ELECTRIC POWER RESEARCH INSTITUTE

Nondestructive Evaluation: Operating Experience with Heat Exchanger Tubing Damage

2014 TECHNICAL REPORT

Nondestructive Evaluation: Operating Experience with Heat Exchanger Tubing Damage

3002003028

Final Report, December 2014

EPRI Project Manager
P. Lara

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

YES NO

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

ACKNOWLEDGMENTS

The Electric Power Research Institute (EPRI) prepared this report.

Principal Investigator
P. Lara

This report describes research sponsored by EPRI.

EPRI would like to thank the Institute of Nuclear Power Operations (INPO) for permission to access their database and use it as the primary source of heat exchanger operating experience events for this project. EPRI also thanks Exelon and John Potts, Exelon's corporate heat exchanger engineer, who assisted this work by providing extensive information on heat exchanger tubing integrity cases at their fleet. Thanks also go to Iver Jacobson of True North Consulting, who assisted by providing valuable comments on the work plan and suggesting the review of many operating experience cases included in this work.

This publication is a corporate document that should be cited in the literature in the following manner:

Nondestructive Evaluation: Operating Experience with Heat Exchanger Tubing Damage. EPRI, Palo Alto, CA: 2014. 3002003028.

PRODUCT DESCRIPTION

This report describes the work performed to capture balance-of-plant (BOP) heat exchanger tubing damage operating experiences at nuclear stations.

Background

Utilities do not have an easy way currently to share operating experience of heat exchanger tube failures. Because of the lack of availability of a common tube failure database to manage a tube bundle integrity program, utilities rely on the plant's own recorded history and consultation with vendors to make inferences on material performance and the effectiveness of inspection programs. Accordingly, it would be beneficial to have access to a database that material performance and inspection programs can be benchmarked against. Indeed, such a database is currently available for other systems at nuclear stations.

Objective

The objective of the work was to capture operating experience and lessons learned on BOP heat exchangers and to document the information to assist in inferring nondestructive examination (NDE) effectiveness and heat exchanger material performance.

Approach

To achieve the stated objectives, the project queried the Institute of Nuclear Power Operations (INPO) database as the primary source of heat exchanger events. Once these events were captured, questions were sent to the utilities authoring the reports to obtain supplemental information not provided in the INPO report. In addition, some utilities contributed additional operating experience cases not included in the INPO database.

Results

The work captured tubing damage operating experience cases in condensers, feedwater heaters, emergency diesel generator heat exchangers, closed cooling water heat exchangers, residual heat removal heat exchangers, and seal oil coolers. Also, some of the cases included a comparison between the NDE evaluations and the corresponding tube laboratory analysis.

The information captured was mapped into six categories for each heat exchanger service: material type, damage mechanism, inspection technique, service life, cleaning and inspection frequency, and plugging criteria.

Applications, Value, and Use

The information obtained in this work can be used by utilities to benchmark their material performance and inspection information against the experiences reported at other plants. In this report, the information is presented in table form. It is foreseen that, in the future, the captured material will grow and the database will migrate to an online query system with the capability to make parametric comparisons.

Keywords
Damage
Heat exchanger
Leaks
Tubing

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1 INTRODUCTION

The objective of this work was to capture operating experience (OE) and lessons learned on balance-of-plant (BOP) heat exchanger (HX) tubing damage and document the information to assist in:

- Inferring nondestructive evaluation (NDE) effectiveness and identifying technology gaps
- Inferring HX material performance to assist plants in their tubing selection

2 BACKGROUND

Utilities do not have an easy way to share operating experience of HX tube failures. Because of the lack of availability of a common tube failure database to manage a tube bundle integrity program, the HX program manager relies on the plant's own recorded history and on consultation with vendors to make inferences on material performance and the effectiveness of inspection programs. Accordingly, it would be beneficial to utilities to have access to a database that material performance and inspection programs can be benchmarked against. Indeed, such a database is currently available for steam generators, but is lacking for HXs.

A major challenge faced when putting together the skeleton of such a database is that within a nuclear station there is a wide variety of HX services, and within a tube bundle there are several types of tube damage and support plate degradation mechanisms that are present depending on the type of service. This variety creates a wide range of options that are difficult to classify and ultimately optimize.

This report describes the methodology used to classify information related to HX material and inspection operating experiences.

3
DATABASE STRUCTURE, CATEGORIES, AND PARAMETERS

In laying out the structure of the database, the first step was to create a vision on how the information is to flow when all the information is in place.

It is envisioned, then, that on one end information is provided on the HX service environment and flow velocity. This information determines the material selection and the corrosion damage morphology.

At the other end, information is provided on the tube failure history. The tube failure history and corrosion damage morphology then determine the inspection technique and implementation frequency.

This flow of information is shown graphically in Figure 3-1. As seen in the figure, distinction is made between damage that originates in the tube's internal diameter (ID), the tube's outside diameter (OD), and the shell side of the HX.

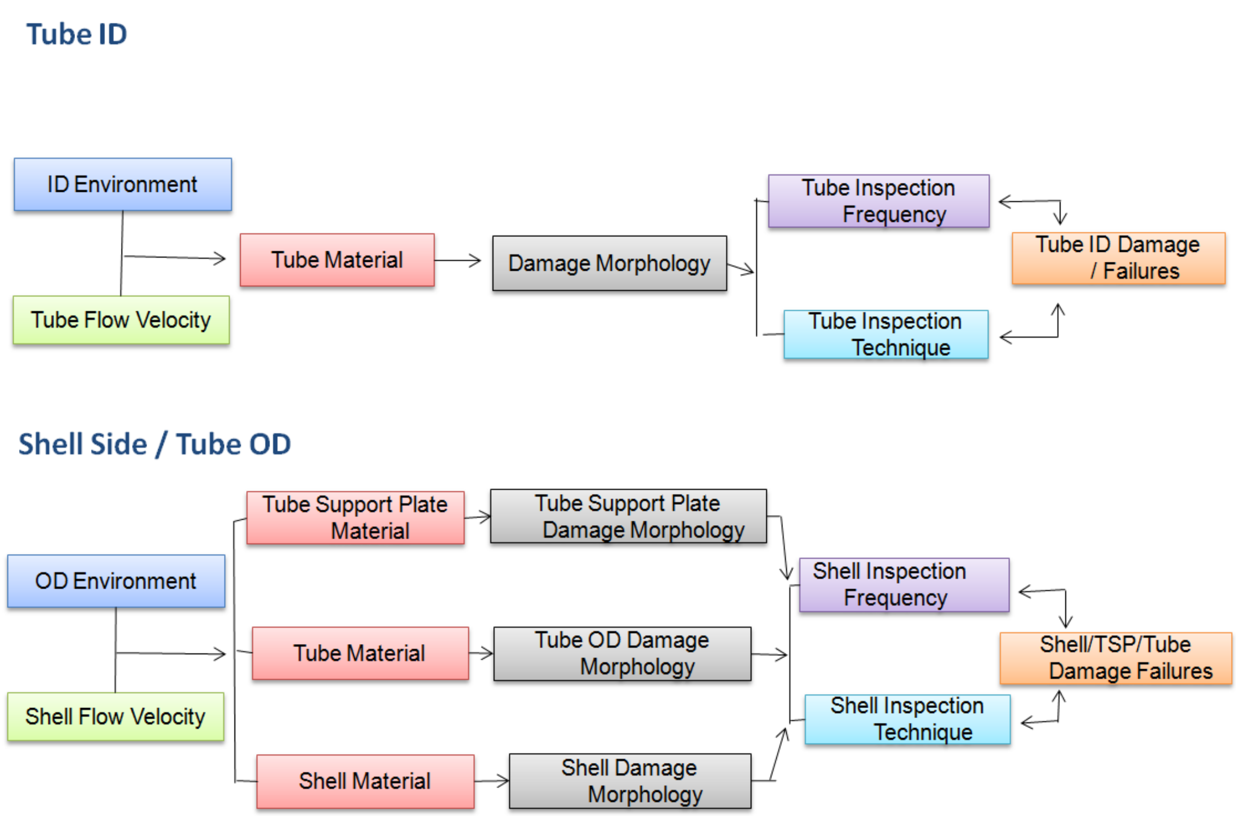

Figure 3-1
Database Flow Diagram

3.1 Categories

Using Figure 3-1 as a basis, the following database categories were identified:

- Corrosion environment
- Material type
- Damage mechanism
- Tube cleaning and inspection frequency
- Tube plugging criterion
- Inspection technique
- Tube service life

Information about these categories for the various HX services was then investigated in this work.

Note that the "inspection frequency" and "plugging criterion" were treated as separate categories. In HX inspection, the plugging criterion plays the role of corrosion rate estimation. In other inspection disciplines, such as flow-accelerated corrosion, corrosion rate is calculated from the wall thickness measurement histories obtained from a component at a particular location. Under this methodology, the inspection frequency is calculated by estimating the time when the corrosion process will reduce the remaining wall thickness to a critical value; the next inspection is then scheduled at approximately an interval of one-half of this estimated time. By comparison, for HXs, the program manager selects a plugging criterion value so as to minimize the chance that the tubing might fail between inspections or, in some cases, between outages. If tubing leak histories occur ahead of schedule, the plugging criterion value is modified (reduced) to synchronize the tubing life with the inspection plan. Accordingly, plugging criterion adjustments in HXs play the same role as corrosion rate estimations in other inspection activities.

