Buried Piping – Inspecting Something You Can't See

By Jeremy Bowen, NRR/DIRS/IRIB

Buried piping is subject to significant degradation from various corrosion mechanisms. Several critical piping systems contain sections of buried piping. As piping ages, coatings deteriorate, and exposed pipe corrodes, piping failure, such as leaks, and possibly rupture, may occur and adversely impact plant operations.

Example of a leaking pipe (non-nucl

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Recent Events.

- **June 2009**. Elevated levels of tritium were found at Dresden during routine sampling of onsite monitoring locations. The suspected source is an active leak in underground piping associated with the condensate storage tank (CST). In 2004 and 2006, other underground piping associated with the CST leaked and was replaced (PNO-III-09-004).
- **May 2009**. While performing the procedure for groundwater monitoring at a well l near the diesel generator building at Hatch, the sampling technician noted a strong diesel/fuel oil odor in the groundwater. Also, the groundwater had a reddish tint, indicative of the red dye used to identify off-road diesel (EN45055).
- **Apr. 2009**. Oyster Creek reported a leaking condensate pump resulting in a potential tritium release (EN44993).
- **Feb. 2009**. Indian Point declared its CST inoperable due to a leak in the buried return line piping (NRC's response to a U.S. Congressman's inquiry and *New York Times* Article)
- **Jul. 2008**. At Tricastin Industrial Complex in France, rupture of a buried pipe containing uranium liquid discharges occurred at a fuel manufacturing plant (OpE COMM).
- **Feb. 2008** NRC conducted a special inspection of the degraded essential service water piping at Byron (IR 2007009).
- **Mar. 2006**. Byron reported elevated tritium levels near buried piping (EN42457).
- **Dec. 2005**. Braidwood reported elevated tritium levels near buried piping (EN42184).
- **Oct. 2005**. Catawba reported an oil spill due to a break in a buried pipe (EN42042).
- **May 2004**. Surry declared the auxiliary feedwater system inoperable due to an underground leak (EN 40771).

What are Some Current Practices?

For buried service water pipe, the licensee typically relies on a quarterly pressure-drop test or system flow test (see *italics in box at right)* to meet the code requirement. With flows ranging from 5000 to 10000 gpm in header piping, a very large leak is required to

ASME code requirements for buried piping:

IWA-5240 VISUAL EXAMINATION
IWA-5244 BURIED COMPONENTS

(a) For buried components surrounded by an annulus, the VT-2 visual examination shall consist of an examination for evidence of leakage at each end of the annulus and at low point drains.

(b) For buried components where a VT-2 visual examination cannot be performed, the examination requirement is satisfied by the following:

(1) The system pressure test for buried components that are isolable by means of valves shall consist of a test that determines the rate of pressure loss. *Alternatively, the test may determine the change in flow between the ends of the buried components. The acceptable rate of pressure loss or flow shall be established by the Owner.*

(2) The system pressure test for nonisolable buried components shall consist of a test to confirm that flow during operation is not impaired.

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see a significant change. A gross pipe leakage failure would more likely be discovered by water welling up from leaking buried pipe, vice the Code test.

Most licensees are voluntarily implementing non-destructive examination (NDE) as part of their raw water program. Specifically, they use torsional guided wave (ultrasonic testing) techniques. Many sites also have a cathodic protection system or another protection and detection system for buried pipe. Most carbon steel piping and tanks have a protective coating applied during installation and are further protected by a cathodic system. Degradation of the coatings would result in additional current from the cathodic protection system. Assessment of the coating and cathodic systems is conducted on an annual basis. Non-carbon steel pipes may also be coated, but they usually do not have a cathodic protection system. Periodic inspections are performed when components are excavated for maintenance or any other reason. For plants receiving a renewal license, it is expected that an opportunistic inspection of buried pipe will occur within 10 years prior to the period of extended operation and again in the 10 years after starting extended operation; otherwise, a deliberate buried pipe inspection is usually required to be performed.

