IAEA-TECDOC-1668

Assessment and Management of Ageing of Major Nuclear Power Plant Components Important to Safety: Steam Generators

IAEA
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IAEA-TECDOC-1668

ASSESSMENT AND MANAGEMENT OF AGEING OF MAJOR NUCLEAR POWER PLANT COMPONENTS IMPORTANT TO SAFETY: STEAM GENERATORS

2011 UPDATE

INTERNATIONAL ATOMIC ENERGY AGENCY
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FOREWORD

At present there are over four hundred forty operational nuclear power plants (NPPs) in IAEA Member States. Ageing degradation of the systems, structures of components during their operational life must be effectively managed to ensure the availability of design functions throughout the plant service life. From the safety perspective, this means controlling, within acceptable limits, the ageing degradation and wear-out of plant components important to safety so that adequate safety margins remain, i.e. integrity and functional capability in excess of normal operating requirements.

This IAEA-TECDOC is one in a series of reports on the assessment and management of ageing of the major NPP components important to safety. The reports are based on experience and practices of NPP operators, regulators, designers, manufacturers, and technical support organizations.

The current practices for the assessment of safety margins (fitness for service) and the inspection, monitoring and mitigation of ageing degradation of selected components of Canada deuterium-uranium (CANDU) reactor, boiling water reactor (BWR), pressurized water reactor (PWR), and water moderated, water cooled energy reactor (WWER) plants are documented in the reports. These practices are intended to help all involved directly and indirectly in ensuring the safe operation of NPPs, and also to provide a common technical basis for dialogue between plant operators and regulators when dealing with age related licensing issues. Since the reports are written from a safety perspective, they do not address life or life cycle management of the plant components, which involves the integration of ageing management and economic planning. The target audience of the reports consists of technical experts from NPPs and from regulatory, plant design, manufacturing and technical support organizations dealing with specific plant components addressed in the reports.

The component addressed in the present publication is the steam generator of the PWR, WWER and CANDU nuclear power plants.

The objective of this report is to update and supersede IAEA-TECDOC-981 in order to provide current ageing management guidance for PWR, WWER and CANDU steam generators to all involved in the operation and regulation of nuclear power plants and thus to help ensure steam generator integrity in IAEA Member States throughout their entire service life.

The IAEA wishes to thank the participants for their contributions. The IAEA officers responsible for this publication were K.S. Kang and L. Kupca of the Division of Nuclear Power.

CONTENTS

1 BACKGROUND

1.1 INTRODUCTION

Managing the safety aspects of nuclear power plant (NPP) ageing requires implementation of effective programmes for the timely detection and mitigation of ageing degradation of plant systems, structures and components (SSCs) important to safety, so as to ensure their integrity and functional capability throughout plant service life. General guidance on NPP activities relevant to the management of ageing is given in the IAEA Safety Standards (NUSS) Code on the Safety of Nuclear Power Plants: Operation (Safety Series No. 50-C-O, Rev.1) and associated Safety Guides on ageing management (NS-G-2.12), in-service inspection (50-SG-O2), maintenance (50-SG-O7, Rev.l) and surveillance (50-SG-O8, Rev.l).

The associated Safety Guides provide further guidance on NPP programmes and activities that contribute to timely detection and mitigation of ageing degradation of SSCs important to safety.

The Safety Guide on 'Ageing Management for Nuclear Power Plants' provides recommendations for managing ageing of SSCs, including recommendations on key elements of effective ageing management. This Safety Guide deals with the establishment, implementation and improvement of ageing management programme, and mainly focuses on managing physical ageing of SSCs important to safety. It also provides recommendations on safety aspects of managing obsolescence and on the application of ageing management for long term operation. Organizational and procedural aspects of establishing and implementing an NPP programme of preventive and remedial maintenance to achieve design performance throughout the operational life of the plant are covered in the Maintenance Safety Guide. Guidance and recommendations on surveillance activities, for SSCs important to safety, (i.e. monitoring plant parameters and systems status, checking and calibrating instrumentation, testing and inspecting SSCs, and evaluating results of these activities) are provided in the Surveillance Safety Guide. The above Safety Guides provide general programmatic guidance, but do not give detailed technical advice for particular SSCs.

Ageing management specific programmatic guidance provided in Technical Reports Series No. 338 'Methodology for the Management of Ageing of Nuclear Power Plant Components Important to Safety' served as a basis for the development of component specific technical documents (IAEA-TECDOCs) on the Assessment and Management of Ageing of Major NPP Components Important to Safety. This publication on Steam Generators Ageing Management supersedes one of such IAEA-TECDOCs.

The steam generators in the pressurized water reactor (PWR), Canada deuterium-uranium (CANDU) reactor, and russian water moderated, water cooled energy reactor (WWER) plants are large heat exchangers that use the heat from the primary reactor coolant to make steam in the secondary side to drive turbine generators. A typical plant has two to six steam generators per reactor, although some units have up to twelve steam generators. The steam generators are shell and tube heat exchangers each with several thousands of tubes. The primary reactor coolant passes through the tubes and boils water on the outside of the tubes (secondary side) to make steam. However, the primary reactor coolant is at a higher pressure than the secondary coolant, so any leakage from defects in the tubes or in the WWER collectors is from the primary to the secondary side, and rupture of the heat exchanger tubing or the WWER collectors can result in release of radioactivity to the environment outside the reactor containment through the pressure relief valves in the secondary system.

The thin walled steam generator tubes are, therefore, an important part of the reactor coolant pressure boundary and, in fact, can comprise well over 60% of the area of the total primary system pressure-retaining boundary. To act as an effective barrier, this tubing must be essentially free of cracks, perforations, and general deterioration. However, widespread degradation of the steam generator tubes has occurred at a number of plants. As a result, many steam generator tubes have been removed from service by plugging or repaired with sleeves. Other tubes with small defects remain in service.

Certain events, such as a sudden break in the steam line, can lead to rapid depressurization of the secondary coolant system. The pressure difference across the tubing walls generated during these accidents may result in simultaneous leakage or rupture of a number of steam generator tubes or rupture of a WWER collector when an active degradation mechanism has damaged a large number of tubes or the collector. Simultaneous leakage or rupture of several tubes or a WWER collector can lead to a plant transient which is difficult to control and radioactivity levels released to the environment which may exceed site limits. The sudden rupture of several steam generator tubes or a WWER collector also results in a rapid depressurization of the primary coolant system and possibly may uncover the core and cause core melting.

Steam generator performance is important to nuclear power plant safety. For example, the various nuclear power plants in the United States of America have a core damage frequency which ranges from a low of 1×10^{-6} per reactor year to about 5×10^{-4} per reactor year. Steam generator tube rupture accidents are relatively small contributors to these values, but are significant risk due to rupture of the primary circuit envelope. A review of 20 US PWR Individual Plant Examinations (IPEs) has shown that the risk associated with steam generator tube ruptures can be as high as 75% of the total plant risk. This risk for significant accidents can be induced by operational transients and rare events with degraded steam generator tubes, which could lead to core melt [1].

To summarize, the major safety function of the steam generator is to act as a barrier between the radioactive primary side and the non-radioactive secondary side. Any degradation mechanism, which impairs this function, i.e. which may lead to either a single or multiple tube rupture or to simultaneous failure (leakage) of several tubes under certain accident conditions or failure of a WWER collector, is a significant safety concern. There is always some risk associated with the operation of steam generators with respect to the safety concerns mentioned above. This IAEA-TECDOC describes the various approaches, practices and requirements used in different countries to obtain a risk of acceptable level.

1.2 OBJECTIVE

The objective of this IAEA-TECDOC is to document the current practices for the assessment and management of the ageing of nuclear power plant steam generators. The IAEA-TECDOC emphasizes safety and engineering aspects and also provides information on current inspection, monitoring and maintenance practices for managing ageing of steam generators.

The underlying objective of this IAEA-TECDOC series is to ensure that the information on the current assessment methods and ageing management techniques is available to all involved, directly and indirectly, in the operation of nuclear power plants in the IAEA Member States.

The target audience includes nuclear power plant operators, regulators, technical support organizations, designers, and manufacturers.

1.3 SCOPE

This IAEA-TECDOC documents current practices for the assessment and management of ageing of the following types of steam generators used in water cooled nuclear power plants: (a) vertical tube sheet boiling steam generators, commonly known as ‘recirculating vertical U tube steam generators’ (b) vertical/tube sheet superheated steam generators, commonly known as ‘once through steam generators,’ and (c) horizontal/collector boiling steam generators used in WWER reactors.

The steam generator subcomponents discussed in this publication are those susceptible to ageing damage and whose consequence of failure have a significant safety impact as discussed in Section 1.1; the steam generator tubes, tube sheets or collectors, plugs (tube and tube sheet), and sleeves (i.e. components whose failure impairs the primary to secondary pressure boundary). In addition, this IAEA-TECDOC also discusses two other subcomponents: feedwater nozzles and shell girth welds. These components have experienced significant degradation in some plants but their failure is a secondary side pressure boundary failure (affects conventional safety) and does not immediately lead to any release of radioactivity.

1.4 STRUCTURE

The steam generator designs are discussed in Section 2. The design bases for the components of interest to steam generator ageing are presented in Section 3. The stressors, susceptible sites, and failure modes associated with the various steam generator degradation mechanisms are presented in Section 4. These degradation mechanisms include primary water stress corrosion cracking (PWSCC; also called inner-diameter stress corrosion cracking: ID-SCC), and secondary side or outer-diameter stress corrosion cracking (OD-SCC); fretting, wear, and thinning; pitting; denting; high cycle fatigue; wastage; erosion-corrosion; and corrosion fatigue. Operational guidelines aimed at preventing or minimizing age related degradation of steam generators are discussed in Section 5. Tubing inspection requirements and technologies are discussed in Section 6. Fitness for service guidelines in various countries are presented in Section 7. Mitigation, repair, and replacement technologies are discussed in Section 8. The IAEA-TECDOC concludes, in Section 9, with guidelines for a systematic steam generator ageing management programme.

2 STEAM GENERATOR DESCRIPTIONS

This section describes the different designs for currently operating steam generators. Recirculating steam generators (RSGs), designed by Westinghouse (USA), Combustion Engineering (USA), Framatome/AREVA NP (France), Mitsubishi Heavy Industries (Japan), Siemens (Germany), Doosan (Republic of Korea) are described first. The Canadian designs are discussed next with the Babcock & Wilcox (USA) once through steam generator design and the Russian (WWER) designs completing the section. Emphasis is placed on the design aspects and fabrication methods, which may affect steam generator degradation.

2.1 PWR RECIRCULATING STEAM GENERATORS

2.1.1 General common description

In RSG, the primary system coolant flows through U tubes with a tube sheet at the bottom of the generator and U bends at the top of the tube bundle (see Figure 2.1). Primary coolant enters the steam generator usually at 315–330°C on the hot leg side and leaves at about 288°C on the cold leg side. Pressurized heavy water reactors (PHWRs) and older PWR plants have lower temperatures. The secondary system water (feedwater) is fed through a feedwater nozzle, to a feedring, into the downcomer, where it mixes with recirculating water draining from the moisture separators. This downcomer water flows to the bottom of the steam generator, across the top of the tube sheet, and then up-wards through the tube bundle, where steam is generated. About 25% of the secondary bulk water is converted to steam as it passes through the tube bundle up-wards, the remainder is recirculated.

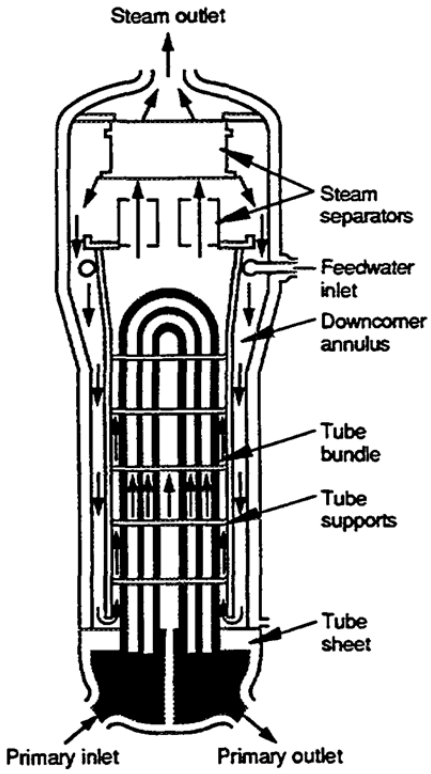


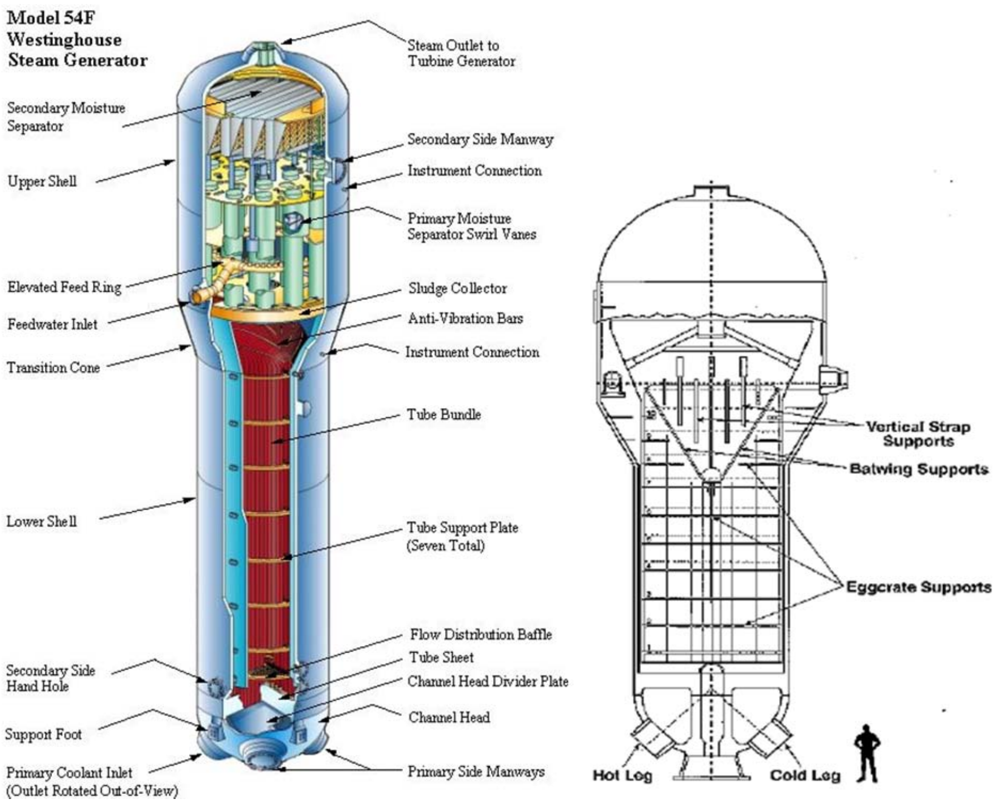
Figure 2.1. Schematic PWR recirculating steam generator cross section. Update figure for USA AP1000 as an example [2] (see Section 2.1.2.1).

Some RSGs include economizer sections (preheaters), which are separate sections in the steam generator near the cold leg outlet, shown in Figure 2.2 and Figure 2.3. The feedwater flows into the preheater through a nozzle located in the lower part of the vessel and there is no feedring in these steam generators. Auxiliary feedwater is injected through a separate nozzle in the upper part of the vessel. Heat from the primary fluid leaving the steam generator is used to preheat the feedwater to near the saturation temperature before it is mixed with the recirculating steam generator secondary bulk water.

2.1.2 Steam generator models in the US (Westinghouse and Combustion Engineering)

In Figure 2.2 schematic design of the steam generators model 54F (Westinghouse) and model system 80 of Combustion Engineering are given as examples. The typical parameters (design features) of the eleven Westinghouse models and two Combustion Engineering steam generator models are summarized in Table 2.1.

In the following section the steam generator model Delta 125 that is used in Westinghouse Advanced PWR 1000 (AP 1000) is described.



(a) *(b)*

Figure 2.2. Schematic design of US steam generators (a) Westinghouse Model 54F [3] (b) Combustion Engineering model system 80.

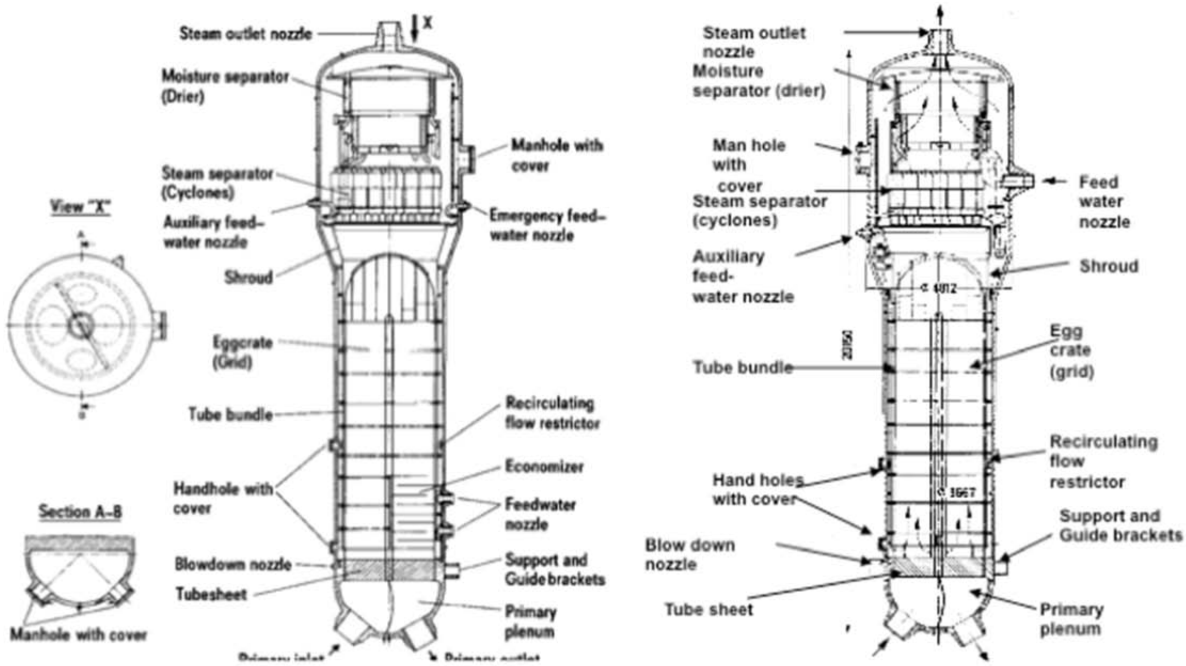


Figure 2.3. Schematic design of Siemens steam generator models with (left) and without internal economizer (right) (Courtesy of T. Schwarz, AREVA).