When searching for HX operating experience information, the author found that "corrosion environment" information was not readily available. Plants collect this information via a variety of techniques including performing periodic sampling and chemical analysis of the water, tracking the corrosion history of metallic coupons, and deploying corrosion rate sensors. Because of the complexity of the task, a database that encompasses corrosion environment information is a subject unto itself, and in the absence of readily available information, the subject was not included in this work.

When capturing the "tube service life" category, it was noticed that tubes that were affected by a single damage mechanism, presumably the one that the material was designed for, exhibited a relatively long life, whereas tubes that were affected by a combination of two or more damage mechanisms had a significantly reduced service life. So when documenting the cases, attention was given to the presence of multiple corrosion processes.

Also, under the "tube service life" category, the survey information could not properly distinguish between time-to-leak and time-to-retube. For a plant, the time-to-retube is the more important economic decision, while from a point of view of inspection frequency, the time-to-leak is the dominant factor.

3.2 Heat Exchanger Types

The HXs used in nuclear stations were divided into the following service types:

- Condenser
- Feedwater heater
- Emergency diesel generator
- Closed cooling water HXs
- Residual heat removal HXs
- Seal oil coolers

The emergency diesel generator system includes the intercooler, jacket water, and lube oil HXs.

The closed cooling water system includes the HXs used to remove heat from systems that carry radioactive fluids and are cooled by other systems (that is, service water) that are cooled by water from the ultimate heat sink. In boiling water reactors (BWRs), the system is divided into turbine and reactor cooling systems, whereas in pressurized water reactors (PWRs), no distinction is made.

Seal oil coolers are typically used to remove the heat from lubricating fluids in rotating equipment. These coolers are normally small straight shell and tube HXs with the seal oil on the shell side and cooling water on the tube side.

4
HEAT EXCHANGER OE SURVEYS

The project used the INPO database as the primary source of HX events. For this work, events occuring from 2002 to March 2013 were used. Once these events were captured and mapped to the categories listed in Section 3.1, questions were sent to the utilities that had authored the reports to obtain supplemental category information not provided in the OE report.

In summary, 124 OE cases were captured as shown in Table 4-1:

Table 4-1
HX OE cases captured

Heat Exchanger	OE Events
Condenser	38
Feedwater heater	25
Emergency diesel generator	12
Closed cooling water	18
Residual heat removal	9
Seal oil cooler	12
NDE events	10
Excluded	58

As seen in the table, 58 OE cases were excluded. This was because the root cause of the events was due to unusual events. For example, tube plug failures and foreign material intrusion are not caused by in-service HX material performace issues.

Next, the cases for each HX type will be detailed. The cases will begin with a summary followed by a discussion of the category parameters captured.

4.1 Condenser OE Cases Captured

Of the HX types, the condenser received the most attention in the survey with 38 captured OE events. Table 4-2 summarizes the OE findings.

Table 4-2
Summary of OE captures for condensers

Material	Damage	Service Life	Inspection Frequency	Plugging Criteria	Inspection Type
Admiralty brass	General ID wall loss/wear	15 y	N/C	N/C	ECT bobbin coil not effective
	Underdeposit corrosion				ECT bobbin coil
	OD steam corrosion				ECT bobbin coil
CuNi 90/10	Underdeposit corrosion	N/C	N/C	70% TW	ECT bobbin coil
	OD steam erosion	N/C	N/C	50% TW	ECT bobbin coil (amplitude)
304 SS	Underdeposit corrosion	15 y	N/C	N/C	ECT bobbin coil
	OD steam erosion /droplet impingement	20 y	N/C	N/C	ECT bobbin coil not effective
	ID inlet erosion	10 y	N/C	N/C	ECT bobbin coil
SeaCure	OD steam erosion /droplet impingement	10 y	N/C	N/C	ECT magnetic saturation
Titanium	OD steam erosion	N/C	N/C	N/C	ECT bobbin coil
	High-cycle fatigue (at scratches)	4 to 5 y			ECT bobbin coil not effective

N/C = Not Captured

As seen in the table, the condenser OE reported tubing leaks caused by both ID and OD corrosion damage mechanisms.

For ID damage, wear, underdeposit corrosion, and tube inlet erosion were reported. To address these ID damage mechanisms, some plants installed corrosion-resistance materials. In the material list shown in the table, admiralty brass is considered the most corrosion susceptible, followed by 90/10 copper-nickel (CuNi 90/10), 304 stainless steel (304 SS), seacure ferritic stainless steel (SeaCure), and titanium, in that order.

For OD damage, steam erosion and droplet impingement was reported. In these cases, the tubes located in the outer perimeter of the condenser were the most susceptible. To address this susceptibility, some plants installed SeaCure tubes in the outer perimeter of the bundle, while other plants upgraded to titanium tubes altogether.

Titanium was reported to exhibit premature cracking failure at some plants. This premature failure was reported to result from the combination of flow-induced vibration and cracking initiated at OD scratches. The flow-induced vibration may have been the result of non-optimal tube support span, while the scratches were believed to have been introduced during tubing installation.

Condenser leak detection was performed primarily by a combination of video cameras and helium leak tracing techniques.

Condenser tubing integrity examinations were performed primarily with bobbin-coil sensor eddy current (ET) methods. For some types of corrosion damage, the bobbin-coil ET sensor was reported to be not effective. These cases included:

- Tube wear
- OD droplet impingement
- Circumferential cracks at tube supports
- High-cycle fatigue cracks

Also, for OD steam erosion, the analysis techniques were modified and "signal amplitude response" methods were used instead of the standard signal phase response assessment. Finally, for SeaCure tubing, magnetic saturation ET techniques were used.

Tables 4-3 to 4-6 list the condenser survey results details. Because of the number of entries, the data for a particular event were separated into two tables. Accordingly, Tables 4-3 and 4-4 are Part 1 and Part 2 of the same cases. The same applies to Tables 4-5 and 4-6.

Table 4-3
OE captures for condensers – 2008 to March 2013, Part 1

Case	Date	Material	Diameter/Wall	Event	Testing Method
1	8/8/2013	304 SS	1"/0.028"	Tube leaks	N/C
2	11/2/2012	N/C	N/C	Two tube leaks	Borescope
3	11/27/2012	N/C	N/C	Tube leak	Borescope
4	7/6/2012	304 SS	1"/22 BWG – 0.028"	Tube cracks caused plugging	ET
5	2/29/2012	304 SS	7/8"/0.028"	Seam weld lack of fusion	ECT
6	2/22/2012		N/C	Tube leak	Chemistry, helium
7	2/21/2012	Carbon steel	N/C	Hotwell and false bottom cracking	Visual
8	12/19/2011	Titanium	N/C	Leak	Helium, visual
9	10/7/2011	304 SS	N/C	Leak	Helium
10	9/21/2011	Titanium	0.875"/0.028"	Tube leak	Borescope, ET

Table 4-3 (Continued)
OE captures for condensers – 2008 to March 2013, Part 1

Case	Date	Material	Diameter/Wall	Event	Testing Method
11	5/26/2011	SeaCure	N/C	Tube leaks	Chemistry
12	5/23/2011	Admiralty brass	N/C	Tube leaks	ET
13	1995	Admiralty brass	N/C	Replacement	ET
14	1/11/2011	Admiralty brass	N/C	Tube leak	Chemistry, conductivity
15	5/26/2010	Titanium	N/C	Tube leaks	Chemistry
16	12/7/2009	304 SS	1"/0.028"	Tube leaks (11 leaks since 2004)	Chemistry – ECT ineffective
17	7/8/2009	304 SS	1"/0.028"	Tube leaks and circ cracks	ECT bobbin, ECT matrix, and rotating pancake (MRPC)
18	3/20/2009	SeaCure	N/C	Tube leak	Chemistry, helium, ECT
19	2/25/2009	Admiralty brass	N/C	Tube leak	Sodium
20	4/30/2008	304 SS	1"/0.028"	Circ cracks 1″ from tubesheet	Visual

1″ = 25.4 mm

Table 4-4
OE captures for condensers – 2008 to March 2013, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
1	8/8/2013	Liquid droplet impingement near the tube-to-support plates.	N/C	N/C	N/C
2	11/2/2012	Linear splits caused by tube wear assisted by tube scoring during installation.	N/C	N/C	N/C
3	11/27/2012	Linear splits caused by tube wear assisted by tube scoring during installation.	N/C	N/C	N/C
4	7/6/2012	Fatigue linear cracks found by ET at the tube weld seam.	N/C	N/C	N/C

