Steam Generator Management Program: Alloy 800 Steam Generator Tubing Experience

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EPRI Project Managers
H. Feldman
R. Wolfe

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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

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Dominion Engineering, Inc.
12100 Sunrise Valley Drive, Suite 220
Reston, VA 20191

Principal Investigators
C. Marks
P. Krull

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ABSTRACT

Nuclear grade (NG) Alloy 800 has been used for steam generator tubing since 1972 in over 50 nuclear power plants worldwide. The operational performance of this alloy has been very good, although some degradation modes have recently been observed. This report describes worldwide operating experience for Alloy 800 steam generator tubing along with differences in tubing material, plant design, and operating conditions that can affect tube degradation. The various types of plants with Alloy 800 steam generator tubing (for example, Siemens-designed pressurized water reactors, Canadian pressurized heavy water reactors, and Westinghouse-designed pressurized water reactors) have substantial differences in design and operating conditions and consequently have shown differing levels of susceptibility to various modes of degradation. The results are useful for identifying potential modes of degradation in Alloy 800 steam generators and for gauging the likelihood of occurrence in a given plant based on the documented differences in materials and designs. These findings will be used in probabilistic models to predict future Alloy 800NG steam generator tubing performance, yielding predicted fractions of tubes repaired as the steam generators accrue increasing service years.

Keywords

Alloy 800NG
CANDU
Generic predictions
Improvement factors
PHWR
PWR

ACRONYMS

AVB	anti-vibration bar
AVT	all volatile treatment
B&W	Babcock and Wilcox
BOP	balance of plant
CANDU	Canada Deuterium Uranium
CNNC	China National Nuclear Corporation
COG	CANDU Owners Group
CPS	condensate polishing system
DHI	Doosan Heavy Industries
EFPY	effective full power year
EOC	end of cycle
EMF	electro-mechanical filter
EPRI	Electric Power Research Institute
EWS	emergency water supply
FAC	flow-accelerated corrosion
FDB	flow distribution baffle
FW	feedwater
IBL	innerbundle sludge lancing
IGA/SCC	intergranular attack/stress corrosion cracking
KHNP	Korea Hydro and Nuclear Power
KWU	Kraftwerk Union
MA	mill annealed
MSR	moisture separator reheater
NASA	Nucleoeléctrica Argentina Sociedad Anónima
NG	nuclear grade

OD	outer diameter
ODSCC	outer diameter stress corrosion cracking
PHWR	pressurized heavy water reactor
PLGS	Point Lepreau Generation System
PWR	pressurized water reactor
RCS	reactor coolant system
SCC	stress corrosion cracking
SG	steam generator
SGMP	Steam Generator Management Program
TAPP	Tarapur Atomic Power Plant
TSP	tube support plate
TTS	top of tubesheet
tw	through wall
VGB	Vereinigung der Großkraftwerksbetreiber

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1 INTRODUCTION AND BACKGROUND

In 1997, EPRI published TR-108501 [1], *Predicted Tube Degradation for Westinghouse Models D5 and F Type Steam Generators*, which predicted the likely progression of tube degradation based on past experience with earlier steam generators using an improvement factor to quantify the expectations of better performance from the thermally treated Alloy 600 steam generator tubes relative to the mill annealed Alloy 600 experience. The factors of improvement were developed largely based on laboratory test results, and plant experience following the 1997 report indicated that the factors of improvement developed were excessively conservative. Therefore, in 2003 EPRI published report 1003589, PWR Generic Tube Degradation Predictions [2], which used new factors of improvement based on actual field experience of plants. The 2003 report included predictions of the extent of steam generator (SG) tube degradation by various mechanisms for several SG designs, yielding predicted fractions of tubes repaired as the SGs age. Predictions were developed for Alloy 600TT and Alloy 690TT tubing using a statistical method that accounts for the absence of detected corrosion at operating plants for substantial periods of operation to determine the factors of improvement of these materials relative to mill annealed Alloy 600. In 2006, the improvement factors developed for Alloy 690TT (but not the degradation predictions) were updated to reflect recent plant experiences and new laboratory data in EPRI 1013640 [3]. Review of these improvement factors for Alloy 690TT indicated that improvement factors based on plant experience were unrealistically conservative because plant experience was not of sufficient duration to make reliable estimates and that improvement factors based on laboratory experience were more accurate. In 2009, these improvement factors for Alloy 600TT and Alloy 690TT (but not the degradation predictions) were again updated to include recent plant degradation experience and, additionally, improvement factors for Alloy 800NG were developed, as documented in EPRI 1019044 [4]. These improvement factors were developed to aid in economic calculations and in the development of technical bases for determining suitable in-service inspection intervals and suitable alloy-specific chemistry specifications, i.e., the improvement factors could be used as inputs to degradation predictions but were also useful for other analyses.

The objective of this report is to determine the modes of degradation to which Alloy 800NG tubing is susceptible in preparation for a future report which will expand EPRI 1003589 to include predictions of degradation of Alloy 800NG tubing. At the time that EPRI 1003589 was written, very little degradation of Alloy 800NG tubing had been observed. This is still true. However, some degradation modes that have become significant since 2002 may warrant consideration, including the following:

- Tubesheet crevice outer diameter stress corrosion cracking (ODSCC) associated with leaks past the upper tube expansion
- Stress corrosion cracking (SCC) associated with tubesheet denting

- ODSCC at crevices at the top of tubesheet
- ODSCC at tube supports

To some extent, information regarding Alloy 800NG degradation has been collected in previous EPRI projects (e.g., EPRI 1019044 [4]). However, it is anticipated that degradation predictions could be enhanced by the collection of additional data.

The remainder of this report is separated into the following chapters:

- Chapter 2 provides a summary of the degradation modes which have affected steam generators with Alloy 800 tubing and the conclusions reached in this report.
- Chapter 3 is a summary of the major similarities and differences amongst the three main plant types discussed in this report: Siemens, CANDU, and Westinghouse plants.
- Chapter 4 describes the variations in the Alloy 800 used to tube the steam generators of plants discussed in this report.
- Chapter 5 describes the major design and operating differences in plants which affect tube degradation.
- Chapter 6 describes the degradation modes which have been experienced by steam generators with Alloy 800 tubing.
- Chapter 7 is a list of the references used in this report.
- Appendix A describes the design and operating conditions of each Siemens-designed plant discussed in this report.
- Appendix B describes the design and operating conditions of each CANDU designed plant discussed in this report.
- Appendix C describes the design and operating conditions of each Westinghouse-designed plant discussed in this report.
- Appendix D describes the design and operating conditions of plants with Alloy 800 tubing which do not fall into the three major plant groups discussed in this report.

2
SUMMARY

Plants with Alloy 800 steam generator tubing have been separated into four groups in this report, Siemens-designed plants, CANDU pressurized heavy water reactor (PHWRs), Westinghouse-designed[1] plants, and all other plants. These plants have substantial differences in design and operating conditions, and have consequently shown differing levels of susceptibility to various modes of degradation. Because of these differences, it is not possible to make generic predictions for the degradation of Alloy 800 tubing for all plants together; predictions for the degradation of Alloy 800 tubing must be developed separately for each type of plant as well as for each mode of degradation.

2.1 Recommended Treatment of Various Degradation Modes

In this review of degradation data, the following modes of degradation were assessed to determine their applicability to Alloy 800NG steam generator tubing:

Primary Water Stress Corrosion Cracking: This mode of degradation has not been experienced by any plant with Alloy 800 tubing, and initiation of this mode of degradation has not been observed in laboratory studies [4]. This indicates that predictions of this mode of degradation do not have to be made separately based on plant design or operating conditions.

Phosphate Wastage: This mode of degradation has been prevalent in plants which used phosphate treatment for secondary chemistry control. Wastage occurred predominantly in the hot leg, top of tubesheet (TTS) region and lower tube supports where sludge had accumulated due to the concentration of aggressive species at steam-water interfaces. Due to this mode of degradation, all plants which originally used phosphate treatment switched to all volatile treatment (AVT) secondary chemistry (except Atucha 1, see Figure 3-1). However, after switching, legacies of phosphate wastage have caused additional tubes to be plugged.

This mode of degradation has affected Siemens-designed plants (see Appendix A) and a CANDU PHWR (Point Lepreau Generating Station- see Appendix B.1), which indicates that this mode of degradation can affect any plant which has used phosphate treatment for secondary chemistry control. Therefore predictions of degradation by this mode do not have to be made separately for each plant group (however, only plants which have used phosphate treatment for secondary chemistry control need be considered).

[1] The term *Westinghouse-designed* is used in this report to refer to the plant rather than the steam generators. The units in this category were designed by Westinghouse or a licensee of Westinghouse (e.g., Framatome) with original steam generators with Alloy 600MA tubing. The replacement steam generators were provided by Siemens/KWU and have Alloy 800NG tubing.

Mechanical wear to due to structural components: This mode of degradation is due to flow induced vibrations, predominantly in the U-bend region, and results in wear scars on the outside surfaces of tubes where they contact support structures. This mode of degradation can be mitigated by replacing the affected support structures or by modification to the U-bend structure to add more supports. However, if left unchecked, the number of affected tubes can increase significantly.

This mode of degradation has affected all three plant groups; however, it has been most prevalent in early Siemens-designed plants (see Appendix A) and one CANDU plant (Darlington Generating Station- see Appendicies B.6 through B.9). The design and materials used for tube supports appear to greatly affect susceptibility to this mode of degradation, which indicates that predictions for the degradation of Alloy 800 tubing by this mode of degradation must be made separately based on support design and material.

Mechanical wear to due loose parts or foreign objects: This mode of degradation is caused by loose objects trapped in the secondary side of steam generators, and thus all steam generators including those with Alloy 800 tubes are susceptible to this mode. The loose objects can be steam generator components formed from degradation during operation or can be foreign objects left in steam generators (tools, etc.) during maintenance outages.

This mode of degradation has affected various plants with Alloy 800 tubing with no noticeable correlation with design or operating conditions; therefore predictions of degradation by this mode do not have to be made separately based on plant design or operating conditions.

Deep tubesheet crevice ODSCC: This mode of degradation has been observed in a small number of the plants that have two mechanical rolls: one near the bottom of the tubesheet and one near the top of the tubesheet. The degradation seems to be the result of water leaking past the upper expansion joint into the deep tubesheet crevice during shutdown periods. It may also be important that the upper joint reseals and traps volatile acidic species in the crevice during power operation, but this is not certain. This degradation has occurred at the top of areas in the crevice that are filled with magnetite corrosion products, which implies that some sort of wetting/drying at the top of the corrosion products may be involved. Additionally, this degradation has affected almost exclusively tubes around the periphery and along the divider plate. This mode of degradation has affected a similar number of tubes and has had similar growth rates on both the hot and cold leg sides, which could indicate that the degradation is occurring during startup and not at full power operation since occurrence and growth at full power should lead to much greater rates at the hot leg than the cold leg, assuming that the degradation mode is thermally activated.

This mode of attack has been observed in at least two Siemens-designed units with Alloy 800 tubing, Biblis A and Unterweser, and has possibly been observed at Biblis B and Neckarwestheim 1 (see Appendices A.3, A.4, A.5, and A.7). This mode of degradation has only affected Siemens-designed units.

Evaluations of the OD surfaces of pulled tubes from several CANDU units indicate that secondary coolant has reached the deep tube sheet crevice in many cases [5]. Therefore, plants with hydraulic expansions may also be susceptible to this mode of degradation. Thus, it is currently believed that all plants with Alloy 800 tubing are generally susceptible to this mode of degradation. Therefore conservative predictions for the degradation of Alloy 800 tubing by this mode of degradation will be made for all plants with Alloy 800 tubing.

ODSCC at TTS Crevices: This mode of degradation has been quite significant at many units with Alloy 600MA tubing. It is known from experience at plants with Alloy 600MA SG tubes [6], and by laboratory tests, that the crevice conditions established by sludge piles in the central regions of tubesheets are conducive to causing axial intergranular attack / stress corrosion cracking (IGA/SCC) in these regions. Tests have shown these crevices develop elevated superheats once filled with deposits [7], and such elevated superheats tend to result in concentrated impurity solutions in crevices that can cause IGA/SCC. In addition, plant experience has shown that the crevices and sludge collars at tubes outside of the sludge pile can also develop axial and volumetric IGA/SCC, although generally later than in the sludge pile. For this reason, all the tubes are susceptible to IGA/SCC, not just the tubes in the sludge pile region.

Axial flaws of this type have been detected in Unterweser, Borselle, Biblis A, and Biblis B which suggests that this mode of degradation can affect Alloy 800 tubing (see Appendix A.7). Based on experiences of plants with Alloy 600MA tubing, susceptibility to this mode of degradation is affected by plant design (e.g., units with integral preheaters). Therefore, predictions for the degradation of Alloy 800 tubing from this mode of degradation should be made separately based on plant design and secondary operating conditions.

TTS Denting and Related ODSCC: This mode of degradation is a local, inward deformation of tubes that is caused by expansive corrosion of the tubesheet and by the corrosion of metal particles in the sludge pile if present from sources such as blasting or machining of steel components of the secondary plant systems. Crevices and expansion transitions at the TTS can result in elevated superheats once they fill with deposits, and such elevated superheats tend to result in concentrated impurity solutions in crevices which increase susceptibility to additional corrosion of the tubesheet. The corrosion products formed in the tubesheet crevices have larger volumes than the steel they replace which applies pressure to the tubes, resulting in inward deformations. Denting at the top of the tubesheet is a result of corrosion of the low-alloy steel tubesheet, and thus denting is not dependent on the particular tube material. The presence of dents causes high stresses and plastic strains in the tube material, increasing its susceptibility to stress corrosion cracking.

Denting has occurred at Doel Unit 3, Asco Units 1 and 2, and Almaraz Units 1 and 2 (see Appendix C), and to a lesser extent, in some Siemens-designed units (see Appendix A). This denting has led to circumferential outer diameter (OD) IGA/SCC at Asco Unit 1 and Almaraz Units 1 and 2. Since replacement steam generators at Westinghouse-designed units have experienced this mode of degradation to a much larger extent, it appears that susceptibility to this mode of degradation is significantly affected by plant design and operating conditions (e.g., balance of plant materials of construction, etc.). Therefore, predictions for the degradation of Alloy 800 tubing from this mode of degradation must be made separately based on plant design.

ODSCC at Tube Supports: This mode of degradation is believed to occur in plants with lattice bar supports. Solid deposits accumulate at the tube/lattice bar intersections such that free flow of water around the tube is impeded. This results in dry-out of the fouled deposit and concentration of impurity chemicals from the steam generator bulk water by boiling in and under the deposit. An aggressive environment is formed that attacks the tube and causes IGA/SCC.

Axial flaws of this type have been detected at Unterweser (see Section A.7), which indicates that this mode of degradation can affect plants with Alloy 800 tubing and lattice bar tube supports. Since this mode of degradation has not affected any other Alloy 800 steam generators worldwide, predictions for the degradation of Alloy 800 tubing from this mode of degradation should be made separately based on tube support design, materials, and secondary operating conditions.

Pitting: Pitting is a form of localized corrosion that leads to the creation of small pits in the tubing of steam generators. Pitting tends to occur when there is a combination of oxidizing conditions coupled with the presence of aggressive anions such as sulfates and chlorides. It occurs preferentially in occluded areas such as crevices and under deposits as a result of the tendency of anions in the bulk water to concentrate in the occluded areas. This concentration occurs because oxygen is depleted by corrosion in the occluded areas, leading to a strong potential difference between the occluded areas and the bulk water that causes the anions to diffuse to the occluded region. Over the course of time, this can lead to development of aggressive acidic conditions in the occluded area even if the concentration of anions in the bulk water is low.

Evidence of micro-pitting[2] has been recently observed at Darlington Generating Station (see Appendices B.6 through B.9). However, this degradation is not detectable by NDE. The micro-pitting was only observed in tubes that were pulled for material surveillance. Furthermore, no tubes have been plugged due to this mechanism. Therefore, the presence of shallow micro-pits cannot currently be predicted using the methods based on NDE results described in this report.

2.2 Remainder of this Report

This report represents an interim work product developed to support an on-going effort to provide generic predictions of Alloy 800NG steam generator tube degradation for a number of PWR and PHWR designs. It therefore serves as a compendium of data for each operating unit that have been collected and reviewed. At this time, no other conclusions have been drawn from this data other than recommendations regarding the treatments of the various degradation modes described above. The remainder of this report provides data that have been collected for each unit.

[2]Note that wastage observed at plants which have used phosphate treatment is considered phosphate wastage not pitting.

3
UNITS WITH ALLOY 800 STEAM GENERATOR TUBING

Alloy 800 has been used in numerous steam generator designs for both light water pressurized water reactors (PWRs) and pressurized heavy water reactors (PHWRs). In this review, these designs were organized into four sets based on design, manufacturer, and availability of information in the open literature. These sets, defined based on the plant type in which the steam generators are installed, are as follows:

- Siemens-designed PWRs
- CANDU PHWRs
- Westinghouse-designed[3] PWRs (with replacement SGs of Siemens/Kraftwerk Union (KWU) design)
- Other plant designs (primarily non-CANDU PHWRs)

Summaries of the design features of the steam generators in these plants are given in the sections below.

3.1 Siemens-Designed PWRs

This section provides a general overview of the significant general design and operational features of the Siemens-designed PWRs with steam generators that have Alloy 800NG tubing. Note that additional details and references for the data presented in this section are provided in Appendix A.

3.1.1 Major Steam Generator Designs and Operating Parameters

Siemens-designed PWRs share many common features. Each steam generator has Alloy 800, nuclear grade (modified) tubing, subjected to cold work for strengthening, and in some cases subject to peening for ODSCC resistance. The chemical composition, cold work, and peening of the Alloy 800, nuclear grade, modified tubing are discussed in detail in Chapter 4 of this report.

The steam generator tubes are 22 mm (0.866") in diameter, 1.2 mm (0.047") thick, arranged in a triangular pitch, and mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel.[4]

[3] The term *Westinghouse-designed* is used in this report to include those units which were designed by Westinghouse or by Westinghouse licensees, e.g., Framatome.

[4] With the exception of Unit 2 of Angra Nuclear Power Plant, which has different tubesheet and tube support materials.

Each steam generator has austenitic stainless steel support grids† in the straight leg region, and austenitic stainless steel corrugated strips in the U-bend region. However, two types of lattice bar tube support systems have been used at Siemens designed plants. The tube supports at all plants that started operation after Neckarwestheim Unit 1 (including the replacement steam generators at Obrigheim) have larger free flow cross-sections that reduce the resistance of water flow through the steam generator [8,9].

Some of the major design differences among Siemens PWRs are presented in Table 3-1.

Table 3-1
Steam Generator Design Differences in Siemens PWRs (see Appendix A for details)

Plant	Initial Operation Date	Country	Hot Leg Temperature (°C)	Power Rating (MWe)	SG Model #	Advanced Tube Support Design	Preheater	FDB	Peened
Stade	1972	Germany	313.9	672		N	N	N	N
Borssele	1973	Netherlands	318.9	515		N	N	N	N
Biblis A	1973	Germany	313.3	1225		N	N	N	N
Biblis B	1976	Germany	319.4	1300		N	N	N	N
Neckarwestheim 1	1976	Germany	322.2	840		N	N	N	N
Unterweser	1978	Germany	317.8	1410		Y	N	N	N
Goesgen	1979	Switzerland	321.1	1035		Y	N	Y	Y
Grafenrheinfeld	1981	Germany	325.6	1345	54GS	Y	Y	Y	Y
Obrigheim[1]	1983	Germany	309.4	357		Y	N	N	Y
Grohnde	1984	Germany	326.7	1430	54GS	Y	Y	Y	Y
Philippsburg 2	1984	Germany	327.8	1468	54S	Y	N	N	Y
Brokdorf	1986	Germany	325.6	1480	54GS	Y	Y	Y	Y
Isar 2	1988	Germany	323.9	1485	54SK	Y	N	N	Y
Emsland	1988	Germany	324.4	1400	54SK	Y	N	N	Y
Trillo 1	1988	Spain	326.1	1066	54GT	Y	Y	Y	Y
Neckarwestheim 2	1989	Germany	324.4	1400	54SK	Y	N	N	Y
Angra 2	2001	Brazil	326.1	1350		Y	N	Y	Y

1) All data presented for Obrigheim Nuclear Power Plant is in reference to its replacement steam Generators
2) Gray Cells indicate that this information was not available

The effects of the designs and operating parameters discussed in this chapter on the degradation experienced at each plant are discussed in detail in Chapter 5.

Each Siemens plant design is discussed in detail in Appendix A.

3.1.2 Major Secondary Side Designs and Operating Parameters

Currently, all Siemens-designed plants have all ferrous secondary side systems. The main condenser tubing is made of stainless steel, the main condenser tubesheet is made of carbon steel clad with stainless steel or coated with an epoxy,[5] and the feedwater heaters and moisture separator reheaters are made of carbon steel. Some Siemens plants inject oxygen upstream of their reheater system to counteract FAC of the moisture separator reheater tubing.

All Siemens design plants recover blowdown to the main condenser via electro-mechanical filters and fixed bed filters in the blowdown line and each plant uses a feedwater tank (deaerator) for continuous deaerating of the condensate.

Originally, Siemens-designed plants used phosphate chemistry for pH control. However, because of phosphate wastage experienced in steam generator tubing (as discussed in Section 6.1), Siemens-designed plants switched to high-AVT for secondary pH control with the following feedwater targets [10,11]:

- pH >9.8
- Cation Conductivity <0.15 μS/cm
- Oxygen <5 ppb
- N_2H_4 >20 ppb (typically 20–150 ppb)

The history of secondary chemistry used in each Siemens plant is presented in Figure 3-1.[6]

[5] Siemens-designed PWRs constructed before Grafenrheinfeld Nuclear Power Plant originally contained copper alloys in the main condenser tubing. However, before switching secondary chemistry to AVT the main condenser tubing was replaced with stainless steel.

[6] Note that Angra Unit 2 is not included in this figure. Angra Unit 2 has always operated with AVT for secondary chemistry control.

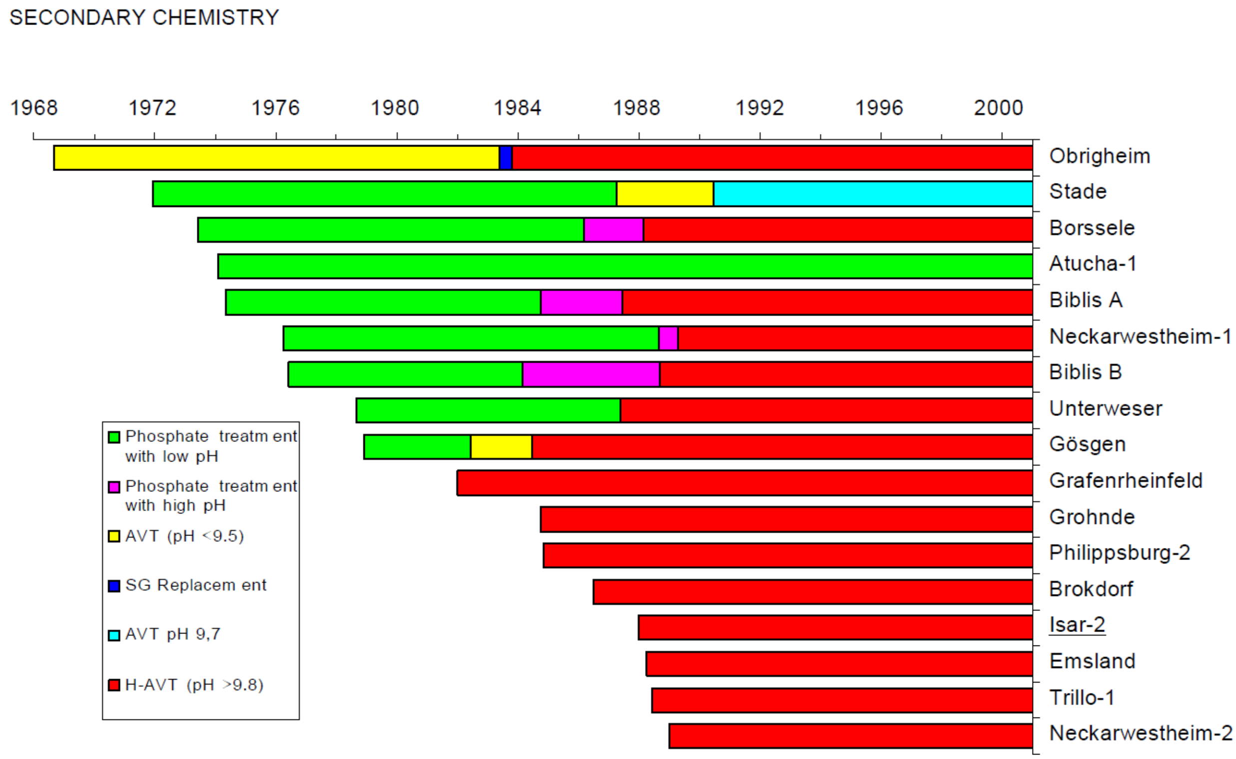

Figure A-1
Secondary Side Water Chemistry History of Siemens-designed Plants (reprinted from Reference [11])

Some of the major secondary side design differences between Siemens PWRs are presented in Table 3-2.

Table 3-2
Secondary Side Differences in Siemens PWRs (see Appendix A for details)

Plant	Ultimate Cooling Water	CPS[2]	Mech Filters & EMF	O_2 Injection into Reheaters (Year)	Years Operating with PO_4 Chemistry
Stade	Fresh	N	N	N	15
Borssele	Brackish	N	N	N	15
Biblis A	Fresh	N	N	Y (2001)	14
Biblis B	Fresh	N	N	Y[3]	12
Neckarwestheim 1	Cooling Tower	N	N	N	13
Unterweser	Brackish	Y	N	N	9
Goesgen	Cooling Tower	N	N	N	3
Grafenrheinfeld	Cooling Tower	N	N	N	0
Obrigheim[1]	Fresh	N	N	N	0
Grohnde	Cooling Tower	Y	N	N	0
Philippsburg 2	Cooling Tower	N	Y[4]	Y (1998)	0
Brokdorf	Cooling Tower	Y	N	N	0
Isar 2	Cooling Tower	N	Y	Y (2003)	0
Emsland	Cooling Tower	N	Y	N	0
Trillo 1	Fresh	N	Y	N	0
Neckarwestheim 2	Cooling Tower	N	Y	N	0
Angra 2	Seawater	N	N	N	0

1) All data presented for Obrigheim Nuclear Power Plant is in reference to its replacement steam generators.
2) Condensate polishing systems are only operational during startup or transients.
3) Biblis B started injecting oxygen into their reheater system after replacing the moisture separator reheaters (date unknown).
4) Philippsburg Nuclear Power Plant Unit 2 only has 30% flow mechanical filters and does not have electro-mechanical filters.

Each Siemens plant design is discussed in detail in Appendix A.

3.1.3 Degradation Experienced

A summary of the degradation experienced in Siemens-designed PWRs are presented in Table 3-3.

Table 3-3
Degradation in Siemens PWRs through 2007[7] [8,12]

Plant	Total # of Tubes	EFPY Through Dec. 2006	EDY through Dec. 2006 at 310.0°C[2]	Tubes Plugged due to PO_4 Wastage	Tubes Plugged for Other Reasons[3]
Stade	11972	26.1	34.7	327	2
Borssele	8468	27.5	52.5	115	22
Biblis A	16240	21.5	27.5	514	102
Biblis B	16084	21.0	41.7	18	63
Neckarwestheim 1	12156	24.6	59.7	4	21
Unterweser	16084	21.9	38.6	19	27
Goesgen	12318	23.7	53.2	1	18
Grafenrheinfeld	16344	21.0	64.4	0	16
Obrigheim[1]	6020	17.5	16.8	0	0
Grohnde	16344	19.8	65.7	0	13
Philippsburg 2	16472	18.8	67.5	0	2
Brokdorf	16344	17.3	53.1	0	6
Isar 2	16472	16.2	44.3	0	0
Emsland	16472	17.3	49.2	0	0
Trillo 1	12258	15.7	50.2	0	24
Neckarwestheim 2	16472	16.4	46.4	0	1
Angra 2	16424	4.7	15.1	0	3

1) All data presented for Obrigheim Nuclear Power Plant is in reference to its replacement steam generators.
2) EDY (Effective Damage Years) calculated using Q=50kcal/mol.
3) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

Degradation of each Siemens-designed plant is discussed in detail in Appendix A.

3.2 CANDU PHWRs

This section provides a general overview of the significant general design and operational features of the CANDU PHWRs with steam generators that have Alloy 800NG tubing. Note that additional details and references for the data presented in this section are provided in Appendix B.

[7] Plant data through 2007 is given because it is the most recent available degradation data; see Appendix A for additional details and for references to the information presented in this table.