TABLE 2.1. TYPICAL US STEAM GENERATOR MODELS AND THEIR PARAMETERS

Manufacturer type and model	**Westinghouse (recirculating)**						
	24	27	33	44[a]	51 A-M[a,g]	D2/D3[g]	D4[f]
Heat transfer area [ft^2][b]	24 834	27 700	33 340	44 500	51 500	48 000	47 000
No of tubes	2604	3794	2604	3260	3388	4674	4578
No of row - 1 tubes	82	100	82	92	94	114	114
Tube pattern	square	square	square	square	square	square	square
Tube spacing [in]	12.187	1.026 or 1.031	1.25	1.200 or 1.234	1.281	1.063	1.063
Tube dimensions [in]	0.875 × 0.050	0.750 × 0.055	0.875 × 0.050	0.875 × 0.050	0.875 × 0.050	0.750 × 0.043	0.750 × 0.043
Tubing material	Alloy 600	Alloy 600	Alloy 600	Alloy 600	Alloy 600	Alloy 600	Alloy 600
Tubing heat treatment	Mill annealed	Mill annealed	Mill annealed	Mill annealed	Mill annealed	Mill annealed	Mill annealed
Tubesheet expansion method	Part depth rolled	Part depth rolled	Part depth rolled	Part depth rolled	Part depth rolled	Part depth rolled	Part depth rolled
Tubesheet crevice depth [in][c]	18.25	18	18	18, 19 or 20	18, 18.75 or 19[d]	None	None
Tube support type	Drilled hole	Drilled hole	Drilled hole	Drilled hole	Drilled hole	Drilled hole	Drilled hole
Tube support material	Carbon steel	Carbon steel	Carbon steel	Carbon steel	Carbon steel	Carbon steel	Carbon steel
Preheater type	None	None	None	None	None	Split flow	Counter flow Expanded Preheater Tubes
Flow distribution baffles	None	None	None	None	None[g]	D2 no D3 yes	Yes

[a] Replacement models 44F 51F and 54F use hydraulically expanded, thermally treated Alloy 600 tubing and 405 stainless steel tube support plates except for the model 54Fs at D C Cook and Indian Point Unit 3 which have thermally treated Alloy 690 tubing The replacement models generally match the heat transfer area of the steam generators they replaced except for the 54 Fs with Alloy 690 tubing which are slightly larger than the original 51s due to the slightly lower thermal heat transfer properties at the Alloy 690 material vis-a-vis the Alloy 600 material.

[b] 1 ft^2 = 0 093 m^2, 1 in = 25.4 mm.

[c] Later model 51s used full depth rolled or explosively expanded tubes The tube sheet thickness ranges from 525 to 610 mm.

TABLE 2.1. TYPICAL US STEAM GENERATOR MODELS AND THEIR PARAMETERS (cont.)

Manufacturer type and model	**Westinghouse (recirculating)**				**B & W once through**	**Combustion Engineering (Recirculating)**	
	D5	E	F	∆75	177	67	80
Heat transfer area [ft^2]	47 000	50 000	50 000	75 180	132 500	90 700	N/A
No of tubes	4570	4864	5626	6307	15 531	8519	11 012
No of row - 1 tubes	114	120	122	70	-	167	N/A
Tube pattern	Square w/ T slot	Square w/ T slot	Square w/ T slot	Triangle	Triangle	Triangle	Triangle
Tube spacing [in][b]	1.063	1.080	0.980	0.980	0.875	0.974 1 00	1.000
Tube dimensions [in]	0.750 × 0.043	0.500 × 0.043	0.688 × 0.040	0.688 × 0.040	0.625 × 0.034	0.750 × 0.048	0.750 × 0.042
Tubing material	Alloy 600	Alloy 600	Alloy 600	Alloy 600	Alloy 600	Alloy 600	Alloy 600
Tubing heat treatment	Thermally Treated	Mill–annealed or Thermally treated	Thermally treated	Thermally treated	Mill-annealed	Mill-annealed	Mill-annealed
Tubesheet expansion method	Hydraulic	Full depth rolled or hydraulic	Hydraulic	Hydraulic	Partial depth rolled	Explosive	Explosive
Tubesheet crevice depth [in][c]	None	None	None	None	22	None	None
Tube support type	Broached quatrefoil	Drilled	Broached quatrefoil	Broached trefoil	Broached trefoil	Egg crate/ vertical	Egg crate/ vertical
Tube support material	Stainless steel	Carbon or stainless	405 stainless Steel	405 stainless Steel	Carbon or MnMo steel	Carbon steel	Stainless steel
Preheater type	Counter flow, expanded pre-heater tubes	Counter flow, expanded pre-heater tubes	None	None	None	None	Axial flow
Flow distribution baffles	Yes	Yes	Yes	Broached Plate	No	None	Yes

[d] For model 51s with part depth rolled tubes only

[e] The crevice radial gaps varied from 0.005 to 0.011 inches except in the model 4 where they were 0.0135–0.0175 inches

[f'] Some later model 51 s were equipped with alloy steel tube support plates and flow distribution baffles

[g] The row 1 and 2 tubes in most model 51 D2/D3, D4 and E steam generators have been u bend heat treated and shot or roto peened for added resistance to PWSCC

2.1.2.1 Delta 125 steam generator

Westinghouse Advanced PWR type AP1000 unit uses two Delta 125 steam generators, with each steam generator rated at 1707.5 MW_{th} (see Figure 2.1). The Delta 125 steam generator is a vertical-shell U tube evaporator with integral moisture separating equipment. The tubes are fabricated from thermally treated nickel base Alloy 690 (Alloy 690TT). Support of the tubes is provided by ferritic stainless steel support plates. The holes in the tube support plates are broached with hole geometry (broached hole TSP) to promote high velocity flow along the tube. The thermal sleeve and feedwater nozzles are fabricated from Alloy 690TT material, which is very resistant to erosion and corrosion. An improved design is to eliminate the conditions linked to the occurrence of steam generator water hammer. The design used 210 modular primary separators with a riser diameter of 7 inches. Double hook and pocket dryers are employed, which provide a convoluted surface for collecting moisture. The steam quality is increased to a designed minimum of 99.75 per cent. A sludge collector located at the lower level of the primary separator risers provides a passive region for sludge settling before the fluids reach the tube support plates and secondary surface of the tube plate.

Sludge collector is a multi-layered box in round shape. It is located at the bottom of steam separator deck above bend section of tube bundle with inlet at box centre and outlet at brim. Some of the recirculation water, joined with feed water, could get into sludge collector, and flow in radius direction. With the flow velocity decreasing, the sludge particles carried by the water could settle down by gravity, which could be removed at outage. Sludge collector is an inactive device with compacted structure, which has little impact on steam generator structure and thermal-hydraulics. It could run during the plant operation to collect the sludge momently with high efficiency and reliability. With sludge collector, the sludge deposits on the tube sheet are greatly reduced, which could be greatly helpful to prevent the tubes from corrosion. Steam generator power is 1707.5 MW_{th}. The design pressures of primary and secondary side are 17.13 MPa and 8.17 MPa respectively. The design temperature of steam side is 315.5°C, and the primary inlet temperature is 321°C.

2.1.3 Siemens steam generator models

Schematic design of the Siemens steam generators with and without economizer is shown in Figure 2.3. Several steam generator models designed by Siemens with their design features and typical parameters are summarized in Table 2.2.

2.1.4 Mitsubishi Heavy Industry steam generator models

The steam generator models designed by Mitsubishi Heavy Industry (MHI) with their design features and typical parameters are summarized in Table 2.3.

2.1.5 Korean recirculating steam generators

The APR1400 steam generator is a vertical shell and U tube evaporator with integral economizer and moisture separating equipment, and the uprated and evolutionary type from the recently operating steam generator in the Republic of Korea (see Figure 2.4). Reactor coolant enters the inlet plenum through the primary inlet nozzle at 291–324°C, flows up through the tube sheet and U bend tubing, and returns through the tube sheet to the outlet plenum and exits through the two outlet nozzles at 291°C.

Feedwater with 232°C enters the economizer region at the tube sheet on the cold leg side of the tube bundle, which is separated from the lower evaporator region by the secondary divider plate. Above the flow distribution plate, feedwater flows upward in axial counter flow, being heated by forced convection to near saturation conditions at the top of the economizer. At this elevation, heated feedwater mixes with cold leg downcomer water and secondary fluid from the hot leg side in the evaporator section of the tube bundle. Heat transfer by nucleate boiling occurs in the evaporator as the secondary fluid flows upward continuously increasing in steam quality. Steam separators mounted on a deck plate at the top of the tube bundle shroud separate the steam from the two phase mixture. Separated steam (about 25%) flows through the dryers and out the steam nozzles while the water (about 75%) returns to the downcomer. The 10% of total feedwater flow is mixed with the recirculated water in the downcomer to condense any steam carry-under, which may exist.

TABLE 2.2. TYPICAL SIEMENS RECIRCULATING STEAM GENERATOR MODELS AND THEIR PARAMETERS

Manufacturer type and model	Man-GHH Obrigheim (Orig.)	MAN-GHH Obrigheim (Repl.)	Balcke Stade	Babcock Biblis A	[h] Standard with preheater	MAN-GHH Konvoy [J]	[14] Replacement SGs for 51051M/D3
Heat transfer area [m^2]	2750	3070	2930	4510	5386	5427	5105/6103/7155 [l]
No of tubes	2605	3010	2993	4060	4086	4118	5130/5428 [m]
No of row - 1 tubes	81	46	49	55	48	54	57/59 [m]
Tube pattern	Rectangular	Triangular	Triangular	Triangular	Triangular	Triangular	Triangular
Tube spacing [mm]	27.9 × 28.8	29.0	29.3	30.0	30.0	30.0	26.164
Tube dimensions [mm]	22 × 1.23 (1.5) [a]	22 × 1.23	22 × 1.23	22 × 1.23	22 × 1.23	22 × 1.23	19.05 × 1.09
Tubing material	Alloy 600MA	Alloy 800 NG [p]	Alloy 800 NG [p]	Alloy 800 NG [p]	Alloy 800 NG [p]	Alloy 800 NG [p]	Alloy 690TT [n], Alloy 800 NG [p]
Tubing heat treatment	Mill annealed	[g]	[g]	[g]	[g]	[g]	Alloy 690TT, Alloy 800 NG [p] [g]
Tubesheet expansion method	Part depth rolled (3 location)	Part depth rolled (both ends)	Part depth rolled (both ends)	Part depth rolled (both ends)	Part depth rolled (both ends)	Part depth rolled (both ends)	Full depth hydraulic plus Part depth rolled (both ends)
TS crevice depth [mm]	None	None	None	None	None	None	None
Tube support type	Egg crate [b]	Egg crate [c]	Egg crate [d]	Egg crate [c]	Egg crate [c]	Egg crate [c]	Egg crate [f]
Tube support material	Stainless steel	Stainless steel	Stainless steel	Stainless steel	Stainless steel	Stainless steel	Stainless steel
Preheater type	None	None	None	None	Split-flow design	None	None
Flow distribution baffles	None	Yes	None	None	Yes	None	Yes
U bend treatment	None	None	None	None	None	None	Alloy 600 Yes [o]
Peening of the roll transition/one	None	None	None	None	None	None	None

Notes
a) Innermost rows wall thickness = 1.5 mm
b) Bend Vertical flat bars
c) Bend Vertical and horizontal flat bars, vertical corrugated strips
d) Bend Vertical flat bars, horizontal and vertical corrugated strips
e) Bend Radial flat bars, vertical corrugated strips
f) Bend Vertical and horizontal flat bars, vertical corrugated ships, block tubing (zero gaps)
g) Similar to ASTM SB 163, UNS N05800
h) Grafenrheinfeld, Grohnde (Manuf: MAN-GHH), Brokdorf (Manuf UDDCOMB), Trillo-1 (Manuf: ENSA)
j) Almost identical plants Isar-2, Neckarwestheim-2, Emsland
k) Replacement steam generator for Westinghouse model 51C (Ringhals-2, Manuf: MAN-GHH), 51M (Doel 3, Manuf: ENSA/CMI), D3 (Asco-1&2 and Almaraz-1&2, Manuf: ENSA), D3 (Ringhals-3, Manuf: Framatome)
l) Replacement steam generator for Ringhals-2: 5105 m^2, Doel 3, Asco-1&2 and Almaraz-1&2: 6103 m^2, Ringhals-3: 7155m^2
m) Replacement steam generator for Ringhals-2, Doel-3, Asco-1&2 and Almaraz-1&2: 5130 tubes, 57 row-1 tubes, Ringhals-3: 5428 tubes, 59 row-1 tubes
n) Replacement generator for Ringhals-2 and Ringhals-3: Alloy 690TT, Doel-3, Asco-1&2 and Almaraz-1&2: Alloy 800 NG
o) Alloy 690TT Tubes with Radius <300 mm
p) Modified according to Siemens/KWU specification

TABLE 2.3. TYPICAL MITSUBISHI HEAVY INDUSTRIES RECIRCULATING STEAM GENERATORS AND THEIR PARAMETERS

Manufacturer and model	MHI 44	MHI 46F	MHI 51, 51A	MHI 51M	MHI 51F, 51FA	MHI 52F, 52FA	MHI 54F, 54FA
Heat transfer area [m^2]	4130	4300	4785	4780	4780	4870	5055
No. of tubes	3260	3382	3388	3382	3382	3382	3382
No. of row-1 tubes	92	94	94	94	94	94	94
Tube pattern	Square	Square	Square	Square	Square	Square	Square
Tube spacing [mm]	31.35	32.54	32.54	32.54	32.54	32.54	32.54
Tube dimensions [mm]	22.23 × 1.27	22.23 × 1.27	22.23 × 1.27	22.23 × 1.27	22.23 × 1.27	22.23 × 1.27	22.23 × 1.27
Tubing material	Alloy 600	Alloy 690	Alloy 600	Alloy 600	Alloy 600	Alloy 690	Alloy 690
Tubing heat treatment	Mill annealed	Thermally treated	Mill annealed	Mill annealed, thermally treated	Thermally treated	Thermally treated	Thermally treated
Tubesheet expansion method	Part depth rolled	Full depth hydraulic and one step rolled	Part depth rolled, full depth rolled	Full depth rolled, full depth hydraulic and rolled	Full depth hydraulic and one step rolled	Full depth hydraulic and one step rolled	Full depth hydraulic and one step rolled
Tubesheet crevice depth [mm]	497[a] (original design)	None	488[a], None	None	None	None	None
Tube support type	Drilled	Broached egg crate	Drilled	Drilled, drilled chamfer	Broached egg crate	Broached egg crate	Broached egg crate
Tube support material	Carbon Steel	405 stainless steel	Carbon steel	Carbon steel, 405 stainless steel	405 stainless steel	405 stainless steel	405 stainless steel
Preheater type	None	None	None	None	None	None	None
Flow distribution baffles	None	Yes	None	Yes	Yes	Yes	Yes

[a] Tubesheet radial gap of 0.185 mm

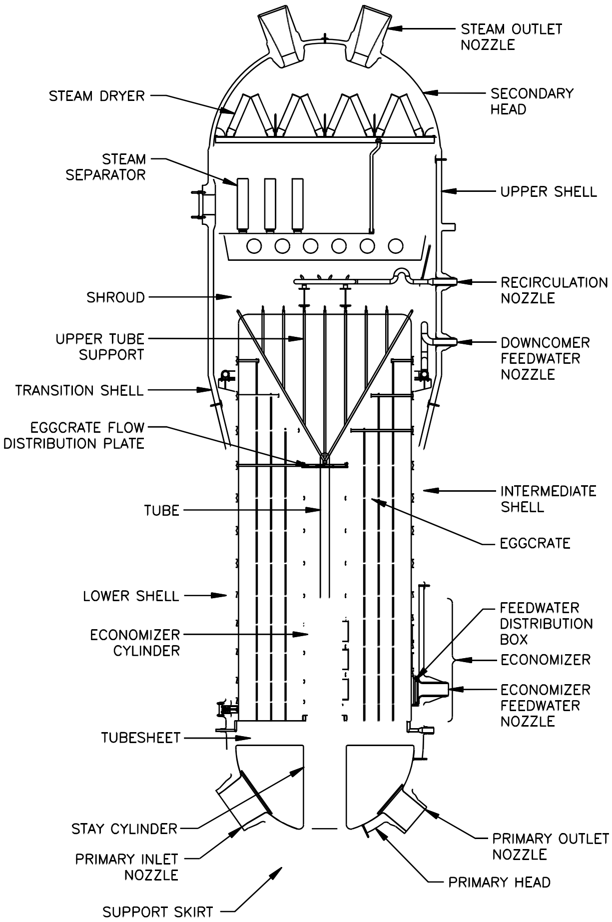


Figure 2.4. Korean recirculating steam generator (Doosan Heavy Industry model).

Major design enhancements include modified primary outlet nozzle angle to improve the mid-loop operation, automatic control of stream generator water level for all operating ranges, design improvement to prevent the flow induced vibration, and employing Alloy 690TT tubes. For maintenance and inspection, the internal structures inside steam generator are accessible via manways and handholes. The design pressures of primary side and secondary side are 17.2 MPa and 8.27 MPa, respectively. The design temperatures of primary side and secondary side are 343°C and 299°C, respectively. The typical design features and parameters are summarized in Table 2.4.

2.1.6 European pressurized water reactor steam generators

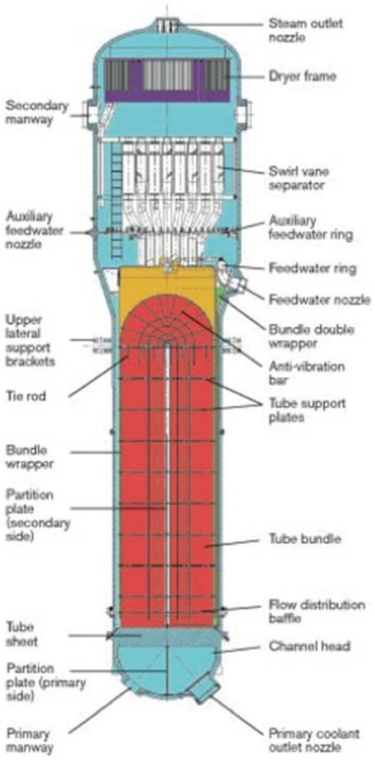
The design and the technical information of the new steam generators designed by AREVA NP for their European pressurized water reactor (EPR) plants are summarized in Figure 2.5.

2.1.7 Canadian recirculating steam generators

Currently operating CANDU steam generators are vertical recirculating steam generators (RSGs) built by Babcock & Wilcox Canada Ltd. The only exception is the Wolsong 1 unit in the Republic of Korea, which uses similar steam generators built by Foster Wheeler. Atomic Energy of Canada Limited (AECL), and for some units Ontario Hydro, selected the key design parameters for the CANDU steam generators including the tubing material and size, the steam generator size, and the key thermal hydraulic parameters. The fabricators did the detailed design of the equipment.