Table 4-4 (Continued)
OE captures for condensers – 2008 to March 2013, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
5	2/29/2012	Seam weld lack-of-fusion fabrication defects – ECT significantly oversized the defects.	N/C	N/C	N/C
6	2/22/2012	Unknown.	N/C	N/C	N/C
7	2/21/2012	Cyclic fatigue.	N/C	N/C	N/C
8	12/19/2011	High energy flow impingement probably caused by heater drain tank sparger failure.	N/C	N/C	N/C
9	10/7/2011	Small pit at tube-to-tubesheet joint too difficult to detect by helium – coating applied.	N/C	N/C	N/C
10	9/21/2011	High-cycle axial fatigue initiated at OD scratches – crack growth: Three cycles – TSP separation further apart than common.	N/C	N/C	N/C
11	5/26/2011	Pitting caused by steam erosion impingement, RFET not effective, Mag-sat ET demonstrated on failed tube.	N/C	N/C	N/C
12	5/23/2011	Pitting near outlet of tube, tube general wall thinning, OD corrosion, linear extrusion.	5639 days	N/C	N/C
13	1995	Pitting, erosion/general wall thinning.	5940 days	N/C	N/C
14	1/11/2011	Internal wear, tube leak due to wear in combination with fabrication linear extruded defects, ECT ineffective at detecting wear.	N/C	N/C	N/C
15	5/26/2010	Groove indentations caused by scale cleaning cutter blades followed by fatigue cracks – ECT ineffective – working with EPRI.	Four years from cleaning	N/C	N/C
16	12/7/2009	Liquid droplet impingement erosion – ECT bobbin coil ineffective at detecting leaks – Pit size OD 0.027" wide, ID 0.006" wide +15% OD erosion.	20 years	N/C	N/C

Table 4-4 (Continued)
OE captures for condensers – 2008 to March 2013, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
17	7/8/2009	Pin hole leaks adjacent to TSP caused by droplet impingement, circumferential cracks at TSP 75% TW, ETC undersized pits and significantly oversized wear – Circ cracks found by matrix probe. Circ cracks previously reported caused by flow-induced vibration.	N/C	N/C	N/C
18	3/20/2009	OD steam erosion.	10 years	N/C	N/C
19	2/25/2009	Unknown.	N/C	N/C	N/C
20	4/30/2008	Tube high-cycle fatigue circ. cracks caused by flow-induced vibration.	N/C	N/C	N/C

1″ = 25.4 mm

Table 4-5
OE captures for condensers – 2002–2007, Part 1

Case	Date	Material	Diameter/Wall	Event	Testing Method
21	10/2/2007	Admiralty brass	N/C	Tube leak	Conductivity
22	12/5/2006	CuNi 70/30	N/C	Tube leak	Chemistry
23	5/25/2006	Admiralty brass	1"/0.049"	Tube leaks	Chemistry
24	3/12/2006	CuNi 70/30	N/C	Tube leak	Conductivity - ECT
25	3/7/2006	304 SS	7/8"/0.028"	Tube leaks – ID pitting	ECT
26	1/17/2006	304 SS	N/C	Tube leaks	Chemistry + helium plenum
27	12/20/2005	Titanium	N/C	Tube leak	Sodium, ECT
28	12/3/2005	304 SS	7/8"/0.028"	Tube sheared	Chemistry
29	2005	304 SS	1"/0.028"	Tube leaks	N/C
30	12/25/2004	SS	N/C	Turbine oil waste (slop) drain pipe crack	Loss of vacuum
31	6/4/2004	N/C	N/C	Tube leaks	Chemistry

Table 4-5 (Continued)
OE captures for condensers – 2002–2007, Part 1

Case	Date	Material	Diameter/Wall	Event	Testing Method
32	12/21/2003	CuNi 70/30	N/C	Tube leak	Chemistry, tracer, ECT
33	11/7/2003	304 SS	7/8"/0.028"	Tube leaks – ID pitting + OD steam erosion	N/C
34	5/3/2003	Admiralty brass	1"/0.049"	Tube cracks	ECT
35	4/2/2003	N/C	N/C	3/8″ tube support plate crack	Visual
36	1/14/2003	Titanium	N/C	Tube leak	Chemistry - SG
37	5/11/2002		N/C	Tube leak	Chemistry, leak test and ECT
38	2/26/2002	304 SS	7/8"/0.028"	Tube leaks – ID pitting	ECT

Table 4-6
OE captures for condensers – 2002–2007, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
21	10/2/2007	Pitting – MIC – Decaying organic matter > sulfides > MIC.	N/C	N/C	N/C
22	12/5/2006	Foreign object believed caused tube leak. ET at previous outage did not detect wear.	N/C	N/C	N/C
23	5/25/2006	OD droplet impingement – ECT could not detect the leak locations.	N/C	N/C	N/C
24	3/12/2006	OD steam impingement erosion in inner 3rd tube row – outer two tube rows made out of SeaCure.	N/C	N/C	50% TW for SeaCure outer rows, 70% for inner rows
25	3/7/2006	Manganese-chloride pitting underdeposit corrosion.	N/C	N/C	N/C
26	1/17/2006	Tubes in perimeter – possible causes steam impingement erosion.	N/C	N/C	N/C
27	12/20/2005	Fretting of tube caused by steam impingement in the vicinity of dump valve where deflector plate had fallen.	N/C	N/C	N/C

Table 4-6 (Continued)
OE captures for condensers – 2002–2007, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
28	12/3/2005	Cyclic bending fatigue caused by inadequate staking (support) and high steam flow rate.	N/C	N/C	N/C
29	2005	Leaks caused droplet impingement and steam erosion.	N/C	N/C	N/C
30	12/25/2004	High-cycle fatigue – cracks at bi-metallic weld.	N/C	N/C	N/C
31	6/4/2004	Fatigue, internal tubes – no foreign objects.	N/C	N/C	N/C
32	12/21/2003	OD steam impingement erosion in periphery tubing – tube plug criterion changed from 70% to 60% for OD steam erosion.	N/C	N/C	60% TW for outer rows
33	11/72003	MIC and manganese-choride pitting under silt deposits – OD grooving due to steam erosion.	N/C	N/C	N/C
34	5/3/2003	OD stress corrosion cracking caused by pre-service storage contamination.	N/C	N/C	N/C
35	4/2/2003	Flow-induced vibration high-cycle fatigue.	N/C	N/C	N/C
36	1/14/2003	Cracks initiated at scratches.	N/C	N/C	N/C
37	5/11/2002	Underdeposit pitting – SeaCure material use in Unit 1.	N/C	N/C	N/C
38	2/26/2002	MIC and manganese-choride pitting under silt deposits.	N/C	N/C	N/C

4.2 Feedwater Heater OE Cases Captured

As listed in Table 4-1, 25 feedwater heater OE cases were captured. Table 4-7 summarizes the OE findings.

Table 4-7
Summary of OE captures for feedwater heaters

Material	Damage	Service Life	Inspection Frequency	Plugging Criteria	Inspection Type
304 SS	Tube wear at supports	29 y	6 y	50% TW	ECT bobbin coil
	Tube wear at supports + high-cycle fatigue (high-velocity operation)	3 y	N/C	N/C	ECT bobbin coil
	Tube wear – steam impingement near drain cooler	30 y	N/C	N/C	ECT bobbin coil
Carbon steel	Internals corrosion	24 y	N/C	N/C	Visual
	Steam impingement plate failure	14–28 y	N/C	N/C	Visual
	Vessel shell erosion	25 y	N/C	N/C	Pulsed eddy current

N/C = Not Captured

As seen in Table 4-7, the feedwater heater OE cases included leaks caused by OD corrosion, damage to the internals, the vessel shell, and the steam impingement plate. The tubing material for the cases was 304 SS, but the internals and vessel shell were made out of carbon steel.

For tubing, the damage mechanisms included wear or high-cycle fatigue. Tube wear was reported at the tubing supports or caused steam impingement near the drain cooler. Tubing high-cycle fatigue was caused by flow-induced vibration associated with high shell-side steam velocity. In the latter case, the OE indicated that HX manufacturers provide a “critical shell-side steam velocity” not to be exceeded because of flow-induced vibration concerns. However, plants that undergo power uprates sometimes find themselves in need of operating above the critical steam velocity recommendations. In addition, tube support enlargement and low-level drain cooler flashing are cited as enhancing tube vibration damage.

Premature tube failure was reported to be caused by the combination of tube wear at supports and high-cycle fatigue. In the cited event, the high-cycle fatigue may have been the result of operating at a high shell-side steam velocity.

Internals corrosion was reported to occur for various reasons including failure to remove non-condensable gases and improper steam flow motion. Inadequate non-condensable gas extraction was reported to be caused by vent channel or vent pipe failures. Improper steam flow was cited as the result of steam impingement plate dislodgement, tube support, or drain cooler shroud damage. This improper steam flow motion was suspected to cause tube failures and/or heater shell erosion.

Tubing integrity assessment was performed primarily with ET bobbin coil techniques. In addition to looking for tube wear at the supports, the techniques were sometimes modified to assess tube support enlargement.

The internals damage assessment was done primarily with video cameras.

Finally, the heater shell wear inspection was typically performed with a combination of pulsed ET and ultrasonic techniques. The pulsed ET was used for screening the shell wall thickness with the insulation in place. In the areas that were identified as suspect, the insulation was removed, and the remaining wall thickness was measured with ultrasonics.

Tables 4-8 to 4-11 list the details of the feedwater heater OE investigation results. As was done in Section 4.1, the data for a particular event were divided into two tables.

