PLANT ALERT:

Don't let erosion/corrosion compromise safety

Thinning of pipe walls and corrosion of other components in high-purity feedwater and steam systems can have catastrophic consequences. Take time to review the problem and apply some important preventive steps

By Otakar Jonas, Jonas Inc

One year ago, the rupture of a feedwater-pipe section just upstream of the economizer resulted in a fatal accident at a US utility drum-boiler unit.[1] The direct cause of the accident was thinning of the pipe wall, apparently the result of erosion/corrosion. An accident similar in origin and consequences occurred in December 1986 at a nuclear pressurized-water reactor (PWR) unit in Virginia.[2]

Although such serious accidents are rare, erosion/corrosion is a relatively common occurrence in all types of steam systems. It joins drum-boiler waterwall-tube failures and deaerator cracking as the most extensive and expensive waterside problems encountered at powerplants.

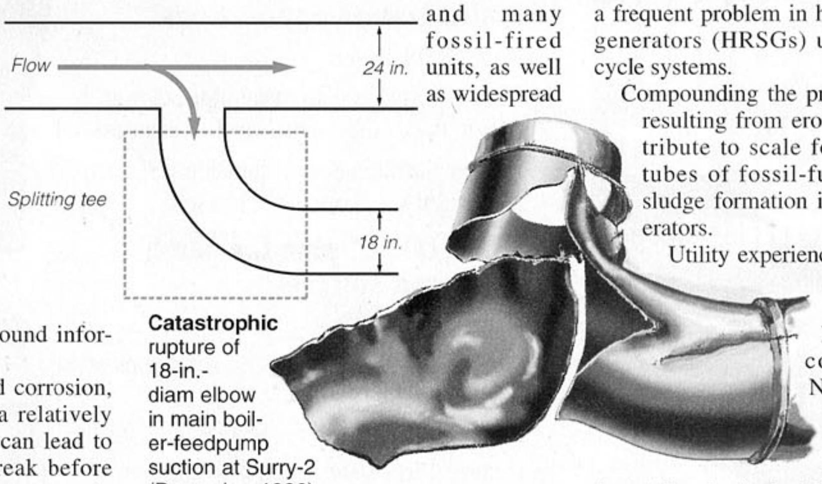
The purpose of this alert is to urge powerplant owners and operators to inspect locations in feedwater and wet-steam components that may be susceptible to wall thinning caused by erosion/corrosion. (An extensive list of references is provided for assistance in obtaining background information.)

Also known as flow-assisted corrosion, or FAC, erosion/corrosion is a relatively slow damage mechanism that can lead to rupture before detection—"break before leak" in industry parlance. It occurs in piping when high flow velocity, temperature, and turbulence interact with the chemical environment to promote dissolution of the protective metal oxide present on carbon and low-alloy steel surfaces. This usually occurs in carbon steel components under slightly acidic conditions, with zero or low O_2 concentrations or with excess O_2 scavenger.

Reported experience

Break-before-leak is rare. Usually massive and destructive, it is always the unexpected failure of a component weakened by corrosion (thinning or cracking) or material degradation (creep, graphitization, embrittlement, etc). It results when a large section of pipe or pressure vessel is almost uniformly weakened, or when the normal pressure and/or other stress factors suddenly increase. The 1986 failure of a carbon steel elbow in a feedwater-line brought the problem into sharp focus (see sketch). This prompted inspection of all US nuclear PWR units and many fossil-fired units, as well as widespread investigation of the erosion/corrosion mechanism.[3-6]

Erosion/corrosion has been recognized as a problem in steam-generation systems for over half a century. The earliest documented occurrence was in industrial steam/condensate-return lines, where low-pH condensate was responsible for grooving and other forms of material removal in carbon and low-alloy steel pipe.[7,8]



Catastrophic rupture of 18-in.-diam elbow in main boiler-feedpump suction at Surry-2 (December 1986) resulted from erosion-corrosion. Phenomenon reduced 0.50-in. wall thickness to 0.048 in. locally, 0.09 in. in larger areas

As summarized in Table 1, both fossil-fired and nuclear plants have experienced erosion/corrosion in feedwater heaters (tubes and shells), condensers, feedwater and wet-steam piping, and steam turbines of all types[5,9-11]; PWR units encounter erosion/corrosion of wet-steam and feedwater piping,[5,12-16] moisture-separator chevrons,[16] and feedwater inlets in steam generators.[17] Erosion/corrosion has also been a frequent problem in heat-recovery steam generators (HRSGs) used in combined-cycle systems.

Compounding the problem, iron oxides resulting from erosion/corrosion contribute to scale formation in boiler tubes of fossil-fueled units and to sludge formation in PWR steam generators.

Utility experience with erosion/corrosion in nuclear plants was highlighted by a survey conducted for the Nuclear Regulatory Commission in 1987.[5] Of the responses received from 28 units in the US and Germany, 12 reported erosion/ corrosion in feedwater piping, eight in steam-generator inlets (J-tubes and feedwater-distribution rings), and 27 in wet-steam piping (Table 2).