TABLE 2.4. TYPICAL DOOSAN HEAVY INDUSTRY RECIRCULATING STEAM GENERATOR PARAMETERS

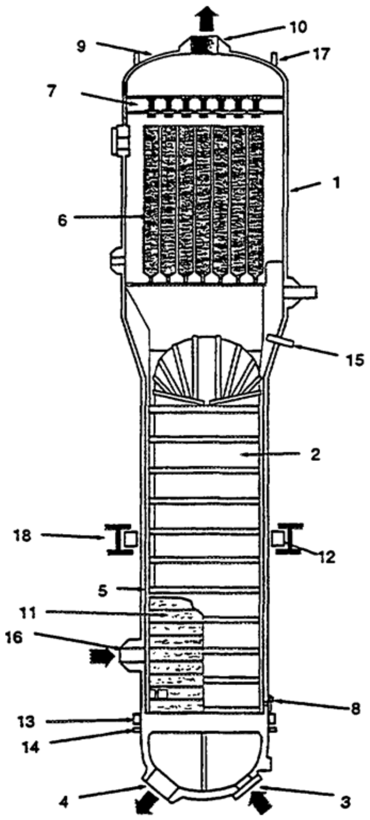
Manufacturer type and model	APR 1400
Heat transfer area [ft2][h]	163 670
No of tubes	13 102
No of row-1 tubes	70
Tube pattern	Triangular
Tube spacing [in]	1.00
Tube dimensions [in]	0.75 × 0.042
Tubing material	Alloy 690
Tubing heat treatment	Thermally Treated
Tubesheet expansion method	Full Depth Hydraulic
Tubesheet crevice depth [in][c]	25.5
Tube support type	Egg crate
Tube support material	Stainless Steel
Preheater type	Axial
Flow Baffle	Cold Side Only



Primary Side Parameters	
• Thermal Power per SG	1131.5 MWth
• Thermal Design Flowrate	12250 lbm/s
• Temperature at SG Inlet	625.6°F (329.8°C)
• Temperature at SG Outlet	563.7°F (295.4°C)
• Average SG Temperature	594.7°F (312.6°C)
• Reactor Coolant Pressure	2250 psia (155 bar)
• Primary Design Pressure	2550 psia
Secondary Side Parameters	
• Outlet Steam Static Pressure	**1118 psia (77.1 bar)**
• Secondary Design Pressure	1450 psia
• Steam Flowrate	1407.4 lbm/s (638.4 kg/s)
• Feedwater Temperature	446°F (230°C)
• Overall Circulation Ratio	3.6
• Water Mass	85.1 Tons (77.2 Metric Tons)
• Steam Mass	6.06 Tons (5.50 Metric Tons)
• Total Mass	**91.2 Tons (82.7 Metric Tons)**
Selected Materials	
• Tubing	**Alloy-690 TT**
• Shell & Channel Head	SA508 Gr3 Cl2
• Channel Head Cladding	308L / 309L SS
• Tube Sheet Cladding	Ni Cr Fe Alloy
• Tube Support Plates	410 SS
• Anti-Vibration Bars	405 SS

Figure 2.5. AREVA EPR steam generator.

CANDU RSGs are very similar to the PWR RSG with some subtle differences in size, materials, operating temperatures and tube support structure. Figure 2.6 depicts the steam generator with integral preheater used in the Darlington Generating Station, which has all the most current features of CANDU RSGs.



1. Steam drum
2. Steam generator
3. Heavy water inlet (2)
4. Heavy water outlet
5. Down-comer annulus
6. Primary cyclones
7. Secondary cyclones
8. Blowdown nozzles
9. Man-way
10. Main steam outlet nozzles
11. Preheater
12. Steam generator support
13. Contaminant seal bar/skirt

Figure 2.6. CANDU recirculating steam generator used at the Darlington station. This design is typical of the current CANDU models. (Courtesy of C. Maruska, Ontario Hydro).

Although the size of CANDU RSGs has escalated greatly with successive reactor designs, they are generally smaller than PWR RSGs, and operate at lower temperatures (290°C to 310°C primary inlet temperature). The lower temperatures generally delay the onset of thermally activated corrosion processes such as primary water stress corrosion cracking (PWSCC or intergranular stress corrosion cracking (IGSCC). Because the primary coolant in a CANDU reactor is heavy water (D_20), relatively small tube sizes [12.7 mm (1/2") OD and, in more recent units, 15.9 mm (5/8") OD] have been used to minimize the heavy water inventory. The smaller size of the primary (lower) head and tubes increases the difficulty in performing maintenance activities such as tube inspection, plugging, removal, etc.

The nominal tube wall thickness ranges from 1.13 mm to 1.2 mm depending on the type of tube alloy used (for example Alloy 800M has a lower thermal conductivity than Alloy 600 requiring thinner tubes).

The most important area of diversity in the CANDU design is in the choice of tube material, the CANDU steam generators currently operate with tubes made from high temperature, mill annealed Alloy 600 (Alloy 600MA), Monel 400 and titanium stabilized Alloy 800.

2.2 PWR ONCE-THROUGH STEAM GENERATORS

US once through steam generators (OTSG) use straight heat exchanger tubes with tube sheets at both the top and bottom of the steam generator, as shown in Figure 2.7. Primary coolant is pumped through the tubes from top to bottom while the secondary coolant moves around the outside of the tubes from bottom to top in a counter-flow direction. The secondary-system water enters a feed annulus above the ninth tube support plate level, where it mixes with steam aspirated from the tube bundle area and is preheated to saturation. The saturated water flows down the annulus, across the lower tube sheet, and up into the tube bundle, where it becomes steam. This superheated steam flows radially outward and then down the annulus to the steam outlet connection. Most of the secondary coolant is completely evaporated in a single pass through the steam generator.

The design features and the parameters of the US OTSG are summarized in Table 2.1 together with the data of US RSGs.

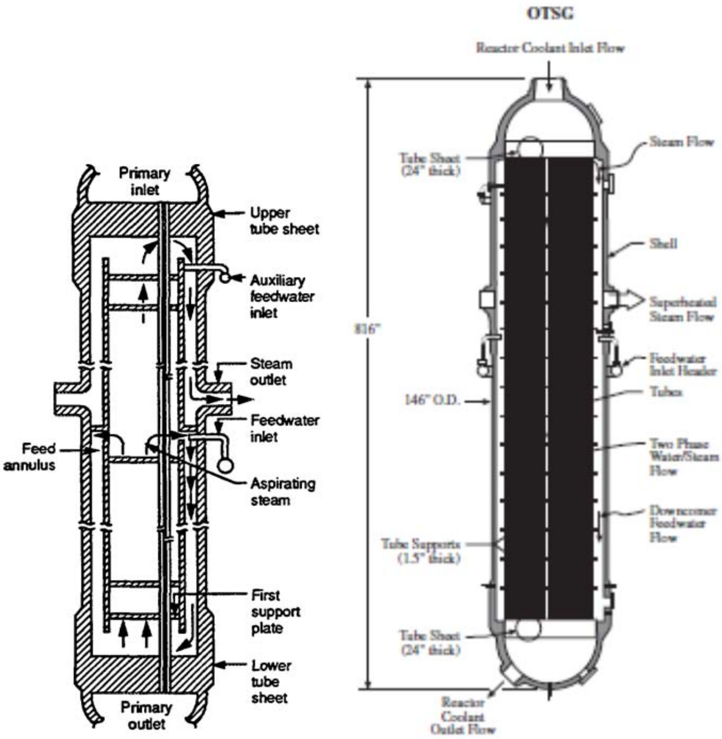
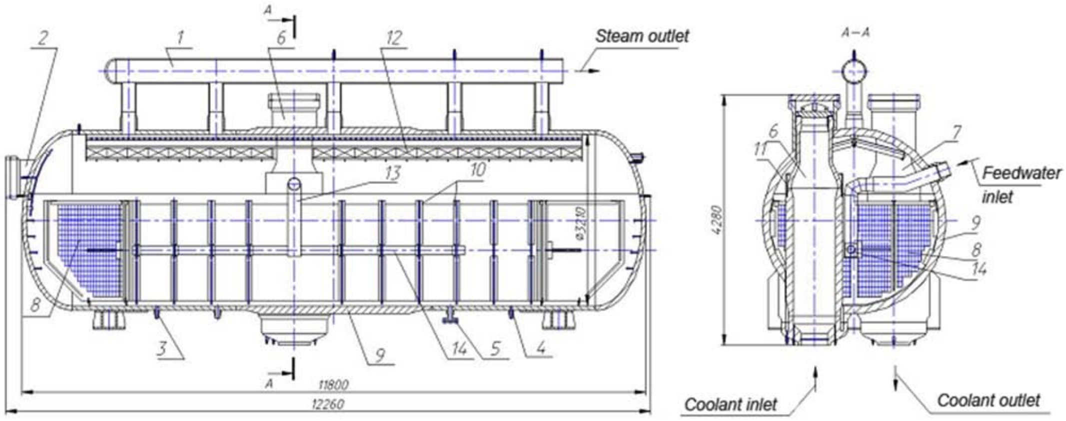


Figure 2.7. PWR once through steam generator cross sections (OTSG) [4]. Copyright Electric Power Research Institute; reprinted with permission (left), right: [3].

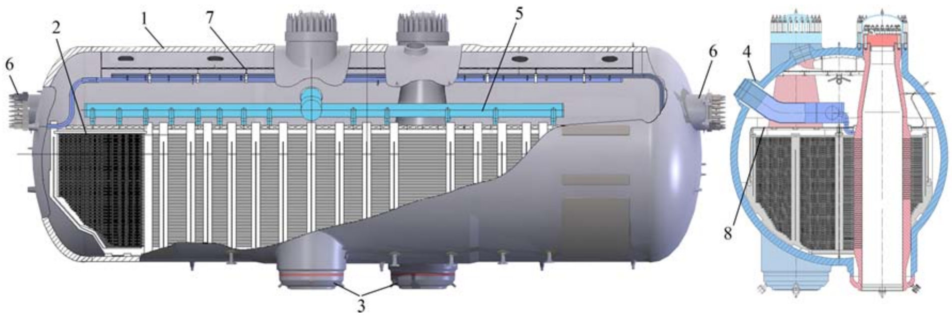
2.3 WWER STEAM GENERATORS

The steam generators used in the Russian designed WWER-440 (PGV-440) and WWER-1000 (PGV-1000 and PGV-1000M) plants are horizontal shell and tube heat exchangers manufactured by ZiO (Podolsk, Moscow Region), Atommash (Volgodonsk, Volgograd Region), and Vitkovice (Czech Republic). They consist of a pressure vessel, a horizontal heat exchange tube bundle, two vertical primary collectors, feedwater piping system, moisture separators, and steam collector. A sketch of a WWER-440 steam generator is shown in Figure 2.8 (side and end views). A sketch of a WWER-1000 steam generator is shown in Figure 2.9. The tube bundle arrangement in the WWER-440 and WWER-1000 steam generators, including the top view, is shown in Figure 2.10.



1 – steam header, 2 – hatch-manhole, 3, 4 – blowdown pipe sleeves, 5 – drainage pipe sleeve, 6,7 – ‘hot and ‘cold’ collector, 8 – heat exchanging tubes, 9 – steam generator vessel, 10 – heat exchanging tube bundle supports, 11 – protective housing, 12 – separation blinds, 13 – feed water supply tube, 14 – feedwater distribution collector.

Figure 2.8. WWER-440 steam generator (side view). (Courtesy of Y. G Dragunov, Gidropress).



1 – vessel, 2 – tube bundle, 3 – coolant inlet and outlet, 4 – feedwater inlet, 5 – feedwater distribution collector, 6 – manhole, 7 – steam distribution plate, 8 – submerged perforated plate.

Figure 2.9. WWER 1000 steam generator PGV-1000MKP (side view).

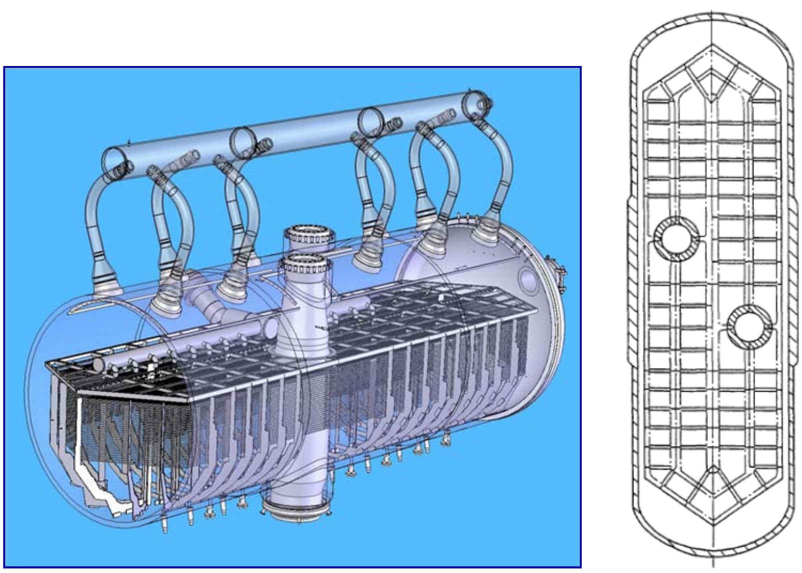


Figure 2.10. WWER-440 and WWER 1000 steam generator tube arrangement, including the top view (Courtesy of Y.G. Dragunov, OKB Gidropress).

Primary coolant enters the steam generator through a vertical collector, travels through the horizontal U shaped submerged stainless steel tubing, and exits through a second vertical collector. The tube ends penetrate the collector wall (which performs the same function as the tube sheet in a PWR steam generator) and are expanded using either a hydraulic or explosive expansion process and then welded at the collector inside wall surface. The WWER-440 collectors are made of Ti-stabilized austenitic stainless steel. The WWER-1000 collectors are made of low alloy steel with higher tensile properties, clad with stainless steel. The WWER-440 tubes are arranged in line (corridor). The WWER-1000 tubes are staggered Grids consisting of stainless steel bars and stamped wave-like plates are used to separate and support the tubes. The distance between the tube supports is 700–750 mm.

The steam generator vessel is a carbon steel (WWER-440) or low alloy bainitic steel (all the newer WWER steam generators, see Table 2.5) horizontal cylinder consisting of forged shells, stamped elliptical ends and stamped branch pipes and hatches welded together as shown in Figure 2.8 and Figure 2.9. The vertical hot and cold primary coolant collectors penetrate the vessel near its mid-point. Feedwater is supplied to the middle of the WWER-400 tube bundle by perforated piping. In the WWER-1000 steam generators, the feedwater is supplied to the top of the hot side of the tube bundle under a submerged perforated sheet. The tube bundle is completely submerged in both designs.

The WWER-440 and WWER-1000 steam generator designs are similar except for:

- Size (the WWER-1000 steam generator is about 4 meters longer)
- Tube arrangement (corridor versus staggered)
- Collector material
- Feedwater supply location
- Submerged perforated top plate (WWER-1000 only)
- Steam dryer arrangement
- Emergency feedwater distribution system (WWER-1000 only)
- Steam header arrangement
- Vessel material.

The WWER-1200 steam generator (PGV-1000MKP) design similar to PGV-1000M except bigger vessel diameter (4200 mm) and corridor tube bundle arrangement. Parameters of steam generator are higher and it is designed for implementation at advanced designs of WWER nuclear power plants. Parameters of WWER steam generators are summarized in Table 2.5.

3 STEAM GENERATOR DESIGN BASIS, FABRICATION, MATERIALS

This section mentions briefly the code requirements used to design steam generators and discusses some of the more important steam generator fabrication practices and materials of construction. Most of the information presented in this section concerns the heat exchanger tubing, including its fabrication, materials of construction and installation into the tube sheets (or collectors). The tube support, feedwater nozzle and steam generator shell designs and materials are also discussed. This section builds on the design and material information presented in Section 2 and concentrates on specific sites susceptible to the degradation mechanisms described in Section 4.

TABLE 3.1. PARAMETERS OF WWER STEAM GENERATORS

Parameters	**PGV-440**	**PGV-640**	**PGV-1000M**	**PGV-1000U**	**PGV-1000MK**	**PGV-1000MKP**	**PGV-1500**	**PGV-1600**
Thermal power [MW]	229	450	750	750	750	800	1062.5	1087.5
Steam capacity [kg/s]	125	254	408	408	408	445	598	613.8
Steam pressure [MPa]	4.61	7.06	6.27	6.27	6.27	7.0	7.34	7.80
Steam temperature [°C]	258.9	286.5	278.5	278.5	278.5	287	289.0	293
Coolant temperature (inlet/outlet) [°C]	297/270	322/295	320/289	322/292	321/291	329/298	330/297.6	330.2/298.6
Coolant pressure [MPa]	12.26	15.7	15.7	15.7	15.7	16.14	15.7	16.2
Coolant flow rate [m^3/h]	7100	14 000	21 200	21 500	21 500	21 400	26 971	28 440
Feedwater temperature [°C]	164–223	164–230	164–220	164–220	164–220	225	187–230	164–230
Average reduced steam velocity at evaporation surface [m/s]	0.21 [1)]	0.24	0.31 [2)]	0.31 [2)]	0.30 [2)]	0.33 [2)]	0.29 [2)]	0.27 [2)]
Reduced heat density [kW/m] [2) 3)]	90	106	123	146	123	131	112	118
Vessel diameter (internal) [m]	3.2	3.8	4.0	4.0	4.2	4.2	4.8	4.8
Vessel material	22K	10GN2MFA	10GN2MFA	10GN2MFA	10GN2MFA	10GN2MFA	10GN2MFA	10GN2MFA
Collector perforated part material	08Kh18N10T	08Kh18N10T-VD	10GN2MFA-Sh	08Kh18N10T-VD	10GN2MFA-Sh	10GN2MFA-Sh	10GN2MFA-Sh	10GN2MFA-Sh
Economizer	no	no	no	no	no	no	no	yes
Tube diameter [mm]	16	16	16	16	16	16	16	16
Tube thickness [mm]	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.3/1.2 [5)]
Tube spacing (vertical/horizontal) in evaporator [mm]	24/29.5	25/23	19/23	22.1/25	22/24	22/24	22/24	22/24
Tube spacing (vertical/horizontal) in economizer [mm]	-	-	-	-	-	-	-	20/19
Tube layout in evaporator/economizer [4)]	corridor	corridor	staggered	staggered	corridor	corridor	corridor	corridor staggered
Heat exchange surface [m] [2)]	2577	4223	6115	5127	6105	6105	9490	9212
Number of tubes	5536	8320	11 000	9157	10 978	10 978	15 120	14 750
Average tube length [m]	9.26	10.10	11.10	11.14	11.10	11.1	12.50	12.43
Availability of SPP	no [6)]	local	yes	yes	yes	yes	yes	yes
Availability of louver separator	yes	no	no [7)]	no	no	no	no	no

[1)] Reduced to surface limited by external tube rows.
[2)] Reduced to surface of SPP.
[3)] Reduced to external surface.
[4)] Tube layout in bundle determined in relation to vertical direction.
[5)] For option made of alloy 03Kh21N32M3B-VI (ChS-33).
[6)] At some units installed locally.
[7)] Available at steam generators manufactured before 1990.

3.1 CODES AND SPECIFICATIONS

Although many countries have, or are developing their own standards and codes for the design of nuclear power plant components, the load restrictions are generally based on Section I of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code or equivalent codes. The objective of designing and performing a stress analysis with the rules of Section III of the ASME Code is to afford protection of life and property against ductile and brittle failure. The ASME Class 1 design requirements are used for all the primary side pressure retaining components. The components on the secondary side are required to satisfy ASME Class 2 requirements. However, common practice is to design the entire steam generator shell to the ASME Class 1 requirements. Therefore, Article NB-2300 of Section III of the ASME Code is referred to for assurance of adequate fracture toughness of all pressure retaining materials in the steam generator. In addition, the steam generator tube/tube sheet complex meets the stress limitations and fatigue criteria specified in the ASME Code. The requirements of Section III are discussed in detail in a companion publication in the IAEA-TECDOC series entitled ‘Assessment and Management of Ageing of Major Nuclear Power Plant Components Important to Safety: Pressurized Water Reactor Pressure Vessels’ [216]. The NPP design requirements in Germany and Russia, which differ from the ASME requirements, are also discussed in that document.