Table 4-8
OE captures for feedwater heaters – 2008 to March 2013, Part 1

Case	Date	Material	Diameter/Wall	Event	Testing Method
39	4/18/2013	304 SS	N/C	Level controller set too low – tube leak suspected	Water level
40	4/9/2012	N/C	N/C	Tube leaks (five tubes)	Flow rate
41	12/29/2010	304 SS	3/4"/20 AW	Tube leak and alternate drain valve failed	Heater level
42	4/23/2010	N/C	N/C	Tube leaks (12 tubes)	N/C
43	4/22/2010	N/C	N/C	Tube leaks	Mismatch feedwater flow, water leak test
44	4/14/2009	N/C	N/C	Tube ruptures (four tubes) and leaks (two)	Increased condensate flow, ECT
45	9/19/2009	N/C	N/C	Tube leaks	Video, ECT
46	4/23/2009	N/C	N/C	Tube ruptures, drain cooler shrouds and internals severely corroded	Visual, leak test, ECT
47	1/12/2009	304 SS	N/C	Tube ruptures (eight tubes) in top of drain cooler section	Pressure
48	4/11/2008	N/C	N/C	Tube ruptures (12 tubes)	Chemistry
49	3/7/2008	304 SS	3/4"/18 BWG – 0.049″	Tube rupture (two tubes)	Pressure, water levels, ECT bobbin
50	1/21/2008	N/C	N/C	Tube rupture	Water level, ECT

Table 4-9
OE captures for feedwater heaters – 2008 to March 2013, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
39	4/18/2013	Unknown.	N/C	N/C	N/C
40	4/9/2012	Unknown.	N/C	N/C	N/C
41	12/29/2010	Unknown.	To be replaced in 2015	N/C	N/C
42	4/23/2010	Tube extensively damaged exhibiting leaks (12 tubes) found. Root cause not established, although it is suspected that the damage was caused by vibration, steam flashing, or ID pitting. Leaking tube left unrepaired in previous outage – 100% inspection planned for next outage.	N/C	N/C	N/C
43	4/22/2010	Tube leaks caused by wear at supports adjacent to the drain nozzle. ET failed to detect wear.	N/C	N/C	N/C
44	4/14/2009	Flow-induced vibration – two phase flow because of tube support enlargement or low level in drain cooler flashing is also a possibility.	N/C	N/C	N/C
45	9/19/2009	Tube leaks found in the vicinity of a failed non-condensable gases vent. Video inspection of the severed vent channel suggested fatigue failure. Sampling of tubes pulled suggested that the tube leaks may have been caused by vibration-induced fretting.	N/C	N/C	N/C
46	4/23/2009	Tube ruptures caused by vibration and steam impingement from holes in the drain cooler shroud. The shroud damage was likely caused by steam impingement from the extraction steam inlet pipe located above the damaged areas. Long tube support spacing contributed to tube vibration. Shell ID erosion wall loss was also found.	N/C	N/C	N/C

Table 4-9 (Continued)
OE captures for feedwater heaters – 2008 to March 2013, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
47	1/12/2009	Tube vibration cracking at supports – Inadequate venting caused corrosion of internals (drain cooler shroud and tube supports) allowing steam to enter drain cooler section and caused tube vibrations. ECT procedure used did not detect precursor tube work hardening cracking damage. ECT "Absolute Drift" technique previously developed was not used.	28 years 299 days	N/C	N/C
48	4/11/2008	Baffle plate had a broken weld near failed tubes.	N/C	N/C	N/C
49	3/7/2008	Tubes rupture – flow-induced vibration – severed behind the tubesheet.	N/C	N/C	N/C
50	1/21/2008	Unknown.	N/C	N/C	N/C

Table 4-10
OE captures for feedwater heaters – 2002–2007, Part 1

Case	Date	Material	Diameter/Wall	Event	Testing Method
51	2/11/2007	Carbon steel	N/C	Shell and heater internals erosion	Shell OD NDT, visual
52	10/23/2007	304 SS	3/4"/20 BWG – 0.035"	Tube leak	ECT
53	5/21/2007	N/C	N/C	Impingement plate failure caused tube leaks	Visual
54	10/30/2006	N/C	N/C	Baffle plate in drain cooler degraded	ECT
55	8/28/2006	N/C	N/C	Tube leaks	Pressure in booster pump
56	1/25/2006	N/C	N/C	Tube leaks	N/C
57	12/6/2005	304 SS	3/4"/20 BWG – 0.035"	Tube leaks	Water level
58	10/20/2005	304 SS	5/8"/	ET indication sent for lab evaluation	ET

Table 4-10 (Continued)
OE captures for feedwater heaters – 2002–2007, Part 1

Case	Date	Material	Diameter/Wall	Event	Testing Method
59	2/12/2005	N/C	N/C	Tube rupture	Borescope
60	9/24/2004	304 SS	N/C	Tube leak	Drain flow increase, ECT
61	3/1/2004	Vents 304 SS	N/C	C-vent nozzle cracking due to IGSCC	Dye penetrant + UT
62	10/26/2003	N/C	N/C	Impingement plate and baffle plate cracks and weld damage	Visual - borescope
63	4/22/2002	N/C	N/C	Tube failures due to vibration	N/C

1″ = 25.4 mm

Table 4-11
OE captures for feedwater heaters – 2002–2007, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
51	2/11/2007	OD heater found to exhibit wall loss following inspection. After removing a portion of the shell for repairs, extensive erosion of the internals were found: the lower support beam had holes, the spacer tubes were eroded, and an 18″ section of the vent pipe fallen off. Periodic NDE of the shell performed and suggests shell and internals erosion correlate.	25 years	N/C	N/C
52	10/23/2007	TGSCC initiated at scoring marks and include chloride traces suggesting exposure during fabrication or unusual event.	N/C	N/C	N/C
53	5/21/2007	Impingement plate design defective – plate broke off causing rubbing on tubes causing the leaks, cable attached to plate ended up in isolation valve (FME).	N/C	N/C	N/C

Table 4-11 (Continued)
OE captures for feedwater heaters – 2002–2007, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
54	10/30/2006	No. 5 heaters had increased baffle damage detected and tracked with ECT. Damage appears to have occurred after power uprate. No tube vibration damage indication was found and no tubes were plugged. Appears baffle spacing close enough to limit vibration.	N/C	N/C	N/C
55	8/28/2006	Vibration-induced wear at tube support plate, caused by localized high-velocity steam flow. Tubes with 48% to 55% in 2000. Inspection frequency revised to 6 years, 60% wall loss plug criteria revised up.	Wear rate 52%/6 y	N/C	N/C
56	1/25/2006	Vibration damage caused by design weakness or tube degradation.	N/C	N/C	N/C
57	12/6/2005	High-cycle fatigue caused by flow-induced vibration due to tube/support wear – shell-side velocity run at 114% of critical during a three-year period, should be < 75%.	N/C	N/C	N/C
58	10/20/2005	TGSCC 90% deep found in pulled tube, ET depth within 15% - in another pulled tube ET calls were false.	N/C	N/C	N/C
59	2/12/2005	Not established.	N/C	N/C	N/C
60	9/24/2004	Tube fretting caused by impingement plate becoming dislodged.	N/C	N/C	N/C
61	3/1/2004	IGSCC.	N/C	N/C	N/C
62	10/26/2003	Flow-induced vibration on the impingement plate – impingement plate weld found to be of poor quality.	28 years	N/C	N/C
63	4/22/2002	Vibration – excessive shell-side velocity caused by power upgrade.	N/C	N/C	N/C

4.3 Emergency Diesel Generator HX OE Cases Captured

The emergency diesel generator system includes three HXs also called *coolers*: the lubrication (lube) oil, the jacket water, and the intercooler HXs. The survey captured 12 OE cases for these HXs, which are summarized in Table 4-12.

Table 4-12
Summary of OE captures for emergency diesel generator HXs

Material	Damage	Service Life	Inspection Frequency	Plugging Criteria	Inspection Type
Lube and Jacket Water					
Admiralty brass	Tube underdeposit corrosion	31 y	2 y	59% TW	ECT bobbin coil
	Tube inlet erosion	12y–16 y	N/C	55% TW	ECT bobbin coil (amplitude)
Intercooler					
Admiralty brass	Tube inlet corrosion	11y–16 y	N/C	55% TW	ECT bobbin coil (amplitude)
CuNi 90/10	Tube inlet erosion	21 y	N/C	N/C	ECT bobbin coil (amplitude)

N/C = Not Captured

As seen in the table, the tubing material used in these heaters included admiralty brass and CuNi 90/10.

Some of the HXs were reported to be operated intermittently, with periods of stagnant flow. Accordingly, tubing in these HXs was found to be susceptible to underdeposit corrosion. A two-year cleaning and inspection frequency was reported that was used for underdeposit corrosion management during a 31-year service life.

When the HXs were in operation, the OE reported cases of high-flow velocities that caused tube inlet erosion damage, effectively reducing their service life. The “high-flow velocity” threshold depended on the tubing material used. For admiralty brass and CuNi 90/10, the thresholds cited were 6 ft/sec and 8 ft/sec (1.8 and 2.4 m/sec), respectively, indicating that the latter material was more resistant to inlet erosion corrosion.

In addition, tubing in floating head HXs were reported to be susceptible to circumferential cracking at the tubesheet.

Examination for tubing integrity was performed primarily with ET bobbin coil methods. When inlet erosion was the primary concern, the amplitude drift calibration technique was used for sizing the damage.

Tables 4-13 to 4-16 list the details of the emergency diesel generator HX survey results. As was done in the sections above, the data for a particular event were divided into two tables.

