperature 120°F (49°C)
- Small bore carbon steel threaded pipe
- Resulted in plant shutdown
- Surface degradation appears to have "orange peel" finish similar to single-phase FAC
- Surface also appears to be rippled

Figure 10-3 Condensate Polishing System [6]

Items of Note

- Low Temperature FAC wear mechanism
- Operating temperature between 90°F to 130°F (32°C to 54°C)
- Low oxygen ~5 ppb
- Degraded pipe surface downstream of butterfly valve
- Utility also noted damage to reducer and expander connected to the butterfly valve
- Velocity in 12" (30.5 cm) NPS < 9 ft/s (2.7 m/s)
- Similar wear was identified at the sister unit

Figure 10-4 Magnification of the Condensate Polishing Pipe Surface from Previous Photograph [6, 27]

Items of Note

- Low Temperature FAC wear mechanism
- Operating temperature between 90°F to 130°F (32°C to 54°C)
- Similar surface characteristic to single-phase FAC
- Neutral pH water environment

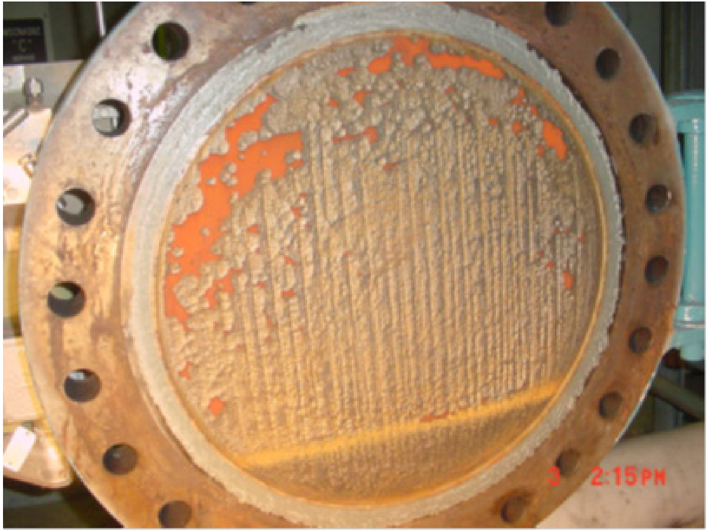


Figure 10-5 Condensate Polisher Resin Trap [6, 27]

Items of Note

- Low Temperature FAC wear mechanism
- Operating temperature 135°F (57°C)
- Low oxygen ~1 to 3 ppb
- Neutral water
- 20″ NPS (508 mm OD)
- Carbon steel material
- Damaged surface appears to have vertical rows of grooves
- Similar damage was found in the other unit on site

Figure 10-6 Condensate Polishing [6]

Items of Note

- Low Temperature FAC wear mechanism
- First elbow downstream of demineralizer
- Operating temperature between 75°F to 125°F (24°C to 52°C)
- Carbon steel material
- Velocity ~9.1 feet/second (2.78 m/s)

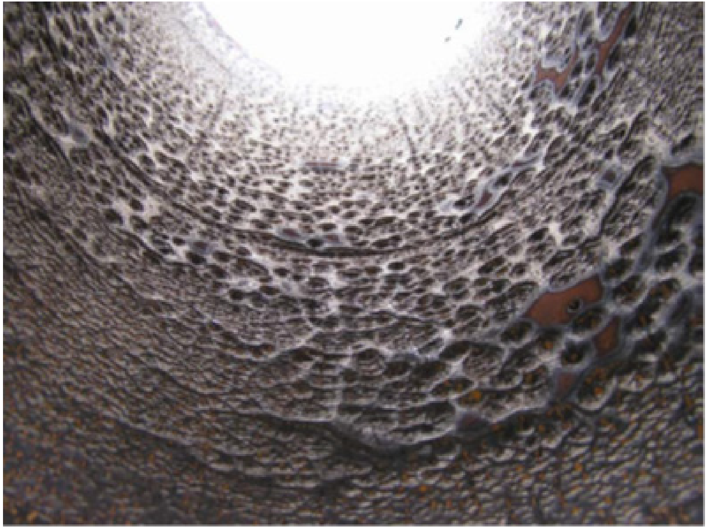


Figure 10-7 Condensate Polishing Surface Degradation Low Temperature FAC [6]