3.2.1 Major Steam Generator Designs and Operating Parameters

CANDU designed PHWRs with original[8] Alloy 800 steam generator tubing share many common features. These CANDU plants are all 2 loop plants, with 4 steam generators (2 in each loop). [9] Each steam generator has an integral steam drum and preheater, Alloy 800 tubing, and forged low alloy steel tubesheets. The tubes, arranged in a triangular pitch, [10] are 15.9 mm (0.625") diameter and are 1.13 mm (0.044") thick. Additionally all CANDU plants have tubes that were hydraulically expanded into the tubesheet except Wolsong Unit 1, which has tubes that were mechanically rolled (partial depth) into the tubesheet.

The Alloy 800 used to tube the steam generators is nuclear grade (modified). The chemical composition, cold work, and peening of Alloy 800, nuclear grade, modified tubing are discussed in detail in Chapter 4 of this report.

Some of the major design differences among the CANDU PHWRs are presented in Table 3-4.

Table 3-4
Steam Generator Design Differences in CANDU PHWRs (see Appendix B for details)

Plant	Initial Operation Date	Country	Hot Leg Temperature (°C)	Power Rating (MWe)	Tube Expansion	Tube Support Design	Tube Support Material	U-Bend Support Design	U-Bend Support Material
Point Lepreau	1983	Canada	309	680	Hydraulic	Broached Plates	410 SS	Staggered, Scallop Bars	410 SS
Wolsong 1	1983	South Korea	309	678	PD Mech Roll	Formed Bars	I-600	Wiggly Bars	AISI 1018
Wolsong 2	1997	South Korea	309	730	Hydraulic	Lattice Grids	410 SS	Flat Bars	SA-240, Cl 3
Wolsong 3	1998	South Korea	309	729	Hydraulic	Lattice Grids	410 SS	Flat Bars	SA-240, Cl 3
Wolsong 4	1999	South Korea	309	730	Hydraulic	Lattice Grids	410 SS	Flat Bars	SA-240, Cl 3
Darlington 1	1992	Canada	309	934	Hydraulic	Lattice Grids	410 SS	Flat Bars	410 SS
Darlington 2	1990	Canada	309	934	Hydraulic	Lattice Grids	410 SS	Flat Bars	410 SS
Darlington 3	1993	Canada	309	934	Hydraulic	Lattice Grids	410 SS	Flat Bars	410 SS
Darlington 4	1993	Canada	309	934	Hydraulic	Lattice Grids	410 SS	Flat Bars	410 SS
Gentilly 2	1983	Canada	310	675	Hydraulic	Broached Plates	410 SS	Staggered, Scallop Bars	410 SS
Embalse	1984	Argentina	309	648	Hydraulic	Broached Plates	SA 515, Cl 2	Staggered, Scallop Bars	SA 515, Cl 2
Cernavoda 1	1996	Romania	310	704.8		Lattice Grids		Flat Bars	
Cernavoda 2	2007	Romania	310	706		Lattice Grids		Flat Bars	
Qin Shan 3-1	2002	China	310	728					
Qin Shan 3-2	2003	China	310	728					

1) Gray Cells indicate that this information was not available

The effects of the designs and operating parameters discussed in this chapter on the degradation experienced at each plant are discussed in detail in Chapter 5.

Each CANDU plant design is discussed in detail in Appendix B.

[8] This report does not address the recently installed replacement steam generators at Bruce, which are also tubed with Alloy 800.

[9] Note that the replacement steam generators at Bruce Units A1 and A2 are made of Alloy 800. These units plan to come online in 2012. These two units are 2 loop plants; however each loop has four steam generators.

[10] It is assumed that all CANDU designed PHWRs have tubes arranged in a triangular pitch because they all have the same diameter and thickness.

3.2.2 Major Secondary Side Designs and Operating Parameters

Currently, all CANDU designed plants use AVT for secondary chemistry control.

Some of the major secondary side design differences between CANDU PHWRs are presented in Table 3-5.

Table 3-5
Secondary Side Differences in CANDU PHWRs (see Appendix B for details)

Plant	Ultimate Cooling Water	Secondary Chemistry Control Agent(s)	BOP Materials	Condensate Polishing System	Blowdown Recovery	Cleaning History[2]
Point Lepreau	Seawater	PO4+Morph/N_2H_4[1]	All Ferrous	Y	Y	7 SL, 1 CC
Wolsong 1	Seawater	Morph+N_2H_4	Ferrous/Copper	Y	N	1 SL
Wolsong 2	Seawater	Morph+N_2H_4	Ferrous/Copper	Y	N	2 SL[3]
Wolsong 3	Seawater	Morph+N_2H_4	All Ferrous	Y	N	2 SL[3]
Wolsong 4	Seawater	Morph+N_2H_4	All Ferrous	Y	N	2 SL[3]
Darlington 1	Fresh- Lake	NH_3+N_2H_4	All Ferrous	N	N	5 SL, 1 MC
Darlington 2	Fresh- Lake	NH_3+N_2H_4	All Ferrous	N	N	3 SL
Darlington 3	Fresh- Lake	NH_3+N_2H_4	All Ferrous	N	N	4 SL
Darlington 4	Fresh- Lake	NH_3+N_2H_4	All Ferrous	N	N	4 SL
Gentilly 2	Fresh- River	Morph+N_2H_4	Ferrous/Copper		Y	1 CC
Embalse	Fresh- Lake	Morph/Ethanolamine+N_2H_4[4]	Ferrous/Copper			2 SL, 1 MC
Cernavoda 1						
Cernavoda 2						
Qin Shan 3-1						
Qin Shan 3-2						

1) Point Lepreau used phosphate chemistry until 2000, when it changed to AVT
2) SL = Sludge Lancing; CC= Chemical Cleaning, MC= Mechanical Cleaning (of primary side)
3) Wolsong Units 2-4 have performed sludge lancings during two outages. However, only two of the four SGs were sludge lanced in each outage.
4) Embalse switched from morpholine to ethanolamine for secondary-side pH control in 2007
5) Gray Cells indicate that this information was not available

Each CANDU plant design is discussed in detail in Appendix B.

3.2.3 Degradation Experienced

A summary of the degradation experienced in CANDU PHWRs is presented in Table 3-6.

Table 3-6
Degradation in CANDU PHWRs (see Appendix B for details)

Plant	Total # of Tubes	EFPY (April 2011)	EDY at 310.0°C[1]	Total Tubes Plugged or Repaired[2]	Reference Date[3]	Primary Form of Degradation
Point Lepreau	14200	20.8	19.3	87	2011	Phosphate Wastage & Debris Fretting
Wolsong 1	14232	22.8	21.0	2	2011	Foreign Object Wear
Wolsong 2	14120	12.2	11.3	0	2011	
Wolsong 3	14120	11.5	10.6	3	2011	Foreign Object Wear
Wolsong 4	14120	10.4	9.6	0	2011	
Darlington 1	18652	15.6	14.4	311	2011	Structural Wear
Darlington 2	18652	16.1	14.8	119	2011	Structural Wear
Darlington 3	18652	15.7	14.5	143	2011	Structural Wear
Darlington 4	18652	15.3	14.1	65	2011	Structural Wear
Gentilly 2	14168	21.3	21.3	5	2005	Structural Wear
Embalse	14168	21.0	19.3	11	2006	Structural Wear
Cernavoda 1		12.0	12.0			
Cernavoda 2		2.5	2.5			
Qin Shan 3-1						
Qin Shan 3-2						

1) EDY (Effective Damage Years) calculated using Q=50kcal/mol.
2) Does not include tubes preventively plugged for corrosion, tubes plugged due to manufacturing flaws, or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.
3) Indicates the date of the most recent reference for total tubes plugged.
4) Gray Cells indicate that this information was not available

Degradation of each CANDU plant is discussed in detail in Appendix B.

3.3 Replacement Steam Generators for Westinghouse-Designed PWRs

This section provides a general overview of the significant general design and operational features of the Westinghouse-designed PWRs with replacement steam generators that have Alloy 800NG tubing. Note that additional details and references for the data presented in this section are provided in Appendix C.

3.3.1 Major Steam Generator Designs and Operating Parameters

The Westinghouse-designed PWRs with replacement steam generators tubed with Alloy 800 share many common features. They are all 3 loop plants, with model KWU-61W or KWU-61W/D3 replacement steam generators. Each steam generator has a feedring and a flow distribution baffle.

The Alloy 800 used to tube the steam generators was nuclear grade (modified). During fabrication the tubes were cold pilgered, and after bending they were full-OD glass bead, shot peened for ODSCC resistance. The chemical composition, cold work, and peening of the Alloy 800, nuclear grade, modified tubing are discussed in detail in Chapter 4 of this report.

The replacement steam generator tubes are 19.1 mm (0.75") in diameter, 1.1 mm (0.043") thick, and arranged in a triangular pitch. The tubes were hydraulically expanded into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The mechanical rolls were used in addition to the hydraulic expansion to provide increased confidence in the seal at the secondary face of the tubesheet and to prevent undesired stresses at the tube-end weld at the primary face of the tubesheet [13]. The tubesheet is made of forged low-alloy steel (SA-508 Class 3, Grade 1). The flow distribution baffle is made of Type 347 stainless steel for Asco Units 1 and 2 and Doel Unit 3, and since the steam generator design of these five units is very similar, it is likely they are all made of Type 347 stainless steel.

The replacement steam generators all have lattice bar tube supports. Both the lattice bar supports and anti-vibration bars are made of Type 321, austenitic stainless steel for Asco Units 1 and 2 and Doel Unit 3, and since the steam generator design of these five units is very similar, it is likely they are all made of Type 321, austenitic stainless steel.

Some of the major design differences in Westinghouse plants with Alloy 800 replacement steam generators are presented in Table 3-7.

Table 3-7
Major Differences in Westinghouse PWRs with Replacement Steam Generators (see Appendix C for details)

Plant	Initial Operation Date	SG Replacement Date	Country	Hot Leg Temperature (°C)	Power Rating (MWe)	SG Model
Doel 3	1982	1993	Belgium	322.8	1056	KWU-61W
Asco 1	1984	1995	Spain	327.2	1032	KWU-61W/D3
Asco 2	1986	1996	Spain	327.2	1027	KWU-61W/D3
Almaraz 1	1981	1996	Spain	327.8	977	KWU-61W/D3
Almaraz 2	1983	1997	Spain	327.2	980	KWU-61W/D3

The effects of the designs and operating parameters discussed in this chapter on the degradation experienced at each plant are discussed in detail in Chapter 5.

Each Westinghouse plant with replacement steam generators and Alloy 800 tubing is discussed in detail in Appendix C.

3.3.2 Major Secondary Side Designs and Operating Parameters

Currently, all Westinghouse PWRs with Alloy 800 replacement steam generators use AVT with ammonia/hydrazine for secondary pH control. Since steam generator replacement, they all have an all ferrous secondary system, and no boric acid treatments (either online or offline) or active molar ratio control has been implemented since SG replacement.

Some of the major secondary side design differences among these plants are presented in Table 3-8.

Table 3-8
Secondary Side Differences Westinghouse PWRs with Replacement Steam Generators (see Appendix C for details)

Plant	Ultimate Cooling Water	Condensate Treatment System	Blowdown Recovery	Secondary Cleaning History[3]
Doel 3	Tower + River[1]	Deep Bed CPS[2]	Y	9 SL, 2 HSL
Asco 1	Fresh- River	N	N	5 SL, 1 HSL
Asco 2	Fresh- River	N	N	4 SL, 2 HSL
Almaraz 1	Closed- Pond	Filter/Demineralizer[2]	Y	7 SL, 1 CC
Almaraz 2	Closed- Pond	Filter/Demineralizer[2]	Y	7 SL, 1 CC

1) The cooling water for Doel 3 consists of a cooling tower and a mixed make-up of fresh water and water from Doel 1 & 2.
2) Only active during startup, cooldown or during transients
3) SL = Sludge Lance; HSL = Hard Sludge Lance; CC - Chemical Cleaning

Each Westinghouse plant design is discussed in detail in Appendix C.

3.3.3 Degradation Experienced

A summary of the degradation experienced in Westinghouse PWRs with replacement steam generators is presented in Table 3-9.

Table 3-9
Degradation Experienced in Westinghouse PWRs with Replacement Steam Generators (see Appendix C for details)

Plant	Hot Leg Temperature (°C)	Reference Date[1]	Repl. SG EFPY	EDY at 310.0°C[2]	# Denting Indications		# Circ. OD IGA/SCC		Tubes Plugged for Other Reasons[3]
					Cold Leg	Hot Leg	Cold Leg	Hot Leg	
Doel 3	323	Jun 2011	15.8	39.9	123	0	0	0	0
Asco 1	327	Mar 2011	13.8	47.4	0	241	0	5[4]	11
Asco 2	327	May 2010	12.4	42.8	144	0	0	0	10
Almaraz 1	328	Jun 2011	13.3	47.8	1164	21	3	0	0
Almaraz 2	327	Nov 2010	11.5	39.8	1270	556	48	64	2

1) Indicates the date of the most recent reference for total tubes plugged.
2) EDY (Effective Damage Years) calculated using Q=50kcal/mol at the time of the Reference Date above.
3) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.
4) Only 2 ODSCC indications were specified to be circumferential at Asco 1. However, it is most likely that all 5 indications were circumferential due to the experiences at Almaraz 1 and 2.

Degradation of each Westinghouse plant with replacement steam generators is discussed in detail in Appendix C.

3.4 Other Units

Note that additional details and references for the data presented in this section are provided in Appendix D. A summary of other units with Alloy 800, nuclear grade (modified) tubing is presented in Table 3-10.

Table 3-10
Major Plant Designs and Parameters in Other Units with Alloy 800NG tubing (see Appendix D for details)

Plant	Initial Operation Date	Country	Hot Leg Temperature (°C)	Power Rating (MWe)	Plant Type	SG EFPY (April 2011)	SG EDY at 310.0°C[1]
Atucha 1	1974	Argentina	306	357	PHWR	25.2	18.7
Narora 1 (NAPS 1)	1991	India	293.4	235	PHWR	10.7	3.0
Narora 2 (NAPS 2)	1992	India	293.4	235	PHWR	10.5	3.0
Kakrapar 1	1993	India	293	235	PHWR	10.0	2.7
Kakrapar 2	1995	India	293	235	PHWR	11.3	3.1
Qin Shan 1	1994	China	315.5	310	PWR		
Chashma 1 (CHASNUPP 1)	1999	Pakistan	315.5	325	PWR	7.7	11.5
Rajasthan 3	2000	India	293	220	PHWR	8.0	2.2
Rajasthan 4	2000	India	293	220	PHWR	7.7	2.1
Kaiga 1	2000	India	293	235	PHWR	7.2	2.0
Kaiga 2	2000	India	293	235	PHWR	7.6	2.1
Kaiga 3	2007	India	293	235	PHWR	1.8	0.5
Tarapur 4 (TAPP 4)	2005	India	304	540	PHWR	3.0	1.9
Tarapur 3 (TAPP 3)	2006	India	304	540	PHWR	2.8	1.8

1) EDY (Effective Damage Years) calculated using Q=50kcal/mol.
2) Gray Cells indicate that this information was not available

The effects of the designs and operating parameters discussed in this chapter on the degradation experienced at each plant are discussed in detail in Chapter 5.

4
VARIATIONS IN ALLOY 800 MATERIAL USED FOR TUBING IN STEAM GENERATORS

This chapter addresses variations in Alloy 800 material used for steam generator tubing. Specifically, chemical composition is addressed in Section 4.1; cold drawing for mechanical strength is addressed in Section 4.2; and OD peening for SCC resistance is addressed in Section 4.3. Tube diameter and wall thickness are addressed with other design issues in Chapter 5.

4.1 Chemical Composition

The Alloy 800 nuclear grade modified used in steam generator tubing is based on the Alloy 800 ASTM 163-66 specification, with narrower specifications made to increase resistance to corrosion. The chemical composition specified by ASTM 163-66 and used for Alloy 800NG modified tubes is presented in Table 4-1.

Table 4-1
Chemical Composition of Alloy 800NG: ASTM 163-66 (UNS N08800) vs. KWU and AECL Modified Specifications [9,5]

	Alloy According To		
Mass Fraction	ASTM 163-66	KWU-Specification	AECL-Specification
C	< 0.10	< 0.03	< 0.03
Ni	30 - 35	32 - 35	32 - 35
Cr	19 - 23	20-23	20-23
Mn	< 1.5	0.4 - 1.0	< 1.0
Si	< 1.0	0.3 - 0.7	< 0.70
Cu	< 0.75	< 0.75	< 0.75
Al	0.15 - 0.60	0.15 - 0.45	0.15 - 0.45
Co		< 0.1	< 0.03
P		< 0.02	
S	< 0.015	< 0.015	< 0.015
N		< 0.03	< 0.03
Ti	0.15-0.60	< 0.60	> 0.35
Mass ratio			
m_{Ti}/m_C		> 12	> 12
m_{Ti}/m_{C-N}		> 8	> 8

1) Gray Cells indicate that the mass fractions of these elements were not specified.

The major changes and their effects [14,5] include:

- Increase in Ni content, which increases resistance to transgranular SCC.
- Increase in Cr content, which increases resistance to pitting and SCC.
- Reduction in allowable carbon content and the specification of titanium to carbon ratios, which reduces risk of sensitization.[11]

4.2 Cold Work for Mechanical Strength

To increase mechanical yield strength, the Alloy 800NG modified tubing can receive a 4% final cold draw. Increasing the mechanical yield strength of the tubing allows steam generator tubes to be thinner, which reduces heat transfer resistance in the steam generators. Additionally, this cold work has been shown to increase resistance to caustic stress corrosion cracking in constant extension rate (CERT) tests. The CERT tests were performed under the following conditions [14,19]:

- 100 g/kg NaOH
- 6 mg/kg N_2H_4
- 320°C
- Strain Rate of 10^{-6}/sec

Of the plants discussed in this report, the following have tubing which has had the cold work described above:

- Siemens: All plants
- CANDU: None
- Westinghouse: All Plants
- Other: See Appendix D.

The KWU and AECL mechanical property specifications for Alloy 800 steam generator tubing are shown in Table 4-2.

[11] Note that the significance of sensitization and efforts to avoid it are different for Alloy 600 and nuclear grade Alloy 800. Alloy 600 is generally susceptible to SCC in several relevant environments, i.e., primary and secondary water. Therefore, there was a significant industry effort to optimize the microstructure of Alloy 600 through thermal processing, which identified a thermal treatment (TT), typically about 700°C for about 15 hours, as highly beneficial with respect to SCC. A key indicator of a successful thermal treatment is semi-continuous grain boundary chromium carbide decoration, which is also dependent on the carbon content and the final mill annealing conditions. The thermal treatment process is also optimized to reduce susceptibility to SCC arising from chromium depletion due to the precipitation of chromium carbides at the grain boundaries (although not necessarily through complete replenishment of depleted chromium). For Alloy 800, most likely due to lower susceptibility to SCC in primary and secondary water and the resulting lower emphasis on solving SCC performance issues, this type of optimization by thermal treatment was not considered necessary. In this regard, the low carbon concentration and the high titanium to carbon ratio used for nuclear grade Alloy 800 essentially eliminated concerns about sensitization and resulting susceptibility to chlorides, and tests showed that nuclear grade Alloy 800 appeared to be highly resistant to attack by primary water.

Table 4-2
Mechanical Properties of Alloy 800NG: KWU and AECL Specifications [16,17,18]

	UNS N08800		KWU Spec	AECL Spec
	Annealed	Cold Worked		
Yield Stress at Room Temperature (MPa)	> 207	> 324	334-471	> 207
Tensile Strength at Room Temperature (MPa)	> 517	> 572	> 572	> 517
Elongation at Room Temperature (%)	30	30	30	None Specified

4.3 Peening for ODSCC Mitigation

When tubing is bent to create U-tubes, the area of the U-bend is put under residual tensile stress. This residual stress has been shown to increase susceptibility to stress corrosion cracking. Shot peening the outside diameter of the U-bend tubing puts the outside diameter surface into compression, significantly reducing the residual tensile stress and susceptibility to stress corrosion cracking [19]. Siemens indicates that the peening develops a compressive layer of at least 120 µm [20].

Recent circumferential IGA/SCC at the TTS associated with denting at Siemens plants, and in the replacement steam generators at Westinghouse plants, indicates that peening of the OD surface may increase susceptibility to OD IGA/SCC in significantly dented regions (as described in Section 6.7). OD peening increases the hardness of the tubing and the depth of the cold worked layer, which, in the presence of significantly deformed areas, could lead to easier growth and initiation of SCC in the peened region. (However, note that, in the absence of denting or other plastic straining, a peened OD surface is expected to be more resistant to OD IGA/SCC than a non-peened surface.)

The Belgians investigated the effects of peening on the likelihood of ODSCC occurring in the transition region at the TTS before deciding to use peening for the Alloy 800 tubes used for the replacement SGs at Doel Nuclear Power Plant Unit 3. Based on X-ray measurement of residual stresses and on SCC tests using stainless steel tubes subjected to boiling magnesium chloride they concluded that use of peened tubes did not increase the risks of ODSCC [21]. However, this evaluation did not investigate the effects of denting at this location, and thus does not address the effect of peening (or cold working) on OD IGA/SCC if significant denting occurs.

Of the plants discussed in this report, the following have tubes which have been peened:

- Siemens: All plants constructed after Unterweser Nuclear Power Plant (see Table 3-1)
- CANDU (with Alloy 800 SGs): None[12]
- Westinghouse (Alloy 800 replacement SGs): All Plants
- Other: See Appendix D.

[12] It is suspected that portions of tubes at one CANDU unit have been peened, but this could not be confirmed.

5 MAJOR DESIGN/OPERATING DIFFERENCES AFFECTING TUBE DEGRADATION

In many cases, design differences are known to have a significant effect on tubing degradation. This chapter summarizes the current understanding of the relationship between design/operating differences and tubing degradation. The following specific differences are discussed in this chapter:

- Tube expansion (Section 5.1)
- Tube supports (Section 5.2)
- Flow distribution baffles (Section 5.3)
- Temperature (Section 5.4)
- Secondary side chemistry (Section 5.5)
- Feed type (pre-heater versus feedring) (Section 5.6)
- Tube diameter and thickness (Section 5.7)

5.1 Tube in Tubesheet Expansion

In the earliest steam generator designs, the tubes were expanded by mechanical rolling to form a seal with the tubesheet for only a few inches at the primary side face of the tubesheet. This left a narrow crevice around the tube for the remaining depth of the tube sheet (approximately 20 in.). Many of the steam generators made with this partial depth tube in tubesheet expansion experienced IGA/SCC from the tube OD in the tubesheet crevices. Because of these crevice corrosion problems, improvements on the expansion process were made. In plants with Alloy 800 tubing, these improvements include top and bottom roll expansions and hydraulic expansions.

All tube expansion processes produce residual stresses, particularly at the transition between the expanded and unexpanded portions of the tube. This increases susceptibility to IGA/SCC in the transition area.

5.1.1 Mechanical Roll Expansion

All Siemens-designed plants use an expansion process which includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. This process improves upon partial depth expansion by sealing off the narrow crevice around the tube with the upper mechanical roll. However, plant experiences have shown that secondary fluid can leak past the upper expansion and cause ODSCC in the tubesheet crevice (as discussed in Section 6.5).

5.1.2 Hydraulic Expansion

This expansion process produces lower residual stresses than mechanical rolling, which, in turn, reduces susceptibility to OD IGA/SCC.

All Westinghouse-designed plants with replacement steam generators with Alloy 800 tubing use a hydraulic expansion process which includes a top and bottom mechanical roll (as described in Section 5.1.1). Details on crevice geometries for Westinghouse replacement steam generators are provided in Appendix C.

All CANDU PHWRs use a hydraulic expansion processes except Wolsong Nuclear Generating Station Unit 1 which uses a mechanical roll (partial roll) and has formed bar supports (see Section 5.2.1.3).

5.2 Tube Supports

5.2.1 Straight Leg Supports

5.2.1.1 Tube Support Plates (TSPs)

Early model TSPs consisted of carbon steel plates with drilled holes for the tubes to pass through. Flow holes in the plates between the tubes provide a flow path for the majority of the secondary side flow. The drilled holes are larger than the tubes leaving an annular crevice around the tube. Calculations based on the crevices being clean indicated that a portion of the coolant flow would pass through the annular gaps around the tube. In practice, it was found that the crevices between the tubes and the TSPs become fouled with deposits relatively quickly after the steam generator entered service so that there was no longer flow through the crevices. The fouled crevices become hideout locations where impurities in the bulk water concentrated to form aggressive environments that caused corrosion and denting of the tubes (as discussed in Section 6.7).

All CANDU designed PHWRs use drilled-hole support plates in the preheater region (see Appendix B).

An improvement over drilled-hole TSPs are broached-hole TSPs. Broached-hole TSPs incorporate flow passages into the same holes that accommodate the tubes. This design forces coolant flow to follow the heat exchanger tubes and limits the narrow crevices adjacent to the tubes to the ends of the broached-hole lands. This reduction in crevice geometry reduces the potential for buildup and concentration of impurities.

Broached-hole TSP designs include trefoil and quatrefoil broached holes; trefoil broached-hole TSPs have 3 lands per hole, and quatrefoil broached-hole TSPs have 4 lands per hole. The lands of broached holes can be concave, convex, or flat. Broached holes with concave lands have the largest crevices adjacent to the tubes, which in turn, increases their susceptibility to denting and associated IGA/SCC at TSPs (as discussed in Section 6.8).

The CANDU plants (with Alloy 800 SG tubes) that have trefoil broached-hole TSPs are Point Lepreau, Gentilly 2, and Embalse Generating Stations. (See Appendices B.1, B.10, B.11 for additional details and the materials of construction.)

5.2.1.2 Lattice Bar Supports

An alternative to TSPs are lattice bar (egg crate) supports. Lattice bar supports have large free flow cross sections and allow for easy passage of coolant and steam, which reduces potential for buildup and concentration of impurities and associated denting. Lattice bar support designs can be used with triangular or square pitch tube bundles.

Of the plants discussed in this report, the following have lattice bar supports:

- Siemens: All Plants have lattice bar supports made of austenitic stainless steel.
- CANDU (with Alloy 800 SG tubes): Wolsong Units 2–4, Darlington and Cernavoda Generating Stations have lattice bar supports made of Type 410 stainless steel.
- Westinghouse (with Alloy 800 tubed replacement SGs): All Plants have lattice bar supports made of Type 321 stainless steel.
- Other: See Appendix D.

5.2.1.3 Formed Bar Supports

Formed bar supports are similar to lattice bar supports. However, they have a smaller contact area with the tubes and the bars are not straight. Among tube support designs, formed bar supports have been shown to have the lowest propensity for particle buildup and fouling due to their large free flow cross sections [22].

Wolsong Generating Station Unit 1 has formed bar supports.

5.2.2 U-Bend Supports

Steam generators include AVBs to support tubes and limit vibration amplitude experienced by tubes in the U-bend region. Due to this vibration, U-tubes are very susceptible to mechanical wear at their intersections with AVBs (as discussed in Section 6.2).

The design and materials used for AVBs greatly affects their susceptibility to degradation. AVBs with small contact areas to U-tubes (e.g. round cross section bars) have higher contact forces, which increases susceptibility to mechanical wear. AVBs with large contact areas to U-tubes provide larger hideout areas for impurities to buildup and concentrate, increasing susceptibility to denting and IGA/SCC.

The design and materials used for AVBs in plants with Alloy 800 tubing are discussed in Subsection 2 of the plant appendices.

5.3 Flow Distribution Baffles (FDB)

In recirculating steam generators, FDBs are placed low in the tube bundle and serve to redistribute coolant flow more uniformly across the bundle. This reduces the formation of areas with stagnant flow where deposits typically collect (central region of tube bundle), reducing susceptibility to TTS denting (as discussed in Section 6.7).

Of the plants discussed in this report, the following have flow distribution baffles:

- Siemens: Gösgen, Grafenrheinfeld, Grohnde, Brokdorf, Trillo 1, and Angra 2
- CANDU (with Alloy 800 SG tubes): None
- Westinghouse (with Alloy 800 tubed replacement SGs): All Plants
- Other: See Appendix D

5.4 Temperature

The main effect of the steam generator temperature on the degradation of Alloy 800 tubing is thermal activation of OD IGA/SCC. OD IGA/SCC is believed to be related to the steam generator temperature by an Arrhenius equation with an activation energy of 50 kcal/mole. This activation energy is based on previous studies performed by EPRI for Alloy 600 [23]. Determination of activation energies for Alloy 800 degradation is an active research area.

Hot leg temperatures are provided in Table 3-1, Table 3-4, Table 3-7, and Table 3-10 and range from 309.4 to 327.8ºC.