Table 4-13
OE captures for emergency diesel generator HX – 2008 to March 2013, Part 1

Case	Date	Material	Diameter/Wall	Event	Testing Method
64	7/4/2012	Admiralty brass	N/C	Tube leak	Crankcase pressure raise
65	10/1/2009	Carbon steel SA53B	N/C	Head pinhole leak	Visual
66	2/26/2009	Admiralty brass	N/C	Tube leaks	Contaminated water, mechanical, ECT
67	1/25/2009	Admiralty brass	N/C	Tube leak	Pressure increase, pressure test
68	11/19/2008	N/C	N/C	Channel wall corrosion	Visual, UT
69	7/21/2008	N/C	N/C	Tube leak	Oil contamination, ECT, leak test

Table 4-14
OE captures for emergency diesel generator HX – 2008 to March 2013, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
64	7/4/2012	N/A – tube failure in the lubrication oil HX suspected, pressure test not effective at locating the leak.	N/C	N/C	N/C
65	10/1/2009	MIC localized corrosion, inhibitor injection deficient, no UT monitoring previously performed.	N/C	N/C	N/C
66	2/26/2009	Jacket water HX tube leaks caused by inlet erosion due to high-flow velocity (>12 ft/s) – mechanical measurements to determine remaining tube wall found not to be accurate.	N/C	N/C	N/C
67	1/25/2009	Leaking tube had circumferential cracks near the floating-end tubesheet – reason unknown.	N/C	N/C	N/C
68	11/19/2008	Channels never cleaned or inspected, tubercles formed, wall loss 65% under tubercles.	N/C	N/C	N/C
69	7/21/2008	Lube oil HX tube leaks caused by erosion corrosion at tube-tubesheet area past the plastacor coating caused by excessive flow rate. ECT ineffective. ECT procedure modified to use signal amplitude for erosion detection.	12 years	N/C	N/C

1 ft/s = 0.31 m/s

Table 4-15
OE captures for emergency diesel generator HX – 2001–2007, Part 1

Case	Date	Material	Diameter/Wall	Event	Testing Method
70	6/20/2007	CuNi 90/10	3/4" OD – 18 BWG	Tube leaks	N/C
71	2/12/2007	N/C	N/C	Tube leaks	ECT
72	4/23/2006	Admiralty brass	N/C	Tube leaks	Leak test, ECT, visual
73	2/7/2006	Admiralty brass	5/8"/0.049" wall	Pitting (seven tubes plugged in jacket cooling water HX and nine tubes plugged in lube oil cooler HX)	ECT
74	1/4/2002	Admiralty brass	3/4"/0.049" wall	Erosion corrosion (severe)	ETC – absolute drift
75	5/22/2001	N/C	N/C	Tube cracking	Visual

1″ = 25.4 mm

Table 4-16
OE captures for emergency diesel generator HX – 2001–2007, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
70	6/20/2007	Intercooler tube leaks caused by erosion corrosion in 1st 1.5" past the coating which was applied up to 1.3" – Flow velocity 9 ft/sec >8 ft/sec threshold.	21 years	N/C	N/C
71	2/12/2007	Intercooler tube inlet erosion corrosion in 1st 6" due to high-flow rate (1850 gpm) – No coating applied – ECT within 1" from tubesheet not effective but further downstream. Also visual not effective at damage detection.	11 years	N/C	N/C
72	4/23/2006	Jacket water HX tube leaks after two years of service due to SCC at tube-to-tubesheet interface – probably caused by floating head HX design – previous HX had tube life of 8–12 years – plan to use specialized ECT (X-probe) at next inspection.	2 years	N/C	N/C

Table 4-16 (Continued)
OE captures for emergency diesel generator HX – 2001–2007, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
73	2/7/2006	Pitting wall loss > 59% per ECT inspection in jacket cooling and lube oil HXs – Low-flow operation – Possible mechanisms: underdeposit corrosion and dezincification, HX operated monthly, flow stagnant for the remainder 30 days. DAEC did not eddy current test the EDG HXs in the past.	31 years	2 years	59%
74	1/4/2002	Severe corrosion was found with ECT in the intercooler HX and also present in the jacket water and lube oil HXs. Corrosion mechanism for the intercooler was suspected to be erosion/corrosion. The intercooler was operated at flows of 5–10 fps; the recommended value is 6 fps. Dealloying may also have been present. Dezincification conditions are favored during periods of stagnant operation.	16 years	N/C	55%
75	5/22/2001	Finned tube cracks at the soldered joints caused by swelling and vibration – Corrosion of supports due to salt-laden atmosphere and thermal cycling were the drivers.	N/C	N/C	N/C

1″ = 25.4 mm
1 gpm = 3.8 lpm
1 ft/s = 0.31 m/s

4.4 Closed Cooling Water HX OE Cases Captured

As mentioned in Section 3.2, the closed cooling water system includes the HXs used to remove heat from systems that carry radioactive fluids. The survey captured 12 OE cases for these HXs, which are summarized in Table 4-12.

Table 4-17
Summary of OE captures for closed cooling water HXs

Material	Damage	Service Life	Inspection Frequency	Plugging Criteria	Inspection Type
Admiralty brass	Tube underdeposit corrosion	35 y	3 y	60% TW	ECT bobbin coil
	Tube aggressive underdeposit corrosion	1.5–5 y	1.5–3 y	N/C	ECT bobbin coil (Undersized pits)
	Tube OD wear at supports	35 y	3 y	45% TW	ECT bobbin coil
	Tube circumferential cracking at supports	15 y	1.5 y	N/C	ECT bobbin coil (Not effective)
CuNi 90/10	Tube underdeposit corrosion	23 y	4 y	50% TW	ECT bobbin coil
	Tube aggressive underdeposit corrosion	1 y	N/C	N/C	N/C
	Tube fatigue circumferential cracking at corroded areas	N/C	N/C	N/C	ECT bobbin coil (Not effective)
304 SS	Tube underdeposit corrosion	14 y	0.5 y	N/C	ECT bobbin coil
AL6XN	No damage reported	N/C	N/C	N/C	N/C

N/C = Not Captured

As listed in the table, the tubing material used in these HXs included admiralty brass, CuNi 90/10, 304 SS, and AL6XN.

Some of HXs were reported to be susceptible to underdeposit corrosion. OE reported that long tubing service life was achieved with periodic cleaning and inspection. However, in some cases, premature tube failure was experienced when the HXs were operated intermittently and a “wet layup” procedure was used. In these cases, the combination of underdeposit corrosion and de-alloying mechanisms resulted in an aggressive corrosion environment that reduced the service life.

Cases of high shell-side flow velocities were also reported, which caused tube OD wear damage at the supports. In some of these cases, circumferential cracking at the supports was also reported, which may have been caused by a combination of high-flow velocity and long tubing support spans.

Examination of tubing integrity was performed primarily with ET bobbin coil methods. In the ET examinations, the plugging criterion used was higher for ID-initiated corrosion (underdeposit corrosion) than for OD-initiated damage (tube wear). When assessing aggressive ID corrosion cases, ET was reported to undersize the pitting damage because a custom calibration standard was not used. Finally, ET was found to be not effective at the detection of circumferential cracking near supports.

Tables 4-18 to 4-21 list the details of the closed cooling water HX survey results. As was done in the sections above, the data for a particular event were divided into two tables.

Table 4-18
OE captures for closed cooling water HX – 2008 to March 2013, Part 1

Case	Date	Heat Exchanger	Material	Diameter/Wall	Event	Testing Method
76	6/12/2014	Closed cooling water HX (all four HXs)	Copper	3/4"/0.049"	Tube end ID erosion and ID pitting	ECT
77	7/12/2012	Closed cooling water HX	CuNi 90/10	3/4"/18 BWG-0.049"	Tube leak – extensive damage found with ECT	Tank level, ETC
78	5/24/2012	Turbine building closed cooling water HX 2A	Admiralty brass	3/4"/0.049"	Tube end erosion	ECT
79	5/7/2012	Reactor building closed cooling water HX 3A	Admiralty brass	3/4"/0.049"	Tube leaks	Air test, ECT
80	9/9/2011	Component cooling water HX	304 SS	N/C	Multiple leaks	Tank level, ECT
81	12/31/2009	Let down cooler – component cooling water system	N/C	N/C	Tube leaks	Radio nuclides detection
82	10/23/2009	Excess letdown residual heat removal HX	N/C	N/C	Tube leak	N/C
83	4/21/2008	Component cooling water HX room cooler	CuNi	N/C	Tube leaks	ECT