Items of Note

- Low Temperature FAC wear mechanism
- Calculations were performed and the cavitation coefficient was greater than the coefficient for incipience, therefore no cavitation would be expected to occur

Figure 10-8 Degradation within Resin Trap [6]

Items of Note

- Low Temperature FAC wear mechanism
- Operating temperature between 90°F to 130°F (32°C to 54°C)
- Low oxygen ~5 ppb
- Degraded section within resin trap
- Similar wear was identified at a sister unit

Figure 10-9 Degradation of Pipe Surface in the Condensate System Downstream of the Polishers [6]

Items of Note

- Low Temperature FAC wear mechanism
- Close-up view of surface degradation
- Operating temperature between 75°F to 125°F (24°C to 52°C)
- Carbon steel material

Figure 10-10 Low Temperature FAC Surface Degradation shows Rippled Surface [9, 27]

Items of Note

- Low Temperature FAC wear mechanism
- Close-up view of surface degradation of elbow
- Operating temperature between 75°F to 125°F (24°C to 52°C)
- Carbon steel material

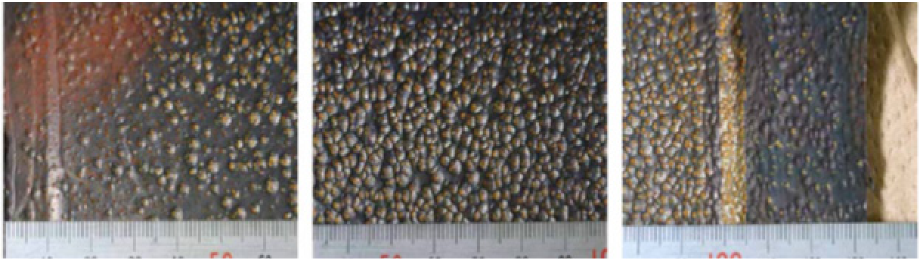


Figure 10-11 Low Temperature FAC Views of Degraded Surfaces in Control Rod Drive System [6, 27]

Items of Note

- Low Temperature FAC
- Carbon steel pipe downstream of orifice
- Operating temperature 95°F (35°C)
- Oxygen < 10 ppb
- Velocity ~3 feet/sec (~1 m/s)
- Surface degradation for single-phase FAC

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Appendix A:
Wear Mechanism Examples by Plant System

Plant System	Wear Mechanism Identified	Figure No.
Bleed Steam System	Liquid Droplet Impingement	Figure 4-4
Bleed Steam System	Liquid Droplet Impingement	Figure 4-13
Boiler Blowdown System	Solid Particle	Figure 5-3
Boiler Blowdown System	Solid Particle	Figure 5-4
Condensate Cooling Water	Cavitation	Figure 2-28
Condensate Cooling Water	Cavitation	Figure 2-29
Condensate Cooling Water	Cavitation	Figure 2-30
Condensate Cooling Water	Cavitation	Figure 2-31
Condensate Polisher and Demineralizer System	Low Temperature FAC	Figure 10-3
Condensate Polisher and Demineralizer System	Low Temperature FAC	Figure 10-4
Condensate Polisher and Demineralizer System	Low Temperature FAC	Figure 10-5

Plant System	Wear Mechanism Identified	Figure No.
Condensate Polisher and Demineralizer System	Low Temperature FAC	Figure 10-6
Condensate Polisher and Demineralizer System	Low Temperature FAC	Figure 10-7
Condensate Polishing System	Low Temperature FAC	Figure 10-1
Condensate Polishing System	Low Temperature FAC	Figure 10-8
Condensate Polishing System	Low Temperature FAC	Figure 10-9
Condensate Polishing System	Low Temperature FAC	Figure 10-10
Condensate System	Cavitation	Figure 2-25
Condensate System	Single Phase FAC	Figure 7-6
Control Rod Drive System	Low Temperature FAC	Figure 10-11
Condenser Tubing, Copper Alloy	Liquid Droplet Impingement	Figure 4-9
Condenser Tubing, Copper Alloy	Liquid Droplet Impingement	Figure 4-10
Core Spray System	Cavitation	Figure 2-27