The effect of temperature and available superheat on crevice chemistry was determined to be small (e.g., in comparison to the effect of thermal activation) in calculations performed in Reference [24]. Based on MULTEQ calculations, it was concluded that system temperature does not significantly affect the pH which develops upon concentration. Specifically, for representative faulted secondary side chemistries, typical available superheats are all high enough that different hot leg temperatures do not change the pH that is achieved during concentration by boiling. This is somewhat contrary to previous conclusions based on highly caustic solutions, which are not considered realistic representations of actual crevice chemistries.

In summary, the only effect of temperature on tube degradation rates expected to be significant is the thermal activation of SCC.

5.5 Secondary Side Chemistry

5.5.1 Phosphate Treatment

All Siemens-designed plants constructed before Grafenrheinfeld originally added sodium phosphate to their secondary side for corrosion control. This treatment was successful in reducing the incidence of caustic stress corrosion cracking, but also caused general tube wastage (as discussed in Section 6.1) [19]. This phosphate wastage caused all Siemens-designed plants (except Atucha 1, a PHWR) to switch to high-AVT chemistry (see Figure 3-1). Point Lepreau (a CANDU unit) also started on phosphate treatment, but then changed to AVT.

5.5.2 All Volatile Treatment (AVT)

In AVT chemistry, hydrazine and ammonia or an organic amine are injected into the condensate system to remove oxygen and to increase the feedwater pH [11]. Hydrazine thermally decomposes to ammonia, using metal ions as a catalyst. This secondary chemistry program maintains reducing conditions in the steam generators and decreases deposit accumulation into the steam generators by reducing the feedwater iron transportation [25].

All Siemens plants currently use hydrazine and ammonia to increase the feedwater pH to values above 9.8 (high AVT–actual operating values are above 10) (see Section 3.1.2). It is estimated that high AVT chemistry reduces the corrosion products in the secondary system by a factor of almost ten over low AVT chemistry [26].

All Westinghouse-designed plants with replacement steam generators with Alloy 800 tubing use hydrazine and ammonia for secondary chemistry control (see Appendix C).

All CANDU plants with Alloy 800 tubing use AVT for secondary chemistry control. The pH control agent(s) used at CANDU plants are as follows (see Appendix B):

- Darlington: Ammonia
- Point Lepreau, Gentilly Unit 2, and Wolsong: Morpholine
- Embalse: Ethanolamine

5.5.3 Oxygen Injection

Some Siemens plants (see Table 3-2) inject oxygen upstream of their moisture separator reheaters to counteract FAC of the carbon steel header tubing. Despite this injection, the feedwater oxygen concentration is maintained below 5 ppb as specified by their secondary chemistry guidelines; in general, oxygen concentrations of about 1–2 ppb have not been exceeded [11,27].

5.6 Preheaters

The thermal-hydraulic conditions in steam generators integral preheaters are different from those in steam generators with feedrings. These differing thermal-hydraulic conditions affect the susceptibility of steam generator tubing to degradation. In previous evaluations for Alloy 600 [1–4] it has been necessary to make OD IGA/SCC degradation predictions separately for plants with and without a preheater. This methodology will also be used in the generic predictions report that is expected to be published in late 2013 to capture the effects of preheaters on the degradation of Alloy 800NG.

Several PWRs with Alloy 600MA tubing have experienced rapid development of circumferential OD IGA/SCC at the TTS, affecting many tubes across the tube sheet. This has been especially true at units with preheaters [28]. This has in part been attributed to the almost complete lack of subcooled boiling in the recirculating water entering the bottom of the tube bundle (in feedring units without preheaters, the water entering the lower portion of the steam generator is more subcooled by mixing with feedwater). This indicates that steam generators with preheaters are more susceptible to IGA/SCC at the hot leg, top of tubesheet region for equivalent reactor hot leg temperature.[13]

[13] Steam generators with integral preheaters have increased thermal efficiency in comparison to that for feedring units. Thus, for steam generators with and without an integral preheater of equivalent size and output steam pressure, the unit with the integral preheater would require a lower hot leg temperature.

Additionally, an integral preheater displaces the cold leg TTS region, which limits impurity buildup and concentration to the hot leg TTS region, increasing susceptibility to TTS denting and related ODSCC in the hot leg region (as discussed in Section 6.7). However, note that none of the plants with Alloy 800NG tubing that have experienced TTS ODSCC has an internal preheater. This indicates that other factors associated with the preheater design such as differences in the velocity distribution and sludge pile location may be more significant to the susceptibility to TTS denting and related ODSCC than just the effect of the preheater on the temperature in the hot leg, top of tubesheet region.

Of the plants discussed in this report, the following have integral preheaters:

- Siemens: Grafenrheinfeld, Grohnde, Brokdorf, and Trillo 1
- CANDU (with Alloy 800 SG tubes): All Plants
- Westinghouse (with Alloy 800 tubed replacement SGs): None
- Other: See Appendix D

5.7 Tube Diameter and Thickness

Differences in tube dimensions (diameter and thickness) lead to different levels of stress and cold work when the same forming process is applied to differing tubes. For example, tube bending to form U-bends or tube expansion in the tubesheet (see Section 5-1) lead to different stress and cold work distributions in the tube.

For U-bends, the residual plastic strain and corresponding strain damage can be calculated using simple geometry. Theoretically, assuming that the center of curvature of the bend (the centerline of the tube) neither lengthens nor shortens during bending the original length of the straight tube can be calculated as follows:

$$L_O = \frac{\pi R_B}{2} \qquad \text{Eq. 5-1}$$

where R_B is the radius of curvature of the bend. The length along the intrados of the bend, where the maximum plastic strain occurs can be similarly calculated as:

$$L_I = \frac{\pi\left(R_B - R_m\right)}{2} \qquad \text{Eq. 5-2}$$

where R_m is the mid wall radius of the tube. The plastic strain caused by bending can be estimated, after some simplification, as follows [29]:

$$\varepsilon_{cf} = \frac{\Delta L}{L} = \frac{L_O - L_I}{L_O} = \frac{R_m}{R_B} \qquad \text{Eq. 5-3}$$

The dimensions of plants with Alloy 800NG tubing are presented in Table 5-1. The analyses above indicate that, all other parameters being equal, tubes with larger diameters may be more susceptible to SCC due to higher bending stresses. However, U-bend SCC (OD and ID) has not been observed in any plant with Alloy 800NG steam generator tubing worldwide.

Table 5-1
Steam Generator Tube Dimensions

Plant	Outer Diameter		Thickness		Mid Wall Radius (R_m)		Prototypical U-Bend Radius (R_B)		ε_{cf} (R_m/R_B)
	in.	mm	in.	mm	in.	mm	in.	mm	-
Siemens	0.866	22.0	0.047	1.19	0.410	10.4	NA	NA	NA
CANDU	0.625	15.9	0.045	1.14	0.290	7.4	4.80	122	0.060
Westinghouse	0.75	19.1	0.043	1.09	0.354	9.0	3.62	92	0.098

6
DEGRADATION MECHANISMS EXPERIENCED IN ALLOY 800 STEAM GENERATORS

This chapter briefly summarizes the major tube degradation modes that have been experienced in steam generators with Alloy 800 tubing.

6.1 Phosphate Wastage

This mode of degradation was very prevalent in early Siemens-designed plants (see Table 3-3), which used phosphate treatment for secondary chemistry control. It was also used at Point Lepreau (see Table 3-6). Phosphate wastage was first observed after phosphate treatment was changed to a low sodium-to-phosphate molar ratio.[14] Phosphate wastage occurred predominantly in the hot leg, TTS region where sludge piles had accumulated. This was due to the concentration of aggressive species at steam-water interfaces [19].

Once the mechanism of wastage became known, Siemens plants reduced phosphate concentration and removed sludge piles by sludge lancing and chemical cleanings. These measures reduced occurrence of phosphate wastage but did not stop it completely. Eventually, all plants switched to high-AVT secondary chemistry (see Figure 3-1), but even after switching, legacies of phosphate wastage have caused additional tubes to be plugged.

6.2 Mechanical Wear Due to Structural Components

This mode of degradation has affected many plants with Alloy 800 tubing, particularly early Siemens-designed plants and CANDU's Darlington units (See Appendices B.6 to B.9). This mechanical wear is due to flow induced vibrations, predominantly in the U-bend region, and results in wear scars and wall thinning on the outside surfaces of tubes where they contact support structures. This form of degradation occurs predominantly in the U-bend region of larger radius tubes, where flow induced vibrations are greatest.

This mode of degradation can be mitigated by replacing the affected support structures or by the addition of supplemental supports. However, if left unchecked, the number of tubes affected can increase significantly. The design and material of the support structures greatly affect the occurrence rate of this degradation (as described in Section 5.2).

[14] This change was made because a high sodium-to-phosphate ratio was shown to cause caustic stress corrosion cracking. The sodium-to-phosphate ratio was reduced to ~ 2.0.

6.3 Mechanical Wear Due to Loose Parts or Foreign Objects

This mode of degradation has affected various plants with Alloy 800 tubing and is caused by loose objects trapped in the secondary side of steam generators. The loose objects can be steam generator components formed from degradation during operation or can be foreign objects inadvertently left in steam generators (tools, etc.) during outages or from manufacturing. Loose objects can cause damage to tubes. However, in general, tubes will leak before large numbers of tubes are damaged by a loose part, which allows plants to repair the tube and remove the loose object during a forced or scheduled outage.

6.4 Cavitation

This mode of degradation is caused by the thermal hydraulic conditions at the steam generator tubing surface near the tube supports. The most important factors that cause this degradation are fouling in the tube-support gap and the inclination (i.e., tilt) of a tube in the support hole. These conditions can cause the local pressure in the tube-to-support gap to decrease and then increase above saturation, which causes voids to develop and collapse. This can occur when the secondary fluid temperature is less than 10ºC below the saturation temperature, and results in mechanical damage to the tubing [30,31].

Degradation attributed to cavitation damage has possibly been observed on a limited population of tubes in the internal preheater region of all Darlington Units. Localized wall loss at preheater supports with reported depths up to about 50% through wall (tw) has been observed. Recent outages indicate that three zones in the preheater are most susceptible to this mode of degradation: peripheral and near-periphery tubes in rows 1-15, 70-80, and 90-101. A review of the ET records of previous inspections has determined that there has been no new initiation of this mode and low or minimal growth of the existing degradation,[15] with one exception. The exception is one indication in 2010 with possible 12% tw growth since 2007.[16] No tubes have been plugged due to this degradation [28,30,31,32].

6.5 Deep Tubesheet Crevice ODSCC

This mode of degradation has been observed in plants that have two mechanical rolls: one near the bottom of the tubesheet and one near the top of the tubesheet. The degradation seems to be the result of water leaking past the upper expansion joint into the deep tubesheet crevice during shutdown periods. It may also be important that the upper joint reseals and traps volatile acidic species in the crevice during power operation, but this is not certain. The Alloy 800 tubing has a higher thermal expansion coefficient than the low alloy steel tubesheet. This results in a tendency for the top expansion to loosen during cooldown and to retighten during heatup [5]. Furthermore, studies have indicated that hydraulic testing may play an important role in creating the

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[15] Note that several new indications have been detected in recent outages at Darlington. However, these new indications were determined to be due to more experience in detecting this type of degradation.

[16] This tube has been pulled for further analysis. At the time this report was written, the details of this analysis are unavailable.

penetration path for the secondary side water [33]. Evaluations of the OD surfaces of pulled tubes from several CANDU units indicate that secondary coolant has reached the deep tube sheet crevice in many cases. Therefore, plants with hydraulic expansions may also be susceptible to this mode of degradation [5].

This mode of attack has been observed in at least two Siemens units with Alloy 800 tubing, Biblis A and Unterweser, but details are available only for the attack at Biblis A. Two other units have detected this type of attack in one tube each. One plant, Neckarwestheim Unit 1, reinspected the tube in which it was detected 8 years after detection and concluded that the flaw had not grown and therefore that the mode was not progressing. The other plant, Biblis B, plugged the tube in which the attack was detected and has not re-inspected it since [8].

This type of situation appears to have developed in some peripheral tubes and tubes along the divider plate at Biblis A. The attack has occurred at the top of magnetite corrosion product filled areas in the crevice, which implies that some sort of wetting/drying at the top of the corrosion products may be involved. The fact that about as many cold leg tubes as hot leg tubes have been affected by this mode at Biblis A indicates that the occurrence of the mode is controlled by a non-thermally activated factor, such as the tightness of the seal at the upper expansion. The fact that the observed crack growth rates are about the same on the cold leg as the hot leg implies that the cracking is not occurring at operating temperature (which would lead to slower growth rates on the cold leg than the hot leg), but rather during startup.

6.6 ODSCC at TTS Crevices

This mode of attack has been quite significant at many units with Alloy 600MA tubing. It is known from experience at plants with Alloy 600MA SG tubes [1], and by laboratory tests, that the crevice conditions established by sludge piles in the central regions of tubesheets are conducive to causing axial IGA/SCC in these regions. Tests have shown these crevices develop elevated superheats once they fill with deposits [7], and such elevated superheats tend to result in concentrated impurity solutions in crevices that can cause IGA/SCC. In addition, plant experience has shown that the crevices and sludge collars at tubes outside of the sludge pile can also develop axial and volumetric IGA/SCC, although generally later than in the sludge pile. For this reason, all the tubes are susceptible to IGA/SCC, not just the tubes in the sludge pile region.

Axial flaws of this type have been detected in Unterweser, Borssele, Biblis A, and Biblis B [8,34]. The progression of these flaws with time at Unterweser is presented in Table 6-1. This experience suggests that this mode of degradation can affect Alloy 800 tubing.

Table 6-1
Cumulative Axial OD IGA/SCC Indications in the TTS Region at Unterweser [34]

% Through Wall	2002	2004	2005	2007	2008
20%-40%	2	3	8	12	15
40%-60%	1	1	2	2	2
>60%	0	0	0	2	2
Total	3	4	10	16	19

6.7 TTS Denting and Related ODSCC

TTS denting is a local, inward deformation of tubes that is caused by expansive corrosion of the tubesheet and by the corrosion of metal particles in the sludge pile if present from sources such as blasting or machining of steel components of the secondary plant systems. As described in Section 6.6, crevices and expansion transitions at the TTS can result in elevated superheats once they fill with deposits [7]. Such elevated superheats tend to result in concentrated impurity solutions in crevices which increases susceptibility to additional corrosion of the tubesheet. The corrosion products formed in the tubesheet crevices have larger volumes than the steel they replace which applies pressure to the tubes and results in inward deformations.

Denting and circumferential OD IGA/SCC has occurred in Westinghouse replacement steam generators with Alloy 800NG tubing; the denting and associated SCC observed in these plants is summarized in Table 6-2. The denting is restricted to the hard sludge pile area, as are the indications of OD IGA/SCC. The tubesheets of these plants are all made of SA-508, Class 3 steel.

Table 6-2
Indications of Denting and Circumferential OD IGA/SCC in Westinghouse Replacement Steam Generators with Alloy 800 Tubes[17] [35,36,37]

Plant	Hot Leg Temperature (°C)	Reference Date[1]	Rep. SG EFPY	Current EDY at 310.0°C[2]	# Denting Indications		# Circ. OD IGA/SCC	
					Cold Leg	Hot Leg	Cold Leg	Hot Leg
Doel 3	323	Jun, 2011	15.8	39.9	123	0	0	0
Asco 1	327	Mar, 2011	13.75	47.4	0	241	0	5[3]
Asco 2	327	May, 2010	12.4	42.8	144	0	0	0
Almaraz 1	328	Jun, 2011	13.3	47.8	1164	21	3	0
Almaraz 2	327	Nov, 2010	11.53827	39.8	1270	556	48	64

1) Indicates the date of the most recent reference for total tubes plugged.
2) EDY (Effective Damage Years) calculated using Q=50kcal/mol.
3) Only 2 OD SCC indications were specified to be circumferential at Asco 1, although it is most likely that all 5 indications were circumferential due to the ODSCC exhibited at other Westinghouse plants.

The Almaraz 2 and Asco 1 replacement SGs had been operating between 12 and 14 years at the time that indications of possible OD IGA/SCC were detected. At Asco 1, inspection data indicate that the denting occurred in about 2007, only two years before detection of possible IGA/SCC which implies that, if denting should occur, OD IGA/SCC can occur rather rapidly [37]. Additionally, the Alloy 800 tubes in these units were glass bead peened on the OD surface [37], which could lead to easier growth and initiation of SCC flaws (as described in Section 4.3).

The fact that both the hot and cold legs are affected by the denting and indications of possible IGA/SCC implies that some portion of the degradation is not thermally activated and could be occurring at low temperature, e.g., during layup or startup. The number of dents is higher on the cold leg side, while the number of crack indications is higher on the hot leg side, but this could

[17] Westinghouse units with replacement steam generators and Alloy 800 tubes are discussed in detail in C.

be explained by the denting occurring mainly at low temperature with the cracking occurring mainly at high temperature. Furthermore, sludge distributions can be asymmetric (e.g. at Doel Unit 3 more sludge has been observed on the cold leg than on the hot leg), which could also explain this difference [38].

These experiences indicate that the occurrence of denting significantly increases risks of OD IGA/SCC occurring at the TTS. The sensitivity to IGA/SCC caused by denting at the TTS has been further demonstrated by experience at several units with non-peened Alloy 600MA tubes, including the original steam generators of Fort Calhoun, Cook 1, Millstone 2, and Tihange 1.

6.8 ODSCC at Tube Supports

The mechanism by which ODSCC at the tube supports occurs is believed to be that solid deposits accumulate at the tube to tube support intersections such that free flow of water around the tube is impeded. This results in dry-out of the fouled deposit and concentration of impurity chemicals from the steam generator bulk water by boiling in and under the deposit, resulting in the formation of an aggressive environment that attacks the tube and causes IGA/SCC.

Axial flaws of this type have been detected at Unterweser, which has lattice bar tube supports [34]. The progression of these flaws with time is presented in Table 6-3. This experience indicates that this mode of degradation can affect plants with Alloy 800 tubing and lattice bar, tube supports. At the time this report was written, this form of degradation has not occurred at any plants plants with broached hole TSPs and Alloy 800 tubing.

Table 6-3
Cumulative Axial OD IGA/SCC Indications at TSP Intersections at Unterweser [34]

% Through Wall	2002	2004	2005	2007	2008
20%-40%	0	1	2	3	3
40%-60%	0	0	0	4	5
>60%	1	1	2	4	4
Total	1	2	4	11	12

6.9 Pitting

Pitting is a form of localized corrosion that leads to the creation of small pits in the tubing of steam generators. Pitting tends to occur when there is a combination of oxidizing conditions coupled with the presence of aggressive anions such as sulfates and chlorides. It occurs preferentially in occluded areas such as crevices and under deposits as a result of the tendency of anions in the bulk water to concentrate in the occluded areas. This concentration occurs because oxygen is depleted by corrosion in the occluded areas, leading to a strong potential difference between the occluded areas and the bulk water that causes the anions to diffuse to the occluded region. Over the course of time, this can lead to development of aggressive acidic conditions in the occluded area even if the concentration of anions in the bulk water is low.

Instances of pitting were observed above the tubesheet at Biblis B in 1981 and led to two tubes being plugged [20]. At this time, Biblis B was still using phosphate chemistry for secondary chemistry. No other tubes have been plugged due to pitting worldwide in any Alloy 800 SG. Given these two factors, it is likely that the pitting was due to phosphate wastage (as described in Section 6.1) and was not a distinct mode of degradation.

Evidence of pitting has been recently observed at Darlington Generating Station. Shallow pits were detected in removed tubes at hot leg supports, in the deep tube sheet crevice, and at the TTS. Note that these pits are not detectable by NDE. The pits detected to date have been small, up to 10% through wall at hot leg supports, and up to 1% through wall at the TTS. Impurities including chloride, sulphur and sometimes copper were detected at the pit locations. It seems unlikely that the pits that have developed at Darlington occurred during normal power operation. This judgment is based on the knowledge that normal operating conditions are highly reducing and protective at Darlington due to the use hydrazine and pH control agents, and low oxygen content of the water during operation. Thus, the most likely conditions for pitting to occur are judged to be shutdown periods and/or startup. The oxidants that could be involved include oxygen in the SG during drained periods, oxygen in the SG fill water, oxygen in the air space above the SG water during layup periods, and reducible metal oxides that are introduced into the SGs from the secondary system during startup evolutions. The limited amount of pitting detected to date may be the result of a limited number of episodes of exposure to unusual oxidizing conditions, and it is possible that no further pitting will occur. However, there is no known way to prove this hypothesis [28,39].

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A
SIEMENS PWR UNITS

A.1 Stade

A.1.1 Major Design and Operating Conditions

Stade Nuclear Power Plant is a Siemens, 672 MWe rated, 4-loop plant in Germany that began commercial operation in 1972. The steam generators have 0.866” (22 mm) diameter Alloy 800NG tubing [40]. On November 13, 2003 Stade was shut down, and at the time this report was written there were no plans to restart the plant [41]. Before shutdown, the steam generators had experienced approximately 26.0 effective full power years (EFPYs) [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), subjected to cold work for strengthening, but not subjected to peening for ODSCC resistance.

A.1.1.1 Tubesheet Design

Each steam generator has 2993 tubes (0.866” (22 mm) diameter) in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

A.1.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel corrugated strips in the U-bend region [20,42].

Tube support designs in different units are discussed in Section 5.2.

A.1.1.3 Balance of Plant Materials of Construction

Originally, the main condenser tubing was made of admiralty brass and the tubesheet was made of muntz metal. Before switching the secondary chemistry to AVT, the main condenser tubing was replaced with stainless steel and the tubesheet was replaced with carbon steel clad with stainless steel. The feedwater heaters and moisture separator reheaters are made of carbon steel [11,19].

A.1.1.4 Operating Temperature

Stade was last operating at a nominal hot leg temperature of 314°C (597°F) and a nominal cold leg temperature of 284°C (544°F) [40].

A.1.1.5 Primary Water Chemistry

Stade's primary water chemistry consisted of the following 3 phases [11]:

- Start–1984: The operating lithium concentration was maintained between 1–2 ppm.
- 1984–1995: A target pH of 6.9 at 300°C was maintained by coordinating lithium and boron concentrations.
- 1995–2003 Shutdown: "Modified Chemistry" - A target pH of 7.4 at 300°C was maintained while limiting [Li] to 2.2 ppm.

A.1.1.6 Secondary Water Chemistry

The ultimate cooling source for Stade was fresh water from the Elbe River. Stade recovered blowdown and used a feedwater tank (deaerator) for continuous deaerating of the condensate [11].

Stade's secondary water chemistry consisted of the following 4 phases [11,20]:

- Used volatile alkalization for the first few weeks of operation
- Following a chemical cleaning, the water chemistry was changed to low pH phosphate treatment
- 1987–1990: AVT with a target pH of <9.5
- 1990–2003 Shutdown: AVT with the following feedwater concentration targets [10,11]:
  - pH ~9.7
  - Cation Conductivity <0.15 µS/cm
  - Oxygen <5 ppb

A.1.2 Summary of Degradation Experienced

In 1981, Stade had a tube leak in the top of tubesheet region of one of the steam generators. The leak was attributed to phosphate wastage [43].

A summary of the tubes plugged due to degradation is presented in Table A-1.

Table A-1
Cumulative Tubes Plugged or Repaired Due to Degradation at Stade [11,8,43]

Degradation Mechanism[1]	1991	2000	2006
PWSCC	0	0	0
Phosphate Wastage	317	322	327
Mechanical Wear due to Structural Components	0	2	2
Mechanical Wear due to Loose Parts	0	0	0
Deep Tubesheet Crevice ODSCC	0	0	0
ODSCC at TTS Crevices	0	0	0
TTS Denting and Related ODSCC	0	0	0
Pitting	0	0	0

1) Does not include tubes preventively plugged or tubes plugged for reasons other than degradation

A.2 Borssele

A.2.1 Major Design and Operating Conditions

Borssele Nuclear Power Plant is a Siemens, 515 MWe rated, 2-loop plant in the Netherlands that began commercial operation in 1973. The steam generators have 0.866” (22 mm) diameter Alloy 800NG tubing [40]. As of April 2011, the steam generators have experienced approximately 31.5 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), subjected to cold work for strengthening, but not subjected to peening for ODSCC resistance.

A.2.1.1 Tubesheet Design

Each steam generator has 4234 tubes of 0.866” (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

A.2.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel corrugated strips in the U-bend region [20,42].

Tube support designs in different units are discussed in Section 5.2.

A.2.1.3 Balance of Plant Materials of Construction

Originally, the main condenser tubing was made of admiralty brass and the tubesheet was made of muntz metal. Before switching the secondary chemistry to AVT, the main condenser tubing was replaced with titanium and the tubesheet was replaced with carbon steel clad with titanium. The feedwater heaters and moisture separator reheaters are made of carbon steel [11,40].

A.2.1.4 Operating Temperature

Borssele currently operates at a nominal hot leg temperature of 319°C (606°F) and a nominal cold leg temperature of 292°C (558°F) [40].

A.2.1.5 Primary Water Chemistry

Borssele's primary water chemistry has consisted of the following 2 phases [11]:

- Start–1980: The operating lithium concentration was maintained between 1–2 ppm.
- 1980–Present: A target pH of 6.9 at 300°C was maintained by coordinating lithium and boron concentrations.

A.2.1.6 Secondary Water Chemistry

The ultimate cooling source for Borssele is brackish water from the Western Scheldt River. Borssele recovers blowdown and uses a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Borssele's secondary water chemistry has consisted of the following 3 phases [11,20]:

- Start–1986: Low pH phosphate treatment
- 1986–1988: High pH phosphate treatment
- 1988–Present: High AVT with the following feedwater concentration targets [10,11]:
  - pH >9.8
  - Cation Conductivity <0.15 µS/cm
  - Oxygen <5 ppb

A.2.2 Summary of Degradation Experienced

Borssele has had one steam generator tube leak due to degradation [11].

A summary of the tubes plugged due to degradation is presented in Table A-2.

Table A-2
Cumulative Tubes Plugged or Repaired Due to Degradation at Borssele [11,8]

Degradation Mechanism[1]	2000	2006
PWSCC	0	0
Phosphate Wastage	115	115
Mechanical Wear due to Structural Components	11	12
Mechanical Wear due to Loose Parts	0	1
Deep Tubesheet Crevice ODSCC	0	0
ODSCC at TTS Crevices	0	9
TTS Denting and Related ODSCC	0	9
Pitting	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

A.3 Biblis Unit A

A.3.1 Major Design and Operating Conditions

Biblis Nuclear Power Plant Unit A (Biblis A) is a Siemens, 1225 MWe rated, 4-loop plant in Germany that began commercial operation in 1974. The steam generators have 0.866” (22 mm) diameter Alloy 800NG tubing [40]. In March of 2011 Biblis A was shut down and at the time this report was written there are no plans to restart the plant [41]. Throughout the lifetime, the steam generator had experienced 23.1 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), subjected to cold work for strengthening, but not subjected to peening for ODSCC resistance.

A.3.1.1 Tubesheet Design

Each steam generator has 4060 tubes of 0.866” (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

A.3.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel corrugated strips in the U-bend region [20,42].

Tube support designs in different units are discussed in Section 5.2.

A.3.1.3 Balance of Plant Materials of Construction

Originally, the main condenser tubing was made of admiralty brass and the tubesheet was made of carbon steel with an epoxy coating. Before switching the secondary chemistry to AVT, the main condenser tubing was replaced with stainless steel. The feedwater heaters and moisture separator reheaters are made of carbon steel [11,19].

A.3.1.4 Operating Temperature

Biblis A last operated at a nominal hot leg temperature of 313°C (596°F) and a nominal cold leg temperature of 543°C (544°F) [40].

A.3.1.5 Primary Water Chemistry

Biblis A's primary water chemistry consisted of the following 3 phases [11]:

- Start–1981: The operating lithium concentration was maintained between 1–2 ppm.
- 1981–1983: A target pH of 6.9 at 300°C was maintained by coordinating lithium and boron concentrations.
- 1983–2011 Shutdown: "Modified Chemistry"- A target pH of 7.4 at 300°C was maintained while limiting [Li] to 2.2 ppm.

In 1998, Biblis A started injecting zinc in the primary cooling loop [11].

A.3.1.6 Secondary Water Chemistry

The ultimate cooling source for Biblis A was fresh water from the Rhine River. Biblis A recovered blowdown and used a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Biblis A's secondary water chemistry consisted of the following 3 phases [11]:

- Start–1984: Low pH phosphate treatment
- 1984–1987: High pH phosphate treatment
- 1987–2011 Shutdown: High AVT with the following feedwater concentration targets [10,11]:
  - pH >9.8
  - Cation Conductivity <0.15 μS/cm
  - Oxygen <5 ppb

In June of 2001, Biblis A started injecting oxygen upstream of their moisture separator reheaters to counteract FAC of the carbon steel header tubing. Biblis A injected ~160 ppb in the reheater system (note the moisture separator reheaters at Biblis A were made of carbon steel and were never replaced). Despite this injection, the feedwater oxygen concentration was maintained below 5 ppb as specified above; in general, oxygen concentrations of about 1–2 ppb were not exceeded [27].