3.2 FABRICATION AND MATERIALS

Materials and methods used to fabricate steam generator components significantly affect their susceptibility to corrosion, especially to stress corrosion cracking.

Degradation of the steam generator tubing is also influenced by other aspects of the steam generator design and construction, such as the tube support design and the method of tube installation. Also the design of the balance of plant systems and components has a decisive influence in the corrosion behaviour of the steam generator, as described in Section 4.

Materials of interest to this discussion include those used for tubes and tube supports. Chemical compositions of all mentioned materials are given in Table 3.1. Figure 3.1 shows a Fe-Cr-Ni ternary diagram with these alloys at their respective compositions together with other Fe-Cr-Ni alloys used in nuclear power plants.

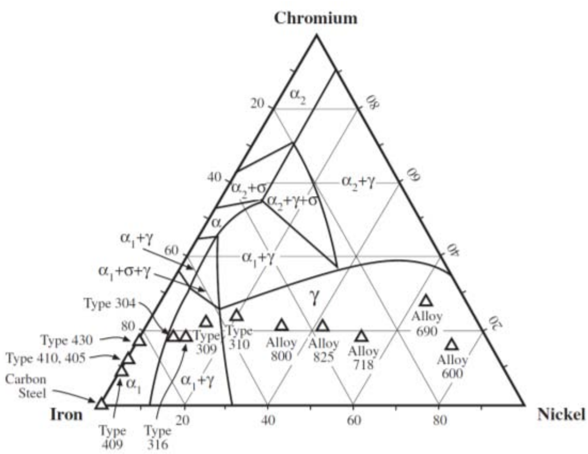


Figure 3.1. Alloys of interest to steam generators superimposed on Fe-Cr-Ni ternary diagram for 400°C. [5].

TABLE 3.1. CHEMICAL COMPOSITION OF USED STEELS AND ALLOYS (continued)

Materials	Content of elements [mass%]															
	C	**Mn**	**Si**	**P**	**S**	**Cr**	**Ni**	**Mo**	**W**	**Ti**	**V**	**Cu**	**Co**	**Al**	**Others**	**Fe**
Monel 400	≤ 0.30	≤ 2.0	≤ 0.50	-	≤ 0.024	-	≤ 63.0	-	-	-	-	28.0 ÷ 34.0	≤ 1.0	-	-	≤ 2.50
SA-106 Grade B	≤ 0.30	0.29 ÷ 1.06	0.10 ÷ 0.40	≤ 0.025	≤ 0.025	≤ 0.40	≤ 0.40	≤ 0.15	-	-	≤ 0.08	≤ 0.40	-	-	-	balance
SA-302 Grade B	≤0.20	1.15 ÷ 1.50	0.15 ÷ 0.40	≤0.035	≤0.035	-	0.40 ÷ 0.70	0.45 ÷ 0.60	-	-	-	-	-	-	-	balance
SA-508 Grade 1	≤ 0.35	0.40 ÷ 1.05	≤ 0.40	≤ 0.025	≤ 0.025	≤ 0.25	≤ 0.40	≤ 0.10	-	-	≤ 0.05	≤ 0.20	-	≤ 0.025	-	balance
SA-533 Grade B	≤ 0.20	1.15 ÷ 1.50	0.15 ÷ 0.40	≤ 0.035	≤ 0.035	-	-	0.45 ÷ 0.60	-	-	-	-	-	-	-	balance
SA-533 type A Class 1	≤ 0.25	1.15 ÷ 1.50	0.15 ÷ 0.40	≤ 0.035	≤ 0.035	-	-	0.45 ÷ 0.60	-	-	-	-	-	-	-	balance

TABLE 3.2. CHEMICAL COMPOSITION OF USED STEELS AND ALLOYS

Materials	Content of elements [mass%]														
	C	Mn	Si	P	S	Cr	Ni	Mo	W	Ti	V	Cu	Co	Al	Others	Fe
08Ch18N10T	≤ 0.08	≤ 2.0	≤ 0.8	0.035	0.020	17 ÷19	9 ÷11	-	-	5xC ÷ 0.7	-	-	-	-	-	balance
10GN2MFA	0.08 ÷ 0.15	0.60 ÷ 0.90	0.1 ÷ 0.37	≤ 0.025	≤ 0.025	≤ 0.30	1.70 ÷ 2.70	0.40 ÷ 0.60	-	-	-	-	-	-	-	balance
22K	0.19 ÷ 0.26	0.75 ÷1.0	0.2 ÷0.4	0.030	0.030	≤ 0.3	≤ 0.3	-	-	-	-	≤ 0.3	-	-	-	balance
304 L	≤ 0.03	≤ 2.0	≤ 0.75	≤ 0.045	≤ 0.030	18.0 ÷ 20.0	8.0 ÷ 12.0	-	-	-	-	-	-	-	N ≤ 0.10	balance
405	≤ 0.08	≤ 1.0	≤ 1.0	≤ 0.040	≤ 0.030	11.5 ÷ 14.5	-	-	-	-	-	-	-	0.10 ÷ 0.30	-	balance
409	≤ 0.03	≤ 1.0	≤ 1.0	≤ 0.040	≤ 0.020	10.5 ÷ 11.70	≤ 0.5	-	-	≥ 8x(C+N)	-	-	-	-	N ≤ 0.03	balance
410	≤ 0.15	≤ 1.0	≤ 1.0	≤ 0.040	≤ 0.030	11.5 ÷ 13.50	≤ 0.5	-	-	-	-	-	-	-	-	balance
ChN35VT-VD	≤ 0.12	1.0 ÷ 2.0	≤ 0.60	0.025	0.015	14 ÷ 16	34.0 ÷ 36.0	-	2.8 ÷3.5	1.1 ÷1.5	-	-	-	-	-	balance
Incoloy Alloy 800	≤ 0.10	≤ 1.5	≤ 1.0	-	≤ 0.015	19.0 ÷ 23.0	30.0 ÷ 35.0	-	-	0.15 ÷ 0.60	-	≤ 0.75	-	0.15 ÷ 0.60	-	≥ 39.5
Inconel 600	≤ 0.15	≤ 1.00	≤ 0.50	≤ 0.020	≤0.015	14.0 ÷ 17.0	≥ 72.0	-	-	-	-	≤ 0.50	-	-	-	6.0 ÷ 10.0
Inconel 690	≤ 0.05	≤ 0.50	≤ 0.50	-	≤ 0.015	27.0 ÷ 31.0	≤ 58.0	-	-	-	-	≤ 0.50	-	-	-	7.0 ÷ 11.0

3.2.1 Heat exchanger tubes

Initially, the heat exchanger tubing in most of the PWR steam generators placed in-service in the western countries (except Germany) was made from nickel based Alloy 600. The first German steam generators designed by Siemens used also Alloy 600 MA, but due to leaks in steam generators after two cycles caused by stress corrosion cracking (SCC), the SGs were replaced by SGs with Alloy-800NG tubing. Since the early 1970s all German SGs were tubed with Alloy 800 NG (I 800NG) material.

Now, most steam generators designed by Westinghouse, AREVA NP, Babcock & Wilcox and Mitsubishi-Heavy Industries, Doosan Heavy Industries are being fabricated with thermally treated Alloy 690 (Alloy 690TT). AREVA NP and Babcock & Wilcox Canada are also supplying replacement steam generators with Alloy-800NG tubing or Alloy 690TT.

Tube fabrication generally starts with extrusion of a shell from an ingot and then several cold reduction steps by either drawing or pilgering. Each reduction step is followed by mill-annealing, which typically consists of passing tube lengths through a furnace on a travelling belt at temperatures high enough to recrystallize the material and dissolve all the carbides (about 980°C or above).

The mill-annealing temperature and initial carbon content are two of the important parameters in controlling the mechanical and corrosion behaviour of nickel based alloys such as Alloy 600. The objective of the mill-annealing steps is to first dissolve all the carbides and obtain a relatively large grain size and then cover the grain boundaries with carbides upon slow cooling in air. Higher carbon content requires a higher mill-annealing temperature to dissolve all the carbides. Undissolved intergranular carbides are undesirable because they provide nucleation sites for the dissolved carbides and prevent precipitation of the carbides on the grain boundaries and, therefore, prevent appropriate grain boundary carbide coverage. The mill-annealing temperature also controls the material yield strength and, therefore, the residual stresses. Higher mill-annealing temperatures result in lower residual stresses (in tubes which are not stress relieved). Starting in the late 1970s, the mill annealed Alloy 600 tubes from some vendors were also given a final thermal treatment at about 705°C for 15 hours in order to relieve fabrication stresses and to further improve the microstructure. The thermal treatment process promotes carbide precipitation at the grain boundaries and diffusion of chromium to the grain boundaries. Therefore, somewhat higher mill-annealing temperatures can be used with the same final grain boundary carbide coverage and the chromium used to form the chromium carbides is replenished on the grain boundary. Alloy 600 tubing with grain boundary chrome depletion is susceptible to outer diameter stress corrosion cracking (ODSCC) in oxidizing acidic conditions. Alloy 600 tubing with insufficient carbides on the grain boundaries is susceptible to primary water stress corrosion cracking (PWSCC).

Subsequent to the final mill-annealing, the tubing is passed through roll straighteners to produce a straight product. The straightening process plastically deforms the tubing, imparting some residual stresses. After straightening, the tubing may be abrasively polished (e.g. using belt abrasives) to remove about 0.025 mm from the exterior surface. This step removes surface imperfections, but also results in the tubes having a thin cold worked surface layer and significant residual surface stresses, which can range from compressive to highly tensile.

The final manufacturing steps for straight tubes involve visual, ultrasonic, and eddy current inspections as well as various cleaning operations, including blasting the interior surfaces with ceramic grit. For RSGs, the straight tubes are bent to the desired U tube configuration. For tight radius bends, internal mandrels are often used to minimize ovality of the bent portion of the tube [6]. In addition, the tight radius U bends of tubes in some of the existing steam generators which had not been thermally treated, were stress relieved at 705°C for at least 5 minutes to relieve bend induced stresses.

The annealing and thermal treatment temperatures and other details of the tube processing were somewhat different for the various manufactures and steam generator models and are briefly discussed below.

Babcock & Wilcox Practice

Babcock & Wilcox practice was to mill-anneal at a relatively high temperature, about 1065–1095°C [7]. In addition, after tube installation, Babcock & Wilcox heat-treated the entire steam generator at about 595°C for 15 hours to reduce residual stresses from tube fabrication and installation (e.g. at roll transitions), and to increase resistance to PWSCC by developing carbides at grain boundaries. However, it also resulted in sensitization (chromium depletion at grain boundaries), making the tubing susceptible to other forms of corrosion (stress corrosion cracking in oxidizing acidic conditions).

Combustion Engineering Practice

The Combustion Engineering tubing was annealed at a relatively high temperature of 980–1065°C [8]. This final mill-anneal resulted in relatively large grain sizes and carbides at the grain boundaries, which has been found to be relatively resistant to PWSCC.

Westinghouse Practice

Up until the late 1970s, Westinghouse practice involved use of relatively low temperature mill annealed tubing, which was not thermally treated [9]. For these earlier steam generators, prior to the introduction of improved heat treatment and other fabrication improvements discussed below, the residual stresses and microstructure of the tube material are such that the tubes are relatively susceptible to primary- and secondary side stress corrosion cracking.

Starting in the late 1970s, Westinghouse used an array of features to reduce the potential for tube corrosion. These features included thermal treatment of tubing for 15 hours at 705°C to relieve the residual stresses and improve the microstructure, followed by stress relief of tight radius U bends. Improvement of the microstructure involves precipitation of the chromium carbides at the grain boundaries. In addition, holding the tubing in the precipitation range for a long period of time allows the chromium to diffuse from the grain interiors to chromium depleted regions near the grain boundaries, preventing sensitization. Because of the improvements associated with this thermal treatment, experience with thermally treated Alloy 600 tubing has shown that only a small fraction of it is susceptible to PWSCC in highly stressed areas.

Current Practice

Current practice by the steam generator suppliers in France, Japan and the USA is to use thermally treated Alloy 690 (Alloy 690TT). This alloy, which is similar to Alloy 600 but has about twice as much chromium (29.5% rather than 15.5%) and proportionally less nickel, has been found in tests to be very resistant to primary water stress corrosion cracking and to have improved corrosion resistance in secondary side environments. Most vendors are using a thermal treatment of about 705°C for 15 hours to relieve the fabrication stresses and improve the microstructure. Some vendors thermally treat the tight radius U bends for various times up to an additional two hours at about 700°C to relieve the residual stresses induced by bending and peen the inside surfaces of the tube legs to produce a layer of cold worked material a few tens of microns deep. No cracking on Alloy 690TT SG tubes has been reported in operating power plants since its first application in 1989. In Germany (Siemens designed European PWRs and replacement SGs included) and Canada, titanium stabilized Alloy 800NG is being further used, based on the good result obtained in long term operation experience with steam generators using this alloy.

Siemens Practice

The first two Siemens steam generators were supplied with Alloy 600 mill annealed tubing and began leaking after two years of operation. Thereafter, since the early 70s, all Siemens steam generators were fabricated with Alloy 800NG tubing. Compared to the standard Alloy 800 ASTM specification, Siemens Alloy 800NG has a reduced carbon content to minimize sensitizations, an increased stabilization ratio (Ti/C: ≥12, Ti/(C+N): ≥ 8, N: ≥ 0.03), and slightly increased chromium and nickel contents to achieve a higher resistance to pitting and trans-granular stress corrosion cracking (TG-SCC). The Alloy 800NG has also a higher resistance against caustic induced SCC and it is almost immune against pure water SCC (PWSCC).

CANDU Practice

Following the use of Alloy 600 in a small demonstration reactor, the material used in the 1960's in the CANDU steam generators was Monel 400 a high nickel/copper alloy. This alloy has good corrosion properties but is extremely sensitive to oxygen content. Its ferromagnetic properties also increase the difficulty of inspection with standard eddy current coils.

The material used for later units was changed to Alloy 800. The practice for Babcock & Wilcox Canada Ltd. for manufacturing Alloy 800 tubing (high temperature mill-annealing and heat treatments) was very similar to the practice of its parent company as described for PWRs. As a result, this type of tubing was expected to behave similarly, with respect to degradation mechanisms, to that used in once through steam generators built by Babcock & Wilcox in the USA; however, Alloy 800NG SG tubes in CANDU plants experienced more favourable field experience.

The current practice for CANDU RSGs is to use titanium stabilized nuclear grade Alloy 800NG tubing and a manufacturing method, which precludes any random heat addition to the tubing.

WWER Tubing Material

The WWER-440 and WWER-1000 steam generator tubing is made of type 08Ch18N10T stainless steel which is a titanium-stabilized austenitic stainless.

3.2.2 Tube installation in the tube sheet

PWR recirculation steam generator tubes have been installed in a thick tube sheet and WWER steam generator tubes have been installed in somewhat thinner walled collectors by mechanical rolling, hydraulic expansion, or explosive expansion (which may introduce high residual stresses) and seal welding to the tube sheet/collector inside surface cladding. For the early PWR plants, the mill annealed tubing was connected to the tube sheet by hard rolling the tubes into the bottom of the tube sheet for a length of about 60 to 100 mm This left an approximately 0.2 mm wide, radial crevice of about 460 mm long between the tube and tube sheet along the top portion of the tube sheet, where chemical impurities could concentrate. In later steam generators of Westinghouse design (early to mid-1970s), the tubing was expanded for the rest of the tube sheet height using an explosive expansion process (Wextex expansion) in the field or by additional hard rolling in the shop. In cases, where the expansion was done by additional rolling, field experience has shown that high residual stresses were introduced into some tubes during rolling anomalies, e.g. at regions rolled twice or at transition regions where rolling was skipped. For Westinghouse type steam generators made in the later part of the 1970s, full depth tube expansion was accomplished in the shop using hydraulic methods. The Siemens steam generators were fabricated with either a three or two step mechanical hard roll until the late 1980s, changing later to a full-length hydraulic expansion. The most recent procedure used by most of the PWR and CANDU steam generator manufactures is to perform a hydraulic expansion over nearly the entire tube sheet thickness (stopping and starting within a few mm of each end). In some cases, the hydraulic expansion was followed by a one (near the top) or two step mechanical hard roll near the top and near the bottom (called a kiss roll). The transition region is formed by the hydraulic expansion, which leaves significantly lower residual stresses in the tubing than the hard mechanical roll expansions. The hard mechanical rolling near the top or near both ends of the tube sheet provides a larger holding force than can be obtained with a hydraulic expansion.

Kiss rolls have been used to install the tubes in the tube sheets of the French steam generators since 1980. This has resulted in lower residual stresses on the secondary side of the tubing, but an increased sensitivity to axial cracking on the primary side surfaces. Westinghouse uses only a hydraulic tube expansion. Westinghouse also machines the tube sheet faces parallel to within 0.38 mm so that the secondary side crevice depth is less than 2.5 mm.

Mechanical tube sheet crevices generally do not exist in the CANDU steam generators. Early units closed the tube sheet crevices by a second roll near the top (secondary side) of the tube sheet. Current CANDU models use a hydraulic method to close the tube sheet crevice.

The WWER steam generators use two vertical cylindrical collectors or headers, each with an inside diameter of 800 mm (WWER-440) or 834 mm (WWER-1000) and a wall thickness of 136 mm (WWER-440) or 171 mm (WWER-1000) rather than a thick wall tube sheet. As mentioned above, the WWER-440 collectors are made of the same Ti-stabilized stainless steel as the tubing (<0.7% Ti). The WWER-1000 collectors are made of the same low alloy bainitic steel (type 10GN2MFA) as the vessel, with stainless steel cladding on the inside surface. The tubes are embedded against the collector wall by explosion or hydraulic expansion and welded at the collector inside surface using argon-arc welding. Collector tube crevices generally do not exist; however, some ‘under-rolling’ of the heat exchanger tubes into the collector wall has been reported, resulting in crevices with depths up to 20 mm (explosive expansions) or 2 mm (hydraulic expansions).

3.2.3 Tube supports

The steam generator tube support structures used in different steam generator models of different vendors and their design evolution are explained in much more detail in Section 4 for better understanding the tube degradation mechanism that is associated with or caused by the selected tube support design. In this section only a brief summary of the used steam generator tube support design is given in the following:

Several types of tube support systems have been used in PWR steam generators, as shown in Figure 3.2 [4]. Most of the original steam generators of Westinghouse Framatome, Mitsubishi design have plate type tube supports. Initially, the tubes passed through drilled holes in the plate. This drilled hole-plate construction leaves a narrow gap around the tube, between the tube and plate, which does not allow secondary coolant to flow effectively through. Separate smaller holes are also provided for the secondary coolant flow. This design was not adequate, being the source of considerable tube damage, as it is explained in Section 4. This design was changed later by broached hole tube support plates, having a design varying according to the provider.