How Can an NRC Inspector Review a Buried Piping Issue?

Most buried piping inspection samples are typically selected as a followup to an actual piping failure, a known degradation, or a problem identified during a review of a condition report. Only after a licensee has a failure in buried safety related piping can they be cited against 10 CFR Part 50, Appendix B, criteria V or IX, for having an inadequate inspection program. If the failure is large enough to create a functional failure, they could also be cited against the maintenance rule (10 CFR 50.65). This current stance of the inspection program is due to the relatively low safety significance associated with most buried piping. However, if an inspector decides to pursue the issue, here are some options:

- Observe a licensee's periodic flow or pressure test of underground pipes, the video or results of a video or camera inspection of underground piping, results of a sound detection system used to detect leaks in underground piping, or the periodic maintenance conducted on a cathodic protection system (or similar system) used to protect underground piping and detect any potential leaks. These reviews can be captured under IP 71111.19 or IP 71111.22.

- If a licensee excavates underground piping for the purpose of repair and replacement, use this opportunity for direct visual inspection of the piping. It can be reviewed under IP 71111.17 or IP 71111.19 (to cover the post maintenace system pressure test).

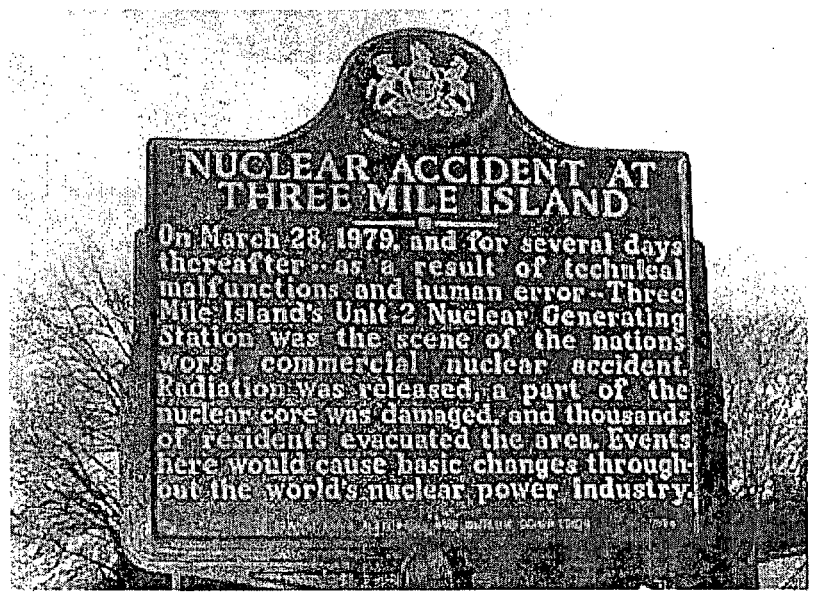
- When a licensee implements corrective actions due to suspected underground piping leaks (as potentially identified by tritium issues, tank inventory loss, chemical loss, excessive running of pumps on fire protection piping or other "keep pressure" systems, a sink hole, etc.), review the licensee's actions under IP 71152 or IP 71111.15.

- Review a licensee's activities associated with buried piping during an inservice inspection as one of the sample requirements in IP 71111.08, which requires a review of two or three types of NDE activities.

- Use IP 71002 during a license renewal inspection, which reviews passive, long lived structures, systems and components, inculding piping.