Plant System	Wear Mechanism Identified	Figure No.
Crossover System	Two Phase FAC	Figure 8-19
Drain System	Single Phase FAC	Figure 7-9
Extraction Steam System	LDI and FAC	Figure 4-16
Extraction Steam System	Two Phase FAC	Figure 8-6
Extraction Steam System	Two Phase FAC	Figure 8-9
Extraction Steam	Two Phase FAC	Figure 8-2
Extraction Steam	Two Phase FAC	Figure 8-3
Extraction Steam System - Chrome-Moly	Liquid Droplet Impingement	Figure 4-14
Feedwater Heater Shell Wear	Two Phase FAC	Figure 8-4
Feedwater Heater Shell Wear	Two Phase FAC	Figure 8-5
Feedwater Heater Vent System	Liquid Droplet Impingement	Figure 4-5

Plant System	Wear Mechanism Identified	Figure No.
Feedwater Heater Vent System - P22 elbow	Liquid Droplet Impingement	Figure 4-18
Feedwater Minimum Flow Recirculation System	Flashing Flow	Figure 3-2
Feedwater Recirculation System	Liquid Droplet Impingement	Figure 4-1
Feedwater Recirculation System	Liquid Droplet Impingement	Figure 4-2
Feedwater Recirculation System - P22 Fitting	Cavitation	Figure 2-6
Feedwater Recirculation System - P22 Fitting	Cavitation	Figure 2-7
Feedwater Recirculation System - P22 Fitting	Cavitation	Figure 2-8
Feedwater Recirculation System to Condenser	Cavitation	Figure 2-19
Feedwater System	Cavitation	Figure 2-24
Feedwater System	Single Phase FAC	Figure 7-7
Feedwater System	Single Phase FAC	Figure 7-8
Feedwater System	Single Phase FAC	Figure 7-11

Plant System	Wear Mechanism Identified	Figure No.
Feedwater System	Entrance Effect/Leading Edge Effect	Figure 9-1
Feedwater System	Entrance Effect/Leading Edge Effect	Figure 9-2
Feedwater System	Entrance Effect/Leading Edge Effect	Figure 9-3
Feedwater System	Entrance Effect/Leading Edge Effect	Figure 9-6
Fire Protection System	Cavitation	Figure 2-4
Heater Drain System	Cavitation	Figure 2-10
Heater Drain System	Cavitation and FAC	Figure 2-15
Heater Drain System	Flashing Flow	Figure 3-4
Heater Drain System	Entrance Effect/Leading Edge Effect	Figure 9-4
Heater Drain System	Entrance Effect/Leading Edge Effect	Figure 9-5
Heater Shell	Liquid Droplet Impingement	Figure 4-3

Plant System	Wear Mechanism Identified	Figure No.
High Pressure Coolant Injection Drain System	Liquid Droplet Impingement	Figure 4-7
High Pressure Core Spray System	Cavitation/Flow Curvature	Figure 2-11
High Pressure Core Spray System	Cavitation/Flow Curvature	Figure 2-12
High Pressure Extraction Steam System	Two Phase FAC	Figure 8-11
High Pressure Extraction Steam System	Two Phase FAC	Figure 8-18
High Pressure Extraction Steam System	Two Phase FAC	Figure 8-20
High Pressure Core Injection Flush Line to Torus	Cavitation	Figure 2-1
High Pressure Core Injection Flush Line to Torus	Cavitation	Figure 2-2
Low Pressure Extraction Steam Line to Condenser	Liquid Droplet Impingement	Figure 4-21
Low Pressure Extraction Steam System	Liquid Droplet Impingement	Figure 4-19
Low Pressure Extraction Steam System	Two Phase FAC	Figure 8-10
Low Pressure Feedwater Heater	Two Phase FAC	Figure 8-8

Plant System	Wear Mechanism Identified	Figure No.
Main Steam System	Liquid Droplet Impingement	Figure 4-12
Miscellaneous Equipment Drain Header	Liquid Droplet Impingement	Figure 4-20
Moisture Separator Drain System	Liquid Droplet Impingement	Figure 4-17
Moisture Separator Emergency Drain	Steam Cutting	Figure 6-5
Moisture Separator Reheater Drain System	Single Phase FAC	Figure 7-15
Moisture Separator Reheater Drain System - P22 Elbow	Cavitation	Figure 2-20
Moisture Separator Reheater System	Two Phase FAC	Figure 8-17
Moisture Separator Reheater System Vents	Liquid Droplet Impingement	Figure 4-15
Moisture Separator Reheater Vent System	Entrance Effect/Leading Edge Effect	Figure 9-7
Reactor Building Closed Loop Cooling System	Low Temperature FAC	Figure 10-2