Industry guides

Reduced operating reliability attributed to erosion/corrosion prompted development of inspection and other guidelines for the industry, including several computer codes to help spot developing trends.[12,18,19] These focus on the following parameters, found to influence wall thinning of carbon steel pipe as a result of erosion/corrosion:

- Chromium, copper, and molybdenum content.
- Water and steam composition (O_2 or scavenger and pH).
- Temperature.
- Component geometry.
- Flow velocities (which, primarily for economic reasons, have steadily increased over the past three decades, often to double or triple the temperature-related design values recommended by the Heat Exchange Institute).

Relationships between these parameters and erosion/corrosion rates are known quantitatively. What is not known accurately are the effects of reducing conditions caused by excessive concentrations of O_2 scavengers and the effects of some new water treatment chemicals, such as chelating agents and polymeric dispersants and their decomposition products.

Because reducing conditions are known to accelerate erosion/corrosion, eliminating O_2 scavengers during normal operation can significantly reduce feedwater iron concentrations in steam cycles.[20] The beneficial effect of low O_2 concentrations in feedwater is also supported by laboratory data, which show that increasing feedwater O_2 above 4 ppb can stop erosion/corrosion. The excellent experience of hundreds of utility units using oxygenated treatment (OT) for high-purity feedwater attests to this improvement.[21]

Precautionary measures

Based on the information available, adoption of the following procedures is strongly recommended:

1. Carbon steel piping and other components operating with hot water and wet steam should be inspected for wall thinning by erosion/corrosion as soon as practical (and periodically thereafter). While 100% inspection is not necessary, priority should be given to components with low chromium content subjected to high flow velocity, low pH, and low O_2 operating in the temperature range 250 to 350F—particularly those with geometries susceptible to this damage mechanism.

2. Such susceptible locations and components should be evaluated using CHECMATE, the accepted computer code.[18]

3. Ultrasonic techniques or radiography can be used to measure wall thickness.

4. If wall thinning from erosion/corrosion is encountered, the problem can be resolved by optimizing water chemistry and/or replacing carbon steel components with steels of higher chromium content. To avoid break-before-leak, maximum stresses and pressures rather than normal (or nominal) operating conditions should be used to determine minimum allowable wall thicknesses.

5. In evaluations of water chemistry, the at-temperature pH values and pH_T of moisture droplets should be used.

6. When new water treatment chemicals and O_2 scavengers are used, their impact and that of their decomposition products on the erosion/corrosion mechanism should be evaluated.

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Table 1: Erosion/corrosion reported in steam-cycle components*

	Cycle			
Component	Fossil-fuel	Industrial	PWR	BWR
Feedwater heaters	X	X	X	X
Condensers	X	X	X	X
Wet-steam piping	—	X	X	—
Feedwater piping	X	X	X	—
Condensate-return lines	X	X	—	—
Moisture separators	—	—	X	X
J-tubes	—	—	X	—
Economizers	X	X	—	—
Deaerators (vertical)	X	—	—	—
Desuperheater liners	X	X	—	—
L-p-turbine discs	—	—	X	—
H-p-turbine casings	—	—	X	—
Turbine-gland areas	—	X	X	X
HRSGs	X	X	—	—

*Sources: References 5, 12-18

Table 2: Occurrence of erosion/corrosion in nuclear PWR cycles[1]

			System	
Unit	Utility	Years in service[2]	Water	Steam
Beaver Valley-1	Duquesne Light Co	11	No	Yes
Calvert Cliffs-1	Baltimore Gas & Electric Co	12	Yes	Yes
Calvert Cliffs-2	Baltimore Gas & Electric Co	10	Yes	Yes
Crystal River-3	Florida Power Corp	10	No	Yes
Fort Calhoun	Omaha Public Power District	14	Yes	Yes
Indian Point-2	Cosolidated Edison Co of NY	14	No	Yes
Indian Point-3	New York Power Authority	11	No	Yes
Kewaunee	Wisconsin Public Service Corp[3]	13	No	Yes
Oconee-1	Duke Power Co	14	No	Yes
Oconee-2	Duke Power Co	13	No	Yes
Oconee-3	Duke Power Co	13	No	Yes
Palisades	Consumers Power Co	15	No	Yes
Rancho Seco	Sacramento Municipal Utility District	13	Yes	Yes
H B Robinson-2	Carolina Power & Light Co	17	No	Yes
Salem-1	Public Service Electric & Gas Co	10	Yes	Yes
Salem-2	Public Service Electric & Gas Co	6	Yes	Yes
San Onofre-1	Southern California Edison Co	19	Yes	Yes
San Onofre-2	Southern California Edison Co	4	Yes	Yes
San Onofre-3	Southern California Edison Co	3	Yes	Yes
Surry-1	Virginia Power	15	Yes	Yes
Surry-2	Virginia Power	14	Yes	Yes
Trojan	Portland General Eletric Co	11	Yes	Yes
Turkey Point-1	Florida Power & Light Co	15	Yes	Yes
Turkey Point-2	Florida Power & Light Co	14	Yes	Yes
Zion-1	Commonwealth Edison Co	14	Yes	Yes
Zion-2	Commonwelath Edison Co	13	Yes	Yes
Neckar-1	GKN (Germany)	11	No	Yes
Brokdorf	KBR (Germany)	1	No	No

[1]Source: Reference 5 [2]As of time of survey [3]With Wisconsin Power & Light Co and Madison Gas & Electric Co, non-operating co-owners

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