Combustion Engineering steam generators mostly use supports formed from a lattice arrangement of bars (egg crate tube supports), but also use drilled plates in some locations in the U bend region (see Figure 3.3).

Babcock & Wilcox steam generators have plate type tube supports, but the holes are broached to give a non-circular hole with three lands to support the tube, with a larger diameter between the lands to allow coolant flow adjacent to the tube (trefoil design broached hole).

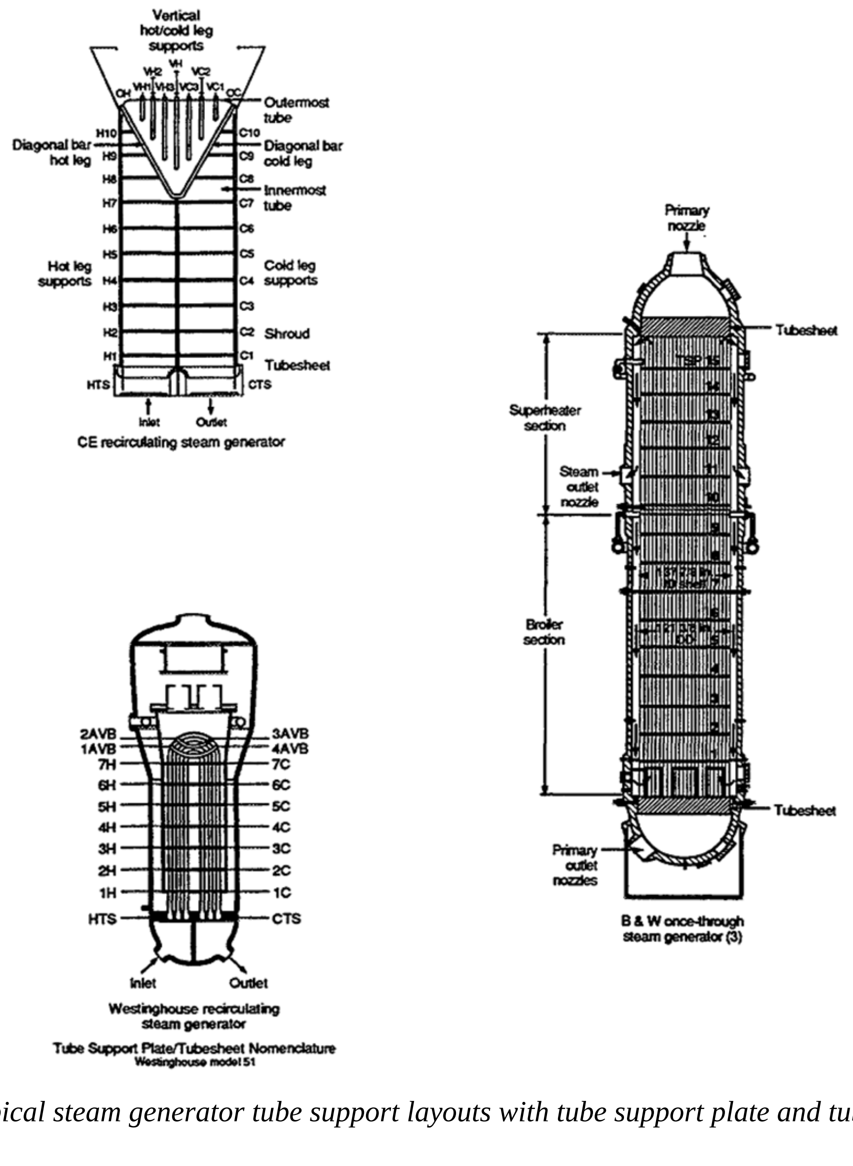


Figure 3.2. Typical steam generator tube support layouts with tube support plate and tube sheet nomenclature.

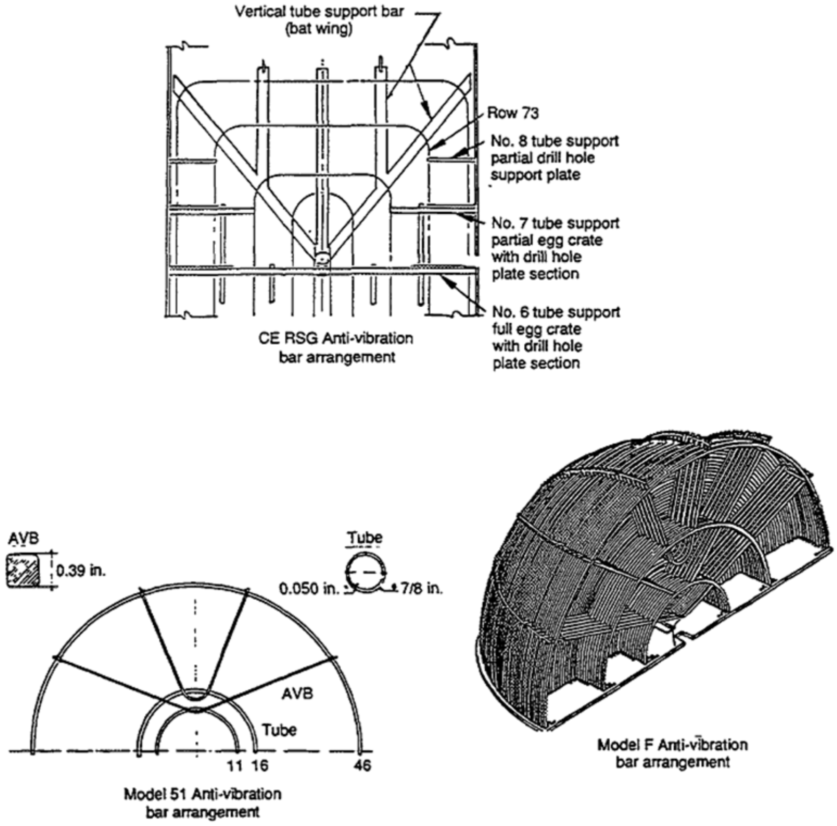


Figure 3.3. Typical recirculating steam generator antivibration bar arrangement.

Later Westinghouse, Mitsubishi and Framatome designs also use broached hole tube support plates (with four lands to support the tube-quatrefoil design). The earlier models have carbon steel as the tube support material, whereas the later models have corrosion resistant type 405 ferritic stainless steel. The design improved to minimize the clogging risk (advanced thin trefoil structures).

Antivibration bars or plates are used in the U bend regions of recirculating steam generator tube bundles to stiffen the tubes and limit vibration amplitudes. Typical arrangements for antivibration bars in Westinghouse and Combustion Engineering steam generators are shown in Figure 3.3. The antivibration bars in Westinghouse type RSGs are installed to provide support to at least row 11, though many were installed to deeper depths, e.g. to row 8. The antivibration bars in later Westinghouse models have a square cross section and are made from Alloy 600 and are chrome plated. The arrangement of antivibration bars in Combustion Engineering steam generators includes vertical, horizontal, and bat wing strips, as shown in Figure 3.3.

The CANDU steam generator tube support design has gone through many changes. Older operating units have a carbon steel lattice grid arrangement, or carbon steel trefoil broached plates (see description of Babcock & Wilcox design above). Recent models use an advanced version of the lattice grids made of stainless steel (see Figure 3.4). Antivibration (U bend) supports have also undergone changes, from carbon steel scallop bars (stacked and staggered) to the current stainless steel flat bar type.

The WWER-440 and WWER-1000 steam generators use stainless steel bar and stamped wave-like plates to separate and support the tubes.

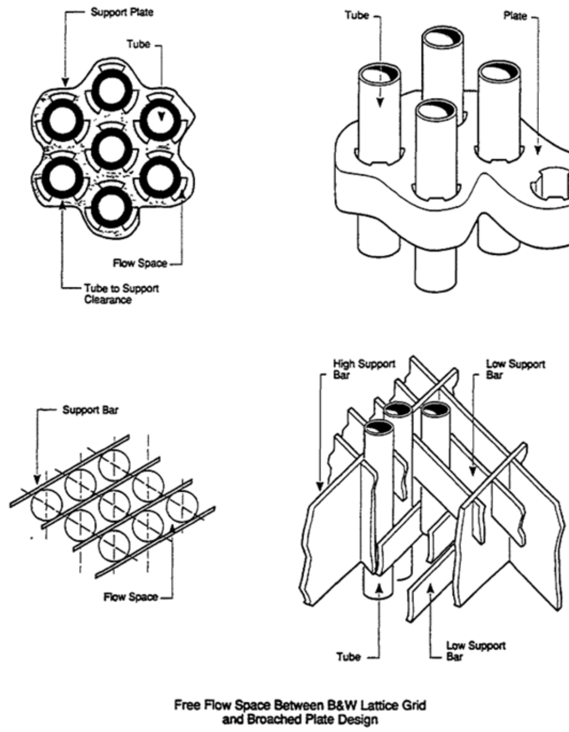


Figure 3.4. Typical CANDU steam generator tube support structures. (Courtesy of C. Maruska, Ontario Hydro).

3.2.4 Feedwater nozzle and shell

Figure 3.5 shows the locations of the feedwater nozzle and the girth welds in a schematic of the shell of a Westinghouse PWR recirculating steam generator without a preheater. Figure 3.6 shows a typical Westinghouse feedwater nozzle and thermal sleeve. The Westinghouse thermal sleeve is welded to the feed ring (not shown in Figure 3.6). It fits snugly against the nozzle, but is not attached to the nozzle. Figure 3.7 shows the original configuration for the piping to nozzle weld (see Section 8.6 for repair). The steam generator shell, including the feedwater nozzle, is made of low alloy ferritic steel, typically SA-533 type A, Class 1 or 2 for the Westinghouse steam generator shells and SA-508 C12 for the feedwater nozzle forgings. (Some of the earlier steam generators made by Westinghouse in their Lester plant used SA-302 Grade B for the plate material, but all the steam generators built at the Tampa plant used SA-533.) The thermal sleeve inside the feedwater nozzle is made of SA-106 Grade B carbon steel.

As stated in Section 3.2.1, Babcock & Wilcox heat treated the entire Babcock & Wilcox once through steam generator at about 595°C for 15 hours, thus reducing residual stresses in the shell and feedwater nozzle, as well as in the tubing. Most of the other steam generator vendors did not thermally treat the entire steam generator.

The WWER steam generator pressure vessels and feedwater nozzles are shown in Figure 2.8 and Figure 2.9. The WWER-440 steam generator shell is made of type 22K carbon steel. The WWER-1000 steam generator shell and feedwater nozzle is made of type 10GN2MFA low alloy steel.

After corrosion erosion problems of the feedwater piping inside the steam generator WWER-440, the structural material was changed to 08Ch18N10T and the distribution system of the feedwater was changed, too.

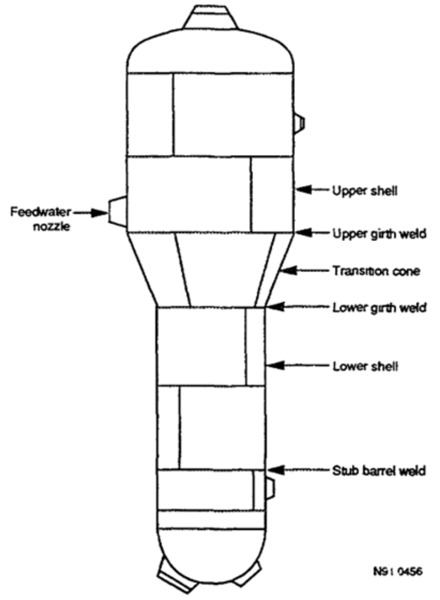


Figure 3.5. PWR steam generator showing shell welds [10]. Copyright Westinghouse Electric; reprinted with permission.

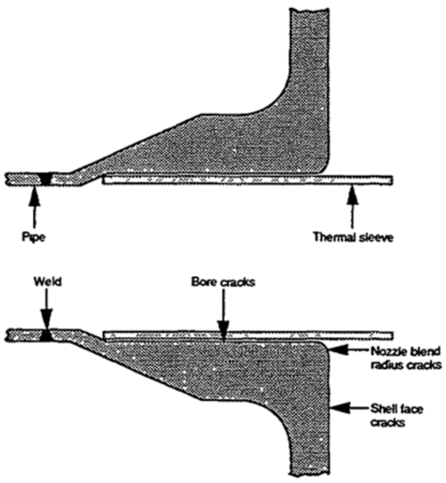


Figure 3.6. Feedwater nozzle sites susceptible to high cycle thermal fatigue damage caused by turbulent mixing of leaking feedwater and hot steam generator coolant [10]. Copyright Westinghouse Electric; reprinted with permission.

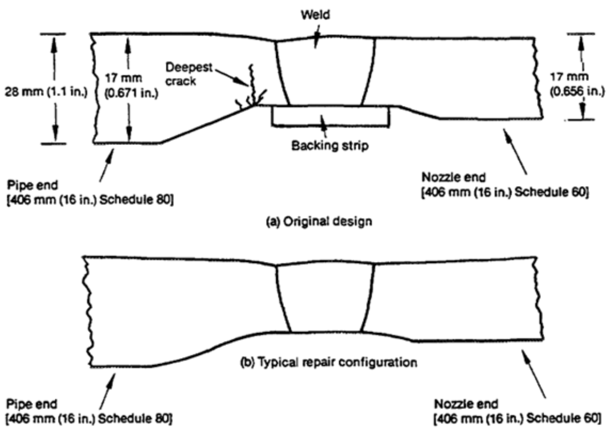


Figure 3.7. Crack locations in the D.C. Cook nozzle [11].

4 STEAM GENERATOR DEGRADATION MECHANISMS

This section discusses:

- The main reasons of SG degradation, including SG and BOP design, materials and chemistry.
- Susceptible sites and failure modes associated with the various steam generator degradation mechanisms.

PWR recirculating steam generator tube degradation is discussed first, including primary water stress corrosion cracking (PWSCC), outer diameter stress corrosion cracking (ODSCC), fretting, pitting, TS and TSP denting, wastage, TSP clogging, tube fouling, tube support plate fouling high cycle fatigue, and wastage. This material is followed by similar information on PWR once through steam generator (OTSG) tube and WWER steam generator tube degradation. A discussion of the tube rupture experience is then presented, followed by information on PWR steam generator shell and feedwater nozzle degradation, and WWER collector stress corrosion cracking and feedwater system erosion-corrosion are also reviewed. Steam generator plug and sleeve degradation is discussed in Section 8.

4.1 PWR RECIRCULATING STEAM GENERATORS

4.1.1 Main reasons of steam generator degradation

The degradation mechanisms that occurred at recirculation steam generators show a great variety [3, 12, 13]. They have been very extensive, affecting both primary and secondary side, from which the secondary side degradation has been the main problem.

These SG problems often forced the plants to perform unscheduled or extended outages for preventive and/or corrective maintenance measures. In addition many SG replacements were necessary, which were costly in terms of repair work, personnel radiation exposure and loss of power [12, 14]. Especially in USA, where the majority of the problems were reported on the secondary side of the SG tubes, the industry made a lot of efforts to improve the design and materials of the SGs and the secondary side water chemistry to minimize the SG degradation problems during the period of 1970s to end of 1990s. Although tremendous progress has been made in controlling the SG degradation problems, as it can be seen in the improvement of the US PWR capacity factors, minimizing its impact on plant operation will remain a continuing challenge worldwide.

Numerous descriptions of the damage mechanisms have been published [15–17]. They are shown in a summarized form in Figure 4.1 [3], identifying degradation sites for PWR steam generators. Table 4.1 lists PWR steam generator degradation mechanisms, sites, stressors, failure mode and inspection methods for tubes and tube sheets. The history of these degradation processes is detailed in Section 0. A description of some of those relevant degradation mechanisms is given in Section 4.1.8. It results evident that most of the degradation mechanisms at SGs are of chemical origin (corrosion). The occurrence of failures has been tightly related with the water chemistry. Therefore, the understanding of the involved mechanisms becomes necessary to improve the SG performance and retard the ageing process. The fundamental aspects involving steam generator degradation are detailed in Sections 4.1.3 to 4.1.7, with the aim of providing a better understanding the root causes, establishing:

- A good approach for optimization of the steam generator operation performance at presently operating plants.
- Basic aspects of plant design for new plants to ensure an extended and safe operation of the steam generators.

TABLE 4.1. SUMMARY OF PWR RECIRCULATING STEAM GENERATOR TUBE RELEVANT DEGRADATION PROCESSES

Rank[a]	Degradation Mechanism	Stressor	Degradation Sites	Potential failure mode	ISI Method
1	ODSCC	Tensile stresses, impurity concentrations, sensitive materials	• Tube to tube sheet crevices • Sludge pile • Tube support late • Free span	• Axial or circumferential crack • Circumferential crack • Axial crack • Axial crack	MRPC MRPC/Cecco5 Bobbin coil/Cecco 5 Bobbin coil (in absolute mode)
2	PWSCC	Temperature, residual tensile stresses, sensitive materials (low mill anneal temperature)	• Inside surface of U bend • Roll transition w/o kiss rolling • Roll transition with kiss rolling • Dented tube regions	• Mixed Crack • Mixed Crack • Axial Crack • Circumferential Crack	MRPC[b] MRPC MRPC Bobbin coil or MRPC
3	Fretting, Wear	Flow induced vibration, aggressive chemicals	• Contact points between tubes and the AVBs, or tubes and the preheater baffles • Contact between tubes and loose parts • Tube to tube contact	• Local wear • Depends on loose part geometry • Axial Wear	Bobbin coil Bobbin coil Bobbin coil
4	High cycle fatigue	High mean stress level and flow induced vibration, initiating defect (crack, dent, pit, etc)	At the upper support late if the tube is clamped	Transgranular circumferential cracking	Leak detection or by detection of precursor
5	Denting	Oxygen, copper oxide, chlorides, temperature, pH, crevice condition, deposits	At the tube support plates, in the sludge pile, in the tube sheet crevices	Flow blockage in tube, may lead to circumferential cracking (see PWSCC), decreases the fatigue resistance	Profilometry, bobbin coil
6	Pitting	Brackish water, chlorides, sulphates, oxygen, copper oxides	Cold leg in sludge pile or where scale containing copper deposits is found, under deposit pitting in hot leg	Local attack and tube thinning, may lead to a hole	Bobbin coil, ultrasonic
7	Wastage	Phosphate chemistry, chloride concentration, resin leakage	Tubesheet crevices, sludge pile, tube support plates, AVBs	General thinning	Bobbin coil

[a] Based on operating experience and number of defects (as of 1993).

[b] Multifrequency rotating pancake coil probe.