1″ = 25.4 mm

Table 4-19
OE captures for closed cooling HX – 2008 to March 2013, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
76	6/12/2014	Tube-end ID erosion and widespread ID pitting found by ECT with pit depths greater than 30% TW. Sediment accumulations (sand, silt, algae) regularly found on tubesheets.	40 years	N/C	N/C
77	7/12/2012	Damage: (BWR) turbine building closed cooling water HX had tube leak failure. The HX is original equipment with 35 years of service. Upon ECT examination, extensive ID pitting and some OD wall loss at tube supports were found with 23% of tubing having wall loss estimates > 70%. Laboratory analysis of sampled tubing confirmed general ID corrosion and tube support wear. ECT may have overestimated ID wall loss – ECT standards revised to address overcalls.	35 years	1 year	60% TW for ID pitting / 45% TW for OD wear
78	5/24/2012	Tube end erosion found with ECT. ECT comparison with laboratory measurements was accurate.	N/C	N/C	N/C
79	5/7/2012	ID inlet erosion and ID pitting. Chemical inhibitors added 10 years ago. ETC oversized erosion wall loss.	40 years	N/C	N/C
80	9/9/2011	Underdeposit/MIC pitting caused by underdeposit and/or MIC due to material susceptibility and low-flow velocity – cleaning and inspection changed from 52 to 26 weeks.	14 years	0.5 year	N/C
81	12/31/2009	Letdown helical design HX manufactured by Graham Co. – probable leak cause: fatigue cracking – flow-induced vibration – no root cause or NDE done.	16 years	6 years	N/C
82	10/23/2009	Excess letdown residual heat removal HX tube leak caused by fretting at the baffle plate due to emergency operation at high shell-side (RCS) flow rate above the HX design value.	N/C	N/C	N/C
83	4/21/2008	Carrier Aerofin U and H cooler with CuNi tubes exhibited leaks caused by underdeposit corrosion/MIC pitting. Coolers were on a four-year preventive maintenance schedule and in 2002, a change in the eddy through-wall acceptance criteria was made. However, leaks developed ahead of maintenance schedule so it is planned to replace the heaters.	23 years	4 years	50% TW

Table 4-20
OE captures for closed cooling water HX – 2001–2007, Part 1

Case	Date	Heat Exchanger	Material	Diameter/Wall	Event	Testing Method
84	4/4/2007	Component cooling water HX	Brass	5/8"/0.049"	Tube pits 75% TW in 18 months	ECT and destructive analysis
85	2006	Stator cooling HX 1A	CuNi 90/10	3/4"/18 BWG-0.049"	Tube pitting	ECT and destructive analysis
86	8/23/2005	Turbine building closed cooling water HX	CuNi 90/10	3/4"/0.049"	Tube leaks 100% TW in 12 months – No passivation after tubes installed	Chemistry
87	6/29/2004	Reactor building closed cooling water HX – 3B	Admiralty brass	N/C	Tube leaks	Air test, ECT
88	4/16/2004	Component water cooling HX	CuNi 90/10	N/C	Tube cracking	Component cooling water tank level
89	6/20/2002	Component water cooling HX	N/C	N/C	Tube leak	ECT
90	5/13/2002	Component water cooling HX	N/C	0.050"	Tube pin hole leaks	ECT
91	5/2/2002	Component water cooling HX	N/C	N/C	Circumferential tube cracks not detected by Bobbin ECT	Visual
92	9/23/2002	Turbine building closed cooling water HX	Admiralty brass	5/8"/18 BWG-0.049"	Tubes found severely corroded	ECT
93	2/14/2002	Recirculating cooling water HX	N/C	N/C	Extensive tube pitting	ECT

1″ = 25.4 mm

Table 4-21
OE captures for closed cooling water HX – 2001–2007, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
84	4/4/2007	Underdeposit corrosion due to low-flow velocity (< 1 ft/sec) caused high pitting growth rates – ECT undersized pits – Changed flush cleaning (5–6 ft/s) to every 12 weeks from 18-month period and revised ECT technique or plug criteria until corrosion mitigated.	75% TW/18 months	1.5 years	N/C
85	2006	Underdeposit corrosion due to low-flow velocity (< 1 ft/sec) caused high pitting growth rates. ECT was found to undersize pits because a custom calibration standard was not used. Changed flush cleaning (5–6 ft/s) to every 12 weeks from 18-month period and revised ECT technique or plug criteria until corrosion mitigated.	3 years	N/C	N/C
86	8/23/2005	Turbine building closed cooling HX 90-10 CuNi tube leaks after one year of service caused by underdeposit corrosion (concentration cell and/or MIC); evidence of denickelification was also found. Tubing ID flow velocity is throttled down periodically to < 3 ft/sec in winter months from its normal 4.5 ft/sec operation, which can lead to silt deposits: EPRI indicated that CuNi 90/10 is suspectible tp pitting for velocity, 3 ft/sec; also limited 2 hr/day chlorination contributed to the high pitting rate. Tube material is proposed to be changed to SeaCure.	1 year	2 years	N/C
87	6/29/2004	ID inlet erosion, general ID wastage, ID pitting, and OD TGSCC.	30 years	N/C	N/C
88	4/16/2004	Vibration fatigue cracking caused by high shell-side flow velocity. Cracks initiated at inlet stress-riser flow-accelerated-corrosion sites. Tubes exhibited long unsupported spans. ET DC2 probes examination inconclusive because of circumferential crack assessment limitation.	N/C	N/C	N/C
89	6/20/2002	Tube leaks at turbine bldg CCW. Upon ECT exam, many tubes showed OD support wear caused by flow-induced erosion at the tube support plates. Wall thinning exceeded criteria so plug criteria was revised.	N/C	N/C	N/C
90	5/13/2002	Underdeposit corrosion.	15 y	N/C	N/C

Table 4-21 (Continued)
OE captures for closed cooling water HX – 2001–2007, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
91	5/2/2002	Circumferential SCC cracks on 50% of the tubes found at the tube transition near tubesheet – Inspection frequency: 18-months using bobbin coil ECT. ECT did not detect the cracks.	N/C	1.5 years	N/C
92	9/23/2002	Admiralty brass HX tubes found severely corroded due to using "wet-layup" procedure. Corrosion damage occurred over a five-year period.	5 year	1 year	N/C
93	2/14/2002	Upon ECT exam, extensive pitting was found caused by infrequent tube cleaning allowing fouling to accumulate.	N/C	N/C	N/C

1 ft = 0.31 m
1 ft/s = 0.31 m/s

4.5 Residual Heat Removal HX OE Cases Captured

Nine OE captured cases for the residual heat removal HX were captured. The cases were by and large divided into two categories: tubing damage and gasket leakage. These events are summarized in Table 4-22.

Table 4-22
Summary of OE captures for residual heat removal exchangers

Material	Damage	Service Life	Inspection Frequency	Plugging Criteria	Inspection Type
Tubing					
304 SS	Tube underdeposit corrosion including the U-bend region	13–16 y	8 y	N/C	ECT bobbin coil
	Tube wear (fretting) due to vibration in the U-bend region	N/C	N/C	N/C	ECT bobbin coil
Floating Head Gasket					
	Corrosion of steel gasket jacketed with rubber	11 y	No	No	No
	Corrosion of soft iron gasket	30 y	No	No	No

N/C = Not Captured

The tubing damage was reported due to underdeposit corrosion or OD wear. For the underdeposit corrosion cases, the tube pitting was reported due to manganese rich deposits. Pitting was detected by ET bobbin coil, and the damage was located both in the straight and U-bend tube sections. In this case, ET was reported to overestimate the pitting damage.

The tube OD wear reported was caused by high-flow velocity resulting in flow-induced tube vibration. The tube wear was detected by ET bobbin coil, and the damage was located in the U-bend tube section.

Five cases of gasket leakage were captured, with four of these occurring in HXs of floating head design. Detection of the gasket damage was identified once the leakage had occurred, either by detection of radio nuclides in the cooling water or by noticing corrosion of the HX studs.

One case was captured on coating failure in the cooling water side. The disbondment was caused by the "cold wall effect," which typically depends on the temperature differential and temperature cycles.

Tables 4-23 and 4-24 list the details of the residual heat removal HX survey results. As was done in the sections above, the data for a particular event were divided into two tables.

Table 4-23
OE captures for residual heat removal HX, Part 1

Case	Date	Material	Diameter/Wall	Event	Testing Method
94	10/30/2011	Gasket: steel jacketed with nitrile rubber	N/C	Gasket failure	Chemistry
95	11/1/2010	Carbon steel	N/C	Coating failure	Visual
96	6/15/2010	Carbon steel	N/C	Gasket failure	Abnormal pressures, leak test, borescope
97	3/13/2010	N/C	N/C	Tube wear (no leaks)	ECT
98	4/25/2009	Gasket	N/C	Gasket failure	Chemistry sampling
99	4/17/2005	Soft iron gasket	N/C	Gasket failure	Chemistry
100	3/13/2003	304 SS	1"/0.049"	Tube pits	ECT
101	2/1/2003	N/C	N/C	U-bend tube pits	ECT
102	1/8/2003	Carbon steel-SA 193 bolts – gasket flexitallic type	N/C	Gasket degraded leak caused studs' corrosion	Visual