Plant System	Wear Mechanism Identified	Figure No.
Reactor Feedwater Pump Minimum Flow System	Flashing Flow	Figure 3-1
Reactor Water Cleanup System	Single Phase FAC	Figure 7-4
Reactor Water Cleanup System	Single Phase FAC	Figure 7-5
Reactor Water Cleanup System	Single Phase FAC	Figure 7-10
Reactor Water Clean-Up System	Liquid Droplet Impingement	Figure 4-8
Reheat Steam and Moisture Separator System	Two Phase FAC	Figure 8-12
Reheat Steam and Moisture Separator System	Two Phase FAC	Figure 8-13
Reheat Steam and Moisture Separator System	Two Phase FAC	Figure 8-14
Reheat Steam and Moisture Separator System	Two Phase FAC	Figure 8-15

Plant System	Wear Mechanism Identified	Figure No.
Reheater Drain System	Cavitation	Figure 2-26
Reactor Feed Pump Turbine Main Steam Supply Drain System	Flashing Flow	Figure 3-3
Solid Particle Erosion Carbon Steel Pipe and Stainless Steel Pipe	Solid Particle	Figure 5-1
Solid Particle Erosion in Heater Shell	Solid Particle	Figure 5-2
SPE Damage to Turbine Blades	Solid Particle	Figure 5-6
Steam Erosion on Feedwater Heater Shell	Steam Cutting	Figure 6-1
Steam Erosion on Feedwater Heater Shell	Steam Cutting	Figure 6-2
Steam Generator Blowdown System	Cavitation	Figure 2-22
Steam Generator Blowdown System	Cavitation	Figure 2-23
Steam Generator Blowdown System	Solid Particle	Figure 5-5

Plant System	Wear Mechanism Identified	Figure No.
Steam Generator Blowdown System - P11 Clad Lined	Solid Particle	Figure 5-7
Steam Generator Blowdown System - Stainless Steel Elbow	Cavitation and LDI	Figure 2-13
Steam Generator Blowdown System - Stainless Steel Elbow	Cavitation and LDI	Figure 2-14
Steam Line	Two Phase FAC	Figure 8-21
Steam Line	Two Phase FAC	Figure 8-22
Steam Seal System	Two Phase FAC	Figure 8-16
Steam Supply System to Gland Steam	Combination FAC and LDI	Figure 8-7
System Unknown	Cavitation	Figure 2-3
System Unknown	Cavitation	Figure 2-5
System Unknown	Entrance Effect/Leading Edge Effect	Figure 9-8

Plant System	Wear Mechanism Identified	Figure No.
System Unknown - Body of Plug Valve	Cavitation	Figure 2-16
System Unknown - Control Valve Trim Damage	Cavitation	Figure 2-9
System Unknown - Drain System	Single Phase FAC	Figure 7-3
System Unknown - Elbow Damage	Cavitation	Figure 2-17
System Unknown - Flange	Steam Cutting	Figure 6-3
System Unknown - Pump Impellor	Cavitation	Figure 2-21
System Unknown - Seat Leakage in dump valve	Liquid Droplet Impingement	Figure 4-22
System Unknown - Single Phase	Single Phase FAC	Figure 7-14
System Unknown - Single Phase FAC	Single Phase FAC	Figure 7-1
System Unknown - Single Phase FAC	Single Phase FAC	Figure 7-2
System Unknown - Single Phase FAC	Single Phase FAC	Figure 7-13

Plant System	Wear Mechanism Identified	Figure No.
System Unknown - Single Phase FAC and Liquid Droplet Impingement	Single Phase FAC and LDI	Figure 7-12
System Unknown - Tee and Downstream Pipe Damage	Cavitation	Figure 2-18
System Unknown	Two Phase FAC	Figure 8-1
Trap Assembly	Steam Cutting	Figure 6-4
Turbine Blades	Liquid Droplet Impingement	Figure 4-6
Turbine Stop Valves and 'B' Moisture Separator Re-heater (MSR) Cross-Under Drain System	Liquid Droplet Impingement	Figure 4-11

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