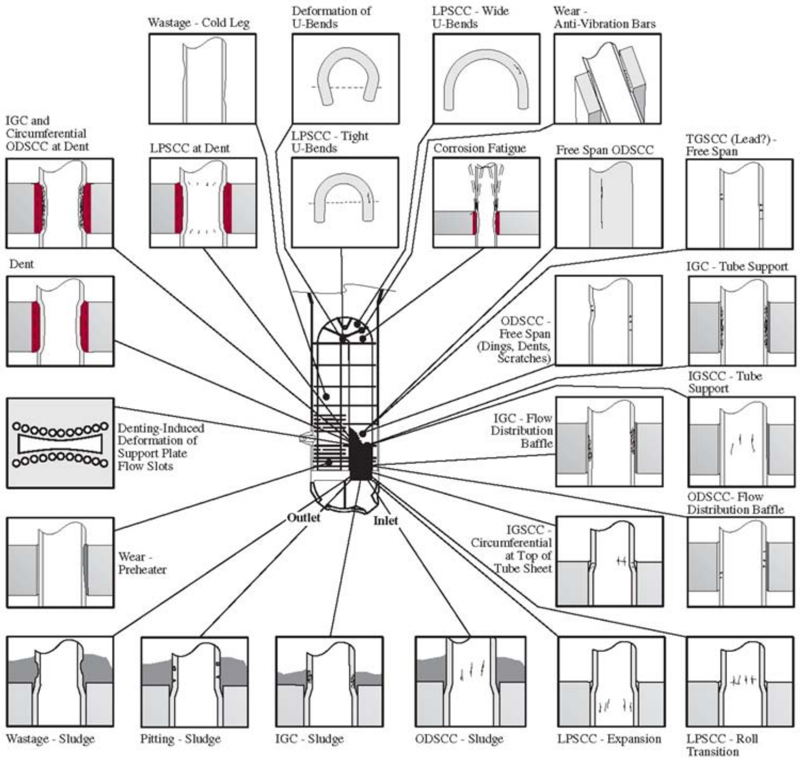


Figure 4.1. Failure types that have occurred in recirculation steam generators [3].

4.1.2 Steam generator degradation history

The relative impact of tube degradation mechanisms on overall PWR steam generator performance has dramatically changed over time. Figure 4.2 shows the percentage of the total number of tube failures[1] caused by each of the major degradation mechanisms for the years 1973 through 2008. Both PWR recirculating steam generator and PWR once through steam generator tube failures worldwide are included. (The Figure 4.2 does not include data from the WWER reactors, except Loviisa Units 1 and 2.). Phosphate Wastage was the major cause of tube failures in PWR steam generators until about 1976. From 1976 to about 1979, Denting was the major cause of PWR steam generator tube failures. After about 1979, when most of the plants abandoned the phosphate treatment and the All Volatile treatment (AVT) started to be applied, a variety of corrosion mechanisms became important, including intergranular stress corrosion cracking (IG-SCC)/intergranular attack (IGA) and pitting on the outer diameters (OD) of the tubes and primary water stress corrosion cracking (PWSCC) on the inner tube surfaces. Fretting damage became more apparent after about 1983. Over 50% of the PWR units worldwide have reported some occurrence of tube fretting and wear. However, some plants report no problems, even after five years of operation (only 7-10% of the plants report no problems after five years of operation). The incidence of these degradation mechanisms on the tube-plugging rate is shown in Figure 4.3.

This evolution resulted in a very intense SG replacement activity word wide: 78 plants out of 130 had to replace the steam generators in the USA according to EPRI (Figure 4.4) [19]. According to IAEA reporting, the number of plants worldwide having replaced SGs is 175 [20].

1 Failure is defined as a non-destructive examination (NDE) indication requiring the tube to be removed from service (plugged) or repaired. The tubes that actually leaked primary coolant are a small proportion of the tubes plugged or repaired. Steam generator tubes are sometimes plugged as a preventive action if they are judged to have a high probability of future failure.

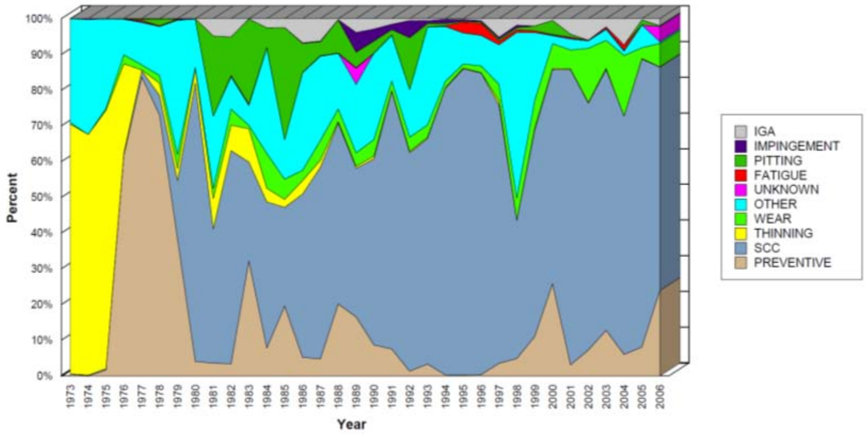


Figure 4.2. Worldwide causes of steam generator plugging [18]. Copyright 2006 Electric Power Research Institute; reprinted with permission.

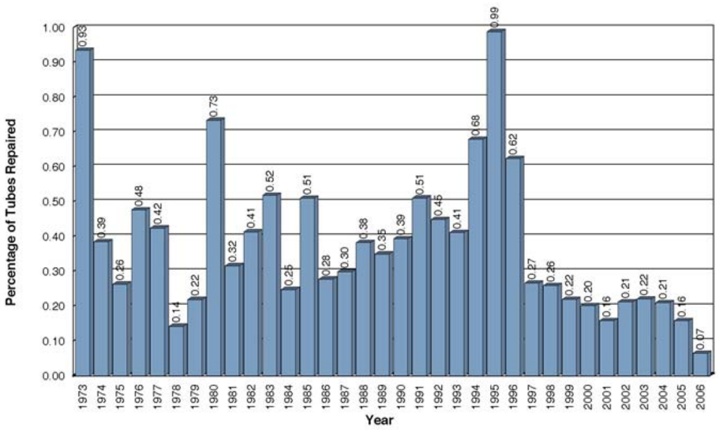


Figure 4.3. Worldwide percentage of plugged tubes [18]. Copyright 2006 Electric Power Research Institute; reprinted with permission.

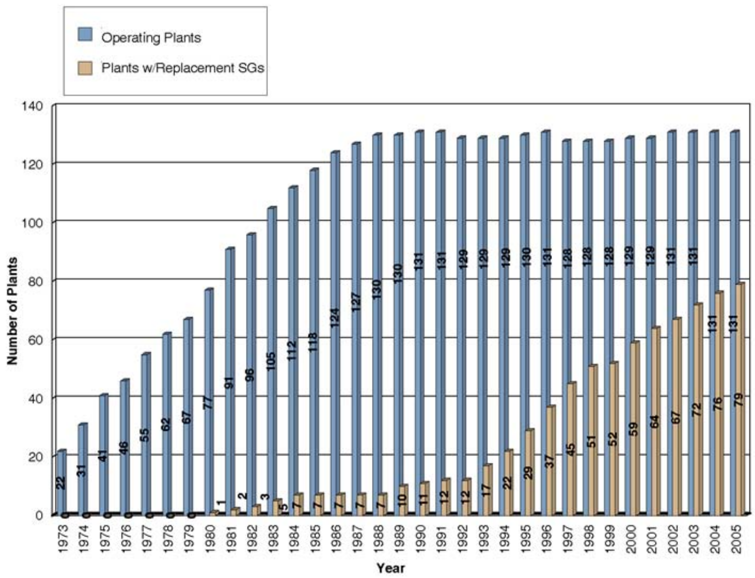


Figure 4.4. Steam generator replacement status worldwide – status 200 [18]. Copyright 2006 Electric Power Research Institute; reprinted with permission.

Most of the PWR steam generator tubes, which have failed over the years, have been mill annealed Alloy 600 (Alloy 600MA) tubes, at plants being operated at low pH and often under insufficiently reducing conditions. However, some failures of thermally treated Alloy 600 (Alloy 600TT) tubing have been reported, primarily due to fretting and denting (degradation mechanisms due to the design of the support plates and antivibration bars and the presence of loose parts, rather than the tubing material). But there have also been a few failures of Alloy 600TT tubing due to primary and secondary side stress corrosion cracking.

ODSCC assisted by lead (Pb) in the tube sheet region of Alloy 600 tubing at Kori-2 was reported in 1990 [21]. Another cracking in Alloy 600TT at Seabrook was considered to be due to high residual stresses caused by re-straightening after the TT heat treatment [22]. The cracked tubes at Vogtle-1 in 2008 appeared to have a mill annealed (MA) microstructure rather than a thermally treated (TT) structure. Ulchin 1 and 2 also showed intergranular carbides structure rather than grain boundary carbides. It seems to likely that the cracked Alloy 600TT tubes in the field had high residual stresses (Seabrook) and poor microstructure (Seabrook, Ulchin-1, 2; Vogtle-1) and some chemicals like lead (Kori-2).

The SG important tube degradation observed in earlier years, is evidently related to tube material as shown in Figure 4.5. However, the optimization of the SG performance is the results of the homogenization of plant design, material concept and chemistry, as stated in Section 4.1.3. The differences in SG performance can be explained not only by considering the SG tube material, but also by many other design and material features and chemistry applied.

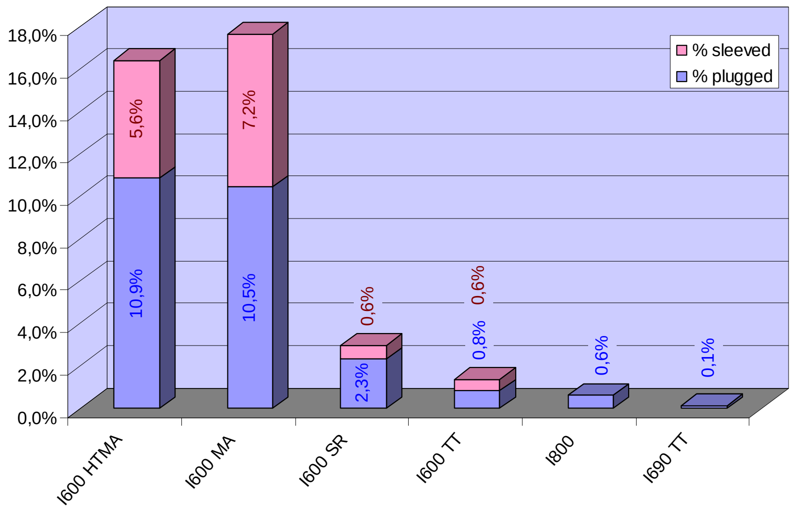


Figure 4.5. Percentage of plugged or sleeved steam generators of different materials in the period 1978–2006 [18].

The plugging and sleeving rate at PWR plants of different vendors is shown in Figure 4.6.

After the SG replacement at big scale, where the susceptible tube material Alloy 600 MA was replaced mainly by Alloy 690TT or Alloy 800 NG, a drastic reduction of acute degradation problems was observed. This is clearly reflected by the improvement of the plant capacity factor related with SG problems in Figure 4.7.

See also Figure 4.8 showing the considerably lower to negligible plugging rate at plants with SGs not having Alloy 600MA or HTMA (High Temperature Mill-Annealed). In this statistic plants with about 30 years operation without SG replacement are included.

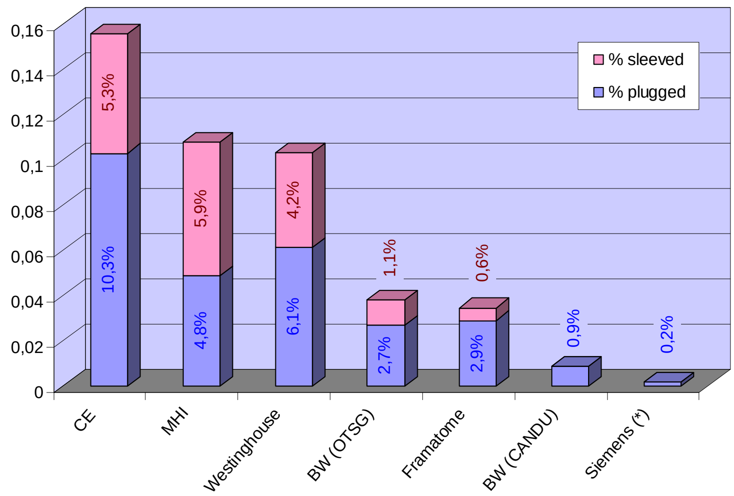


Figure 4.6. Percentage of plugged or sleeved tubes at plants of different vendors in the period 1978–2006 [18].

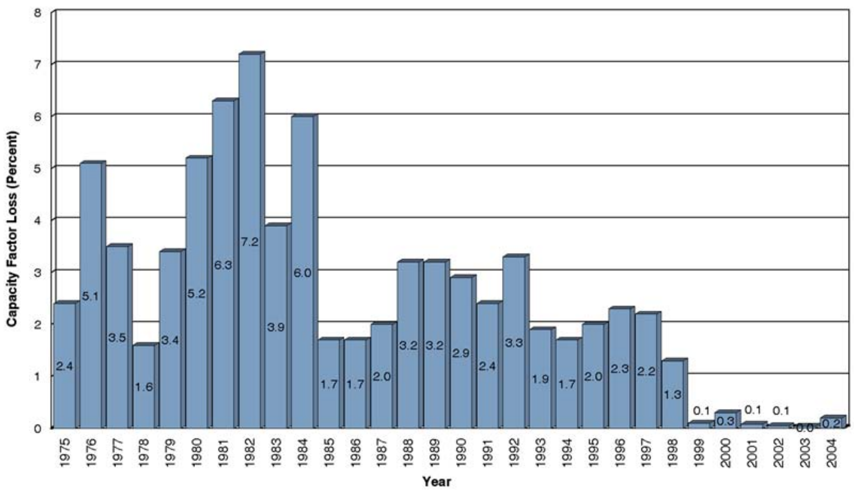


Figure 4.7. US capacity factor due to steam generator problems [18]. Copyright 2006 Electric Power Research Institute; reprinted with permission.

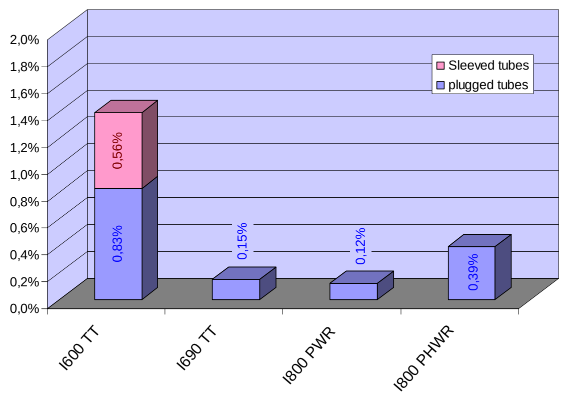


Figure 4.8. Percentage of plugged or sleeved tubes in newer plants, replacement steam generators or plants in the period 1978–2006 which had no I600 tubing [18].

The Alloy 800NG (NG = nuclear grade, sometimes called also modified as: 800M) tubing used in the Siemens and CANDU steam generators has performed very well since the very beginning.

There were Alloy 800NG tubing failures due to wastage in the Siemens steam generators, which began operation in the 1970s with phosphate water chemistry, but there have been almost no failures in the Siemens steam generators, which began operation in 1979 or later with all volatile water treatment (AVT).

There has also been some Alloy 800NG tubing fretting failures in the Siemens steam generators, which began operation before 1986. The fretting damage mostly at the u bend area was due to construction features and solved by reinforcing the antivibration devices.

Tube outer diameter damage: until end of the 1990s only one Alloy 800NG pulled tube has been affected by a stress corrosion cracking (identified as fabrication failure), two pits have been found on only two Alloy 800NG tubes, and no Alloy 800NG tubes have exhibited detectable intergranular attack or primary water stress corrosion cracking.

Denting at the TS appeared at minor extent at some plants after many operation years. In some cases it was identified to have been caused by ferritic deposits occluded in hard-caked oxide deposits.

A summary of the operative experience of SGs with Alloy 800NG at Siemens plants is shown in Table 4.2. Most of the damage was due to wastage and fretting in the first operation decade, decreasing drastically after 1981.

The Siemens SGs with Alloy 800NG tubing have a record of 1950 SG Operation years (8.1 million SG tube years) with a plugging rate of less than 0.5%, and a negligible failure rate due to corrosion, as shown in Table 4.3. The operation history of this SG type is summarized in Figure 4.9.

TABLE 4.2. OPERATING EXPERIENCE WITH SIEMENS STEAM GENERATORS: DAMAGE MECHANISMS

Operating Experience with SIEMENS PWR Steam Generator Inconel 800 Heating Tubes as at 31/01/2009

Plant	Commissioning	No. Of SGs	No. Of Tubes	No. Of Tube Leaks	No. Of Plugged Tubes	Cause of Damage and No. Of Sealed Tubes: Wastage extensive	Wastage local	Fretting AVB	Fretting LP	Fretting SCO	P	SCC ID	SCC OD grid	SCC OD TS	SCC OD TTS	Cav	Other	
A	1972	4	11.972	1	335	315	12	2	-	-	-	-	-	-	-	-	6	Conventional Tube Bundle Support
B	1973	2	8.468	1	137	115	-	12	1	-	-	-	-	-	9	-	-	
C	1974	2	7.890	5	232	4	14	167	7	-	-	-	28	-	-	-	12	
D	1974	4	16.240	3	696	492	22	61	3	-	-	-	-	35	3	-	80	
E	1976	4	16.084	3	112	7	11	53	5	-	2	-	-	1	2	29	2	
F	1976	3	12.063	2	35	4	1	6	20	-	-	-	-	-	-	-	4	
G	1978	4	16.084	0	112	-	31	1	12	10	-	-	15	15	25	-	3	Standard Tube Bundle Support
H	1979	3	12.318	0	22	1	-	-	19	-	-	-	-	-	-	-	2	
I	1981	4	16.344	1	58	-	-	4	24	2	-	-	-	-	-	21	7	Commissioning under High-AVT
J	1983	2	6.020	0	0	-	-	-	-	-	-	-	-	-	-	-	-	
K	1984	4	16.344	0	13	-	-	3	3	7	-	-	-	-	-	-	-	
L	1984	4	16.424	0	5	-	-		4	-	-	-	-	-	-	-	1	
M	2000	4	16.424	0	5	-	-	2	-	2	-	-	-	-	-	-	1	
N	1986	4	16.344	0	40	-	-	-	6	28	-	-	-	-	-	-	6	
O	1988	4	16.472	0	0	-	-	-	-	-	-	-	-	-	-	-	-	
P	1988	4	16.472	0	0	-	-	-	-	-	-	-	-	-	-	-	-	
Q	1988	3	12.258	4	31	-	-	1	24	3	-	-	-	-	-	-	3	
R	1989	4	16.472	0	9	-	-	-	-	1	-	-	-	-	-	8	-	
R1	1989	3	15.390	0	11	-	-	-	11	-	-	-	-	-	-	-	-	Improved Tube Bundle Support
R2	1993	3	15.390	0	0	-	-	-	-	-	-	-	-	-	-	-	-	
R3	1995	3	16.284	0	0	-	-	-	-	-	-	-	-	-	-	-	-	
R4	1995	3	15.390	0	10	-	-	-	7	-	-	-	-	-	-	-	3	
R5	1996	3	15.390	0	0	-	-	-	-	-	-	-	-	-	-	-	-	
R6	1996	3	15.390	1	12	-	-	1	6	-	-	-	-	-	-	-	5	
R7	1997	3	15.390	0	1	-	-	-	1	-	-	-	-	-	-	-	-	
R8	2000	2	10.856	0	17	-	-	-	16	-	-	-	-	-	-	-	1	
R9	2008	2	10.856															
		86	381.029	21	1.893	938	91	313	169	53	2	0	43	51	39	58	136	
				Plugging rate:	0,50%						Total: 135							