A.3.2 Summary of Degradation Experienced

In 1983, Biblis A had 3 tube leaks due to degradation. One leak was in the innermost tube rows in the U-bend region and was attributed to phosphate wastage (as discussed in Section 6.1). The other two leaks were in the outer tube rows in the U-bend region and were attributed to fretting [43].

Several tubes have been plugged due to stress corrosion cracking of the tubesheet region at Biblis A due to corrosion. The degradation mechanism was identified as deep tubesheet crevice ODSCC as discussed in Section 6.5 [8].

A summary of the tubes plugged due to degradation is presented in Table A-3. Additional details on the number of tubes affected by and plugged due to deep tubesheet crevice ODSCC is presented in Table A-4.

Table A-3
Cumulative Tubes Plugged or Repaired Due to Degradation at Biblis A [11,8,33,43]

Degradation Mechanism[1]	1991	1999	2000	2002	2005	2006
PWSCC	0	0	0	0	0	0
Phosphate Wastage	468	468	497	≥ 497[2]	≥ 497[2]	514
Mechanical Wear due to Structural Components	48	48	56	≥ 56[2]	≥ 56[2]	61
Mechanical Wear due to Loose Parts	0	0	1	≥ 1[2]	≥ 1[2]	3
Deep Tubesheet Crevice ODSCC[4]	0	≥ 1[3]	≥ 1[3]	≥ 2[3]	20	35
ODSCC at TTS Crevices	0	0	0	≥ 0[2]	≥ 0[2]	3
TTS Denting and Related ODSCC	0	0	0	0	0	0
Pitting	0	0	0	0	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

2) The number of new tubes affected by this mechanisms is unknown for this outage.

3) The number of tubes plugged by this mode of degradation are only known for the hot leg side of one steam generator (SG3) for these outages.

Table A-4
Cumulative Tubes Affected by or Plugged due to Deep Tubesheet Crevice ODSCC at Biblis A [9,34]

	1991	1999	2000	2002	2003	2005	2006
# Indications	0	≥ 1[2]	≥ 1[2]	≥ 2[2]	7	27	53[3]
# Plugged	0	≥ 1[2]	≥ 1[2]	≥ 2[2]		20	35

1) Grey Cells indicate that the data is unavailable.

2) The number of tubes plugged by this mode of degradation are only known for the hot leg side of one steam generator (SG3) for these outages.

3) 28 tubes affected on the Hot Leg and 25 tubes affected on the Cold Leg.

A.4 Biblis Unit B

A.4.1 Major Design and Operating Conditions

Biblis Nuclear Power Plant Unit B (Biblis B) is a Siemens, 1300 MWe rated, 4-loop plant in Germany that began commercial operation in 1976. The steam generators have 0.866” (22 mm) diameter Alloy 800NG tubing [40]. In March of 2011 Biblis B was shut down and at the time this report was written there are no plans to restart the plant [41]. Throughout the lifetime, the steam generator had experienced approximately 23.2 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), subjected to cold work for strengthening, but not subjected to peening for ODSCC resistance.

A.4.1.1 Tubesheet Design

Each steam generator has 4021 tubes of 0.866” (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

A.4.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel, corrugated strips in the U-bend region [20,42].

Tube support designs in different units are discussed in Section 5.2.

A.4.1.3 Balance of Plant Materials of Construction

Originally, the main condenser tubing was made of admiralty brass and the tubesheet was made of carbon steel with an epoxy coating. Before switching the secondary chemistry to AVT, the main condenser tubing was replaced with stainless steel. The feedwater heaters and moisture separator reheaters are made of carbon steel [11,19].

A.4.1.4 Operating Temperature

Biblis B last operated at a nominal hot leg temperature of 319°C (607°F) and a nominal cold leg temperature of 288°C (551°F) [40].

A.4.1.5 Primary Water Chemistry

Biblis B’s primary water chemistry consisted of the following 3 phases [11]:

- Start–1980: The operating lithium concentration was maintained between 1–2 ppm.
- 1980–1983: A target pH of 6.9 at 300°C was maintained by coordinating lithium and boron concentrations.

- 1983–2011 Shutdown: “Modified Chemistry” - A target pH of 7.4 at 300°C was maintained while limiting [Li] to 2.2 ppm.

In 1996, Biblis B started injecting zinc in the primary cooling loop [11].

A.4.1.6 Secondary Water Chemistry

The ultimate cooling source for Biblis B was fresh water from the Rhine River. Biblis B recovers blowdown and used a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Biblis B’s secondary water chemistry consisted of the following 3 phases [11]:

- Start–1984: Low pH phosphate treatment
- 1984–1988: High pH phosphate treatment
- 1988–2011 Shutdown: High AVT with the following feedwater concentration targets [10,11]:
  - pH >9.8
  - Cation Conductivity <0.15 μS/cm
  - Oxygen <5 ppb

Biblis B started injecting oxygen upstream of their moisture separator reheaters to counteract FAC of the carbon steel header tubing after replacing their moisture separator reheaters. Biblis B injected ~ 160ppb in the reheater system. Despite this injection, the feedwater oxygen concentration was maintained below 5 ppb as specified above; in general, oxygen concentrations of about 1–2 ppb were not exceeded [27].

A.4.2 Summary of Degradation Experienced

In 1980, Biblis B had a tube leak in the top of tubesheet region. This leak was attributed to phosphate wastage with simultaneous pitting (as discussed in Section 6.1) [43].

A summary of the tubes plugged due to degradation is presented in Table A-5.

Table A-5
Cumulative Tubes Plugged or Repaired Due to Degradation at Biblis B [11,8,43]

Degradation Mechanism[1]	1991	2000	2006
PWSCC	0	0	0
Phosphate Wastage	7	8	18
Mechanical Wear due to Structural Components	43	51	53
Mechanical Wear due to Loose Parts	0	2	5
Deep Tubesheet Crevice ODSCC	0	0	1
ODSCC at TTS Crevices	1	1	2
TTS Denting and Related ODSCC	0	0	0
Pitting	2	2	2

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

A.5 Neckarwestheim Unit 1

A.5.1 Major Design and Operating Conditions

Neckarwestheim Nuclear Power Plant Unit 1 (Neckarwestheim 1) is a Siemens, 840 MWe rated, 3-loop plant in Germany that began commercial operation in 1976. The steam generators have 0.866” (22 mm) diameter Alloy 800NG tubing [40]. In March of 2011 Neckarwestheim 1 was shut down and at the time this report was written there are no plans to restart the plant [41]. Throughout the lifetime, the steam generator had experienced approximately 27.1 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), subjected to cold work for strengthening, but not subjected to peening for ODSCC resistance.

A.5.1.1 Tubesheet Design

Each steam generator has 4052 tubes of 0.866” diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

A.5.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel, corrugated strips in the U-bend region [20,42].

Tube support designs in different units are discussed in Section 5.2.

A.5.1.3 Balance of Plant Materials of Construction

Originally, the main condenser tubing was made of admiralty brass and the tubesheet was made of carbon steel clad with stainless steel. Before switching the secondary chemistry to AVT, the main condenser tubing was replaced with stainless steel. The feedwater heaters and moisture separator reheaters are made of carbon steel [11,40].

A.5.1.4 Operating Temperature

Neckarwestheim 1 last operated at a nominal hot leg temperature of 322°C (612°F) and a nominal cold leg temperature of 293°C (560°F) [40].

A.5.1.5 Primary Water Chemistry

Neckarwestheim 1's primary water chemistry consisted of the following 2 phases [11]:

- Start–1981: The operating lithium concentration was maintained between 1–2 ppm.
- 1981–2011 Shutdown: "Modified Chemistry" - A target pH of 7.4 at 300°C was maintained while limiting [Li] to 2.2 ppm.

A.5.1.6 Secondary Water Chemistry

The ultimate cooling source for Neckarwestheim 1 was fresh water from the Neckar River. Neckarwestheim 1 recovered blowdown and used a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Neckarwestheim 1's secondary water chemistry consisted of the following 3 phases [11]:

- Start–1989: Low pH phosphate treatment
- 1989: High pH phosphate treatment
- 1989–2011 Shutdown: High AVT with the following feedwater concentration targets [10,11]:
  - pH >9.8
  - Cation Conductivity <0.15 µS/cm
  - Oxygen <5 ppb

A.5.2 Summary of Degradation Experienced

In 1991, Neckarwestheim 1 had a tube leak in the outer rows of the top of tubesheet. The leak was attributed to fretting due to a loose part [43].

A summary of the tubes plugged due to degradation is presented in Table A-6.

Table A-6
Cumulative Tubes Plugged or Repaired Due to Degradation at Neckarwestheim 1 [11,8,43]

Degradation Mechanism[1]	1991	2000	2006
PWSCC	0	0	0
Phosphate Wastage	4[2]	4	4
Mechanical Wear due to Structural Components	4	6	6
Mechanical Wear due to Loose Parts	0	10	15
Deep Tubesheet Crevice ODSCC	0	0	0
ODSCC at TTS Crevices	0	0	0
TTS Denting and Related ODSCC	0	0	0
Pitting	0	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

2) Earliest reference specifies 8 tubes plugged due to phosphate wastage. However multiple later references specify only 4 total tubes plugged due to Phosphate Wastage.

A.6 Neckarwestheim Unit 2

A.6.1 Major Design and Operating Conditions

Neckarwestheim Nuclear Power Plant Unit 2 (Neckarwestheim 2) is a Siemens, 1400 MWe rated, 4-loop plant in Germany that began commercial operation in 1989. The steam generators are model 54SK and have 0.866” (22 mm) diameter Alloy 800NG tubing [40]. As of April 2011, the steam generators have experienced approximately 20.4 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), and after bending, the tubing was OD glass bead, shot peened for ODSCC resistance [20].

A.6.1.1 Tubesheet Design

Each steam generator has 4118 tubes of 0.866" (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

A.6.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel, corrugated strips in the U-bend region. The tube supports at Neckarwestheim 2 have larger free flow cross-sections than the tube supports at earlier designed Siemens units. This design reduces the resistance of water flow through the steam generator [8,9,20,42].

Tube support designs in different units are discussed in Section 5.2.

A.6.1.3 Balance of Plant Materials of Construction

The main condenser tubing is made of austenitic stainless steel and the tubesheet is made of carbon steel clad with stainless steel. The feedwater heaters and moisture separator reheaters are made of carbon steel [11,19].

A.6.1.4 Operating Temperature

Neckarwestheim 2 currently operates at a nominal hot leg temperature of 324°C (616°F) and a nominal cold leg temperature of 292°C (558°F) [40].

A.6.1.5 Primary Water Chemistry

Neckarwestheim 2 uses modified chemistry in the primary cooling loop: targets a pH of 7.4 at 300°C while limiting [Li] to 2.2 ppm.

A.6.1.6 Secondary Water Chemistry

The ultimate cooling source for Neckarwestheim 2 is fresh water from the Neckar River. Neckarwestheim 2 has full flow mechanical filters in the condensate system and full flow electro-mechanical filters in the high pressure heater drain system which are active during both startup and normal power operation. Neckarwestheim 2 recovers blowdown and uses a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Neckarwestheim 2 uses high AVT for secondary chemistry control with the following feedwater concentration targets [10,11].

- pH >9.8
- Cation Conductivity <0.15 µS/cm
- Oxygen <5 ppb

A.6.2 Summary of Degradation Experienced

A summary of the tubes plugged due to degradation is presented in Table A-7.

Table A-7
Cumulative Tubes Plugged or Repaired Due to Degradation at Neckarwestheim 2 [11,8,43]

Degradation Mechanism[1]	1991	2000	2006
PWSCC	0	0	0
Phosphate Wastage	0	0	0
Mechanical Wear due to Structural Components	0	1	1
Mechanical Wear due to Loose Parts	0	0	0
Deep Tubesheet Crevice ODSCC	0	0	0
ODSCC at TTS Crevices	0	0	0
TTS Denting and Related ODSCC	0	0	0
Pitting	0	0	0

1) Does not include tubes preventively plugged or tubes plugged for reasons other than degradation

A.7 Unterweser

A.7.1 Major Design and Operating Conditions

Unterweser Nuclear Power Plant is a Siemens, 1410 MWe rated, 4-loop plant in Germany that began commercial operation in 1978. The steam generators have 0.866” (22 mm) diameter Alloy 800NG tubing [40]. In March of 2011 Unterweser was shut down and at the time this report was written there are no plans to restart the plant [41]. Throughout the lifetime, the steam generator had experienced approximately 25.5 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), subjected to cold work for strengthening, but not subjected to peening for ODSCC resistance.

A.7.1.1 Tubesheet Design

Each steam generator has 4021 tubes of 0.866” (22 mm) diameter in a triangular pitch, which are mechanically expanded into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40]. Tubesheet expansions in different units are discussed in Section 5.1.

A.7.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel, corrugated strips in the U-bend region. The tube supports at Unterweser have larger free flow cross-sections than the tube supports at earlier designed Siemens units. This design reduces the resistance of water flow through the steam generator [8,9,20,42].

Tube support designs in different units are discussed in Section 5.2.

A.7.1.3 Balance of Plant Materials of Construction

Originally, the main condenser tubing was made of admiralty brass and the tubesheet was made of muntz metal. Before switching the secondary chemistry to AVT, the main condenser tubing was replaced with titanium and the tubesheet was replaced with carbon steel clad with titanium. The feedwater heaters and moisture separator reheaters are made of carbon steel [11,19].

A.7.1.4 Operating Temperature

Unterweser was last operating at a nominal hot leg temperature of 318°C (604°F) and a nominal cold leg temperature of 287°C (548°F) [40].

A.7.1.5 Primary Water Chemistry

The primary water chemistry at Unterweser consisted of the following 3 phases [11].

- Start–1982: The operating lithium concentration was maintained between 1–2 ppm.
- 1982–1999: A target pH of 6.9 at 300°C was maintained by coordinating lithium and boron concentrations.
- 1999–2011 Shutdown: “Modified Chemistry” - A target pH of 7.4 at 300°C was maintained while limiting [Li] to 2.2 ppm.

A.7.1.6 Secondary Water Chemistry

The ultimate cooling source for Unterweser was water from the Weser River. The water is brackish with greater than 1000 ppm chloride. Unterweser had a condensate demineralizer system, but it was only operational during startup and transients. Unterweser recovered blowdown and used a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

The secondary water chemistry at Unterweser consisted of the following 2 phases [11]:

- Start–1987: Low pH phosphate treatment
- 1987–2011 Shutdown: High AVT with the following feedwater concentration targets [10,11]:
  - pH >9.8
  - Cation Conductivity <0.15 μS/cm
  - Oxygen <5 ppb

A.7.2 Summary of Degradation Experienced

In October of 1992, denting was observed in the hot leg of steam generator 4 at Unterweser Power Plant affecting 30 tubes in the top of tubesheet (TTS) region. The deposits were subsequently removed. A visual inspection following chemical cleaning indicated that the existing deposits (tubesheet collars) had been removed [44].

Unterweser has experienced axial OD IGA/SCC in the TTS region and at TSP intersections [34]. Its OD IGA/SCC history is presented in Table A-8 and Table A-9 and a summary of the tubes plugged due to degradation is presented in Table A-10.

Table A-8
Cumulative Axial OD IGA/SCC Indications in the TTS Region at Unterweser [34]

% Through Wall	2002	2004	2005	2007	2008
20%-40%	2	3	8	12	15
40%-60%	1	1	2	2	2
>60%	0	0	0	2	2
Total	3	4	10	16	19

Table A-9
Cumulative Axial OD IGA/SCC Indications at TSP Intersections at Unterweser [34]

% Through Wall	2002	2004	2005	2007	2008
20%-40%	0	0	2	3	3
40%-60%	0	0	0	4	5
>60%	1	2	2	4	4
Total	1	2	4	11	12

Table A-10
Cumulative Tubes Plugged or Repaired Due to Degradation at Unterweser [11,8,43,44]

Degradation Mechanism[1]	1991	1992	2000	2006
PWSCC	0	0	0	0
Phosphate Wastage	0	0	11	19
Mechanical Wear due to Structural Components	0	0	10	11
Mechanical Wear due to Loose Parts	0	0	0	4
Deep Tubesheet Crevice ODSCC	0	0	0	9
ODSCC at TTS Crevices	0	0	0	0
TTS Denting and Related ODSCC[2]	0	0/30	0/30	0/30
Pitting	0	0	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.
2) (# of tubes plugged or repaired due to denting) / (# of tubes with denting indications)

A.8 Gösgen

A.8.1 Major Design and Operating Conditions

Gösgen Nuclear Power Plant is a Siemens, 1035 MWe rated, 3-loop plant in Switzerland that began commercial operation in 1979. The steam generators have a flow distribution baffle and have 0.866” (22 mm) diameter Alloy 800NG tubing [11,40]. As of April 2011, the steam generators have experienced approximately 27.9 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), and after bending, the tubing was OD glass bead, shot peened for ODSCC resistance [20].

A.8.1.1 Tubesheet Design

Each steam generator has 4106 tubes of 0.866" (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel and the flow distribution baffle is made of austenitic stainless steel [40,42].

Tubesheet expansions in different units are discussed in Section 5.1.

A.8.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel, corrugated strips in the U-bend region. The tube supports at Gösgen have larger free flow cross-sections than the tube supports at earlier designed Siemens units. This design reduces the resistance of water flow through the steam generator [8,9,20,42].

Tube support designs in different units are discussed in Section 5.2.

A.8.1.3 Balance of Plant Materials of Construction

Originally, the main condenser tubing was made of admiralty brass and the tubesheet was made of carbon steel clad with stainless steel. Before switching the secondary chemistry to AVT, the main condenser tubing was replaced with stainless steel. The feedwater heaters and moisture separator reheaters are made of carbon steel [11,40].

A.8.1.4 Operating Temperature

Gösgen currently operates at a nominal hot leg temperature of 321°C (610°F) and a nominal cold leg temperature of 292°C (558°F) [40].

A.8.1.5 Primary Water Chemistry

The primary water chemistry at Gösgen has consisted of the following 3 phases [11]:

- Start–1986: The operating lithium concentration was maintained between 1–2 ppm.
- 1986–1998: "Modified Chemistry" - A target pH of 7.4 at 300°C was maintained while limiting [Li] to 2.2 ppm.
- 1998–Present: Modified Chemistry plus enriched boric acid use.

A.8.1.6 Secondary Water Chemistry

Gösgen uses water from a cooling tower for the secondary coolant. Gösgen recovers blowdown and uses a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

The secondary water chemistry at Gösgen has consisted of the following 3 phases [11]:

- Start–1983: Low pH phosphate treatment
- 1983–1984: AVT with a pH target of < 9.5

- 1984–Present: High AVT with the following feedwater concentration targets [10,11]:
  - pH >9.8
  - Cation Conductivity <0.15 µS/cm
  - Oxygen <5 ppb

A.8.2 Summary of Degradation Experienced

A summary of the tubes plugged due to degradation is presented in Table A-11.

Table A-11
Cumulative Tubes Plugged or Repaired Due to Degradation at Gösgen [11,8]

Degradation Mechanism[1]	2000	2006
PWSCC	0	0
Phosphate Wastage	1	1
Mechanical Wear due to Structural Components	0	0
Mechanical Wear due to Loose Parts	13	18
Deep Tubesheet Crevice ODSCC	0	0
ODSCC at TTS Crevices	0	0
TTS Denting and Related ODSCC	0	0
Pitting	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

A.9 Grafenrheinfeld

A.9.1 Major Design and Operating Conditions

Grafenrheinfeld Nuclear Power Plant is a Siemens, 1345 MWe rated, 4-loop plant in Germany that began commercial operation in 1981. The steam generators are model 54GS, with an integral preheater and 0.866” (22 mm) diameter Alloy 800NG tubing [40]. As of April 2011, the steam generators have experienced approximately 24.7 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), and after bending, the tubing was OD glass bead, shot peened for ODSCC resistance [20].

A.9.1.1 Tubesheet and Preheater Design

Each steam generator has 4086 tubes of 0.866” (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40].

The preheater is a split flow design, is located at the lower section of the cold leg, and is made of austenitic stainless steel [42].

Tubesheet expansions in different units are discussed in Section 5.1.

A.9.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel, corrugated strips in the U-bend region. The tube supports at Grafenrheinfeld have larger free flow cross-sections than the tube supports at earlier designed Siemens units. This design reduces the resistance of water flow through the steam generator [8,9,20,42].

Tube support designs in different units are discussed in Section 5.2. [20].

A.9.1.3 Balance of Plant Materials of Construction

The main condenser tubing is made of austenitic stainless steel and the tubesheet is made of carbon steel clad stainless steel. The feedwater heaters and moisture separator reheaters are made of carbon steel [11,40].

A.9.1.4 Operating Temperature

Grafenrheinfeld currently operates at a nominal hot leg temperature of 325°C (618°F) and a nominal cold leg temperature of 290°C (555°F) [40].

A.9.1.5 Primary Water Chemistry

The primary water chemistry at Grafenrheinfeld has consisted of the following 3 phases [11]:

- Start–1989: A target pH of 6.9 at 300°C was maintained by coordinating lithium and boron concentrations
- 1989–1997: “Modified Chemistry” - A target pH of 7.4 at 300°C was maintained while limiting [Li] to 2.2 ppm
- 1997–Present: Modified Chemistry plus enriched boric acid use

A.9.1.6 Secondary Water Chemistry

Grafenrheinfeld uses water from a cooling tower for the secondary coolant. Grafenrheinfeld recovers blowdown and uses a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Grafenrheinfeld uses high AVT for secondary chemistry control with the following feedwater concentration targets [10,11]:

- pH >9.8
- Cation Conductivity <0.15 µS/cm
- Oxygen <5 ppb

A.9.2 Summary of Degradation Experienced

A summary of the tubes plugged due to degradation is presented in Table A-12.

Table A-12
Cumulative Tubes Plugged or Repaired Due to Degradation at Grafenrheinfeld [11,8,43]

Degradation Mechanism[1]	1991	2000	2006
PWSCC	0	0	0
Phosphate Wastage	0	0	0
Mechanical Wear due to Structural Components	0	4	4
Mechanical Wear due to Loose Parts	0	7	12
Deep Tubesheet Crevice ODSCC	0	0	0
ODSCC at TTS Crevices	0	0	0
TTS Denting and Related ODSCC	0	0	0
Pitting	0	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

A.10 Obrigheim (Replacement SGs)

A.10.1 Major Design and Operating Conditions

Obrigheim Nuclear Power Plant is a Siemens, 357 MWe rated, 2-loop plant in Germany that began commercial operation in 1968. The original steam generators had I-600 tubing, but were replaced in 1983. The new steam generators have 0.866” (22 mm) diameter Alloy 800NG tubing [40]. In May of 2005, Obrigheim was shut down and at the time this report was written there are no plans to restart the plant. At the time of shutdown, the replacement steam generators had experienced approximately 16.7 EFPY [12,40].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), and after bending, the tubing was OD glass bead, shot peened for ODSCC resistance [20].

A.10.1.1 Tubesheet Design

The replacement steam generators have 3010 tubes of 0.866” (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

A.10.1.2 Tube Support Design

Its replacement steam generators have austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel, corrugated strips in the U-bend region. The tube supports at Obrigheim have larger free flow cross-sections than the tube supports at earlier designed Siemens units. This design reduces the resistance of water flow through the steam generator [8,9,20,42].

Tube support designs in different units are discussed in Section 5.2.

A.10.1.3 Balance of Plant Materials of Construction

Originally, the main condenser tubing was made of admiralty brass and the tubesheet was made of carbon steel with an epoxy coating. Before switching the secondary chemistry to AVT, the main condenser tubing was replaced with stainless steel. The feedwater heaters and moisture separator reheaters are made of carbon steel [11,19].

A.10.1.4 Operating Temperature

Obrigheim currently operates at a nominal hot leg temperature of 309°C (589°F) and a nominal cold leg temperature of 278°C (534°F) [40].

A.10.1.5 Primary Water Chemistry

Obrigheim’s primary water chemistry has consisted of the following 3 phases [11]:

- Start–1981: The operating lithium concentration was maintained between 1–2 ppm.

- 1981–1990: A target pH of 6.9 at 300°C was maintained by coordinating lithium and boron concentrations.
- 1990–2005 Shutdown: “Modified Chemistry”- A target pH of 7.4 at 300°C was maintained while limiting [Li] to 2.2 ppm.

In 1998, Obrigheim started injecting zinc the primary cooling loop [11].

A.10.1.6 Secondary Water Chemistry

The ultimate cooling source for Obrigheim is water from the Neckar River. The water is brackish with greater than 1000 ppm chloride. Obrigheim recovers blowdown and uses a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Obrigheim’s secondary water chemistry has consisted of the following 2 phases [11]:

- Start–SG replacement: AVT with a target pH <9.5
- Post SG replacement : High AVT with the following feedwater concentration targets [10,11]:
  - pH >9.8
  - Cation Conductivity <0.15 µS/cm
  - Oxygen <5 ppb

A.10.2 Summary of Degradation Experienced

Since steam generator replacement, Obrigheim has not had to plug any tubes due to degradation [8].

A.11 Grohnde

A.11.1 Major Design and Operating Conditions

Grohnde Nuclear Power Plant is a Siemens, 1430 MWe rated, 4-loop plant in Germany that began commercial operation in 1984. The steam generators are model 54GS, with an integral preheater, flow distribution baffle, and 0.866” (22 mm) diameter Alloy 800NG tubing [40]. As of April 2011, the steam generators have experienced approximately 23.8 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), and after bending, the tubing was OD glass bead, shot peened for ODSCC resistance [20].

A.11.1.1 Tubesheet and Preheater Design

Each steam generator has 4086 tubes of 0.866” (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel and the flow distribution baffle is made of austenitic stainless steel [40,42].

The preheater is a split flow design, is located at the lower section of the cold leg, and is made of austenitic stainless steel [42].

Siemens PWR Units

Tubesheet expansions in different units are discussed in Section 5.1.

A.11.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel, corrugated strips in the U-bend region. The tube supports at Grohnde have larger free flow cross-sections than the tube supports at earlier designed Siemens units. This design reduces the resistance of water flow through the steam generator [8,9,20,42].

Tube support designs in different units are discussed in Section 5.2.

A.11.1.3 Balance of Plant Materials of Construction

Originally, the main condenser tubing was made of admiralty brass and the tubesheet was made of carbon steel with titanium. Before switching the secondary chemistry to AVT, the main condenser tubing was replaced with titanium. The feedwater heaters and moisture separator reheaters are made of carbon steel [11,40].

A.11.1.4 Operating Temperature

Grohnde currently operates at a nominal hot leg temperature of 327°C (620°F) and a nominal cold leg temperature of 293°C (559°F) [40].

A.11.1.5 Primary Water Chemistry

Grohnde uses modified chemistry in the primary coolant loop: A target pH of 7.4 at 300°C is maintained while limiting [Li] to 2.2 ppm. In 1999, Grohnde started using enriched boric acid [11].

A.11.1.6 Secondary Water Chemistry

Grohnde uses water from a cooling tower for the secondary coolant. Grohnde has a condensate demineralizer system, but it is only operational during startup and transients. Grohnde recovers blowdown and uses a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Grohnde uses high AVT for secondary chemistry control with the following feedwater concentration targets [10,11]:

- pH >9.8
- Cation Conductivity <0.15 µS/cm
- Oxygen <5 ppb

A.11.2 Summary of Degradation Experienced

A summary of the tubes plugged due to degradation is presented in Table A-13.

Table A-13
Cumulative Tubes Plugged or Repaired Due to Degradation at Grohnde [11,8]

Degradation Mechanism[1]	1991	2000	2006
PWSCC	0	0	0
Phosphate Wastage	0	0	0
Mechanical Wear due to Structural Components	1	1	10
Mechanical Wear due to Loose Parts	0	0	3
Deep Tubesheet Crevice ODSCC	0	0	0
ODSCC at TTS Crevices	0	0	0
TTS Denting and Related ODSCC	0	0	0
Pitting	0	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

A.12 Philippsburg Unit 2

A.12.1 Major Design and Operating Conditions

Philippsburg Nuclear Power Plant Unit 2 (Philippsburg 2) is a Siemens, 1468 MWe rated, 4-loop plant in Germany that began commercial operation in 1984. The steam generators have 0.866” (22 mm) diameter Alloy 800NG tubing [40]. As of April 2011, the steam generators have experienced approximately 22.8 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), and after bending, the tubing was OD glass bead, shot peened for ODSCC resistance [20].

A.12.1.1 Tubesheet Design

Each steam generator has 4118 tubes of 0.866” (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

A.12.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel, corrugated strips in the U-bend region. The tube supports at Phillipsburg 2 have larger free flow cross-sections than the tube supports at earlier designed Siemens units. This design reduces the resistance of water flow through the steam generator [8,9,20,42].