1″ = 25.4 mm

Table 4-24
OE captures for residual heat removal HX, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
94	10/30/2011	Inner head gasket failure in floating head HX design. Gasket type: steel jacketed with nitrile rubber.	11 years	N/C	N/C
95	11/1/2010	Damage: coating, ARCOR type, became disbonded on the service water side head cover and channel head. Coating disbondment caused by "cold wall effect" which depends on the temperature differential and temperature cycles. The coating service life was 15 years. Reference: NRC IN 97-013.	15 years	N/C	N/C
96	6/15/2010	Floating inner head gasket leak caused by corrosion of the flange face or failure of the seal ring.	N/C	N/C	N/C
97	3/13/2010	Tubing vibration-induced fretting in the U-bend region caused by high flow rate > 894 gpm. Damage measured by ECT. No tubes found leaking, but some were plugged.	N/C	N/C	N/C
98	4/25/2009	Reactor coolant leakage caused by corrosion of the floating head gasket and gasket seating surface.	N/C	N/C	N/C
99	4/17/2005	Reactor coolant leakage caused by corrosion of the floating head soft iron gasket and gasket seating surface at the head/tubesheet interface in the RHR HX 2A. Gasket replaced with a modified split-ring and seal weld design.	30 years	N/C	N/C
100	3/13/2003	Pitting found with ECT caused by manganese-rich underdeposit corrosion primarily in the U-bend section. Last cleaning and inspection performed in 4/15/95, eight years ago. Manganese-rich deposits removed by mechanical cleaning and inspection and cleaning frequency increased. Hydrolyzing cleaning found ineffective. ET oversized pit depths.	13 years	8 years	N/C

Table 4-24 (Continued)
OE captures for residual heat removal HX, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
101	2/1/2003	Tube pitting found in U-bend section with ECT caused by MIC/underdeposit corrosion. 38% of tubes plugged. Tubes never inspected or cleaned prior to 2002. Heat exchanger mostly operated in standby mode. Going forward, water conductivity monitored and flushed when alert range is reached.	16 years	N/C	N/C
102	1/8/2003	80% of SA 193 carbon steel HX studs found corroded by boric acid attack. Gasket leak caused the boric acid accumulation. The leak was due to repeated heating and cooling of gasket. The flexitallic gasket lost its filler material and caused relaxation of the joint. The original gasket was then replaced with a graphite Flexpro gasket. After this gasket was replaced, another leak occurred because the proper hot retorquing was not done on the bolting.	25 years	N/C	N/C

1 gpm = 3.8 lpm

4.6 Seal Oil Cooler HX OE Cases Captured

As was mentioned in Section 3.2, seal oil coolers are typically small straight-shell-and-tube HXs with the seal oil flowing in the shell side and cooling water in the tube side. The HXs cited had admiralty brass, Copper SB75 and CuNi 90/10 tubing. These events are summarized in Table 4-25.

Table 4-25
Summary of OE captures for residual heat removal exchangers

Material	Damage	Service Life	Inspection Frequency	Plugging Criteria	Inspection Type
Admiralty brass	Tube aggressive underdeposit corrosion	6 y	1.5 y	60% TW	ECT bobbin coil
	Tube ID inlet erosion	3.5 y	1 y	N/C	Visual
Copper SB75	Tube ID erosion	3–8 y	N/C	N/C	N/C
CuNi 90/10	Tube underdeposit corrosion	10–40 y	N/C	N/C	ECT bobbin coil
	Tube aggressive underdeposit corrosion	0.3–3 y	N/C	N/C	ECT bobbin coil
	Tube OD wear at the tubesheet	30 y	N/C	N/C	ECT bobbin coil

N/C = Not Captured

For admiralty brass, the aggressive underdeposit corrosion conditions were due to the water having low pH and high oxygen concentration and a low ID water velocity. The tube ID inlet erosion was caused by high water velocity.

For copper tubing, the ID erosion was also caused by high water velocity, but, in addition, entrained particles were reported to have contributed to the wall loss damage.

The CuNi 90/10 tubing was reported susceptible to underdeposit corrosion and OD wear at the tubesheet supports. Premature tube failures were reported due to poorly developed oxide passivation layer and de-alloying in combination with low ID water velocity or stagnant flow conditions.

Tables 4-26 and 4-27 list the details of the seal oil cooler HX survey results. As was done in the sections above, the data for a particular event were divided into two tables.

Table 4-26
OE captures for seal oil cooler HX, Part 1

Case	Date	Heat Exchanger	Material	Diameter/Wall	Event	Testing Method
103	4/25/2012	Seal oil cooler	CuNi 90/10	1"/0.049"	Cooler failure – major leak	Visual
104	3/20/2012	Air-side seal oil cooler	CuNi 90/10	N/C	Tube pitting (34 tubes – 26% of bundle)	ECT
105	3/14/2012	HPCI room cooler	Copper SB/B75 + spiral aluminum fins	5/8"/0.025"	Tube leaks	N/C
106	2/11/2011	Lube oil cooler	Admiralty brass	0.025"/	Tube leaks	N/C
107	4/21/2010	Air-side and hydrogen-side seal oil cooler	Admiralty brass	N/C	Tube pitting	ECT
108	6/19/2009	LPCI room cooler	Copper SB/B75 + aluminum fins	5/8"/0.025"	Tube leaks	N/C
109	6/8/2009	Drywell chiller 44A	CuNi 90/10 - Fins	0.75"/0.049"	Tube leaks at non-finned areas	ECT
110	9/11/2006	Standby lube oil cooler HX	CuNi 90/10	N/C	Multiple tube leaks (20–30)	Oil found with water, ECT

Table 4-26 (Continued)
OE captures for seal oil cooler HX, Part 1

Case	Date	Heat Exchanger	Material	Diameter/Wall	Event	Testing Method
111	3/14/2006	EHC cooler	CuNi 90/10	3/8"/0.025"	ET indications – 58% deep max	ECT
112	12/20/2003	Lube oil coolers 1A & 2C	Admiralty brass	0.375"/0.025"	Tube leaks	Oil condition in pump gearbox
113	7/1/2003	Stator cooler	CuNi 90/10	5/8"/0.049"	Tube pitting due to denickelification	ECT
114	11/19/2001	Hydrogen coolers	CuNi 90/10 + helical copper fins	3/4"/0.049"	Tube pitting due to incomplete passivation	ECT

1″ = 25.4 mm

Table 4-27
OE captures for seal oil cooler HX, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
103	4/25/2012	Generator seal oil cooler with finned tubes and dual floating tubesheet had a leak due to tube thinning and tubesheet displacement. The cooler had never been ET tested.	30 years	N/C	N/C
104	3/20/2012	Recently replaced tubes in a particular bundle were found severely ID pitted with 26% of tubes exhibiting wall loss > 50% upon ET examination. The rapid corrosion was due to poorly developed oxide passivation layer contaminated with foreign material and low ID water velocity conditions that promoted underdeposit corrosion.	4 months	N/C	N/C
105	3/14/2012	Internal wall thinning due to erosion caused by high flow velocity. Wall thinning more pronounced in the tube’s bottom, suggesting that entrained particles played a role in the erosion.	8 years	N/C	N/C
106	2/11/2011	Tubes leaked due to tube ID inlet erosion corrosion caused by high ID flow velocity.	3.5 years	N/C	N/C

Table 4-27 (Continued)
OE captures for seal oil cooler HX, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
107	4/21/2010	Tubes found severely ID pitted with some tubes exhibiting wall loss > 60%. The tubes had been in service for six years and had been cleaned and visually inspected every 18 months. The rapid corrosion was due to the water having low pH/high oxygen and ID low-velocity conditions that promoted underdeposit corrosion.	6 years	N/C	60%
108	6/19/2009	Internal wall thinning due to erosion. Since nominal ID flow velocity was < 4 ft/s, the erosion may have been caused by entrained particles. Wall thinning was more pronounced in the tube's bottom, suggesting that entrained particles did play a role.	3 years	N/C	N/C
109	6/8/2009	Tube leaks in non-finned areas caused by long-term, underdeposit pitting corrosion. Non-finned areas exhibited larger ID (0.652") than finned areas (0.567"). Variable ID affected performance of ET. ET did not detect the tube leaks.	40 years	N/C	N/C
110	9/11/2006	Tubes were found with multiple leaks (20–30) due to dealloying. ET examination found the tubes extensively ID pitted. The rapid corrosion was due to the improper passivation and contamination during installation causing dealloying. Low, throttled down, velocity conditions (5%–10%) during layup times also contributed to the corrosion.	3 years	N/C	N/C
111	3/14/2006	De-alloying resulting in internal pitting caused by low-flow velocity (< 5 ft/s) or stagnant conditions.	3 years	N/C	N/C
112	12/20/2003	Tubes leaked due to tube ID inlet erosion corrosion caused by zinc anode bloom deposits that created turbulent flow conditions. Excessive buildup from zinc anode corrosion deposits that cause blockage is considered the primary reason for the failure.	5.75 and 8.25 years	N/C	N/C

Table 4-27 (Continued)
OE captures for seal oil cooler HX, Part 2

Case	Date	Morphology	Service Life	Inspection Frequency	Plugging Criteria
113	7/1/2003	Localized pitting due to denickelification 40% deep. ETC indications accurately depth sized. Pit growth rate determined to be slow. HX was drained and dried while idle.	10 years	N/C	N/C
114	11/19/2001	Incomplete passivation caused by use of chloride and hypochloride. ETC indications up to 100% TW.	2 years	N/C	N/C

1 ft/s = 0.31 m
1″ = 25.4 mm

5
HEAT EXCHANGER NDE PERFORMANCE CAPTURED CASES

In addition to the tubing integrity cases described in Section 4, the survey also captured cases where the NDE performance was documented.