Fretting	AVB	Anti-Vibration-Bar (Tube Support)
	LP	Loose Part(s) (Foreign Object)
	SCO	Structural Component (Einbauteil)
	PB	Pre-Heater; Fretting at Pre-Heater Baffles
Other Damage Mechanisms	SCC	Stress Corrosion Cracking
	P	Pitting
	D	Denting
	Cav	Cavitation from Tube-Sheet Cleaning (cleaning jet damage)
Location Dependent Damage	TS Area	Indication in Tube-Sheet Region between Upper and Lower Expansions
	TTS	Top of Tube Sheet: Indications in Deposit Region on top of Tube Sheet
	ID	Inner Diameter
	OD	Outer Diameter

SGs with Preheater

Nuclear Plants shut down

Inconel 690 Tubing

TABLE 4.3. OPERATING EXPERIENCE WITH SIEMENS STEAM GENERATORS: PLUGGING RATE

		Tube Material		
		Alloy 800 (mod.)	Alloy 690 TT	Alloy 800 (mod.) and Alloy 690 TT
Number of NPPs with Siemens KWU steam generators		23 (5 W-NPPs with RSGs)	3 (3 W-NPPs with RSGs)	26 (8 W-NPPs with RSGs)
Number of steam generators		78 (15 RSGs)	8 (8 RSGs)	86 (23 RSGs)
SG operation years accumulated		1825	116	1941
Number of tubes		327 643	42 530	370 173
Tube operation years accumulated		7 458 389	613 424	8 071 813
Plugged tubes	No.	1865	28	1893
	%	0.57	0.07	0.51
Number of tubes leaks		21	~	21
Tube leaks per accumulated tube operations years		2.8×10^{-6}	~	2.6×10^{-6}

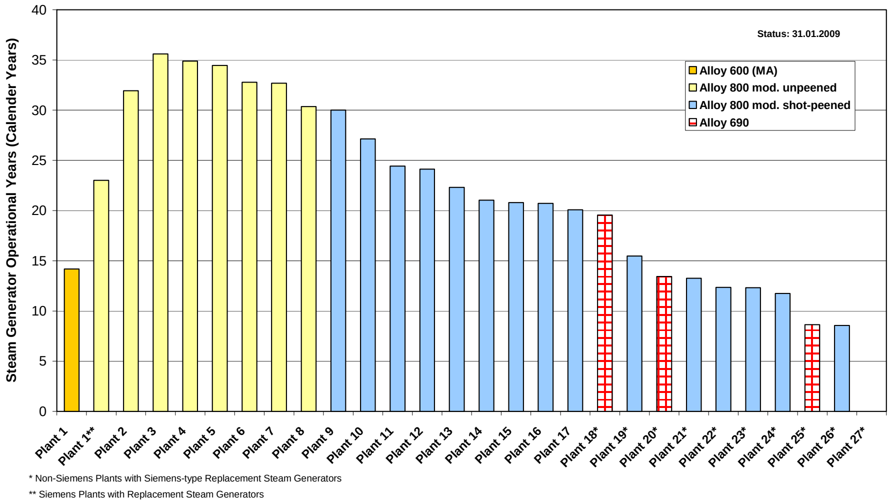


Figure 4.9. Operation experience with Siemens Alloy 800NG tubed steam generators – status 2009.

The operation experience with Alloy 690TT, starting by end of the 1980s, is also very satisfactory [19], as in the case of Alloy 800NG there are almost no failures reported, even though the operation time with this alloy is shorter. Anyway, based mainly in the operation experience, the Alloys 690TT and 800NG are considered as equivalent with a view to corrosion risk. Figure 4.10 shows the differences in susceptibility to caustic induced SCC of Alloys 600MA, 600TT, 690TT and 800NG. Alloy 690TT and Alloy 800NG show a very similar behaviour, clearly non-susceptible.

The influence of the nickel content on the stress corrosion cracking processes of the materials Alloy 600MA, Alloy 800NG and Alloy 690TT is shown in Figure 4.11 [23]. As indicated on the figure, Alloy 600MA although showing good resistance against chlorine induced transgranular SCC, is susceptible to intergranular stress corrosion cracking even under pure water conditions; whereas, Alloy 690TT and Alloy 800NG are generally not susceptible to none of the above mentioned degradation mechanisms.

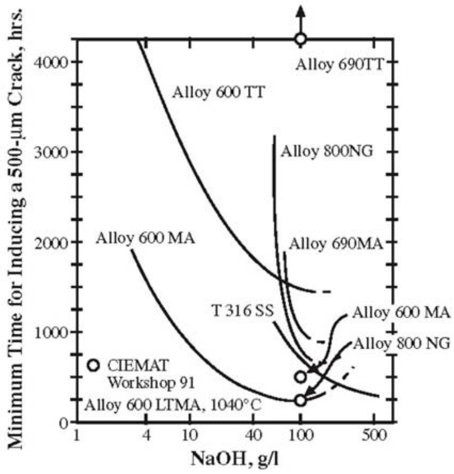


Figure 4.10. Comparison of the cracking susceptibility of candidate SG tube materials.

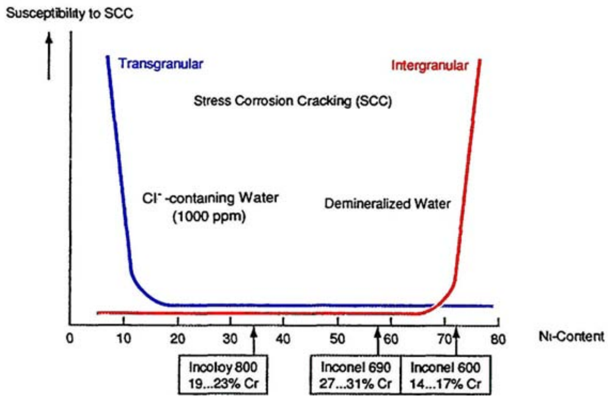


Figure 4.11. Schematic diagram showing the influence of nickel content on the cracking processes occurring in three steam generator tubing materials stressed slightly above the yield point in 350°C water. [23].

Consequently, after the SG replacement at big scale, where the susceptible tube material Alloy 600 MA was replaced mainly by Alloy 690TT or Alloy 800NG, a drastic reduction of most of the formerly observed acute degradation problems was observed, as shown in the Figure 4.8.

But in fact, SG performance is not a matter of tube material only, a long term damage cannot be excluded on any of the today accepted materials if adverse operation conditions are given. As before mentioned, after 30 years operation even good designed SGs may start having an initiation of secondary side chemistry induced SG tube degradation.

The following section intends to provide a better understanding of the SG degradation problematic covering the fundamental aspects involved in SG degradation of chemical origin.

4.1.3 Fundamental aspects on steam generator degradation and water chemistry

The most main reason for steam generator degradation is found to be corrosion of the SG tubing. Therefore, the basic aspects of chemistry related SG degradation deserve special attention. The SG tubing corrosion depends of the simultaneous influence of three factors, as indicated in Figure 4.12:

- SG and balance of plant system design
- SG and balance of plants materials
- Chemistry

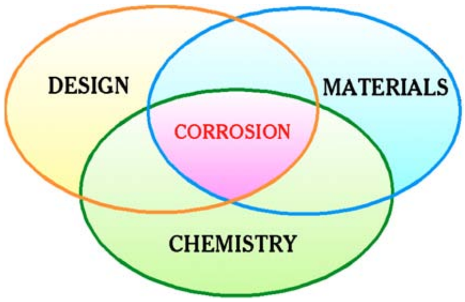


Figure 4.12. Factors affecting corrosion.

The most frequent cases of SG degradation are due to incompatibility between these three factors. Plants having a good design and material concept can afford a less restrictive chemistry, and vice versa. It is not possible to speak about secondary side chemistry without establishing how the plant design is and with which materials it has to be confronted. In the same way, the behaviour of a certain material cannot be assessed without considering the chemistry applied and in which plant design this material is inserted.

As it is described in the following sections, most of the extended and severe degradation problems were a consequence of incompatibilities of this kind. The experience gained led to considerable improvements of design, materials and operating chemistry, which resulted in significant improvement of the SG performance. But the long term SG degradation is still a problem requiring the implementation of preventive and corrective measures, either for the planning and construction of new units as well as for the safe and reliable operation of existing plants.

4.1.4 Basic mechanism of secondary side steam generator tube degradation

In a first observation of the damages reported, it results evident that there has been practically no damage of SG tubing in the free span sections of the tubing, where the tubes are in contact with the bulk water under turbulent regime, with few exceptions [3]. The basic mechanism for the occurrence of SG tube corrosion deserves attention since it gives the basis for a correct SG and plant design and the associated chemistry.

The steam generation causes all the non-volatile compounds present in traces in the feedwater flow to be concentrated (enriched) in the SG water, achieving concentrations quite higher than those of feedwater. To keep these concentrations at a reasonable level, the SGs are regularly purged by continuous blowdown. At a SG blowdown rate of for example 0.5% of the feedwater flow rate, the equilibrium concentrations of dissolved impurities in the bulk SG water are in principle expected to be therefore 200 times of the feedwater concentration for a non-volatile compound.

In fact:

Ingress by feedwater = elimination by blowdown + elimination by main steam [g/h]

$C_{fw}\, F_{fw} = C_{bd}\, F_{bd} + C_{ms}\, F_{ms} \approx C_{bd}\, F_{bd}$ [g/h]

$C_{bd} = C_{fw}\, F_{fw}/F_{bd} = C_{fw}\, 200$ [µg/kg]

Where:

C_{fw} is the impurity concentration in feedwater
F_{fw} is the feedwater flow rate
C_{bd} is the impurity concentration in SG blowdown

F_{bd} is the SG blowdown flow rate
C_{ms} is the impurity concentration in main steam
F_{ms} is the main steam flow rate.

That means, for the usual concentration of impurities in feedwater (in the rule below the limits of detection, i.e. quite below 1 µg/kg for most of the non-volatile impurities), the concentrations of these impurities in the SGs are expected to be few µg/kg only, provided that these substances are soluble and homogeneously distributed in the SG bulk water.

Owing to the SG tubing material properties, these expected concentrations in SG are far insufficient to cause any corrosion damages. This is widely supported by laboratory as well as the field experience, reporting no or negligible tube damage in the free span area of the tubes.

However, there is also a permanent ingress of corrosion products, mainly magnetite into the SGs, and deposits will be accumulated on the SG tube surfaces at top of tube sheet or in the tube to tube support crevices.

If the accumulated corrosion product deposits are sufficiently thick there is a risk of local enrichment of impurities beneath these deposits. This can occur at the tube sheet area within the flow steadied zone (sludge pile) and also at heavily encrusted tube to tube support device intersections. See Figure 4.13 [24] that represents the case at the tube sheet, as a matter of example. In fact, if thick corrosion product deposits accumulate in contact with the tube heat transfer surfaces, there will be a local overheating due to the additional resistance to heat transfer, causing the deposits to dry out. The surrounding water will keep the outer surface of the deposits wet, and this water will evaporate as it penetrates the deposit, creating a dry-to-wet interface where there will be a permanent boiling. This boiling will cause non-volatile impurities to concentrate at the wet/dry interface up to very high local concentrations. The concentration factors may achieve very high values, in the range of 10^4 to 10^6 times the bulk concentration.

These high impurity concentrations, associated to the locally higher temperatures (overheating) may be responsible for initiation of corrosion processes on the involved metal surfaces, especially at the SG tubing.

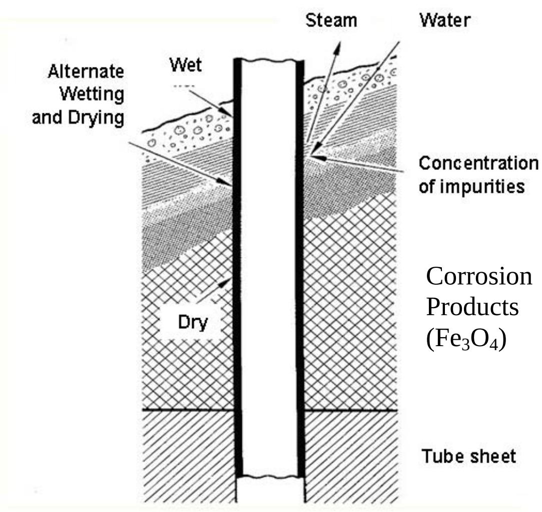


Figure 4.13. Impurity enrichment mechanism beneath deposits at the SG tube sheet (schematic).

Depending on the composition of the impurities in question, a series of physic-chemical changes will occur, like hydrolysis, precipitation of compounds after achievement the solubility product, etc.

These processes are very complex and strongly dependent on the composition rather than the concentration present in the bulk SG water. The composition of the bulk impurities will be given by the impurity sources, mainly:

- Ingress via make-up water (output quality of the water treatment plant),
- Condenser leaks (composition of cooling water),
- Consumables and auxiliary products which may enter into contact with inner surfaces (montage aids, for example),
- Impurities in the conditioning chemicals,
- Others.

As the concentration of the impurities in deposits increase, the pH can shift locally in these areas to acidic or alkaline conditions, entering in a pH range where initiation of corrosion phenomena cannot be longer excluded.

By maintaining of sufficiently reducing conditions, the occurrence of certain corrosion mechanisms will be excluded (like pitting), but certain forms of SG tube corrosion may still occur.

If these concentration mechanisms are considered, together with the redox condition of the system, a variety of possible corrosion mechanisms may appear [3, 13, 18, 19], including denting, SCC, IGA or the combination of both (IGA-SCC), pitting, among others, which are schematically shown in the Figure 4.14 below, where the possible corrosion mechanisms at different pH-redox conditions are graphically shown.

Worldwide performed investigations show clearly the SG tube material lack of stability against corrosion in the case of extremely acidic and/or alkaline conditions. Even with reducing conditions, stress corrosion cracking (SCC) of SG tubes cannot be excluded, if pH_T values of < 5.0 or > 9.5 prevail (see Figure 4.15 for I800 SG tube material[2] and Figure 4.16 for Alloys 600MA/TT and 690TT).

That means that ensuring a local pH_T value within the range of 5.0 up to 9.5 under reducing conditions would minimize the risk of stress corrosion cracking, according to this source. However, the safe pH range at operation temperature shall be considered to be roughly 4 to 8.5, based on available experience.

This pH cannot be measured, but only calculated. This calculation is strongly dependent on the input data, and the results should be interpreted as indicative only.

Computer aided programmes like the EPRI's MULTEQ have been developed to model the on-going processes as impurities concentrate, departing of a known (pre-defined) composition and concentration of impurities present in the SG bulk water. For instance, it can be predicted how a condenser leak will modify the chemical environment in the enrichment areas, or also the influence of the make-up water quality.

From these calculations, it results evident that depending on the input composition, the local chemical environment at the enrichment zones may shift to aggressive environmental conditions or not, depending on which species are being concentrated. A possible output of such calculations is schematically shown in Figure 4.17.

[2] In this figure, the redox potential is indicated by the author as 'oxidation potential'. Negative values mean reducing conditions. SHE: Standard Hydrogen Electrode.

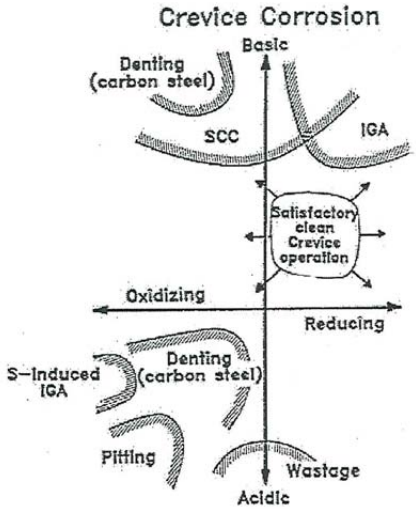


Figure 4.14. Illustration of SG tube corrosion in dependence of environmental conditions.

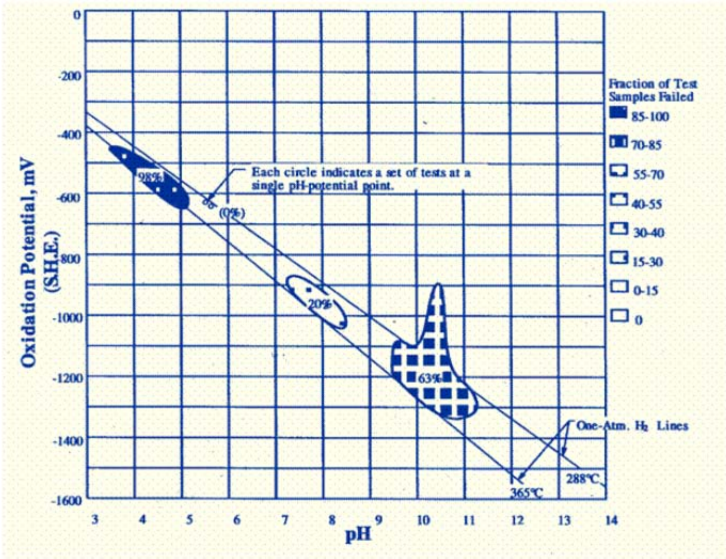


Figure 4.15. Stress corrosion cracking of I800 as a function of pH.

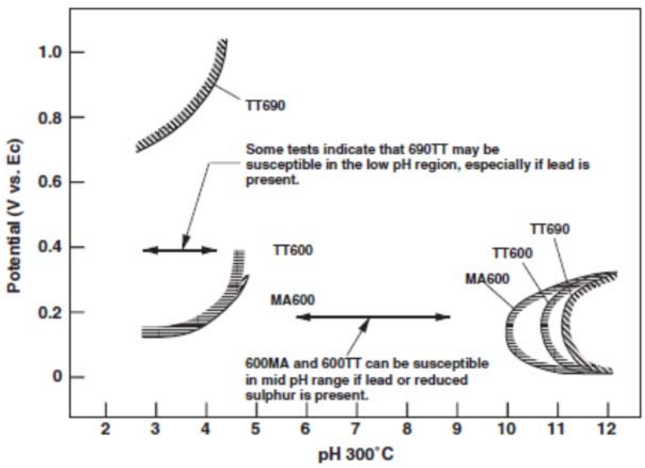
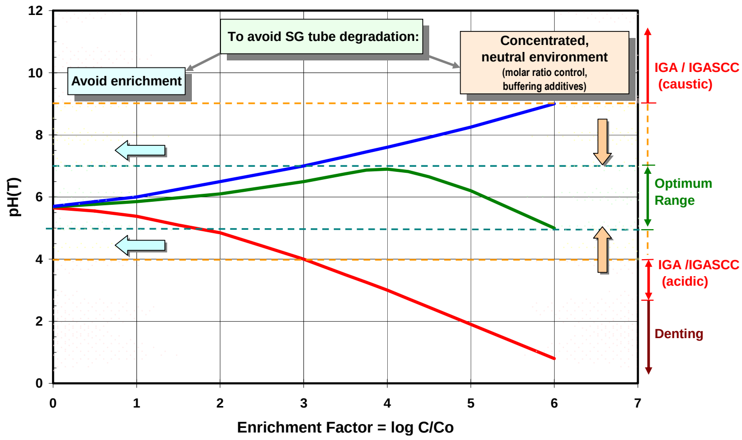


Figure 4.16. Stress corrosion cracking susceptibility of Alloy 600MA/TT and 690TT as a function of pH_T [25].