Tube support designs in different units are discussed in Section 5.2.

A.12.1.3 Balance of Plant Materials of Construction

The main condenser tubing is made of austenitic stainless steel and the tubesheet is made of carbon steel clad with stainless steel. The feedwater heaters and moisture separator reheaters are made of carbon steel [11,19].

A.12.1.4 Operating Temperature

Philippsburg 2 currently operates at a nominal hot leg temperature of 328°C (622°F) and a nominal cold leg temperature of 292°C (557°F) [40].

A.12.1.5 Primary Water Chemistry

Philippsburg 2 uses modified chemistry in the primary coolant loop: A target pH of 7.4 at 300°C is maintained while limiting [Li] to 2.2 ppm. In 1998, Philippsburg 2 started using enriched boric acid [11].

A.12.1.6 Secondary Water Chemistry

Philippsburg 2 uses water from a cooling tower for the secondary coolant. Philippsburg 2 has 30% flow mechanical filters in the condensate system, which are active during both startup and normal power operation. Philippsburg 2 recovers blowdown and uses a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Philippsburg 2 uses high AVT for secondary chemistry control with the following feedwater concentration targets [10,11]:

- pH >9.8
- Cation Conductivity <0.15 µS/cm
- Oxygen <5 ppb

In August of 1998, Philippsburg 2 started injecting oxygen upstream of their moisture separator reheaters to counteract FAC of the carbon steel header tubing. The oxygen concentration was increased stepwise, and by 2006 had reached an average value of ~140 ppb in the reheater system. Despite this injection, the feedwater oxygen concentration was maintained below 5 ppb as specified above; in general, oxygen concentrations of about 1–2 ppb were not exceeded [27].

A.12.2 Summary of Degradation Experienced

A summary of the tubes plugged due to degradation is presented in Table A-14.

Table A-14
Cumulative Tubes Plugged or Repaired Due to Degradation at Philippsburg 2 [11,8]

Degradation Mechanism[1]	1991	2000	2006
PWSCC	0	0	0
Phosphate Wastage	0	0	0
Mechanical Wear due to Structural Components	0	1	1
Mechanical Wear due to Loose Parts	0	1	1
Deep Tubesheet Crevice ODSCC	0	0	0
ODSCC at TTS Crevices	0	0	0
TTS Denting and Related ODSCC	0	0	0
Pitting	0	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

A.13 Angra Unit 2

A.13.1 Major Design and Operating Conditions

Angra Nuclear Power Plant Unit 2 (Angra 2) is a Siemens, 1350 MWe rated, 4-loop plant in Brazil that began commercial operation in 2001. The steam generators have a flow distribution baffle and have 0.866” (22 mm) diameter Alloy 800NG tubing [40]. As of April 2011, the steam generators have experienced approximately 8.5 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), and after bending, the tubing was OD glass bead, shot peened for ODSCC resistance [20].

A.13.1.1 Tubesheet Design

Each steam generator has 4106 tubes of 0.866” (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The tubesheet is made of 20MnMoNi55 pressure vessel steel (similar to SA508) and the flow distribution baffle is made of austenitic stainless steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

A.13.1.2 Tube Support Design

Each steam generator has type X10CrNiNb19-8, austenitic stainless steel support grids (similar to Type 347) and austenitic stainless steel, corrugated strips in the U-bend region. The tube supports at Angra 2 have larger free flow cross-sections than the tube supports at earlier designed Siemens units. This design reduces the resistance of water flow through the steam generator [8,9,40].

Tube support designs in different units are discussed in Section 5.2.

A.13.1.3 Balance of Plant Materials of Construction

The main condenser tubing is made of titanium and the tubesheet is made of carbon steel clad with titanium. The high pressure feedwater heater is made of austenitic stainless steel and the low pressure feedwater heater is made of carbon steel [40].

A.13.1.4 Operating Temperature

Angra 2 currently operates at a nominal hot leg temperature of 326°C (619°F) and a nominal cold leg temperature of 287°C (549°F) [40].

A.13.1.5 Primary Water Chemistry

Angra 2 uses modified chemistry in the primary coolant loop: A target pH of 7.4 at 300°C is maintained while limiting [Li] to 2 ppm. Angra 2 has injected zinc into the primary loop since startup [11].

A.13.1.6 Secondary Water Chemistry

Angra 2 uses seawater for the secondary coolant. Angra 2 recovers blowdown and uses a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

As of 2005, Angra 2 uses AVT for the secondary chemistry with the following operating conditions [40]:

- Hydrazine concentration of 20 ppb
- Ammonia concentration of 5 ppm

The secondary side of the steam generators was sludge lanced in 2003 and 2007 [40].

A.13.2 Summary of Degradation Experienced

A summary of the tubes plugged due to degradation is presented in Table A-15.

Table A-15
Cumulative Tubes Plugged or Repaired Due to Degradation at Angra 2 [11,8,40]

Degradation Mechanism[1]	2006	2008
PWSCC	0	0
Phosphate Wastage	0	0
Mechanical Wear due to Structural Components	2	3
Mechanical Wear due to Loose Parts	0	0
Deep Tubesheet Crevice ODSCC	0	0
ODSCC at TTS Crevices	0	0
TTS Denting and Related ODSCC	0	0
Pitting	0	0

1) Does not include tubes preventively plugged or tubes plugged for reasons other than degradation

A.14 Brokdorf

A.14.1 Major Design and Operating Conditions

Brokdorf Nuclear Power Plant is a Siemens, 1480 MWe rated, 4-loop plant in Germany that began commercial operation in 1986. The steam generators are Model 54GS, with an integral preheater, flow distribution baffle, and 0.866” (22 mm) diameter Alloy 800NG tubing [11,40]. As of April 2011, the steam generators have experienced approximately 21.4 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), and after bending, the tubing was OD glass bead, shot peened for ODSCC resistance [20].

A.14.1.1 Tubesheet and Preheater Design

Each steam generator has 4086 tubes of 0.866” (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel and the flow distribution baffle is made of austenitic stainless steel [40,42].

The preheater is a split flow design, is located at the lower section of the cold leg, and is made of austenitic stainless steel [42].

Tubesheet expansions in different units are discussed in Section 5.1.

A.14.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel, corrugated strips in the U-bend region. The tube supports at Brokdorf have larger free flow cross-sections than the tube supports at earlier designed Siemens units. This design reduces the resistance of water flow through the steam generator [8,9,20,42].

Tube support designs in different units are discussed in Section 5.2.1.

A.14.1.3 Balance of Plant Materials of Construction

The main condenser tubing is made of titanium and the tubesheet is made of carbon steel clad with titanium. The feedwater heaters and moisture separator reheaters are made of carbon steel [40].

A.14.1.4 Operating Temperature

Brokdorf currently operates at a nominal hot leg temperature of 326°C (618°F) and a nominal cold leg temperature of 292°C (558°F) [40].

A.14.1.5 Primary Water Chemistry

Brokdorf's primary water chemistry has consisted of the following 2 phases [11]:

- Start–1997: A target pH of 6.9 at 300°C was maintained by coordinating lithium and boron concentrations.
- 1997–Present: "Modified Chemistry" with enriched boric acid - A target pH of 7.4 at 300°C was maintained while limiting [Li] to 2.2 ppm.

A.14.1.6 Secondary Water Chemistry

Brokdorf uses water from a cooling tower for the secondary coolant. Brokdorf has a condensate demineralizer system, but it is only operational during startup and transients. Brokdorf recovers blowdown and uses a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Brokdorf uses high AVT for secondary chemistry control with the following feedwater concentration targets [10,11]:

- pH >9.8
- Cation Conductivity <0.15 µS/cm
- Oxygen <5 ppb

A.14.2 Summary of Degradation Experienced

A summary of the tubes plugged due to degradation is presented in Table A-16.

Table A-16
Cumulative Tubes Plugged or Repaired Due to Degradation at Brokdorf [11,8]

Degradation Mechanism[1]	1991	2000	2006
PWSCC	0	0	0
Phosphate Wastage	0	0	0
Mechanical Wear due to Structural Components	0	0	0
Mechanical Wear due to Loose Parts	0	1	6
Deep Tubesheet Crevice ODSCC	0	0	0
ODSCC at TTS Crevices	0	0	0
TTS Denting and Related ODSCC	0	0	0
Pitting	0	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

A.15 Isar Unit 2

A.15.1 Major Design and Operating Conditions

Isar Nuclear Power Plant Unit 2 (Isar 2) is a Siemens, 1485 MWe rated, 4-loop plant in Germany that began commercial operation in 1973. The steam generators are Model 54SK and have 0.866" (22 mm) diameter Alloy 800NG tubing [40]. As of April 2011, the steam generators have experienced approximately 20.4 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), and after bending, the tubing was OD glass bead, shot peened for ODSCC resistance [20].

A.15.1.1 Tubesheet Design

Each steam generator has 4118 tubes of 0.866" (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

A.15.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel, corrugated strips in the U-bend region. The tube supports at Isar 2 have larger free flow cross-sections than the tube supports at earlier designed Siemens units. This design reduces the resistance of water flow through the steam generator [8,9,20,42].

Tube support designs in different units are discussed in Section 5.2.

A.15.1.3 Balance of Plant Materials of Construction

The main condenser tubing is made of stainless steel and the tubesheet is made of carbon steel clad with stainless steel. The feedwater heaters and moisture separator reheaters are made of carbon steel [40].

A.15.1.4 Operating Temperature

Isar 2 currently operates at a nominal hot leg temperature of 324°C (615°F) and a nominal cold leg temperature of 292°C (558°F) [40].

A.15.1.5 Primary Water Chemistry

Isar 2 uses modified chemistry in the primary coolant loop: A target pH of 7.4 at 300°C is maintained while limiting [Li] to 2.2 ppm. In 1999, Isar 2 started using enriched boric acid in the primary loop [11].

A.15.1.6 Secondary Water Chemistry

Isar 2 uses water from a cooling tower for the secondary coolant. Isar 2 has full flow mechanical filters in the condensate system and full flow electro-mechanical filters in the high pressure heater drain system which are active during both startup and normal power operation. Isar 2 recovers blowdown and uses a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Isar 2 uses high AVT for secondary chemistry control with the following feedwater concentration targets [10,11]:

- pH >9.8
- Cation Conductivity <0.15 µS/cm
- Oxygen <5 ppb

In August of 2003, Isar 2 started injecting oxygen upstream of their moisture separator reheaters to counteract FAC of the carbon steel header tubing. The oxygen concentration was increased stepwise, and by 2006 had reached an average value of approximately 100 ppb in the reheater system. Despite this injection, the feedwater oxygen concentration was maintained below 5 ppb as specified above; in general, oxygen concentrations of about 1–2 ppb were not exceeded [27].

A.15.2 Summary of Degradation Experienced

Isar 2 has not had to plug any tubes due to degradation [8].

A.16 Emsland

A.16.1 Major Design and Operating Conditions

Emsland Nuclear Power Plant is a Siemens, 1400 MWe rated, 4-loop plant in Germany that began commercial operation in 1988. The steam generators are model 54SK and have 0.866” (22 mm) diameter Alloy 800NG tubing [40]. As of April 2011, the steam generators have experienced approximately 21.49 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), and after bending, the tubing was OD glass bead, shot peened for ODSCC resistance [20].

A.16.1.1 Tubesheet Design

Each steam generator has 4118 tubes of 0.866” (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

A.16.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel, corrugated strips in the U-bend region [20,42].

Tube support designs in different units are discussed in Section 5.2.

A.16.1.3 Balance of Plant Materials of Construction

The main condenser tubing is made of stainless steel and the tubesheet is made of carbon steel clad with stainless steel. The feedwater heaters and moisture separator reheaters are made of carbon steel [40].

A.16.1.4 Operating Temperature

Emsland currently operates at a nominal hot leg temperature of 324°C (616°F) and a nominal cold leg temperature of 292°C (557°F) [40].

A.16.1.5 Primary Water Chemistry

Emsland uses modified chemistry in the primary coolant loop: A target pH of 7.4 at 300°C is maintained while limiting [Li] to 2.2 ppm. In 2000, Emsland started using enriched boric acid in the primary loop [11].

A.16.1.6 Secondary Water Chemistry

Emsland uses water from a cooling tower for the secondary coolant. Emsland has full flow mechanical filters in the condensate system and full flow electro-mechanical filters in the high pressure heater drain system which are active during both startup and normal power operation. Emsland recovers blowdown and uses a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Emsland uses high AVT for secondary chemistry control with the following feedwater concentration targets [10,11]:

- pH >9.8
- Cation Conductivity <0.15 µS/cm
- Oxygen <5 ppb

A.16.2 Summary of Degradation Experienced

Emsland has not had to plug any tubes due to degradation [8].

A.17 Trillo Unit 1

A.17.1 Major Design and Operating Conditions

Trillo Nuclear Power Plant Unit 1 (Trillo 1) is a Siemens, 1066 MWe rated, 3-loop plant in Spain that began commercial operation in 1988. The steam generators are model 54GT, with an integral preheater, flow distribution baffle, and 0.866" (22 mm) diameter Alloy 800NG tubing [40,20,11]. As of April 2011, the steam generators have experienced approximately 19.6 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), and after bending, the tubing was OD glass bead, shot peened for ODSCC resistance [20].

A.17.1.1 Tubesheet and Preheater Design

Each steam generator has 4086 tubes of 0.866" (22 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40].

The preheater is a split flow design, is located at the lower section of the cold leg, and is made of austenitic stainless steel [42].

Tubesheet expansions in different units are discussed in Section 5.1.

A.17.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids in the straight leg region, and austenitic stainless steel, corrugated strips in the U-bend region. The tube supports at Trillo 1 have larger free flow cross-sections than the tube supports at earlier designed Siemens units. This design reduces the resistance of water flow through the steam generator [8,9,20,42].

Tube support designs in different units are discussed in Section 5.2.

A.17.1.3 Balance of Plant Materials of Construction

The main condenser tubing is made of titanium and the tubesheet is made of carbon steel clad with stainless steel. The feedwater heaters and moisture separator reheaters are made of carbon steel [11].

A.17.1.4 Operating Temperature

Trillo 1 currently operates at a nominal hot leg temperature of 326°C (619°F) and a nominal cold leg temperature of 294°C (561°F) [40].

A.17.1.5 Primary Water Chemistry

Trillo 1 uses modified chemistry in the primary coolant loop: A target pH of 7.4 at 300°C is maintained while limiting [Li] to 2.2 ppm [11].

A.17.1.6 Secondary Water Chemistry

The ultimate cooling source for Trillo 1 is water from the Tajo River. Trillo 1 has full flow mechanical filters in the condensate system and full flow electro-mechanical filters in the high pressure heater drain system which are active during both startup and normal power operation. Trillo 1 recovers blowdown and uses a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Trillo 1 uses high AVT for secondary chemistry control with the following feedwater concentration targets [10,11]:

- pH >9.8
- Cation Conductivity <0.15 µS/cm
- Oxygen <5 ppb

A.17.2 Summary of Degradation Experienced

Trillo 1 has had 4 steam generator tube leak due to degradation [8].

A summary of the tubes plugged due to degradation is presented in Table A-17.

Table A-17
Cumulative Tubes Plugged or Repaired Due to Degradation at Trillo 1 [11,8]

Degradation Mechanism[1]	2000	2006
PWSCC	0	0
Phosphate Wastage	0	0
Mechanical Wear due to Structural Components	4	4
Mechanical Wear due to Loose Parts	12	20
Deep Tubesheet Crevice ODSCC	0	0
ODSCC at TTS Crevices	0	0
TTS Denting and Related ODSCC	0	0
Pitting	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

B
CANDU PHWR UNITS

B.1 Point Lepreau

B.1.1 Major Design and Operating Conditions

Point Lepreau Generation System (PLGS) is a New Brunswick Power, 680 MWe rated, 2-loop plant in Canada that began commercial operation in 1983. Its 4 steam generators (2 in each loop) are a Babcock and Wilcox (B&W) Canada design with an integral steam drum, preheater, and 0.625" (15.8 mm) diameter Alloy 800NG tubing [45].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), not subjected to cold work for strengthening, and not subjected to peening for ODSCC resistance.

In March of 2008, PLGS was shut down to be refurbished and is currently scheduled to return to operation in the Fall of 2012 [46]. At the time of shutdown, the steam generators had experienced approximately 20.8 EFPY [12].

B.1.1.1 Tubesheet Design

Each steam generator has 3550 tubes of 0.625" (15.8 mm) diameter in a triangular pitch, which are hydraulically expanded into the tubesheet. The tubesheet is made of SA-508 steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

B.1.1.2 Tube Support Design

Each steam generator has Type 410 stainless steel tube supports. The tube supports consist of broached-hole support plates and U-Bend staggered, scallop bars [45].

Tube support designs in different units are discussed in Section 5.2.

B.1.1.3 Balance of Plant Materials of Construction

The preheater and emergency water supply (EWS) sections were originally made of carbon steel (except the preheater upper baffle plates, which have always been made of Type 410 stainless steel). From 1986–1990, secondary side carbon steel piping significantly affected by FAC was replaced with either austenitic stainless steel or Cr-Mo steel. In 1996, the carbon steel EWS header was replaced with Cr-Mo steel [45].

The feedwater and condensate heaters are made of Type 304 stainless steel. The moisture separator reheaters are made of Type 405 stainless steel (SA-240). During the 2008 Refurbishment outage the main condenser bundle was replaced,[18] and the aluminum-bronze tubesheet was replaced with one made of grade 2 titanium [47].

B.1.1.4 Operating Temperature and Pressure

PLGS was last operating at a nominal hot leg temperature of 309°C (590°F) and a nominal cold leg temperature of 266°C (511°F). On the primary side, the inlet pressure was 9.89 MPa and the outlet pressure is 9.61 MPa [45].

B.1.1.5 Primary Water Chemistry

PLGS is a pressurized heavy water reactor; the primary coolant specifications are presented in Table B-1. To ensure that sufficient dissolved deuterium is present during startup, hydrogen (molecular deuterium) is added to the primary side. In 2003, 25 ml hydrogen per kilogram coolant was added to the primary coolant [48].

Table B-1
CANDU Primary Coolant Specifications at Point Lepreau

Parameter	Specification Range	Desired Range
Dissolved Deuterium	3 - 10 mL/kg	4 - 10 mL/kg
Dissolved Oxygen	< 10 μg/kg	Non-detectable
Lithium Ion	0.34 - 0.55 μg/kg	0.34 - 0.55 μg/kg
Conductivity	0.86 - 1.37 mS/m	0.86 - 1.37 mS/m
pH	10.2 - 10.4	10.2 - 10.4
Chloride Ion	< 50 μg/kg	< 50 μg/kg

In 1995, the primary side of 8209 tubes (approximately 60%) were cleaned; 789 kg of deposit mass was removed by this cleaning [45].

In 2009, the primary side was chemically cleaned using AECLs CANDUClean system: 13,407 tubes (~98%) were cleaned and 1,082 kg of magnetite was removed [47].

B.1.1.6 Secondary Water Chemistry

The ultimate cooling source for PLGS was seawater from the Bay of Fundy.

PLGS had a condensate polishing system; however, it was only operational during startup and transients. Originally, PLGS used phosphate chemistry with morpholine as the pH control agent, but switched to ammonia in 1988, and switched to AVT in 2000 [45].

Water lancing of the tubesheets was performed in 1987, 1991, 1992, 1993, 1995, 1999, 2004, and 2008. In 1995, a high temperature chemical cleaning of each SG was performed; 1236 kg of material was removed by this cleaning [45,47].

---

[18] The replacement main condenser bundle is made of titanium, the same material as the original.

An overview of the secondary water chemistry employed by PLGS up to 2006 is provided in Figure B-1.

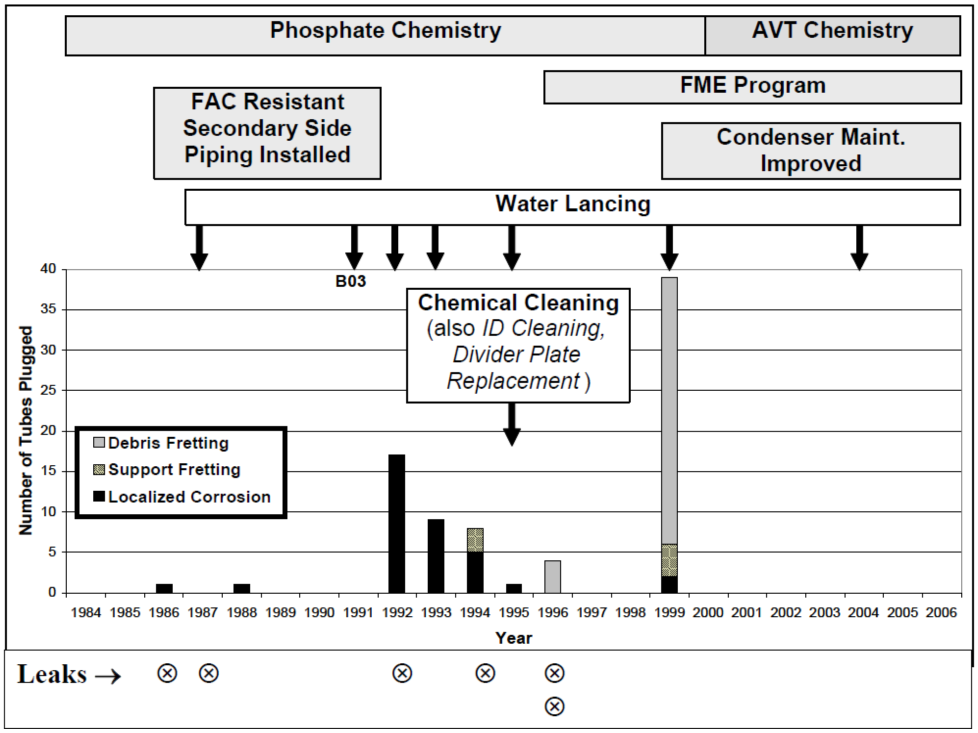

Figure B-1

Point Lepreau Secondary Chemistry Improvement History [45]

B.1.2 Summary of Degradation Experienced

As of 2006, tube degradation has led to 6 tube leaks (1985, 1987, 1992, 1994, and two in 1996) and has caused around 85 tubes to be plugged, including [45,47]:

- 31 tubes plugged due to pitting or phosphate wastage due to fouling deposits on hot leg tube support plates. Undercutting due to pitting has been attributed to the local presence of copper and chloride ions.
- 37 tubes plugged due debris fretting, either from materials left in the secondary system during maintenance or from loose parts formed by degradation (the two tube leaks in 1996 have been attributed to debris fretting).
- 7 tubes plugged due to fretting of U tubes at anti-vibration bars.

In 2009, 2 tubes were plugged due to obstruction (possible debris on secondary side). Additionally, ET was performed on steam generators 1 and 3 in 2009. The results of this inspection were as follows [47]:

- No evidence of cracking was detected in the roll transition zone, small radius U-bends or at U-bend deformations.

- No new indications of support fretting were observed,[19] with one exception. One fretting indication was observed in steam generator 1. However, the ET signal was found to be heavily influenced by ID magnetite (note that ET was performed after the primary side cleaning).
- Growth of existing support frets was minimal. The maximum growth rate was 3% tw/yr.
- Growth of existing pitting and wastage indications was minimal. The maximum growth rate was 3% tw/yr.

B.2 Wolsong Unit 1

B.2.1 Major Design and Operating Conditions

Wolsong Nuclear Generating Station Unit 1 (Wolsong 1) is a KHNP, 678 MWe rated, 2-loop plant in South Korea that began commercial operation in 1983. The 4 steam generators (2 in each loop) are a Foster Wheeler design with an integral steam drum, preheater, and 0.625" (15.8 mm) diameter Alloy 800NG tubing [49,50].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), not subjected to cold work for strengthening, and not subjected to peening for ODSCC resistance.

As of April 2011, the steam generators have experienced approximately 22.8 EFPY [12].

B.2.1.1 Tubesheet Design

Each steam generator has 3558 tubes of 0.625" (15.8 mm) diameter in a triangular pitch, which are mechanically rolled (partial roll) into the tubesheet. The tubesheet is 15.75" thick, with 0.633" holes. The tubesheet is made of type SA-508, Class 2 steel [49].

Tubesheet expansions in different units are discussed in Section 5.1.

B.2.1.2 Tube Support Design

Each steam generator has tube supports made of Alloy 600. They have 14 total sets of, formed bar tube supports: 9 on the hot leg side, and 5 on the cold leg side. They have 12 anti-vibration bars [22,49].

Tube support designs in different units are discussed in Section 5.2.

B.2.1.3 Balance of Plant Materials of Construction

The main condenser's tubes are made of titanium; the main condenser's tubesheet is made of aluminum bronze (B-171, Alloy 614); the low pressure feedwater heaters are made of SA-249, Type 304L steel. The high pressure feedwater heaters were made of SA-179 steel and were

[19] The last new indication of support fretting was observed in 2002.

replaced with ones made of SA-688, Type 304L steel in 2008. The moisture separator reheaters were made of carbon steel (A-210, Grade A-1) and were replaced with ones made of SA-268, Type 439 steel in 2011 [40,51].

B.2.1.4 Operating Temperature

Wolsong 1 operates at a nominal hot leg temperature of 309°C (588°F) and a nominal cold leg temperature of 266°C (510°F) [40].

B.2.1.5 Primary Water Chemistry

Wolsong 1 is a pressurized heavy water reactor with the following reactor coolant system (RCS) operating specifications [40]:

- Maximum lithium concentration of 0.68 ppm
- Duterium concentration range of 3.3–7.4 cm^3/kg

B.2.1.6 Secondary Water Chemistry

Wolsong 1 uses seawater for cooling, does not have a condensate polishing system, and blowdown is not recovered. The secondary chemistry control is AVT using morpholine and hydrazine. As of the 2007 outage, EOC 20, the secondary side operating conditions were as follows [40]:

- No ammonia addition
- No molar ratio control
- Morpholine Concentration of 18 ppm
- FW [N_2H_4] of 94 ppb
- FW [Fe] of 2.2 ppb
- FW [Cu] of 0 ppb

Wolsong Unit 1 performed sludge lancing in 2001 [51].

B.2.2 Summary of Degradation Experienced

Wolsong 1 has had to plug 6 tubes. Four tubes were plugged during the preservice inspection due to cracking indications on the ID. Two tubes were plugged due to possible foreign object indications: one in EOC 11 and one in EOC 12 [40,49,51].

B.3 Wolsong Unit 2

B.3.1 Major Design and Operating Conditions

Wolsong Nuclear Generating Station Unit 2 (Wolsong 2) is a KHNP, 700 MWe rated, 2-loop plant in South Korea that began commercial operation in 1997. The 4 steam generators (2 in each loop) are a DHI-B&W design with an integral steam drum, preheater, and 0.625” (15.8 mm) diameter Alloy 800NG tubing [49,50].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), not subjected to cold work for strengthening, and not subjected to peening for ODSCC resistance.

As of April 2011, the steam generators have experienced approximately 12.2 EFPY [12].

B.3.1.1 Tubesheet Design

Each steam generator has 3530 tubes of 0.625” (15.8 mm) diameter, which are hydraulically expanded into the tubesheet [52]. The tubesheet is 15.5” thick, with 0.638” holes. The tubesheet is made of Type SA-508, Class 3 steel [49,52].

Tubesheet expansions in different units are discussed in Section 5.1.

B.3.1.2 Tube Support Design

Each steam generator has tube supports made of SA-240 steel. There are a total of 15 sets of lattice grid tube supports: 9 on the hot leg side, and 6 on the cold leg side. There are 6 anti-vibration bars of the flat bar design [49,53].

Tube support designs in different units are discussed in Section 5.2.

B.3.1.3 Balance of Plant Materials of Construction

The main condenser tubes are made of titanium; the main condenser tubesheet is made of carbon steel with titanium cladding; the low and high pressure feedwater heaters are made of SA-268, Type 439 steel; the moisture separator reheaters are made of SA-268, Type 439 steel [40,51].

B.3.1.4 Operating Temperature

Wolsong 2 operates at a nominal hot leg temperature of 309°C (588°F) and a nominal cold leg temperature of 266°C (511°F) [40].

B.3.1.5 Primary Water Chemistry

Wolsong 2 is a pressurized heavy water reactor with the following RCS operating specifications [40]:

- Maximum Lithium concentration of 0.68 ppm
- Duterium concentration range of 3.2–7.8 cm^3/kg

B.3.1.6 Secondary Water Chemistry

Wolsong 2 uses seawater for cooling, does not have a condensate polishing system, and blowdown is not recovered. The secondary chemistry control is AVT using morpholine and hydrazine. As of the September 2009 outage (EOC 10), the secondary side operating conditions were as follows [40,51]:

- No ammonia addition
- No molar ratio control

- FW [N_2H_4] of 77.8 ppb
- FW [Fe] of 1.89 ppb
- FW [Cu] of 0.04 ppb
- Morpholine Concentration of 17 ppm

Starting in 2009 (EOC 10), Wolsong 2 has performed sludge lancings in two SGs during every refueling outage [51].