References

- Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning"
- Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment"
- Generic Letter 9005, "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping"
- IP 49001, "Inspection of Erosion-Corrosion/Flow-Accelerated-Corrosion Monitoring Programs"
- IMC 9900, STSOPD, "Operability Determinations and Functionality Assessments for Resolution of Degraded or Non-Conforming Conditions Adverse to Quality or Safety" (Section C.10)
- NUREG -1801, "Generic Aging Lessons Learned (GALL) Report"
- NUREG/CR-6876, "Risk-Informed Assessment of Degraded Buried Piping Systems in Nuclear Power"
- Information Notice 2007-06, "Potential Common Cause Failures in Essential Service Water Systems"
- Information Notice 2006-13, "Groundwater Contamination due to Undetected Leakage of Radioactive Water"
- SER 7-06, "Degradation of Essential Service Water Piping"
- Buried Pipe Design, Moser, A.P., McGraw Hill, 2nd Edition, 2001.
- Previous ROP inspection findings related to underground piping issues



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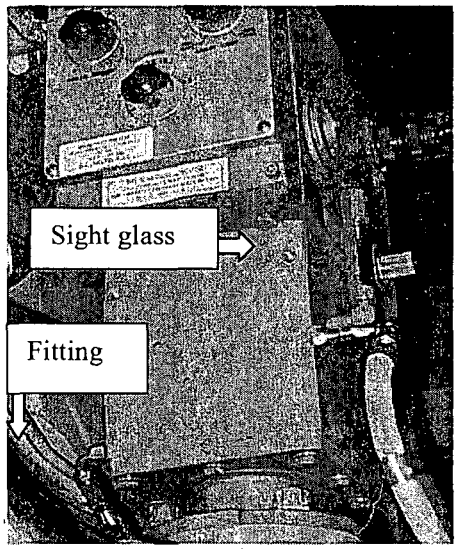
2 SBO DGs Out at Same Time:

Ineffective Risk Management

by Jim McGhee, Senior Resident Inspector, Quad Cities Nuclear Power Station, RIII

Background. On August 12, 2008, the Quad Cities' staff began planned maintenance to install a new governor on the Unit 1 Station Blackout (SBO) diesel generator (DG). This modification made the Unit 1 SBO DG inoperable and unavailable. The resident inspector performed a maintenance risk sample for the work day in accordance with IP 71111.13, "Maintenance Risk Assessments and Emergency Work Control." This activity was selected for configuration verification due to recent changes to the licensee risk evaluation software that credited both of the SBO DGs for loss of electrical power events and other risk significant equipment that was out of service at the time the diesel work was being performed.



The problem. On August 13, while performing a walkdown of the redundant Unit 2 SBO DG, the resident inspector saw that the engine governor sight glass had no visible oil. The inspector immediately reported the condition to the work control center, and operators verified that the oil level was not visible. The oil had leaked out through a loose fitting at the bottom of the governor oil reservoir and collected into a well formed by engine supports beneath the governor; oil leakage was not readily visible from the floor. The fitting was found to be only finger-tight.

The Unit 2 SBO DG was declared inoperable and made unavailable at 11:10 a.m. Using their Probable Risk Assessment model, the plant staff determined on-line risk to have changed from Green to Yellow. Quad Cities' risk management actions for this configuration required protection of high pressure steam driven injection sources (high pressure coolant injection and reactor core isolation cooling systems). Mechanical maintenance staff then tightened the fitting and refilled the governor oil sump (approximately 16 oz. of oil in a 47 oz. sump). The Unit 2 SBO DG was made available at 1:00 p.m., and the licensee returned to a Green-risk condition. In addition, the licensee initiated an extent of condition inspection for the safety-related diesels. Oil levels on all safety-related diesel governors were found to be acceptable.

Investigation. The SBO diesel modification installed a new governor to replace the existing obsolete governor that did not have an oil level sight glass. Followup investigation revealed that this modification had recently been completed on the Unit 2 SBO DG and technicians did not follow work instructions to correctly tighten the fitting, resulting in a slow leak. Further investigation revealed that, as part of this modification, a change was initiated to operator rounds to check the governor oil level; but the procedure was scheduled to be completed on August 29, 2008—three months after the physical modification was completed. No interim equipment checks were put in place, and operators had apparently not checked the oil level sight glass on the SBO DG governor since the modification was completed. A check of the operator rounds for