The cases were limited to tubing examination with an ET bobbin coil. These cases compared the ET measurement with the metallurgical laboratory assessment obtained by sectioning the tube and analyzing the damage at the location of the call. The comparison is considered useful in that it points to areas were the NDE procedures may need improvement, while assisting in the design of mockups for examination procedure validation. However, this work did not investigate the NDE procedures used in detail to identify any improvements that might be warranted. That task will be the subject of a future work scope.

5.1 Condenser NDE Performance Captured Cases

A summary of the ET performance cases in condenser examination are listed in Table 5-1. As indicated in the table, the tubing material in these cases was 304 SS.

Table 5-1
Summary of captured ET condenser examination performance cases

Case	Heat Exchanger	Material	Diameter	Damage	ET Performance
115	Condenser	304 SS	1"	Wear in the support plate	Depth overestimated
116	Condenser	304 SS	1"	Fatigue linear cracks at the tube’s weld seam	Depth overestimated
117	Condenser	304 SS	0.75"	Seam weld lack of fusion	Depth overestimated
118	Condenser	304 SS	1"	Circumferential cracks	Not detected
119	Condenser	304 SS	1"	OD droplet impingement	Not detected or depth underestimated

1″ = 25.4 mm

The data captured are detailed next in the order listed in the table.

ET was found to overestimate the depth of tube wear damage near the tube support plate by 54%. ET estimated 61% wall loss while the measured damage was 7%.

Also, ET was found to overestimate the depth of fatigue linear cracks at the tube weld seam by an average of 17% and a maximum difference of 28%. The comparative data are listed in Table 5-2.

Table 5-2
Comparison between ET depth estimates and laboratory measurements in condenser tubing with linear fatigue cracks at the weld seams

Indication	Eddy Current Measured Depth	Laboratory Measured Depth
1	99%	71%
2	85%	68%
3	95%	71%
4	59%	60%
5	83%	75%
6	67%	39%
Average	**81%**	**64%**

In addition, ET was found to overestimate the depth of seam weld lack-of-fusion fabrication defects by an average of 43% and a maximum difference of 67%. Laboratory analysis identified the flaws as fabrication defects not caused by in-service conditions. The comparative data are listed in Table 5-3.

Table 5-3
Comparison between ET depth estimates and laboratory measurements in condenser tubing with lack of fusion defects at the weld seams

Indication	Eddy Current Measured Depth	Laboratory Measured Depth
1	99%	54%
2	99%	32%
3	97%	48%
4	52%	34%
Average	**87%**	**42%**

ET was found to be not effective at detecting circumferential cracks near tube support plates. However, it was reported that the circumferential cracks were detected with Matrix and motorized rotating pancake coil (MRPC) probes.

ET was found to be not effective at detecting through-wall leak locations caused by OD droplet impingement. It was reported that the small ID size of the pinhole in combination with the presence of erosion and other pitting damage in the vicinity location contributed to the ET current performance difficulties. Table 5-4 documents the ID and OD pinhole openings and associated erosion depths for the cases captured.

Table 5-4
Pinhole size and erosion depth due to OD droplet impingement in condenser tubing

Indication	OD Width (Inch)	ID Width (Inch)	Erosion Wall Loss
1	0.027	0.006	14%
2	0.015	0.005	32%
3	0.020	0.005	21%
4	0.020	0.007	18%

1″ = 25.4 mm

In a separate droplet impingement damage case, ET was again found to be not capable of identifying the leak locations while underestimating the wall loss. Pit depth was underestimated on average by 22%, exhibiting a maximum difference of 34%. The pinholes were located in erosion-affected areas near tube support plates. The comparative data are listed in Table 5-5.

Table 5-5
Comparison between ET depth estimates and laboratory measurements in condenser tubing with droplet impingement damage

Indication	Eddy Current Measured Depth	Laboratory Measured Depth
1	80%	100%
2	85%	100%
3	51%	85%
4	90%	100%
Average	**77%**	**96%**

5.2 Feedwater Heater NDE Performance Cases Captured

A summary of the ET examination performance cases in feedwater heater examinations is listed in Table 5-6.

Table 5-6
Summary of captured ET feedwater heater examination performance cases

Case	Heat Exchanger	Material	Damage	ET Performance
120	Feedwater Heater	304 SS	Fabrication defects	False calls
121	Feedwater Heater	304 SS	OD transgranular SCC	Accurate depth estimate

Five false indications were reported in the captured cases. Upon performing laboratory analysis, the indications were identified as “lap” type fabrication defects. The ET signal response from these lap defects incorrectly assessed their depth ranging from 87% to 96%.

Three axial transgranular stress corrosion cracks (TGSCCs) were also reported. TGSCC flaws normally occur as a result of tubing exposure to chlorides in the presence of water. The laboratory analysis identified the cracks as having multiple branches. The ET depth assessment of the cracks was found to be accurate.

The comparative data are shown in Table 5-7.

Table 5-7
Comparison between ET depth estimates and laboratory measurements in feedwater heater tubing with TGSCC damage

Indication	Damage	Eddy Current Measured Depth	Laboratory Measured Depth
1, 2, 3, 4, 5, 6	False call	87%, 93%, 90%, 93%, 83%, 94%	No wall loss
7	TGSCC	80%	65%
8	TGSCC	75%	85%
9	TGSCC	88%	90%
Average TGSCC		**81%**	**80%**

5.3 Closed Cooling Water HX NDE Performance Cases Captured

A summary of the ET examination performance cases in closed cooling water HX examinations is listed in Table 5-8.

Table 5-8
Summary of captured ET closed cooling water HX performance cases

Case	Heat Exchanger	Material	Diameter	Damage	ET Performance
122	Closed cooling heater	Admiralty brass	3/4"	ID erosion	Depth overestimated
123	Residual heat removal	Admiralty brass	1"	Underdeposit corrosion caused by manganese deposits.	Depth overestimated

1″ = 25.4 mm

In these cases, ET was reported to overestimate the depth of ID inlet erosion and underdeposit corrosion. The tubing material was admiralty brass.

For the ID inlet erosion case, ET overestimated the wall loss by 7% on average, exhibiting a maximum deviation of 31%. This ID inlet erosion damage was reported due to long periods of HX operation with cooling water velocity exceeding the 6 ft/sec (1.8 m/sec) threshold for admiralty brass. The comparative data are shown in Table 5-9.

Table 5-9
Comparison between ET depth estimates and laboratory measurements in closed cooling water HX admiralty brass tubing with ID inlet erosion damage

Indication	Eddy Current Measured Depth	Laboratory Measured Depth
1	45%	50%
2	83%	73%
3	31%	23%
4	64%	62%
5	45%	48%
6	38%	27%
7	36%	37%
8	56%	25%
9	45%	43%
10	57%	37%
11	52%	46%
Average	**50%**	**43%**

For the underdeposit corrosion case, ET overestimated the wall loss by 32% on average and a maximum deviation of 51%. The damage was reported due to manganese deposits that resulted in ID pitting, exhibiting a "closed-tunneling" morphology rather than wall loss. The latter morphology was cited as a reason for the large discrepancy between ET and the laboratory assessment. The comparative data are shown in Table 5-10.

Table 5-10
Comparison between ET depth estimates and laboratory measurements in closed residual heat removal HX admiralty brass tubing with underdeposit corrosion damage

Indication	Eddy Current Measured Depth	Laboratory Measured Depth
1	89%	57%
2	86%	35%
3	83%	43%
4	37%	34%
Average	**74%**	**42%**

5.4 Seal Oil Cooler NDE Performance Case Captured

One ET examination performance case was captured for seal oil cooler HXs. This case is summarized in Table 5-11.

Table 5-11
Summary of captured ET seal oil cooler HX performance case

Case	Heat Exchanger	Material	Diameter	Damage	ET Performance
124	Seal oil cooler HX	CuNi 90/10	3/8"	Underdeposit corrosion	Accurate depth estimate

1″ = 25.4 mm

In this case, the laboratory evaluations found the ID pit depths to be within the range measured by ET. The damage was found to be caused by underdeposit corrosion in combination with de-alloying. This mechanism is normally caused by low or stagnant flow conditions. The comparative data is shown are Table 5-12.

Table 5-12
Comparison between ET depth estimates and laboratory measurements in a seal oil cooler HX CuNi 90/10 tubing with underdeposit corrosion damage

Indication	Eddy Current Measured Depth	Laboratory Measured Depth
1	45%–58%	52%
2	43%–58%	48%

6 CONCLUSIONS

This work captured 124 BOP HX operating experiences to assist in inferring NDE effectiveness and HX tubing material performance.

The cases captured addressed events in condensers, feedwater heaters, emergency diesel generator HXs, closed cooling water HXs, residual heat removal HXs, and seal oil coolers.

The information captured was mapped into six categories for each HX service:

- Material
- Damage mechanism
- Inspection technique
- Service life
- Cleaning and inspection frequency
- Plugging criteria

The events included 10 NDE performance evaluation cases where the ET wall loss estimation was compared with laboratory analysis of the sectioned tube at the call location.

In this report, the captured data are presented in table form. It is recommended that future work be performed to fill the information gaps identified and to migrate the information to an online database query system with the capability of making parametric comparisons.

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute Inc., (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent approximately 90 percent of the electricity generated and delivered in the United States, and international participation extends to more than 30 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together...Shaping the Future of Electricity

Program:

Nondestructive Evaluation

3002003028

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com