B.3.2 Summary of Degradation Experienced

As of May 2011, Wolsong 2 has not had to plug or repair any tubes due to degradation [49].

B.4 Wolsong Unit 3

B.4.1 Major Design and Operating Conditions

Wolsong Nuclear Generating Station Unit 3 (Wolsong 3) is a KHNP, 700 MWe rated, 2-loop plant in South Korea that began commercial operation in 1998. The 4 steam generators (2 in each loop) are a DHI-B&W design with an integral steam drum, preheater, and 0.625” (15.8 mm) diameter Alloy 800NG tubing [49,50].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), not subjected to cold work for strengthening, and not subjected to peening for ODSCC resistance.

As of April 2011, the steam generators have experienced approximately 11.5 EFPY [12].

B.4.1.1 Tubesheet Design

Each steam generator has 3530 tubes of 0.625” (15.8 mm) diameter in a triangular pitch, which are hydraulically expanded into the tubesheet [52]. The tubesheet is 15.5” thick, with 0.638” holes. The tubesheet is made of type SA-508, Class 3 steel [49,52].

Tubesheet expansions in different units are discussed in Section 5.1.

B.4.1.2 Tube Support Design

Each steam generator has tube supports made of SA-240 steel. They have 15 total sets of lattice grid tube supports: 9 on the hot leg side, and 6 on the cold leg side. They have 6 anti-vibration bars of the flat bar design [49,53].

Tube support designs in different units are discussed in Section 5.2.

B.4.1.3 Balance of Plant Materials of Construction

The main condenser’s tubes are made of titanium; the main condenser’s tubesheet is made of carbon steel clad with titanium; the low and high pressure feedwater heaters are made of SA-268, Type 439 steel; the moisture separator reheaters are made of SA-268, Type 439 steel [40].

B.4.1.4 Operating Temperature

Wolsong 3 operates at a nominal hot leg temperature of 309°C (588°F) and a nominal cold leg temperature of 266°C (511°F) [40].

B.4.1.5 Primary Water Chemistry

Wolsong 3 is a pressurized heavy water reactor with the following RCS operating specifications[20] [40]:

- Maximum Lithium concentration of 0.68 ppm
- Duterium concentration range of 3.2–7.8 cm^3/kg

B.4.1.6 Secondary Water Chemistry

Wolsong 3 uses seawater for cooling, does not have a condensate polishing system, and blowdown is not recovered. The secondary chemistry control is AVT using morpholine and hydrazine. As of the February 2006 outage (EOC 5), the secondary side operating conditions were as follows [40]:

According to latest operation results (EOC 10), the secondary side operating conditions were as follows:

- No ammonia addition
- No molar ratio control
- Morpholine concentration of 20 ppm
- FW [N_2H_4] of 79 ppb
- FW [Fe] of 2.0 ppb
- FW [Cu] of 0 ppb

Starting in 2008 (EOC 8), Wolsong 3 has performed sludge lancings in two of its SGs during every refueling outage [51].

B.4.2 Summary of Degradation Experienced

Wolsong 3 has had to plug 12 tubes due to degradation. Nine of these tubes were plugged due to manufacturing flaws (over expanded roll transitions beyond the tubesheet secondary face). Two tubes were plugged in first outage and secen were plugged in the second outage [41,52].

In the August 2003 outage (EOC 4), 3 tubes were preventatively plugged due to a foreign object [40,51].

[20] The primary water operating specifications were based off of values for Wolsong 2.

B.5 Wolsong Unit 4

B.5.1 Major Design and Operating Conditions

Wolsong Nuclear Generating Station Unit 4 (Wolsong 4) is a KHNP, 700 MWe rated, 2-loop plant in South Korea that began commercial operation in 1999. The 4 steam generators (2 in each loop) are a DHI-B&W design with an integral steam drum, preheater, and 0.625” (15.8 mm) diameter Alloy 800NG tubing [49,50].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), not subjected to cold work for strengthening, and not subjected to peening for ODSCC resistance.

As of April 2011, the steam generators have experienced approximately 10.4 EFPY [12].

B.5.1.1 Tubesheet Design

Each steam generator has 3530 tubes of 0.625” (15.8 mm) diameter in a triangular pitch, which are hydraulically expanded into the tubesheet [52]. The tubesheet is 15.5” thick, with 0.638” holes. The tubesheet is made of Type SA-508, Class 3 steel [49,52].

Tubesheet expansions in different units are discussed in Section 5.1.

B.5.1.2 Tube Support Design

Each steam generator has tube supports made of SA-240 steel. There are a total of 15 sets of lattice grid tube supports: 9 on the hot leg side, and 6 on the cold leg side. There are 6 anti-vibration bars of the flat bar design [49,53].

Tube support designs in different units are discussed in Section 5.2.

B.5.1.3 Balance of Plant Materials of Construction

The tubes of the main condenser are made of carbon steel clad with titanium; the main condenser’s tubesheet is made of carbon steel; the low and high pressure feedwater heaters are made of SA-268, Type 439 steel; the moisture separator reheaters are made of SA-268, Type 439 steel [40].

B.5.1.4 Operating Temperature

Wolsong 4 operates at a nominal hot leg temperature of 309°C (588°F) and a nominal cold leg temperature of 266°C (511°F) [40].

B.5.1.5 Primary Water Chemistry

Wolsong 4 is a pressurized heavy water reactor with the following RCS operating specifications[21] [40]:

- Maximum Lithium concentration of 0.68 ppm
- Duterium concentration range of 3.2–7.8 cm^3/kg

B.5.1.6 Secondary Water Chemistry

Wolsong 4 uses seawater for cooling, has a condensate polishing system, and blowdown is not recovered. The secondary chemistry control is AVT using morpholine and hydrazine. As of the October 2005 outage (EOC 5), the secondary side operating conditions were as follows [40,51]:

According to latest operation results (EOC 10), the secondary side operating conditions were as follows:

- No ammonia addition
- No molar ratio control
- Morpholine concentration of 22 ppm
- FW [N_2H_4] of 82 ppb
- FW [Fe] of 2.6 ppb
- FW [Cu] of 0 ppb

Starting in 2008 (EOC 7), Wolsong Unit 4 has performed sludge lancings in two of its SGs during every outage [51].

B.5.2 Summary of Degradation Experienced

Wolsong 4 has had to plug 15 tubes due to degradation. All 15 tubes were plugged due to manufacturing flaws (over expanded roll transitions beyond the tubesheet secondary face). Six tubes were plugged during the pre-service inspection; three tubes were plugged in the first outage; and six tubes were plugged in the second outage [40,52].

B.6 Darlington Unit 1

B.6.1 Major Design and Operating Conditions

Darlington Nuclear Generating Station Unit 1 (Darlington 1) is an Ontario Power Generation, 934 MWe rated, 2-loop plant in Canada that began commercial operation in 1992. The 4 steam generators (2 in each loop) are a B&W Canada design with an integral steam drum, integral preheater, and 0.624” (15.85 mm) outer diameter Alloy 800NG tubing [45].

[21] The primary water operating specifications were based off of values for Wolsong 2.

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), not subjected to cold work for strengthening, and not subjected to peening for ODSCC resistance.

As of April 2011, the steam generators have experienced approximately 15.6 EFPY [54].

B.6.1.1 Tubesheet Design

Each steam generator has 4663 tubes of 0.625” (15.8 mm) diameter in a triangular pitch, which are hydraulically expanded near the secondary face into the tubesheet. The tubesheet is made of forged low alloy steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

B.6.1.2 Tube Support Design

Each steam generator has Type 410S stainless steel tube supports. The tube supports consist of drilled-hole baffle plates in the preheater region, lattice bar grids in the straight leg region, and fan bar AVBs in the U-bend region [55,56]. During the Spring 2004 outage, auxiliary AVB supports were installed in between existing supports to complement the existing system and alleviate AVB fretting.

Tube support designs in different units are discussed in Section 5.2.

B.6.1.3 Balance of Plant Materials of Construction

Darlington 1 has an all ferrous secondary side. The main condenser tubesheet is made of carbon steel with stainless steel cladding; the main condenser tubing, and low and high pressure feedwater heaters are made of Type 304 stainless steel; the moisture separator reheaters are made of Type 321 stainless steel (SA-249) [40].

B.6.1.4 Operating Temperature

Darlington 1 operates at a nominal hot leg temperature of 309°C (588°F) and a nominal cold leg temperature of 267°C (512°F) [40].

B.6.1.5 Primary Water Chemistry

Darlington 1 is a pressurized heavy water reactor with the following RCS operating specifications [40]:

- pH range of 9.6 to 9.9
- Duterium concentration range of 3–10 cm^3/kg

B.6.1.6 Secondary Water Chemistry

The ultimate cooling source for Darlington 1 is fresh water from the Lake Ontario. The secondary chemistry control is ammonia AVT using hydrazine. Darlington 1 does not have condensate polishers and blowdown is not recovered [40].

Sludge lancing was performed during the 1996, 2000, 2004, 2008, and 2011 outages [32,40].

B.6.2 Summary of Degradation Experienced

The steam generators at Darlington 1 have exhibited many instances of fretting at the intersection of U-bend tubes and AVB supports. Fretting has been observed at both the original and the new auxiliary AVB supports. A summary of the tubes plugged due to degradation is presented in Table B-2 [40]. There have been no instances of SCC at Darlington 1.

Other degradation at Darlington 1 includes [28,32,31,54,55]:

- Fretting at hot leg lattice bar supports has also been observed at Darlington 1, but has only led to one tube plugging (in 2000).
- In 2004, two tubes were plugged with flaws in the preheater region. From more recent experience it is now considered that the flaws on these two plugged tubes were associated with cavitation damage (see Section 6.4).
- In 2005, a metallurgical examination of removed tubes reported the presence of micro pits, 0.4%tw to 1%tw, on the OD surface of many tubes in the TTS region.
- In 2008, 22 indications of wall loss at preheater supports were detected in 22 tubes. The maximum depth was determined to be ~40%; however, comparison with inspection data available from 2004 indicated that the indications had not increased in size.
- In 2011, 160 indications of wall loss at preheater supports were detected in 150 tubes. The maximum depth was determined to be ~50%. The increase in indications from 2008 to 2011 was attributed to more experience and expertice in detecting this type of degradation. Compariion with the inspection data from 2004 and 2008 indicated that the indications had not increased in size.
- In 2011, 2 tubes with clusters of small micropit-like OD indications (~0.2 mm diameter) with depths to ~30% tw were detected by UT; however, comparison with UT inspection data available from 1996 UT indicated that the indications had not increased in size.

Table B-2
Cumulative Tubes Plugged or Repaired Due to Degradation at Darlington 1 [32,40,54]

Degradation Mechanism[1]	2000	2004	2006	2008	2011
PWSCC	0	0	0	0	0
Phosphate Wastage	0	0	0	0	0
Mechanical Wear due to Structural Components	173	308	308	309	309
Mechanical Wear due to Loose Parts	0	0	0	0	0
Cavitation	0	2	2	2	2
Deep Tubesheet Crevice ODSCC	0	0	0	0	0
ODSCC at TTS Crevices	0	0	0	0	0
TTS Denting and Related ODSCC	0	0	0	0	0
Pitting	0	0	0	0	0

1) Does not include tubes preventively plugged or tubes plugged for reasons other than degradation (e.g. for metallurgical exams)

B.7 Darlington Unit 2

B.7.1 Major Design and Operating Conditions

Darlington Nuclear Generating Station Unit 2 (Darlington 2) is an Ontario Power Generation, 934 MWe rated, 2-loop plant in Canada that began commercial operation in 1990. The 4 steam generators (2 in each loop) are a B&W Canada design with an integral steam drum, integral preheater, and 0.624” (15.85 mm) outer diameter Alloy 800NG tubing [45].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), not subjected to cold work for strengthening, and not subjected to peening for ODSCC resistance.

As of April 2011, the steam generators have experienced approximately 16.1 EFPY [57].

B.7.1.1 Tubesheet Design

Each steam generator has 4663 tubes of 0.625” (15.8 mm) diameter in a triangular pitch, which are hydraulically expanded near the secondary face into the tubesheet. The tubesheet is made of forged steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

B.7.1.2 Tube Support Design

Each steam generator has Type 410S stainless steel tube supports. The tube supports consist of drilled-hole baffle plates in the preheater region, lattice bar grids in the straight leg region, and fan bar AVBs in the U-bend region [55,56]. In the unit's Spring 2005 outage, auxiliary AVB supports were installed in between existing supports to complement the existing system and alleviate AVB fretting.

Tube support designs in different units are discussed in Section 5.2.

B.7.1.3 Balance of Plant Materials of Construction

Darlington 2 has an all ferrous secondary side. The main condenser tubesheet is made of carbon steel with stainless steel cladding; the main condenser tubing, and low and high pressure feedwater heaters are made of Type 304 stainless steel; the moisture separator reheaters are made of Type 321 stainless steel (SA-249) [40].

B.7.1.4 Operating Temperature

Darlington 2 operates at a nominal hot leg temperature of 309°C (588°F) and a nominal cold leg temperature of 267°C (512°F) [40].

B.7.1.5 Primary Water Chemistry

Darlington 2 is a pressurized heavy water reactor with the following RCS operating specifications [40]:

- pH range of 9.6 to 9.9
- Duterium concentration range of 3–10 cm^3/kg

B.7.1.6 Secondary Water Chemistry

The ultimate cooling source for Darlington 2 is fresh water from the Lake Ontario. The secondary chemistry control is ammonia AVT using hydrazine. Darlington 2 does not have condensate polishers and blowdown is not recovered [40].

Sludge lancing was performed during the 2001, 2007, and 2010 outages [32,40].

B.7.2 Summary of Degradation Experienced

The steam generators at Darlington 2 have exhibited many instances of fretting at the intersection of U-bend tubes and AVB supports. Fretting has been observed at both the original and the new auxiliary AVB supports [28]. A summary of the tubes plugged due to degradation is presented in Table B-3 (note that all of the tubes plugged from mechanical wear due to structural components was caused by AVB fretting) [40]. Fretting at hot leg supports has also been observed at Darlington 2, but has not led to any tube plugging [28]. There have been no instances of SCC at Darlington 2.

Other degradation at Darlington 2 includes [28,30,31,58]:

- In 1998 there was a tube leak which resulted in a month long forced outage in 1998. The leak was in a preheater tube just above the thermal plate.
- In 2005, a 10% through wall pit was detected under deposits at the fifth hot leg support.
- In 2007, 53 indications of wall loss at preheater supports were detected in 51 tubes. The maximum depth was determined to be ~50%. However, comparison with inspection data available from 2001 indicated that the indications had not increased in size.
- In 2010, 197 indications of wall loss at preheater supports were detected in 171 tubes. The maximum depth was determined to be ~50%. The increase in indications from 2007 to 2010 was attributed to more experience and expertise in detecting this type of degradation. Comparison with the inspection data from 2001 and 2007 indicated that the indications had not increased in size with one possible exception. One indication had grown 12% tw since 2007. This tube was pulled for analysis. However, metallurigical examination at this location could not confirm or refute this growth.

Table B-3
Cumulative Tubes Plugged or Repaired Due to Degradation at Darlington 2 [32,40,58]

Degradation Mechanism[1]	1997	1998	1999	2001	2005	2007	2010
PWSCC	0	0	0	0	0	0	0
Phosphate Wastage	0	0	0	0	0	0	0
Mechanical Wear due to Structural Components	0	0	10	95	107	108	108
Mechanical Wear due to Loose Parts	0	6	11	11	11	11	11
Deep Tubesheet Crevice ODSCC	0	0	0	0	0	0	0
ODSCC at TTS Crevices	0	0	0	0	0	0	0
TTS Denting and Related ODSCC	0	0	0	0	0	0	0
Pitting	0	0	0	0	0	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

B.8 Darlington Unit 3

B.8.1 Major Design and Operating Conditions

Darlington Nuclear Generating Station Unit 3 (Darlington 3) is an Ontario Power Generation, 934 MWe rated, 2-loop plant in Canada that began commercial operation in 1993. The 4 steam generators (2 in each loop) are a B&W Canada design with an integral steam drum, integral preheater, and 0.624” (15.85 mm) outer diameter Alloy 800NG tubing [45].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), not subjected to cold work for strengthening, and not subjected to peening for ODSCC resistance.

As of April 2011, the steam generators have experienced approximately 15.7 EFPY [59].

B.8.1.1 Tubesheet Design

Each steam generator has 4663 tubes of 0.625” (15.8 mm) diameter in a triangular pitch, which are hydraulically expanded near the secondary face into the tubesheet. The tubesheet is made of forged steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

B.8.1.2 Tube Support Design

Each steam generator has Type 410S stainless steel tube supports. The tube supports consist of drilled-hole baffle plates in the preheater region, lattice bar grids in the straight leg region, and fan bar AVBs in the U-bend region [55,56]. During the Fall 2004 outage, auxiliary AVB supports were installed in between existing supports to complement the existing system and alleviate AVB fretting.

Tube support designs in different units are discussed in Section 5.2.

B.8.1.3 Balance of Plant Materials of Construction

Darlington 3 has an all ferrous secondary side. The main condenser tubesheet is made of carbon steel with stainless steel cladding; the main condenser tubing, and low and high pressure feedwater heaters are made of Type 304 stainless steel; the moisture separator reheaters are made of Type 321 stainless steel (SA-249) [40].

B.8.1.4 Operating Temperature

Darlington 3 operates at a nominal hot leg temperature of 309°C (588°F) and a nominal cold leg temperature of 267°C (512°F) [40].

B.8.1.5 Primary Water Chemistry

Darlington 3 is a pressurized heavy water reactor with the following RCS operating specifications [40]:

- pH range of 9.6 to 9.9
- Duterium concentration range of 3–10 cm^3/kg

B.8.1.6 Secondary Water Chemistry

The ultimate cooling source for Darlington 3 is fresh water from the Lake Ontario. The secondary chemistry control is ammonia AVT using hydrazine. Darlington 3 does not have condensate polishers and blowdown is not recovered [40].

Sludge lancing was performed during the January 1999, March 2002, March 2006, and April 2009 outages [40].

B.8.2 Summary of Degradation Experienced

The steam generators at Darlington 3 have exhibited many instances of fretting at the intersection of U-bend tubes and AVB supports. Fretting has been observed at both the original and the new auxiliary AVB supports [28]. A summary of the tubes plugged due to degradation is presented in Table B-4 (note that all of the tubes plugged from mechanical wear due to structural components was caused by AVB fretting) [40]. Fretting at hot leg supports has also been observed at Darlington 3, but has not led to any tube plugging [28]. There have been no known instances of SCC at Darlington 3.

Other degradation at Darlington 3 includes [28,60]:

- In 2006, a 5% through wall pit was detected under deposits at the fifth hot leg support.
- In 2009, 48 indications of wall loss at preheater supports were detected in 48 tubes. The maximum depth was determined to be ~34% tw.

Table B-4
Cumulative Tubes Plugged or Repaired Due to Degradation at Darlington 3 [32,40]

Degradation Mechanism[1]	1999	2002	2004	2006	2009
PWSCC	0	0	0	0	0
Phosphate Wastage	0	0	0	0	0
Mechanical Wear due to Structural Components	45	136	139	143	143
Mechanical Wear due to Loose Parts	0	0	0	0	0
Deep Tubesheet Crevice ODSCC	0	0	0	0	0
ODSCC at TTS Crevices	0	0	0	0	0
TTS Denting and Related ODSCC	0	0	0	0	0
Pitting	0	0	0	0	0

1) Does not include tubes preventively plugged or tubes plugged for reasons other than degradation

B.9 Darlington Unit 4

B.9.1 Major Design and Operating Conditions

Darlington Nuclear Generating Station Unit 4 (Darlington 4) is an Ontario Power Generation, 934 MWe rated, 2-loop plant in Canada that began commercial operation in 1993. The 4 steam generators (2 in each loop) are a B&W Canada design with an integral steam drum, integral preheater, and 0.624” (15.85 mm) outer diameter Alloy 800NG tubing [40].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), not subjected to cold work for strengthening, and not subjected to peening for ODSCC resistance.

As of April 2011, the steam generators have experienced approximately 15.3 EFPY [61].

B.9.1.1 Tubesheet Design

Each steam generator has 4663 tubes of 0.625” (15.8 mm) diameter in a triangular pitch, which are hydraulically expanded near the secondary face into the tubesheet. The tubesheet is made of forged steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

B.9.1.2 Tube Support Design

Each steam generator has Type 410S stainless steel tube supports. The tube supports consist of drilled-hole baffle plates in the preheater region, lattice bar grids in the straight leg region, and fan bar AVBs in the U-bend region [55,56]. In the 2003 outage, auxiliary AVB supports were installed in between existing supports to complement the existing system and alleviate AVB fretting.

Tube support designs in different units are discussed in Section 5.2.

B.9.1.3 Balance of Plant Materials of Construction

Darlington 4 has an all ferrous secondary side. The main condenser tubesheet is made of carbon steel with stainless steel cladding; the main condenser tubing, and low and high pressure feedwater heaters are made of Type 304 stainless steel; the moisture separator reheaters are made of Type 321 stainless steel (SA-249) [40].

B.9.1.4 Operating Temperature

Darlington 4 operates at a nominal hot leg temperature of 309°C (588°F) and a nominal cold leg temperature of 267°C (512°F) [40].

B.9.1.5 Primary Water Chemistry

Darlington 4 is a pressurized heavy water reactor with the following RCS operating specifications [40]:

- pH range of 9.6 to 9.9
- Duterium concentration range of 3–10 cm^3/kg

B.9.1.6 Secondary Water Chemistry

The ultimate cooling source for Darlington 4 is fresh water from the Lake Ontario. The secondary chemistry control is ammonia AVT using hydrazine. Darlington 4 does not have condensate polishers and blowdown is not recovered [40].

Sludge lancing was performed during the 1995, 2003, 2007, and 2010 outages [40].

B.9.2 Summary of Degradation Experienced

Darlington 4's steam generators have exhibited many instances of fretting at the intersection of U-bend tubes and AVB supports. Fretting has been observed at both the original and the new auxiliary AVB supports [28]. A summary of the tubes plugged due to degradation is presented in Table B-5 (note that all of the tubes plugged from mechanical wear due to structural components was caused by AVB fretting) [40].

Fretting at hot leg supports has also been observed at Darlington 4, but has not led to any tube plugging [28]. There have been no instances of SCC at Darlington 4.

Other degradation at Darlington 4 includes [28,62]:

- In 1995, micro-pits with a maximum depth of 0.5% through wall were detected on the OD surface of many tubes in the hot leg TTS region.
- In 2003, a 5% through wall pit was detected under deposits at the fourth hot leg support.
- In 2007, a 3–4% through wall pit was detected under deposits at a hot leg support.
- In 2010, 28 indications of wall loss at preheater supports were detected in 26 tubes. The maximum depth was determined to be ~26% tw.

Table B-5
Cumulative Tubes Plugged or Repaired Due to Degradation [40]

Degradation Mechanism[1]	1999	2003	2007	2010
PWSCC	0	0	0	0
Phosphate Wastage	0	0	0	0
Mechanical Wear due to Structural Components	27	65	65	65
Mechanical Wear due to Loose Parts	0	0	0	0
Deep Tubesheet Crevice ODSCC	0	0	0	0
ODSCC at TTS Crevices	0	0	0	0
TTS Denting and Related ODSCC	0	0	0	0
Pitting	0	0	0	0

1) Does not include tubes preventively plugged or tubes plugged for reasons other than degradation

B.10 Gentilly Unit 2

B.10.1 Major Design and Operating Conditions

Gentilly Nuclear Generating Station Unit 2 (Gentilly 2) is a Hydro Quebec, 675 MWe rated, 2-loop plant in Canada that began commercial operation in 1983. The 4 steam generators (2 in each loop) are a B&W Canada design with an integral steam drum, preheater, and 0.625” (15.8 mm) diameter Alloy 800NG tubing [45].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified) and not subjected to cold work for strengthening.

As of April 2011, the steam generators have experienced approximately 21.3 EFPY [12].

B.10.1.1 Tubesheet Design

Each steam generator has 3542 tubes of 0.625” (15.8 mm) diameter in a triangular pitch, which are hydraulically expanded into the tubesheet. The tubesheet is made of forged low alloy steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

B.10.1.2 Tube Support Design

Each steam generator has Type 410 stainless steel tube supports. The tube supports consist of broached-hole support plates and U-Bend staggered, scallop bars [53]. Tube support designs in different units are discussed in Section 5.2.

B.10.1.3 Balance of Plant Materials of Construction

The secondary system is an all ferrous/copper system. The low pressure feedwater heater is stainless steel, and the high pressure feedwater heater is carbon steel. The main condenser tubing is admiralty brass. The moisture separator reheater (MSR) tubing is made of carbon steel [53].

B.10.1.4 Operating Temperature and Pressure

Gentilly 2 operates at a nominal hot leg temperature of 310°C (590°F) and a nominal cold leg temperature of 265°C (509°F) [40]. The primary side pressure is 9.9 MPa [63].

B.10.1.5 Primary Water Chemistry

Gentilly 2 is a pressurized heavy water reactor; the primary coolant specifications are presented in Table B-6 [48].

Table B-6
CANDU Primary Coolant Specifications at Gentilly 2

Parameter	Specification Range	Desired Range
Dissolved Deuterium	3 - 10 mL/kg	4 - 10 mL/kg
Dissolved Oxygen	< 10 µg/kg	Non-detectable
Lithium Ion	0.34 - 0.55 µg/kg	0.34 - 0.55 µg/kg
Conductivity	0.86 - 1.37 mS/m	0.86 - 1.37 mS/m
pH	10.2 - 10.4	10.2 - 10.4
Chloride Ion	< 50 µg/kg	< 50 µg/kg

B.10.1.6 Secondary Water Chemistry

Gentilly 2 uses fresh water from the St. Lawrence River for cooling and blowdown is recovered. The secondary chemistry control is AVT using morpholine and hydrazine [53].

The secondary side of the steam generators was chemically cleaned in the 2005 outage [64].

B.10.2 Summary of Degradation Experienced

Gentilly has plugged 5 tubes due to degradation. In the April 1999 outage, 3 tubes were plugged due to structural wear (loose part) on the outside diameter of the hot leg, tubesheet region and in the April 2001 outage, 2 tubes were plugged due to structural wear in the tube support region [40].

B.11 Embalse

B.11.1 Major Design and Operating Conditions

Embalse is a NASA (Nucleoeléctrica Argentina Sociedad Anónima), 648 MWe rated, 2-loop plant in Argentina that began commercial operation in 1984. The 4 steam generators (2 in each loop) are a B&W Canada design with an integral steam drum, preheater, and 0.625" (15.8 mm) diameter Alloy 800NG tubing [65].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified), not subjected to cold work for strengthening, and not subjected to peening for ODSCC resistance.

As of April 2011, the steam generators have experienced approximately 21.0 EFPY [12].

B.11.1.1 Tubesheet Design

Each steam generator has 3542 tubes of 0.625" (15.8 mm) diameter in a triangular pitch. During the original manufacturing process, the tubes were mechanically rolled into the tubesheet. However, in 1980 (before plant operation) the steam generators were re-tubed, and the tubes were hydraulically expanded into the tubesheet [65]. The tubesheet is made of SA-508, Class 2, carbon steel and has Alloy 600 cladding. The primary head, shell, integral steam drum, and divider plate are all made of SA-516, Grade 70, carbon steel [65,66].

Tubesheet expansions in different units are discussed in Section 5.1.

B.11.1.2 Tube Support Design

Each steam generator has SA-515, Grade 70, carbon steel tube supports. The tube supports consist of 8 broached-hole support plates in the straight sections of the tubes and 6 sets of staggered, scallop bars in the U-bend region [65,66].

In 2004, 3 additional sets of anti-vibration bars were installed in the U-bend regions of each steam generator [66].

Tube support designs in different units are discussed in Section 5.2.

B.11.1.3 Balance of Plant Materials of Construction

The secondary system is a mixed metal system. The low pressure feedwater heater is Type 304 stainless steel and the high pressure feedwater heater is carbon steel. The main condenser tubing is admiralty brass [67].

B.11.1.4 Operating Temperature and Pressure

Embalse operates at a nominal hot leg temperature of 309°C (588°F) and a nominal cold leg temperature of 266.6°C (512°F). The primary side, hot leg pressure is 9.88 MPa and the primary side, cold leg pressure is 9.63 MPa. Loss of heat transfer efficiency in the SGs has caused Embalse to reduce the secondary side pressure to reduce the average reactor inlet (cold leg) temperature. From 1999 to 2002, the average reactor inlet header temperature has dropped from 268.6°C (515°F) to 263.5°C (506°F) [65].

B.11.1.5 Primary Water Chemistry

Embalse is a pressurized heavy water reactor; the primary coolant specifications are presented in Table B-7 [48].

Table B-7
CANDU Primary Coolant Specifications at Embalse

Parameter	Specification Range	Desired Range
Dissolved Deuterium	3 - 10 mL/kg	4 - 10 mL/kg
Dissolved Oxygen	< 10 µg/kg	Non-detectable
Lithium Ion	0.34 - 0.55 µg/kg	0.34 - 0.55 µg/kg
Conductivity	0.86 - 1.37 mS/m	0.86 - 1.37 mS/m
pH	10.2 - 10.4	10.2 - 10.4
Chloride Ion	< 50 µg/kg	< 50 µg/kg

During the 2000 scheduled outage, the primary side of the steam generator tubes was chemically cleaned by the Siemens SIVABLAST process. It was estimated that 2602 kg of magnetite was removed [65].

B.11.1.6 Secondary Water Chemistry

The cooling source at Embalse is fresh water from Embalse lake. Embalse uses AVT chemistry for pH control, but due to FAC, the operating specifications have changed throughout the operational history. The secondary chemistry history can be summarized as follows [66,65]:

- 1983–2007: Used morpholine as pH control agent with the following targets:
  - 1983–2004: pH of 9.2–9.5
  - 2004–2006: pH of 9.5–9.6
  - 2006–2007: pH of 9.6–9.8
- 2007: Switched from morpholine to ethanolamine:
  - ethanolamine concentration of 7 ppm
  - pH ~10.2

The steam generators were sludge lanced in 2002 and 2007 [65,66].

B.11.2 Summary of Degradation Experienced

As of 2009, Embalse has had 11 tube leaks (1986, 1987, 1991, 1992, 1996 (2), 1998, 2001, 2003 (2), and 2006). Five tube leaks were attributed to wear due to loose parts, and six have been attributed to FAC of the carbon steel supports in the cold leg region of the U-bends. Sixty four tubes have been preventatively plugged due to FAC of the cold leg region of the U-bends [28,65,66].

B.12 Cernavoda Unit 1

B.12.1 Major Design and Operating Conditions

Cernavoda Unit 1 is a CNE, 704.8 MWe rated, 2-loop plant in Romania that began commercial operation in 1996. The 4 steam generators (2 in each loop) are a B&W Canada design with an integral steam drum, preheater, and 0.625" (15.8 mm) diameter Alloy 800NG tubing [63,68]. As of April 2011, the steam generators have experienced approximately 12.0 EFPY [12].

Cernavoda Unit 1 is based off the CANDU 6 NPP design and is likely to have similar design and operating conditions to Wolsong Units 2–4 [63].

B.12.1.1 Tube Support Design

Each steam generator has lattice support grids in the straight leg region and flat bar supports in the U-bend region [69].

Tube support designs in different units are discussed in Section 5.2.

B.12.1.2 Operating Temperature

Cernavoda 1 is currently operating at a nominal hot leg temperature of 310°C (590°F) and a nominal cold leg temperature of 266°C (510°F) [68].

B.12.1.3 Primary Water Chemistry

Cernavoda Unit 1 is a pressurized heavy water reactor.

B.12.2 Summary of Degradation Experienced

Six indications of denting have been observed at Cernavoda 1: In 2000, 11% of the tubes of SG 2 and 4 were inspected and 3 tubes had indications of denting, and in 2001, 11% of the tubes of SGs 1 and 3 were inspected and had 3 indications of denting [70].

B.13 Cernavoda Unit 2

B.13.1 Major Design and Operating Conditions

Cernavoda Unit 2 is a CNE, 706 MWe rated, 2-loop plant in Romania that began commercial operation in 2007. The 4 steam generators (2 in each loop) are a B&W Canada design with an integral steam drum, preheater, and 0.625" (15.8 mm) diameter Alloy 800NG tubing [63,68]. As of April 2011, the steam generators have experienced approximately 2.5 EFPY [12].

Cernavoda Unit 2 is based off the CANDU 6 NPP design and is likely to have similar design and operating conditions to Wolsong Units 2–4 [63].

B.13.1.1 Tube Support Design

Each steam generator has lattice support grids in the straight leg region and flat bar supports in the U-bend region [69].

Tube support designs in different units are discussed in Section 5.2.

B.13.1.2 Operating Temperature

Cernavoda 1 is currently operating at a nominal hot leg temperature of 310°C (590°F) and a nominal cold leg temperature of 266°C (510°F) [68].

B.13.1.3 Primary Water Chemistry

Cernavoda Unit 2 is a pressurized heavy water reactor.

B.14 Qin Shan III Unit 1

B.14.1 Major Design and Operating Conditions

Qin Shan III Unit 1 is a 728 MWe rated, 2-loop plant in China that began commercial operation in 2002. The 4 steam generators (2 in each loop) are a B&W Canada design with an integral steam drum, preheater, and 0.625” (15.8 mm) diameter Alloy 800NG tubing [12,63].

Qin Shan III Unit 1 is based off the CANDU 6 design of Wolsong Units 3 and 4 and is likely to have similar design and operating conditions [63].

B.14.1.1 Operating Temperature and Pressure

Qin Shan III Unit 1 operates at a nominal hot leg temperature of 310°C (590°F) and a primary side pressure of 9.9 MPa [63].

B.14.1.2 Primary Water Chemistry

Qin Shan III Unit 1 is a pressurized heavy water reactor.

B.15 Qin Shan III Unit 2

B.15.1 Major Design and Operating Conditions

Qin Shan III Unit 2 is a 728 MWe rated, 2-loop plant in China that began commercial operation in 2003. The 4 steam generators (2 in each loop) are a B&W Canada design with an integral steam drum, preheater, and 0.625” (15.8 mm) diameter Alloy 800NG tubing [63].

Qin Shan III Unit 2 is based off the CANDU 6 design of Wolsong Units 3 and 4 and is likely to have similar design and operating conditions [63].

B.15.1.1 Operating Temperature and Pressure

Qin Shan III Unit 2 operates at a nominal hot leg temperature of 310°C (590°F) and a primary side pressure of 9.9 MPa [63].

B.15.1.2 Primary Water Chemistry

Qin Shan III Unit 2 is a pressurized heavy water reactor.

C WESTINGHOUSE-TYPE UNITS (REPLACEMENT SGS)

C.1 Doel Unit 3

C.1.1 Major Design and Operating Conditions

Doel Nuclear Power Plant Doel 3 (Doel 3) is a Westinghouse-type, 1056 MWe rated, 3-loop plant in Belgium that began commercial operation in 1982. The original steam generators were Framatome Model 51M steam generators with carbon steel, drilled-hole support plates, and Alloy 600LTMA tubing. In 1993 (EOC 11) the steam generators were replaced with KWU Model 61W steam generators with, flow distribution baffle, austenitic stainless steel eggcrate supports, and Alloy 800NG tubing [40,71].

The Alloy 800 used to tube the steam generators was nuclear grade (modified) and during fabrication, the tubes were cold pilgered, and after bending, were full OD glass bead, shot peened for ODSCC resistance, as discussed in Chapter 4 [40].

As of the most recent refueling outage (EOC 29 in June 2011) the replacement steam generators had experienced 15.8 EFPY [40].

C.1.1.1 Tubesheet Design

The Doel 3 replacement steam generators each have 5130 tubes of 0.75” diameter in a triangular pitch which are hydraulically expanded into the tubesheet to full depth [40,71]. The tube expansion process also included a hard-roll step at the top and at the bottom of the tubesheet [72]. The tubesheet material for the replacement steam generators is SA-508, Class 3 steel [71]. The flow distribution baffle is made of Type 347 stainless steel [38].

Tubesheet expansions in different units are discussed in Section 5.1.

C.1.1.2 Tube Support Design

The Doel 3 replacement steam generator has stainless steel eggcrate tube supports [40]. Both the lattice bar supports and anti-vibration bars are made of Type 321, austenitic stainless steel [38].

Tube support designs in different units are discussed in Section 5.2.

C.1.1.3 Balance of Plant Materials of Construction

The main condenser tubes and tubesheet at Doel 3 were originally made of aluminum brass, but were replaced with titanium in 1991(before SG replacement). The low and high pressure feedwater heaters are made of stainless steel; the moisture separator reheaters are made of Type 439 stainless steel [40].

C.1.1.4 Operating Temperature

From steam generator replacement (1993, EOC 11) to 2001 (EOC 19, 6.9 EFPY for the replacement steam generators), Doel 3 operated at a hot leg temperature of 325°C (617°F). The hot leg temperature was reduced to the current level of 323°C (613°F) during Cycle 20. The current cold leg temperature is 283°C (541°F) [40].

C.1.1.5 Primary Water Chemistry

Doel 3 uses a modified pH program. The current operating specifications (August 2011) are as follows [40]:

- Target pH of 7.2
- Max [Li] of 3.35 ppm
- Max [H_2] of 50 cm^3/kg

Doel 3 began adding zinc to the primary system in April of 2011 [40].

C.1.1.6 Secondary Water Chemistry

The ultimate cooling source for Doel 3 consists of a cooling tower and a mixed make-up of fresh water and water from Doel 1 and Doel 2 [40]. The cooling water is classified as brackish river water [40]. Between Cycle 21 (2002) and Cycle 28 (2010), the average feedwater impurity concentrations were as follows [71]:

- 0.5 ppb Chlorine
- 0.4 ppb Sodium
- 0.6 ppb Sulfate
- 0.8 ppb Iron
- 0.025 ppb Copper

The Doel 3 secondary system chemistry is maintained with the following feedwater concentration targets:

- 7 ppm Ammonia
- 100–120 ppb Hydrazine (reduced from 200 ppb in 2002) [73]

Since SG replacement, no boric acid treatments (either online or offline) have been used. Likewise, no active molar ratio control has been implemented since SG replacement.

Doel 3 has partial flow, deep bed polishers, but the polishers are only used during transients, start up, and cool down. Blowdown is recovered, and the recovery process includes filtration and demineralization [72,38]. However, it is important to note that blowdown is drawn from a circular groove in the periphery of the tubesheet, rather than a tube in the center of the tubesheet. This has been noted to lead to significantly reduced, or a total lack of, corrosion product removal by blowdown [73].

A summary of sludge lancing history at Doel 3 is presented in Table C-1. The steam generators at Doel 3 have not been chemically cleaned.

Table C-1
Masses of Deposits Removed during Each Outage at Doel 3 [40,71]

Outage	Cleaning Method	Mass Removed from All SGs, lb (kg)
EOC28	Sludge lancing and Hard Sludge Lancing (1 SG)	21 (9.5)
EOC28	Sludge lancing and Hard Sludge Lancing (1 SG)	272.6 (123.9)
EOC27	None	—
EOC26	Sludge lancing	247 (112)
EOC25	Sludge lancing	133 (60.5)
EOC24	None	—
EOC23	Sludge lancing	84 (38)
EOC22	None	—
EOC21	None	—
EOC20	None	—
EOC19	None	—
EOC18	Sludge lancing	121 (55.0)
EOC17	None	—
EOC16	None	—
EOC15	Sludge lancing	267 (121)
EOC14	None	—
EOC13	Sludge lancing	34 (15)
EOC12	Sludge lancing	18 (8.2)
EOC11	None	SG Replacement Outage

C.1.2 Summary of Degradation Experienced

Doel 3's history of condenser tube in-leakage since steam generator replacement is presented in Table C-2.

Table C-2
Condenser Leaks in Each Cycle since SG Replacement at Doel 3 [71]

Cycle	Year	Number of Condenser Leaks	Notes
27	2008 - 2009	5	Exceeded AL 2 for Na during one condenser leak[1]
26	2007 - 2008	3	
25	2006 - 2007	4	Exceeded AL 2 for Na during one condenser leak[1]
24	2005 - 2006	2	
23	2004 - 2005	7	Exceeded AL 2 for Na during two condenser leaks[1]
22	2003 - 2004	6	Exceeded AL 2 for Na at startup[1]
21	2002 - 2003	1	High Fe and Na (100 ppb) at startup
20	2001 - 2002	1	
19	2000 - 2001	1	
18	1999 - 2000	5	
17	1998 - 1999	0	
16	1997 - 1998	0	
15	1996 - 1997	3	
14	1995 - 1996	0	
13	1994 - 1995	1	Uncertainty in number of condenser leaks
12	1993 - 1994	0	

1) Action Level 2 as defined by EPRI Guidelines.

Westinghouse-Type Units (Replacement SGs)

The steam generators at Doel 3 have exhibited denting in the cold leg, top of tubesheet region in the latest 3 outages (EOC 27–30). The inspection threshold for denting was 25 μm. The denting history of Doel 3 is summarized in Table C-3. SCC has not been observed in dented tubes [40].

Table C-3
Total New Tubes with Denting Indications at Doel 3 [40]

	EOC 27 (May 09)	EOC 28 (June 10)	EOC 29 (June 11)
% Tubes Inspected (Across All 3 SGs)	18.3%	100.0%	66.7%
Total New HL Denting	0	0	0
Total New CL Denting	28	89	6

C.2 Asco Unit 1

C.2.1 Major Design and Operating Conditions

Asco Nuclear Power Plant Unit 1 (Asco 1) is a Westinghouse, 1032 MWe rated, 3-loop plant in Spain that began commercial operation in 1984. The original steam generators were Westinghouse Model D3 steam generators with carbon steel, drilled-hole support plates and Alloy 600MA tubing. In 1995 (EOC 11), the steam generators were replaced with KWU Model 61W/D3 steam generators with feedring, flow distribution baffle, and 0.75” diameter Alloy 800NG tubing [37].

The Alloy 800 used to tube the steam generators was nuclear grade (modified) and during fabrication, the 800NG tubes were cold pilgered, with a 3 minute 971°C (1780°F) bright anneal, and a 4% final cold draw. After bending, tubing was full OD glass bead, shot peened for ODSCC resistance, as discussed in Chapter 4 [74].

As of the most recent refueling outage (EOC 21 in March 2011) the replacement steam generators had experienced 13.75 EFPY [40].

C.2.1.1 Tubesheet Design

The Asco 1 replacement steam generators each have 5130 tubes of 0.75” diameter in a triangular pitch which are hydraulically expanded into the tubesheet to full depth [40]. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The Asco 1 SGs are reported by the fabrication ET profilometry to have a small crevice depth (0.12” average; 0.24” maximum) on the tubesheet secondary face. The diametral tube to tubesheet gap is reported as 8.7 mils (0.22 mm) [75].

The tubesheet is made of forged low-alloy steel (SA-508 Class 3, Grade 1), and the flow distribution baffle is made of Type 347 stainless steel [37,40].

Tubesheet expansions in different units are discussed in Section 5.1.

C.2.1.2 Tube Support Design

The Asco 1 replacement steam generators have lattice bar tube supports. Both the lattice bar supports and anti-vibration bars are made of Type 321, austenitic stainless steel [37].

Tube support designs in different units are discussed in Section 5.2.

C.2.1.3 Balance of Plant Materials of Construction

Prior to SG replacement, all balance of plant (BOP) equipment with copper alloys was replaced. The main and auxiliary condensers were originally constructed with admiralty alloy, and were replaced with titanium or carbon steel with titanium cladding. The low and high pressure feedwater heaters were originally constructed of admiralty alloy and Monel respectively; both were replaced with AISI 304L stainless steel [40].

The moisture separator reheaters at Asco 1 originally had Monel (Cu/Ni 90/10) reheater tube bundles and were replaced with ferritic stainless steel tubes (SA-268 AISI 439) in 1991. The rest of the MSR was originally carbon steel, and was replaced with FAC resistant materials in 2011 (EOC 21) [75].

C.2.1.4 Operating Temperature

Asco 1 is currently operating at a nominal hot leg temperature of 327°C (621°F) and a nominal cold leg temperature of 288°C (551°F) [40].

C.2.1.5 Primary Water Chemistry

Asco 1 uses a coordinated B-Li pH program. The operating specifications (May 2001) are as follows [40]:

- Coordinated B-Li to pH 7.0
- 2.2 ppm Li to pH 7.4
- Max [Li] of 3.5 ppm
- [H_2] range of 25–50 cm^3/kg

C.2.1.6 Secondary Water Chemistry

The ultimate cooling source for Asco 1 is fresh water from the Ebro River. Asco 1 does not have condensate polishers and blowdown is not recovered. Asco 1 has always used AVT. The historical feedwater chemistry is presented in Table C-4, and the historical blowdown impurities are presented in Table C-5 [75].

Table C-4
Asco 1 Historical Feedwater Chemistry [75]

Species	Cycle Average BD Concentration (ppb)								US Plants Median (ppb)	Non-US Plants Median (ppb)
	13	14	15	16	17	18	19	20		
Na	1.1	0.6	0.5	1.2	0.9	1.0	0.9	0.5	0.26	1.21
Cl	2.0	2.3	2.7	2.2	1.7	2.0	2.5	1.8	0.49	2.69
SO_4	3.1	2.5	2.5	3.0	2.1	2.4		1.6	0.54	4.0

Table C-5
Asco 1 Blowdown Impurities [75,76]

Cycle	13	14	15	16	17	18	19	20
Cycle Average Na Concentration (ppb)	1.1	0.6	0.5	1.2	0.9	1.0	0.9	0.5
Cycle Average Cl Concentration (ppb)	2.0	2.3	2.7	2.2	1.7	2.0	2.5	1.8
Cycle Average SO_4 Concentration (ppb)	3.1	2.5	2.5	3.0	2.1	2.4		1.6

The Asco 1 secondary system chemistry is currently maintained with the following feedwater concentration targets [37,75]:

- 25 ppm Ammonia
- 100 ppb Hydrazine
- pH of 10.2

Since SG replacement, Asco 1 has not used any boric acid treatments or implemented any molar ratio control [75]. There have been no chemical cleanings of the replacement SGs. Since SG replacement, sludge lancing has been performed 7 of the 10 outages. The results of the first 9 cleanings are summarized in Table C-6. During the March 2011 (EOC 21) outage, a conventional "hard sludge lancing" and an "innerbundle sludge lancing" (IBL) were performed to remove hard sludge bridges and collars [75]. The results of EOC 21 are summarized in Table C-7.

Table C-6
Masses of Deposits Removed during Each Outage through EOC 20 at Asco 1 [40,77]

Outage	Cleaning Method	Pounds Removed (all SGs)
EOC20	Hard sludge lancing	216
EOC19	None	—
EOC18	Sludge lancing	57
EOC17	None	—
EOC16	Sludge lancing	201
EOC15	None	—
EOC14	Sludge lancing	141
EOC13	Sludge lancing	139
EOC12	Sludge lancing	90
EOC11	None	SG Replacement Outage

Table C-7
Masses of Deposits Removed during EOC 21 at Asco 1 [75]

SG	A	B	C
Standard SL duration (h)	32	32	32
Dry sludge removed (kg)	**11.1**	**15.1**	**28.4**
IBL duration (h)	60	72	66
Rinse SL duration (h)	12	12	16
Dry sludge removed (kg)	**66.2**	**50.4**	**35.2**
Dry sludge removed (total, kg)	**77.3**	**65.5**	**63.6**

C.2.2 Summary of Degradation Experienced

The following four instances of condenser tube in-leakage between Cycle 16 and Cycle 20 were reported [77,75]:

- Beginning April 4, 2001 (Cycle 16), a minor leak (no action level) lasted two days.
- Beginning September 1, 2005 (Cycle 18), a minor leak (no action level) lasted two days.
- Beginning November 26, 2005 (Cycle 18), a minor leak (no action level) lasted 13 days. The SG blowdown was increased to 12 metric tons per hour per SG. The sodium concentration in the blowdown was between 1.5–5 ppb and the cation conductivity in the blowdown was between 0.18–0.27 µS/cm.
- Beginning May 13, 2006 (during the start-up of Cycle 19), a major leak (action level 2) lasted four days. The SG blowdown was increased to 33 metric tons per hour per SG. The sodium concentration in the blowdown was >1000 ppb and the cation conductivity in the blowdown was >50 µS/cm, but according to German VGB Secondary Chemistry Guidelines, a power reduction was neither required nor applied, maintaining the plant at a 75% of nominal power.

The steam generators at Asco 1 have exhibited denting in the hot leg, top of tubesheet region in the latest 4 outages (EOC 18–21). Five indications of ODSCC have been detected in dented tubes, all in SG A (2 in EOC19 and 3 in EOC 21) [75]. Additionally, loose part wear has caused several tubes to be plugged and has led to tube leaks in EOC 19 and 20 [74]. The denting and degradation histories at Asco 1 are summarized in Table C-8 and Table C-9.

Note that the number of new denting indications was calculated using the following equation:

$$d_n = D_n - D_{n-1} + c_{n-1} \qquad \text{Eq. C-1}$$

Where d_n is the number of new denting indications in the n^{th} outage, D_n is the total number of denting indications in the n^{th} outage, and c_n is the total number of denting indications plugged in the n^{th} outage.

Westinghouse-Type Units (Replacement SGs)

The number of cumulative denting indications was calculated using the following equation:

$$C_n = \sum_{i=1}^{n} d_i \qquad \text{Eq. C-2}$$

Where C_n is the cumulative denting indications in the nth outage and d_i is the number of new denting indications in the nth outage calculated from Equation [C-1].

Table C-8
Total New Tubes with Denting Indications at Asco 1 [75]

	EOC 18 (Apr 06)	EOC 19 (Oct 07)	EOC 20 (May 09)	EOC 21 (March 11)
% Tubes Inspected (Across All 3 SGs)	20.7%	66.7%	100.0%	100.0%[1]
Total New HL Denting	3	161	42	33
Total New CL Denting	0	0	0	0
HL Circumferential SCC Indications	0	2	0	3
CL Circumferential SCC Indications	0	0	0	0

Table C-9
Cumulative Tubes Plugged or Repaired Due to Degradation at Asco 1 [75,78,79,80]

Degradation Mechanism[1]	EOC 18 (Apr 06)	EOC 19 (Oct 07)	EOC 20 (May 09)	EOC 21 (March
PWSCC	0	0	0	0
Phosphate Wastage	0	0	0	0
Mechanical Wear due to Structural Components	0	0	3	3
Mechanical Wear due to Loose Parts	0	9	9	9
Deep Tubesheet Crevice ODSCC	0	0	0	0
ODSCC at TTS Crevices	0	0	0	0
TTS Denting and Related ODSCC[2]	0/3	0/164	2/208	5/241
Pitting	0	0	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

2) (# of tubes plugged or repaired due to denting) / (# of tubes with denting indications)

C.3 Asco Unit 2

C.3.1 Major Design and Operating Conditions

Asco Nuclear Power Plant Unit 2 (Asco 2) is a Westinghouse, 1027 MWe rated, 3-loop plant in Spain that began commercial operation in 1986. The original steam generators were Westinghouse Model D3 steam generators with carbon steel, drilled-hole support plates and Alloy 600MA tubing. In 1996 (EOC 10), the steam generators were replaced with KWU Model 61W/D3 steam generators with feedring, flow distribution baffle, and 0.75” diameter Alloy 800NG tubing [37].

The Alloy 800 used to tube the steam generators was nuclear grade (modified) and during fabrication, the 800NG tubes were cold pilgered, with a 3 minute 971°C (1780°F) bright anneal, and a 4% final cold draw. After bending, tubing was full OD was glass bead, shot peened for ODSCC resistance, as discussed in Chapter 4 [74].

As of the most recent refueling outage (EOC 19 in May 2010) the replacement steam generators had experienced approximately 12.4 EFPY [75].

C.3.1.1 Tubesheet Design

The Asco 2 replacement steam generators each have 5130 tubes of 0.75” diameter in a triangular pitch which are hydraulically expanded into the tubesheet to full depth [75]. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The Asco 2 SGs are reported by the fabrication ET profilometry to have a small crevice depth (0.12” average; 0.24” maximum) on the tubesheet secondary face. The diametral tube-tubesheet gap is reported as 8.7 mils (0.22 mm) [75].

The tubesheet is made of forged low-alloy steel (SA-508 Class 3, Grade 1), and the flow distribution baffle is made of Type 347 stainless steel [37,40].

Tubesheet expansions in different units are discussed in Section 5.1.

C.3.1.2 Tube Support Design

The Asco 2 replacement steam generators have lattice bar tube supports. Both the lattice bar supports and anti-vibration bars are made of Type 321 austenitic stainless steel [37].

Tube support designs in different units are discussed in Section 5.2.

C.3.1.3 Balance of Plant Materials of Construction

Prior to SG replacement, all BOP equipment with copper alloys was replaced. The main and auxiliary condensers were originally constructed with admiralty alloy, and were replaced with titanium or carbon steel with titanium cladding. The low and high pressure feedwater heaters were originally constructed of admiralty alloy and Monel respectively; both were replaced with AISI 304L stainless steel [40].

Asco 2’s moisture separator reheaters originally had Monel (Cu/Ni 90/10) reheater tube bundles and were replaced with ferritic stainless steel tubes (SA-268 AISI 439) in 1991. The rest of the MSR is originally carbon steel, and is scheduled to be replaced with FAC resistant materials in 2011 (EOC 20) [75].

C.3.1.4 Operating Temperature

Asco 2 is currently operating at a nominal hot leg temperature of 327°C (621°F) and a nominal cold leg temperature of 288°C (551°F) [40].

C.3.1.5 Primary Water Chemistry

Asco 2 uses a coordinated B-Li pH program. The operating specifications (May 2001) are as follows [40]:

- Coordinated B-Li to pH 7.0
- 2.2 ppm Li to pH 7.4
- Max [Li] of 4.0 ppm
- $[H_2]$ of 25–50 cm^3/kg

Asco 2 added zinc to the primary system in January of 2007 [40].

C.3.1.6 Secondary Water Chemistry

The ultimate cooling source for Asco 2 is fresh water from the Ebro River. Asco 2 does not have condensate polishers and blowdown is not recovered. Asco 2 has always used AVT. The historical feedwater chemistry is presented in Table C-10, and the historical blowdown impurities are presented in Table C-11 [75].

Table C-10
Asco 2 Historical Feedwater Chemistry [75]

Cycle	11	12	13	14	15	16	17	18	19
Cycle Average Hydrazine Concentration (ppb)	248	244	184	155	110	115	112	117	123
Hydrazine Concentration Target (ppb)	≥100	≥100	≥100	≥100	≥100	≥100	≥100	≥100	≥100
Cycle Average Ammonia Concentration (ppm)	9.8	10.2	10.7	10.6	10.7	10.5	8.9	8.6	9.7
Ammonia Concentration Target (ppm)	5.4-12.0	5.4-12.0	5.4-12.0	5.4-12.0	5.4-12.0	5.4-12.0	5.4-12.0	5.4-12.0	5.4-12.0

Table C-11
Asco 2 Blowdown Impurities [75,76]

Species	Cycle Average BD Concentration (ppb)									US Plants Median (ppb)	Non-US Plants Median (ppb)
	11	12	13	14	15	16	17	18	19		
Na	1.0	0.7	0.3	0.5	0.7	1.1	1.2	0.6	0.7	0.26	1.21
Cl	1.9	2.1	2.3	2.4	1.8		3.0	1.6	1.6	0.49	2.69
SO_4	6.0	6.2	2.9	2.5	2.2	3.0	4.0	2.6	2.2	0.54	4.0

The Asco 2 secondary system chemistry is currently maintained with the following feedwater concentration targets [37,75]:

- 25 ppm Ammonia
- ≥100 ppb Hydrazine
- pH of 10.2

Since SG replacement, Asco 2 has not used any boric acid treatments or implemented any molar ratio control [75]. There have been no chemical cleanings of the replacement SGs. Since SG replacement, sludge lancing has been performed 6 of the 9 outages. The results of the 9 cleanings are summarized in Table C-12.

Table C-12
Masses of Deposits Removed during Each Outage at Asco 2 [75]

Outage	Cleaning Method	Pounds Removed (all SGs)
EOC19	Hard sludge lancing	174
EOC18	Hard sludge lancing	121
EOC17	None	—
EOC16	Sludge lancing	43
EOC15	None	—
EOC14	Sludge lancing	75
EOC13	None	—
EOC12	Sludge lancing	64
EOC11	Sludge lancing	220
EOC10	None	SG Replacement Outage

C.3.2 Summary of Degradation Experienced

The following two instances of condenser tube in-leakage between Cycle 15 and Cycle 19 were reported [77]:

- Beginning October 18, 2004 (Cycle 15), a leak (mode 4, no action level) lasted eight days.
- Beginning December 31, 2006 (Cycle 17), a major leak (action level 3) lasted four days. The sodium concentration in the blowdown was >1000 ppb (for a limited time period) and the cation conductivity in the blowdown was between 24–30 µS/cm. According to German VGB Secondary Chemistry Guidelines, the plant was shut down.

The steam generators at Asco 2 have exhibited denting in the cold leg, top of tubesheet region in the latest 5 outages (EOC 15-19). The denting and degradation histories are summarized in Table C-13 and Table C-14. SCC has not been observed in dented tubes [75].

Table C-13
Total New Tubes with Denting Indications at Asco 2 [75]

	EOC 15 (2004)	EOC 16 (2005)	EOC 17 (2007)	EOC 18 (2008)	EOC 19 (2010)
% Tubes Inspected (Across All 3 SGs)	3.0%	22.7%	33.3%	33.3%	100.0%
Total New HL Denting	0	0	0	0	0
Total New CL Denting	1	0	9	58	76
HL Circumferential SCC Indications	0	0	0	0	0
CL Circumferential SCC Indications	0	0	0	0	0

Table C-14
Cumulative Tubes Plugged or Repaired Due to Degradation at Asco 2 [74,75,81,82,83]

Degradation Mechanism[1]	EOC 11 (1998)	EOC 12 (1999)	EOC 15 (2004)	EOC 16 (2005)	EOC 17 (2007)	EOC 18 (2008)	EOC 19 (2010)
PWSCC	0	0	0	0	0	0	0
Phosphate Wastage	0	0	0	0	0	0	0
Mechanical Wear due to Structural Components	0	0	0	0	6	7	7
Mechanical Wear due to Loose Parts	2	4	4	4	4	5	7
Deep Tubesheet Crevice ODSCC	0	0	0	0	0	0	0
ODSCC at TTS Crevices	0	0	0	0	0	0	0
TTS Denting and Related ODSCC[2]	0	0	0/1	0/1	0/10	0/68	0/144
Pitting	0	0	0	0	0	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.
2) (# of tubes plugged or repaired due to denting) / (# of tubes with denting indications)

C.4 Almaraz Unit 1

C.4.1 Major Design and Operating Conditions

Almaraz Nuclear Power Plant Unit 1 (Almaraz 1) is a Westinghouse, 977 MWe rated, 3-loop plant in Spain that began commercial operation in 1981. The original steam generators were Westinghouse Model D3 steam generators with carbon steel, drilled-hole support plates and Alloy 600MA tubing. In 1996, the steam generators were replaced with KWU Model 61W/D3 replacement steam generators with austenitic stainless steel support grids, flow distribution baffle and Alloy 800NG tubing [40,74].

The Alloy 800 used to tube the steam generators was nuclear grade (modified) and during fabrication, the 800NG tubes were cold pilgered, with a 3 minute 971°C (1780°F) bright anneal, and a 4% final cold draw. After bending, tubing was full OD, shot peened for ODSCC resistance, as discussed in Chapter 4 [74].

As of April 2011 the replacement steam generators have experienced approximately 13.3 EFPY [12,40].

C.4.1.1 Tubesheet Design

The Almaraz replacement steam generators each have 5130 tubes of 0.75” diameter in a triangular pitch which are hydraulically expanded into the tubesheet to full depth [40]. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The crevice between the tubes and the tubesheet has a nominal depth of 3–6 mm, and the nominal annulus is 0.2 mm in thickness [35].

The tubesheet is made of forged low-alloy steel (A 508, Class 3, which is now referred to as SA-508 Grade 3, Class 1) [35,40]. The flow distribution baffles of Asco 1 and 2 are made of Type 347 stainless steel and since the designs of these units are very similar, it is likely that the flow distribution baffle of Almaraz 1 is also made of Type 347 stainless steel.

Tubesheet expansions in different units are discussed in Section 5.1.

C.4.1.2 Tube Support Design

The Almaraz 1 replacement steam generators have lattice bar tube supports. Both the lattice bar supports and anti-vibration bars are made of Type 321, austenitic stainless steel for Asco Units 1 and 2, and since the steam generator design of Almaraz 1 is very similar to these units, it is likely lattice bar supports and anti-vibration bars at Almaraz 1 are also made of Type 321, austenitic stainless steel.

Tube support designs in different units are discussed in Section 5.2.

C.4.1.3 Balance of Plant Materials of Construction

The Almaraz 1 balance of plant had components made with copper-based alloys. The main condenser tubesheet was originally made with 90/10 Cu/Ni and the tubes were made of admiralty brass. However, the condenser was replaced with non-copper containing materials before steam generator replacement [35]. The low and high pressure feedwater heaters are made of Type 304L, stainless steel. The moisture separator reheaters were made of ferritic stainless steel and were replaced in 2009 [40,84].

C.4.1.4 Operating Temperature

Almaraz 1 is currently operating at a nominal hot leg temperature of 327.8°C (622°F) and a nominal cold leg temperature of 289.2°C (553°F). Prior to Cycle 21, the hot leg temperature was 325°C (617°F), the cold leg temperature was 290°C (554°F) [35].

C.4.1.5 Primary Water Chemistry

Almaraz 1 uses a coordinated B-Li pH program. The operating specifications (January 1997) are as follows [40,85]:

- Coordinated B-Li to pH 7.15
- Max [Li] of 3.5 ppm
- [H_2] of 25–50 cm^3/kg (normally 35-50 cm^3/kg)

C.4.1.6 Secondary Water Chemistry

The cooling source for Almaraz 1 is closed-pond water [40]. The circulating water has the following dissolved solids concentrations [35]:

- Calcium ~112 ppm
- Magnesium ~38.4 ppm
- Sodium ~145 ppm
- Potassium ~11 ppm
- Chlorine ~163 ppm
- Sulfate ~355 ppm
- Fluorine ~0.3 ppm
- Silica ~4.4 ppm

Almaraz 1 does not have deep bed condensate polishers or a condensate filter-demineralizer. Steam generator blowdown flows through a collection of cationic, weak and strong anionic, and two mixed bed resins prior to recovery. The cycle average blowdown impurity concentrations are presented in Table C-15 [35,85].

Westinghouse-Type Units (Replacement SGs)

The Almaraz 1 secondary system chemistry is maintained with the following feedwater chemistry targets [36,35]:

- 27–29 µS/cm Specific conductivity. Prior to Cycle 21, the target specific conductivity was 21 µS/cm.
- 11 ppm Ammonia (since June 2009).
- 100 ppb Hydrazine.

The cycle average feedwater concentrations for hydrazine and ammonia are presented in Table C-16.

No boric acid treatments (either online or offline) have been used since SG replacement. Likewise, active molar ratio control has not been used since SG replacement.

Table C-15
Almaraz 1 Cycle Average Blowdown Impurities – Cycles 12 to 20 [35,76]

Species	Cycle 12 SG BD Average (ppb)	Cycle 13 SG BD Average (ppb)	Cycle 14 SG BD Average (ppb)	Cycle 15 SG BD Average (ppb)	Cycle 16 SG BD Average (ppb)	Cycle 17 SG BD Average (ppb)	Cycle 18 SG BD Average (ppb)	Cycle 19 SG BD Average (ppb)	Cycle 20 SG BD Average (ppb)	US Plants Median (ppb)	Non-US Plants Median (ppb)
Na	1.5	3.1	0.9	0.7	1.1	0.8	0.9	0.8	1.3	0.26	1.21
Cl	6.9	3.4	0.6	0.5	1	0.9	0.8	1	0.8	0.49	2.69
SO_4	8.5	10.9	3.4	3.1	2.5	1.4	3.1	2.7	2.9	0.54	4.0

The concentration of iron in the feedwater has been reported to fall in the range 1.5–2 ppb around June 2009, and this value was not significantly impacted by an increase in ammonia concentration to 11 ppm. During the 22nd Cycle, iron in the feedwater ranged between 1.0 and 1.4 ppb [36,85].

Table C-16
Almaraz 1 Cycle Average Feedwater Chemistry – Cycles 12 to 20 [35, 76]

Species	Cycle 12 Feedwater Average	Cycle 13 Feedwater Average	Cycle 14 Feedwater Average	Cycle 15 Feedwater Average	Cycle 16 Feedwater Average	Cycle 17 Feedwater Average	Cycle 18 Feedwater Average	Cycle 19 Feedwater Average	Cycle 20 Feedwater Average	US Plants Median	Non-US Plants Median
N_2H_4 (ppb)	110	110	112	116	114	103	104	102	103	92.4	39.7
NH_3 (ppm)			7.1	6.7	6.7	7.0	6.7	6.6	7.2	2.5	0.5

A summary of the sludge lancing history at Almaraz 1 is presented in Table C-17. The steam generators underwent chemical cleaning at 160°C (320°F) during the outage in November 2009 (EOC 20) [36,84].

Table C-17
Masses of Deposits Removed during Each Outage at Almaraz 1 [35,84]

Outage	Cleaning Method	Mass Removed from All SGs by Sludge Lancing, lb (kg)
EOC21	Sludge lancing and inner bundle lancing	136 (61.9)
EOC20	Sludge lancing and chemical cleaning	730 (332)
EOC19	Sludge lancing	344 (156)
EOC18	Sludge lancing	138 (62.7)
EOC17	Sludge lancing	71 (32)
EOC16	None	—
EOC15	Sludge lancing	148 (67.3)
EOC14	None	—
EOC13	Sludge lancing	126 (57.3)
EOC12	Sludge lancing	84 (38)
EOC11	None	SG Replacement Outage

C.4.2 Summary of Degradation Experienced

The following two instances of condenser tube in-leakage after steam generator replacement have been reported reported [87]:

- On January 7, 1997, a 15.9 L/hr leak occurred (action level 2). The maximum impurity concentrations were 100 ppb chloride, 200 ppb sulfate, and 50 ppb sodium.
- On January 16, 1997, a 50 L/hr leak occurred when decreasing power from mode 1 to mode 2 (no action level). The maximum impurity concentrations were 120 ppb chloride, 200 ppb sulfate, and 75 ppb sodium.

The steam generators at Almaraz 1 have exhibited denting in the cold and hot leg, top of tubesheet region in the latest 2 outages (EOC 19 and 20). The denting history is summarized in Table C-18.

Table C-18
Total New Tubes with Denting Indications at Almaraz 1 [35,86]

	EOC 19 (Apr 08)	EOC 20 (Oct 09)	EOC 21 (Jun 11)
% Tubes Inspected (Across All 3 SGs)	17.1%	55.9%	57.6%
Total New HL Denting	0	10	11
Total New CL Denting	28	1054	82
HL Circumferential SCC Indications	0	0	0
CL Circumferential SCC Indications	0	0	3

C.5 Almaraz Unit 2

C.5.1 Major Design and Operating Conditions

Almaraz Nuclear Power Plant Unit 2 (Almaraz 2) is a Westinghouse, 980 MWe rated, 3-loop plant in Spain that began commercial operation in 1983. The original steam generators were Westinghouse Model D3 steam generators with carbon steel, drilled-hole support plates and Alloy 600MA tubing. In 1997, the steam generators were replaced with KWU Model 61W/D3 replacement steam generators with austenitic stainless steel support grids, flow distribution baffle, and Alloy 800NG tubing [40,74].

The Alloy 800 used to tube the steam generators was nuclear grade (modified) and during fabrication, the 800NG tubes were cold pilgered, with a 3 minute 971°C (1780°F) bright anneal, and a 4% final cold draw. After bending, tubing was full OD glass bead, shot peened for ODSCC resistance, as discussed in Chapter 4 [74].

As of April 2011 the replacement steam generators have experienced approximately 11.5 EFPY [12,40].

C.5.1.1 Tubesheet Design

The Almaraz 2 replacement steam generators each have 5130 tubes of 0.75” diameter in a triangular pitch which are hydraulically expanded into the tubesheet to full depth [40]. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The crevice between the tubes and the tubesheet has a nominal depth of 3–6 mm, and the nominal annulus is 0.2 mm in thickness [35].

The tubesheet is made of forged low-alloy steel (A 508, Class 3, which is now referred to as SA-508 Grade 3, Class 1) [35,40]. The flow distribution baffles of Asco 1 and 2 are made of Type 347 stainless steel and since the designs of these units are very similar, it is likely that the flow distribution baffle of Almaraz 2 is also made of Type 347 stainless steel.

Tubesheet expansions in different units are discussed in Section 5.1.

C.5.1.2 Tube Support Design

The Almaraz 2 replacement steam generators have lattice bar tube supports. Both the lattice bar supports and anti-vibration bars are made of Type 321, austenitic stainless steel for Asco Units 1 and 2, and since the steam generator design of Almaraz 2 is very similar to these units, it is likely Almaraz 2's lattice bar supports and anti-vibration bars are also made of Type 321, austenitic stainless steel.

Tube support designs in different units are discussed in Section 5.2.

C.5.1.3 Balance of Plant Materials of Construction

The Almaraz 2 balance of plant had components made with copper-based alloys. The main condenser tubesheet was originally made of 90/10 Cu/Ni and the tubes were originally made of admiralty brass. However, the consenser was replaced with non-copper containing materials in 2009 [35]. The low and high pressure feedwater heaters are made of Type 304L, stainless steel. The moisture separator reheaters were made of ferritic stainless steel, and were replaced in 2009 [40,84].

C.5.1.4 Operating Temperature

Almaraz 2 is currently operating at a nominal hot leg temperature of 621°F and a nominal cold leg temperature of 553°F [40].

C.5.1.5 Primary Water Chemistry

Almaraz 2 uses a coordinated B-Li pH program.[22] The operating specifications (January 1997) are as follows [40,84]:

- Coordinated B-Li to pH 7.15
- Max [Li] of 3.5 ppm
- $[H_2]$ of 25–50 cm^3/kg (normally 35-50 cm^3/kg)

C.5.1.6 Secondary Water Chemistry

The cooling source for Almaraz 2 is closed-pond water [40]. The circulating water has the following dissolved solids concentrations [35]:

- Calcium ~112 ppm
- Magnesium ~38.4 ppm
- Sodium ~145 ppm
- Potassium ~11 ppm
- Chlorine ~163 ppm

[22] These primary operating conditions were assumed based on those of Almaraz 1.

- Sulfate ~355 ppm
- Fluorine ~0.3 ppm
- Silica ~4.4 ppm

Almaraz 2 does not have deep bed condensate polishers or a condensate filler-demineralizer] Steam generator blowdown flows through a collection of cationic, weak and strong anionic, and two mixed bed resins prior to recovery[23] [35,84].

The Almaraz 2 secondary system chemistry is maintained with the following feedwater chemistry targets [36,35]:

- 27 – 29 µS/cm Specific conductivity. Prior to the current cycle (Cycle 20), the target specific conductivity was 21 µS/cm.
- 11 ppm Ammonia (since June 2009).
- 100 ppb Hydrazine.

No boric acid treatments (either online or offline) have been used since SG replacement. Likewise, active molar ratio control has not been used since SG replacement.

The concentration of iron in the feedwater has been reported to fall in the range 1.5–2 ppb around June 2009, and this value was not significantly impacted by an increase in ammonia concentration to 11 ppm [36].

A summary of the sludge lancing history at Almaraz 2 is presented in Table C-19. A chemical cleaning was executed during the November 2010 outage (EOC 19) [35,36].

[23] It was assumed that Almaraz 2 has the same blowdown recovery system as Almaraz 1.

Table C-19
Masses of Deposits Removed during Each Outage at Almaraz 2 [35,36,40]

Outage	Cleaning Method	Mass Removed from All SGs by Sludge Lancing, lb (kg)
EOC19	Sludge lancing and chemical cleaning	1120 (509.1)
EOC18	Sludge lancing	161 (73.2)
EOC17	Sludge lancing	269 (122)
EOC16	Sludge lancing	174 (79.1)
EOC15	None	—
EOC14	Sludge lancing	141 (64.1)
EOC13	None	—
EOC12	Sludge lancing	128 (58.2)
EOC11	Sludge lancing	157 (71.4)
EOC10	None	SG Replacement Outage

C.5.2 Summary of Degradation Experienced

In 1998, during the startup of the 12th cycle, approximately 223 kg of the cationic resin ingressed into the secondary system of Almaraz 2. During this chemistry transient, the maximum sulfate concentration and cationic conductivity in the steam generator blowdown was ~30 ppm and 250 uS/cm, respectively. It was estimated that approximately 57 kg of the cationic resin decomposed in the steam generators and 166 kg of the cationic resin was removed from the secondary system [88].

Almaraz 2 has had one instance of condenser tube in-leakage after steam generator replacement: On February 10, 2000, a 3.0 L/hr leak occurred (no action level). The maximum impurity concentrations were 30 ppb chloride, 70 ppb sulfate, and 24 ppb sodium. Additionally, prior to startup in March of 2006, water from the reservoir (closed loop pond water) went through the secondary side. The maximum impurity concentrations were 330 ppb chloride, 1697 ppb sulfate, and 340 ppb sodium [87].

The steam generators at Almaraz 2 have exhibited denting in the cold and hot leg, top of tubesheet region in the latest 4 outages (EOC 16–20). In the last 2 outages (EOC 19 and 20), the steam generators have exhibited circumferential cracking indications in dented tubes in both the hot and cold legs. All tubes with cracking indications were plugged. The denting and degradation history are summarized in Table C-20 and Table C-21 [35,36].

Note that the number of new denting indications was calculated using the following equation:

$$d_n = D_n - D_{n-1} + k_{n-1} \qquad \text{Eq. C-3}$$

Where d_n is the number of new denting indications in the nth outage, D_n is the total number of denting indications in the nth outage, and k_n is the total number of denting indications plugged in the nth outage.

The number of cumulative denting indications was calculated using the following equation:

$$C_n = \sum_{i=1}^{n} d_i \qquad \text{Eq. C-4}$$

Where C_n is the cumulative denting indications in the nth outage and d_i is the number of new denting indications in the nth outage calculated from Equation [C-3].

Table C-20
Total New Tubes with Denting and Cracking Indications at Almaraz 2 [35,36]

	EOC 16 (Apr 06)	EOC 17 (Oct 07)	EOC 18 (Apr 09)	EOC 19 (Nov 10)
% Tubes Inspected (Across All 3 SGs)	13.5%	16.8%	60.2%	69.3%
Total New HL Denting Indications	0	2	516	38
Total New CL Denting Indications	258	199	604	209
HL Circumferential SCC Indications	0	0	43	21
CL Circumferential SCC Indications	0	0	35	13

Table C-21
Cumulative Tubes Plugged or Repaired Due to Degradation at Almaraz 2 [35,36]

Degradation Mechanism[1]	EOC 16 (Apr 06)	EOC 17 (Oct 07)	EOC 18 (Apr 09)	EOC 19 (Nov 10)
PWSCC	0	0	0	0
Phosphate Wastage	0	0	0	0
Mechanical Wear due to Structural Components	0	0	1	1
Mechanical Wear due to Loose Parts	0	0	1	1
ODSCC at TTS Crevices	0	0	0	0
Deep Tubesheet Crevice ODSCC	0	0	0	0
TTS Denting and Related ODSCC[2,3]	0/258	0/459	78/1579	112/1826
Pitting	0	0	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.
2) (# of tubes plugged or repaired due to denting) / (# of tubes with denting indications)
3) Note that the total number of dented tubes may be less than these numbers since denting was observed on both the hot and cold legs.

D
OTHER UNITS

D.1 Atucha Unit 1

D.1.1 Major Design and Operating Conditions

Atucha Nuclear Power Plant Unit 1 (Atucha 1) is a 357 MWe rated, 2-loop PHWR in Argentina designed by Siemens that began commercial operation in 1974. The steam generators have 0.709" (18 mm) diameter Alloy 800NG tubing [40]. As of April 2011, the steam generators have experienced approximately 25.2 EFPY [12].

As discussed in Chapter 4, the Alloy 800 used to tube the steam generators was nuclear grade (modified) [20].

D.1.1.1 Tubesheet Design

Each steam generator has 3945 tubes of 0.709" (18 mm) diameter in a triangular pitch, which are mechanically rolled into the tubesheet. The expansion process includes two mechanical rolls: one near the bottom and one near the top of the tubesheet. The tubesheet is made of forged low alloy steel [40].

Tubesheet expansions in different units are discussed in Section 5.1.

D.1.1.2 Tube Support Design

Each steam generator has austenitic stainless steel support grids [20].

Tube support designs in different units are discussed in Section 5.2 [20].

D.1.1.3 Balance of Plant Materials of Construction

The main condenser tubing is made of admiralty brass and the tubesheet is made of carbon steel with a bitumen coating. The feedwater heaters and moisture separator reheaters are made of carbon steel [40].

D.1.1.4 Operating Temperature

Atucha 1 currently operates at a nominal hot leg temperature of 306°C (582°F) and a nominal cold leg temperature of 272°C (521°F) [40].

D.1.1.5 Primary Water Chemistry

Atucha 1 is a pressurized heavy water reactor.

D.1.1.6 Secondary Water Chemistry

The ultimate cooling source for Atucha 1 is water from the Paraná de las Palmas River. Atucha 1 recovers blowdown and uses a feedwater (deaerator) tank for continuous deaerating of the condensate [11].

Atucha 1 uses low pH phosphate chemistry for the secondary chemistry control [11].

D.1.2 Summary of Degradation Experienced

Atucha 1 has had 5 tube leaks: 1 in 1983, 2 in 1987, and 2 in 1987 [20,40].

A summary of the tubes plugged due to degradation is presented in Table D-1 [11,20].

Table D-1
Cumulative Tubes Plugged or Repaired Due to Degradation at Atucha 1[1]

Degradation Mechanism[1]	2000	2006
PWSCC	0	0
Phosphate Wastage	6	18
Mechanical Wear due to Structural Components	165	167
Mechanical Wear due to Loose Parts	2	7
ODSCC at TTS Crevices	0	0
Deep Tubesheet Crevice ODSCC	0	0
TTS Denting and Related ODSCC	0	0
Pitting	0	0

1) Does not include tubes preventively plugged for corrosion or tubes plugged for reasons other than degradation. Does include tubes preventively plugged due to the proximity of a foreign object.

D.2 Narora Unit 1 (NAPS 1)

Narora Nuclear Power Plant Unit 1 is a 235 MWe rated, 2-loop plant in India that began commercial operation in 1991 [68]. As of April 2011, the steam generators have experienced approximately 10.7 EFPY [12].

Narora Unit 1 is a pressurized heavy water reactor. The steam generators have Alloy 800NG tubing [68].

D.2.1.1 Operating Temperature

Narora Unit 1 currently operates at a nominal hot leg temperature of 293.4°C (560°F) and a nominal cold leg temperature of 249°C (480°F) [68].

D.3 Narora Unit 2 (NAPS 2)

Narora Nuclear Power Plant Unit 2 is a 235 MWe rated, 2-loop plant in India that began commercial operation in 1992 [68]. As of April 2011, the steam generators have experienced approximately 10.5 EFPY [12].

Narora Unit 2 is a pressurized heavy water reactor. The steam generators have Alloy 800NG tubing [68].

D.3.1.1 Operating Temperature

Narora Unit 2 currently operates at a nominal hot leg temperature of 293.4°C (560°F) and a nominal cold leg temperature of 249°C (480°F) [68].

D.4 Kakrapar Unit 1

Kakrapar Nuclear Power Plant Unit 1 is a 235 MWe rated, 2-loop plant in India that began commercial operation in 1993 [68]. As of April 2011, the steam generators have experienced approximately 10.0 EFPY [12].

Kakrapar Unit 1 is a pressurized heavy water reactor. The steam generators have Alloy 800NG tubing [68].

D.4.1.1 Operating Temperature

Kakrapar Unit 1 currently operates at a nominal hot leg temperature of 293°C (559°F) and a nominal cold leg temperature of 249°C (480°F) [68].

D.5 Kakrapar Unit 2

Kakrapar Nuclear Power Plant Unit 2 is a 235 MWe rated, 2-loop plant in India that began commercial operation in 1995 [68]. As of April 2011, the steam generators have experienced approximately 11.3 EFPY [12].

Kakrapar Unit 2 is a pressurized heavy water reactor. The steam generators have Alloy 800NG tubing [68].

D.5.1.1 Operating Temperature

Kakrapar Unit 2 currently operates at a nominal hot leg temperature of 293°C (559°F) and a nominal cold leg temperature of 249°C (480°F) [68].

D.6 Qin Shan I

Qin Shan I is a 310 MWe rated, 2 loop plant in China that began commercial operation in 1994 [89]. The two steam generators have 2977 tubes made of Alloy 800 nuclear grade (modified) tubing [90].

Qin Shan 1 is currently operating at a nominal hot leg temperature of 315.2°C (599°F) and a nominal cold leg temperature of 288.8°C (552°F) [89].

D.7 Chashma Unit 1 (CHASNUPP 1)

D.7.1 Major Design and Operating Conditions

Chashma Unit 1 is a CNNC, 325 MWe rated, 2-loop plant in Pakistan that began commercial operation in 2000 [68]. Chashma Unit 1 is currently in the fourth cycle, and as of April 2011, has experienced approximately 7.7 EFPY [12].

The steam generators have Alloy 800NG tubing [12].

D.7.1.1 Operating Temperature and Pressure

Chashma Unit 1 is currently operating at a nominal hot leg temperature of 315.5°C (600°F) and a nominal cold leg temperature of 288.5°C (551°F), with an operating pressure of 15.2 MPa [89].

D.8 Rajasthan Unit 3

Rajasthan Nuclear Power Plant Unit 3 is a 220 MWe, 2-loop rated plant in India that began commercial operation in 2000 [68]. As of April 2011, the steam generators had experienced approximately 8.0 EFPY [12].

The steam generators have Alloy 800NG tubing. Rajasthan Unit 3 is a pressurized heavy water reactor [68].

D.8.1.1 Operating Temperature

Rajasthan Unit 3 currently operates at a nominal hot leg temperature of 293°C (559°F) and a nominal cold leg temperature of 249°C (480°F) [68].

D.9 Rajasthan Unit 4

Rajasthan Nuclear Power Plant Unit 4 is a 220 MWe, 2-loop rated plant in India that began commercial operation in 2000 [68]. As of April 2011, the steam generators had experienced approximately 7.7 EFPY [12].

The steam generators have Alloy 800NG tubing [68].

Rajasthan Unit 3 is a pressurized heavy water reactor.

D.9.1.1 Operating Temperature

Rajasthan Unit 4 currently operates at a nominal hot leg temperature of 293°C (559°F) and a nominal cold leg temperature of 249°C (480°F) [68].

D.10 Kaiga Unit 1

Kaiga Nuclear Power Plant Unit 1 is a 235 MWe rated, 2-loop plant in India that began commercial operation in 2000 [68]. As of April 2011, the steam generators have experienced approximately 7.2 EFPY [12].

Kaiga Unit 1 is a pressurized heavy water reactor. The steam generators have Alloy 800NG tubing [68].

D.10.1.1 Operating Temperature

Kaiga Unit 1 currently operates at a nominal hot leg temperature of 293°C (559°F) and a nominal cold leg temperature of 249°C (480°F) [68].

D.11 Kaiga Unit 2

Kaiga Nuclear Power Plant Unit 2 is a 235 MWe rated, 2-loop plant in India that began commercial operation in 2000 [68]. As of April 2011, the steam generators have experienced approximately 7.6 EFPY [12].

Kaiga Unit 2 is a pressurized heavy water reactor. The steam generators have Alloy 800NG tubing [68].

D.11.1.1 Operating Temperature

Kaiga Unit 2 currently operates at a nominal hot leg temperature of 293°C (559°F) and a nominal cold leg temperature of 249°C (480°F) [68].

D.12 Kaiga Unit 3

Kaiga Nuclear Power Plant Unit 3 is a 235 MWe rated, 2-loop plant in India that began commercial operation in 2007 [68]. As of April 2011, the steam generators have experienced approximately 1.8 EFPY [12].

Kaiga Unit 2 is a pressurized heavy water reactor. The steam generators have Alloy 800NG tubing [68].

D.12.1.1 Operating Temperature

Kaiga Unit 3 currently operates at a nominal hot leg temperature of 293°C (559°F) and a nominal cold leg temperature of 249°C (480°F) [68].

D.13 Tarapur Unit 3 (TAPP 3)

Tarapur Atomic Power Plant Unit 3 is a 540 MWe rated, 2-loop plant in India that began commercial operation in 2006 [68]. As of April 2011, the steam generators have experienced approximately 2.8 EFPY [12].

Tarapur Unit 3 is a pressurized heavy water reactor. The steam generators have Alloy 800NG tubing [68].

D.13.1.1 Operating Temperature

Tarapur Unit 3 currently operates at a nominal hot leg temperature of 304°C (579°F) and a nominal cold leg temperature of 260°C (500°F) [68].

D.14 Tarapur Unit 4 (TAPP 4)

Tarapur Atomic Power Plant Unit 4 is a 540 MWe rated, 2-loop plant in India that began commercial operation in 2005 [68]. As of April 2011, the steam generators have experienced approximately 3.0 EFPY [12].

Tarapur Unit 4 is a pressurized heavy water reactor. The steam generators have Alloy 800NG tubing [68].

D.14.1.1 Operating Temperature

Tarapur Unit 4 currently operates at a nominal hot leg temperature of 304°C (579°F) and a nominal cold leg temperature of 260°C (500°F) [68].

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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