Co: impurity concentration at the SG bulk water
C: impurity concentration inside the deposit

Figure 4.17. Evolution of pH_T as a function of the impurity enrichment factor C/Co.

A shift into alkaline conditions may be responsible for the initiation of caustic induced SCC. A shift to moderately acidic conditions implies a risk of IGA initiation. Strongly acidic conditions associated with insufficiently reducing conditions have been responsible for the initiation of denting[3] in plants having carbon steel tube support plates.

Summarizing: Where corrosion products accumulate, local overheating may occur, increasing the local temperature and causing enrichment of the impurities dissolved in the SG bulk water up to corrosive levels. Corrosion is likely to occur, almost independently of the tube material.

There have been five ways selected by different suppliers to avoid the formation of aggressive local environments (see Figure 4.17):

1. **Avoid the enrichment of impurities by avoiding at the maximum possible extent the accumulation of corrosion products inside the SGs:**
   This is mainly achieved by SG design having less sites for accumulation of corrosion products:
   - High pH chemistry by use of high hydrazine concentration and its decomposition product ammonia.
   - Copper free secondary system is required. Common procedure in the 1980s and 1990s in plants with Cu bearing materials in the system was to keep pH low to avoid Cu corrosion by ammonia-oxygen attack.
   - Use of Advanced Amines (e.g. Morpholine, ETA) to reduce FAC in wet steam areas materials resistant to FAC. This became necessary in plants having Cu bearing materials in the system.

2. **Avoid at the maximum extent the ingress of impurities.**
   This method serves only to retard the time to achieve the aggressive environment. Zero input is unachievable. Impurity reduction shall be applied together with a high pH, i.e. a reduced corrosion product input.

3. **Molar ratio control.**
   A main method used by the industry especially in USA and Japan to try to keep the pH of heated crevices in the desired low SCC growth rate range is to control their pH using molar ratio control

[3] The corrosion of the drilled hole carbon steel TSPs under acidic conditions caused a deformation of the SG tubes (called „dent') due to augmentation of the corrosion product volume inside the tube-to-TSP crevices, causing the tube to be subjected to big forces. This deformation cause material stress making the area susceptible to SCC.

[3, 26]. The basis for this approach is that the molar ratio of strong cations (e.g. sodium, potassium) to strong anions (e.g. chloride, sulphate) in the crevice liquids is considered to define the pH_T (pH at temperature) in the crevice during operation. Since the concentration of these species in crevices cannot be measured during power operation, attempts are made to estimate what they were during the previous operating cycle by performing hide-out return[4] analyses immediately after plant shut down. These analyses involve measuring the concentration of chemicals returning to the steam generator bulk water after the plant is shut down. Based on these analyses, adjustments are made to the chemical balance for the next operating cycle. Adjustments were made in some cases even injecting ammonium chloride to improve the anion/cation ratio. However, the control of the crevice pH is considered to be very difficult and subject to many uncertainties [27].

4. **System conditioning with hydrolysable substances.**
   Hydrolysable substances able to buffer locally enriched impurities. These substances that present at much higher concentrations than the rest of the other impurities, will also concentrate inside deposits, leading to a moderate pH, avoiding the undesired shift to acidic or caustic conditions. Two buffer based chemistry treatments have been used in PWR plants with this purpose:

   - Phosphate treatment (PT)
   - Boric acid treatment (BAT)

   Phosphate buffers the environment to a slightly alkaline pH, avoiding the formation of free caustic and therefore avoiding caustic induced SCC as well as corrosion forms under acidic conditions.

   BAT was used in plants having Alloy 600MA tubing, highly sensitive to caustic induced SCC. Boric acid buffers the crevice environment to a slightly acidic pH in. It was successful to stop denting, but it could not palliate the SCC evolution.

   Both buffer conditioning treatments had drawbacks. In the case of phosphate a new form of corrosion appeared called wastage, initiated through the same concentration mechanism as formerly described in Figure 4.13 and mostly located at the tube sheet level, beneath deposits. The wastage corrosion mechanism was observed to be strongly dependent on the temperature, so that whereas ‘hot’ plants (SG temperature ~ 285°C) were severely affected by wastage in few years, ‘cooler’ plants (260 to 270°C) showed a slower progression of wastage.

5. **Intensification of impurity removal from SG.**
   Impurity removal can take place during normal operation through the SG blowdown. Increasing the blowdown rate will decrease the bulk water concentration and slow down the enrichment process. The blowdown rate is often limited due to economical reasons in plants, which are not designed for heat recovery of the blowdown (blowdown expansion tank, blowdown cooler using condensate returning to the feedwater train). Most of the plants have blowdown demineralizers giving the possibility of recovering the blowdown water. Plants having both features are in the position of operation at higher blowdown rates.

   The hide-out return of impurities during the shutdown (cooldown) transient has been also used to reduce the impurity inventory by keeping the SGs at an intermediate temperature of about 140°C to let hidden impurities re-dissolve and remove them by draining. The effectiveness is questionable.

[4] Hide-out return refers to the return into solution of salts which were ‘hidden’ in accumulation sites (crevices, deposits) during power operation. The return takes place as the SG temperature decreases in the cool down transient.

The only effective mean to remove accumulated impurities is the performance of mechanical and/or chemical cleaning of deposits.

At WWER plants, intermittent blowdown and a stepwise evaporation technique has been used to remove impurities.

4.1.5 Basis for the chemistry control

The main target of the secondary side chemistry is therefore to avoid or minimize the generation of local aggressive environments by enrichment.

Based on the arguments given above, there are three key chemistry parameters ruling the SG corrosion behaviour. In order of importance:

- Control of corrosion product ingress, pre-requisite for the formation of enrichment zones leading to aggressive environments.
- Control of reducing conditions, by conditioning with hydrazine.
- Control of impurity input (amount, composition).

These controls shall be performed for normal operation as well as during startup and shutdown periods.

4.1.5.1 Power operation

4.1.5.1.1 Control of corrosion product ingress

Main sources of corrosion products during operation are detailed in the following

General corrosion of carbon steels

The overall corrosion of carbon steel surfaces is strongly dependent on the pH of the medium in contact with the carbon steel surfaces, as shown in Figure 4.18 [28]. From this, if weak bases (amines) are used as pH conditioners, a practical limit for pH (25°C) is found to be about 10.0.

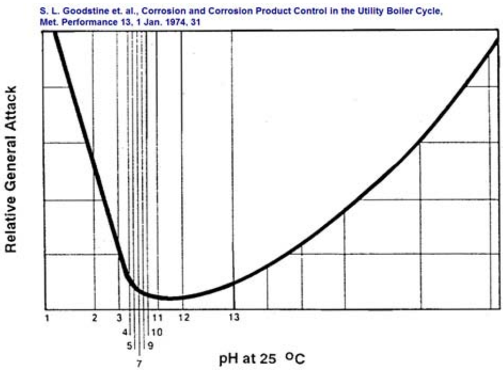


Figure 4.18. Relative general corrosion of carbon steels as a function of $pH_{25°C}$

Flow accelerated corrosion

This degradation mechanism is treated in detail in Section 4.5.4. In wet steam areas of the steam water cycle, typically the cross-under line, steam extraction lines and MSR region, amines may be stripped out from the water phase in contact with the metal depending on their volatility, resulting in a local pH decrease. This phenomenon, associated with a low oxygen concentration, may cause a corrosion form known as ‘flow accelerated corrosion’ (FAC) [29–33], on unalloyed carbon steel materials. This corrosion form is particularly enhanced in the temperature range of 150–200°C.

Factors influencing FAC are:

- pH value
- Oxygen concentration
- Material composition
- Temperature
- Geometry
- Linear flow velocity of the liquid in contact with the metal (FAC is a water-metal interaction)
- Steam humidity (presence of a water film in contact with the metal).

The areas of the secondary side most endangered to suffer FAC are those having a temperature of roughly 100–200°C, see Figure 4.65 [31].

The influence of pH on FAC is shown in Figure 4.64, showing the dependence of FAC rate with the pH value in the water film in contact with the metal.

If ammonia is the alkalizing agent, a pH of 6.5 at 190°C corresponds with a $pH_{25°C}$ = 9.5 in the water film. This curve shows that a non-alloyed steel experiments a reduction of the metal loss rate by a factor of > 100 by increasing the $pH_{25°C}$ of the water film in contact with the metal from 9.0 to 9.5. The ammonia concentration corresponding with this pH is ~1.15 ppm. Making an ammonia mass balance in the circuit, it results that the ammonia concentration in feed water must be close to 7.5 mg/kg, and the resulting $pH_{25°C}$ is 9.9. See Figure 4.19 showing a typical mass balance for a 900 MW(e) plant. The mass balance results are given in Figure 4.20.

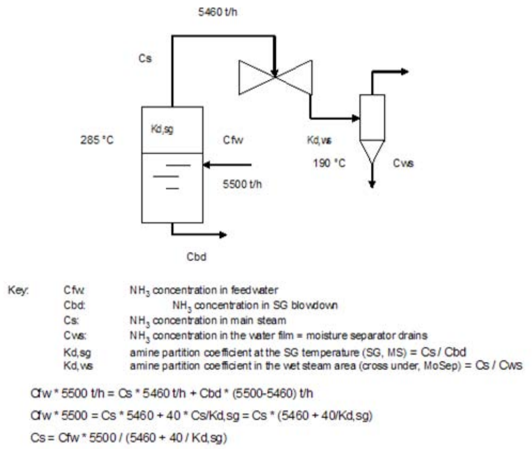


Figure 4.19. Amine mass balance in the steam water cycle.

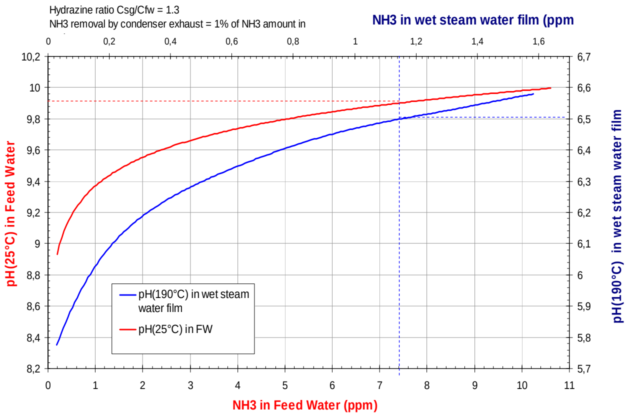


Figure 4.20. Correlation between pH and NH_3 in feed water and wet steam areas with NH_3 as alkalizing agent.

Plants having a lower cross-under temperature need also lower ammonia concentration in feedwater. For a cross under temperature of ~175°C the resulting ammonia concentration is 0.6 ppm and the $pH_{25°C}$ in feedwater necessary to have a $pH_{175°C}$ = 9.5 results to be ~9.8, achievable with 7.7 ppm ammonia.

These ammonia concentrations are readily achievable by thermal decomposition of hydrazine, which as to be injected anyway to ensure reducing conditions.

Results of the application of this concept on German plants

The corrosion product transport into the SGs was reduced by a factor of 5 to 10. The typical Fe concentration in feed water is ≤ 1 µg Fe/kg. See Figure 4.21 and Figure 4.22. This effect was recognized already in 1983 [24, 34].

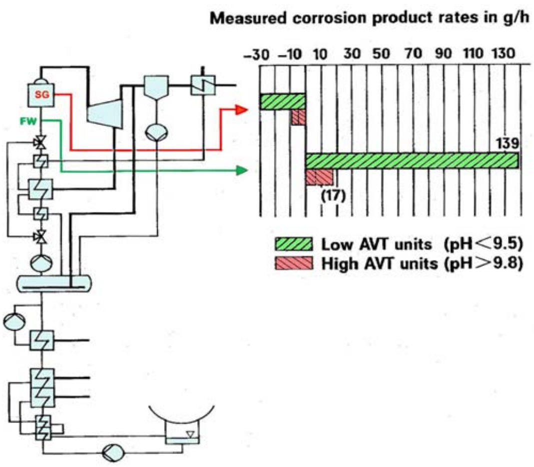


Figure 4.21. Fe transport along the water-steam cycle of German plants operating with high pH AVT - hydrazine-only treatment [34, 35].

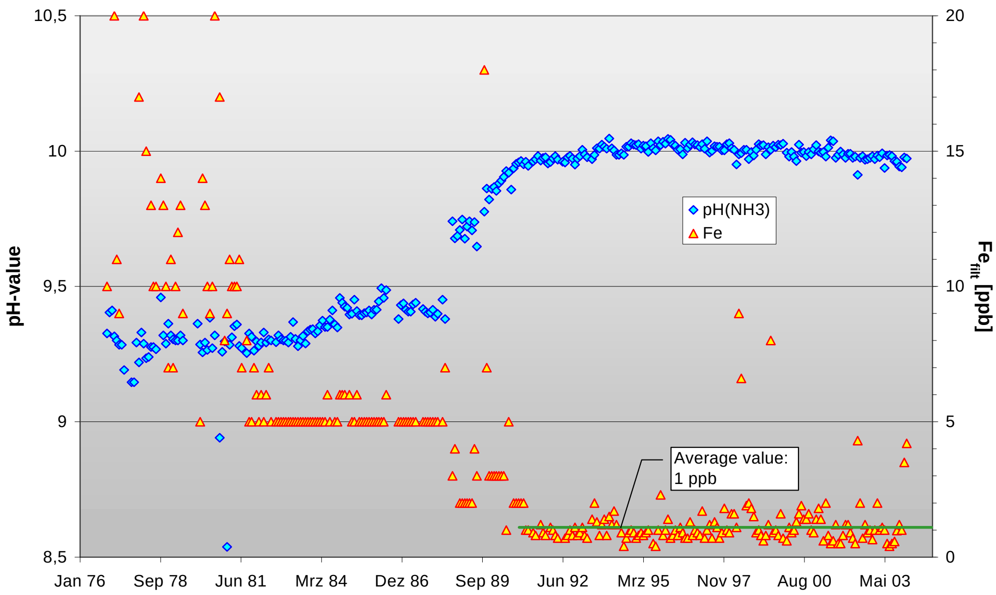


Figure 4.22. Measured pH and Fe concentration in feed at a plant converting from low AVT to high AVT - hydrazine-only treatment [36].

In case that the ammonia generated by hydrazine decomposition were not sufficient to achieve the target pH values as above defined, the injection of additional ammonia or another amine (Morpholine, ETA) becomes necessary. This has been the case at plants with limited hydrazine because of Cu presence in the BOP (see Section 4.1.5.1). This will depend of two factors:

- Ammonia removal rate by condenser exhaust.
- Degree of decomposition of hydrazine (N_2H_4), which can be estimated departing from the measured values of the hydrazine concentration ratio blowdown/feedwater.

Drawback of alternative amines: Increase of the cation conductivity in the system, masking the chemistry supervision.

The use of organic amines can promote fouling of ion exchange resins [37], particularly ETA. EDF reports satisfactory operation of the blowdown demineralizers working after amine breakthrough.

Film forming amines like octadecylamine and dodecylamine have been used in WWER plants with success.

Besides the need of controlling FAC to protect the SGs, FAC must be counteracted to protect the integrity of the whole system. The areas most affected by FAC are those at the temperatures of >100 to 200°C (Figure 4.65) which are namely:

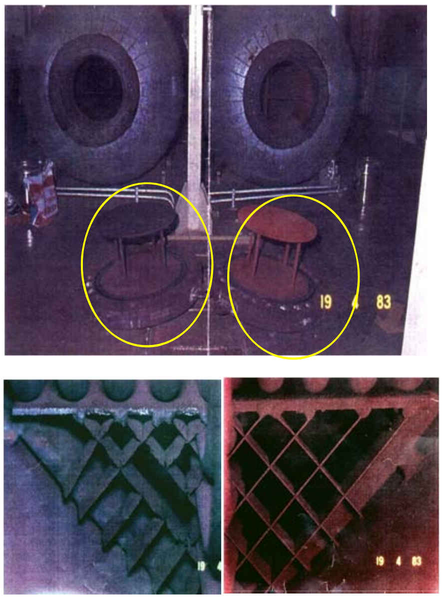
- Feed water train (single phase FAC).
- Steam systems, where there is moisture and a water film can be formed on the pipe and system surfaces (two phase FAC).

One important aspect of the FAC mechanism is that also the oxygen concentration plays an important role (see Section 4.5.4). In fact, very small amounts of dissolved oxygen will form preferentially hematite (Fe_2O_3) layers, less soluble than magnetite (Fe_3O_4), which is formed in absence of oxygen. Hematite is more resistant to erosion corrosion, increasing significantly the resistance to FAC. This can be seen in the example of Figure 4.23, corresponding to a plant having two FW trains having different oxygen concentrations. In one of them (oxygen free) mainly magnetite was formed on the surfaces, whereas the other (with small amount of oxygen content) had a reddish colour typical for hematite. The heaters having the red colour had no damage, whereas FAC was found in the black ones.

Plants having Cu in the system must limit the hydrazine concentration, and this force to keep the O_2 concentration in the condensate as low as possible, even more if the plant has no feedwater Deareator, to avoid oxygen to reach the steam generators. Low O_2 concentration associated to unalloyed carbon steels and unsuitable geometries like low radius elbows, T-joints, orifices, etc. may result in severe FAC damage of the feedwater or condensate train.

Plants with no hydrazine limitation can afford having some 5–10 ppb oxygen in condensate. It will react with hydrazine at the HP heaters where the temperature increase accelerates the oxygen scavenging reaction so that the final feedwater is oxygen free before achieving the SGs.

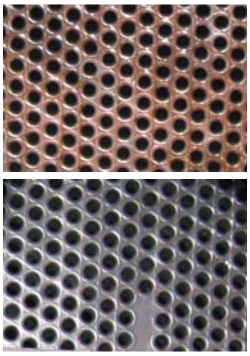
Typically, HP heater inspections at plants operated in this way show red colour at the inlet, and black colour at the outlet, like shown in Figure 4.24 [13].



Train A: no O_2, black surfaces (Fe_3O_4). FAC damage.

Train B: few O_2 ppb, reddish surfaces (Fe_2O_3). No FAC damage.

Figure 4.23. High pressure (HP) feedwater heater inspection of two parallel feedwater trains at a German plant, having different O_2 concentrations.



FW inlet:
red color (Fe_2O_3) due to few ppb O_2 still existing because of slow N_2H_4 –O_2 reaction at lower temperature (T ~ 180°C

FW outlet
Black color (Fe_3O_4) indicative of reducing conditions at final feed water after ~ 150 times faster O_2 scavenging by excess N_2H_4 (T~ 220°C)

Reaction constant ratio $k_{220}/k_{180} \approx 150$

Figure 4.24. Feed water HP heater inspection at a plant operated with high AVT (N_2H_4 – NH_3).

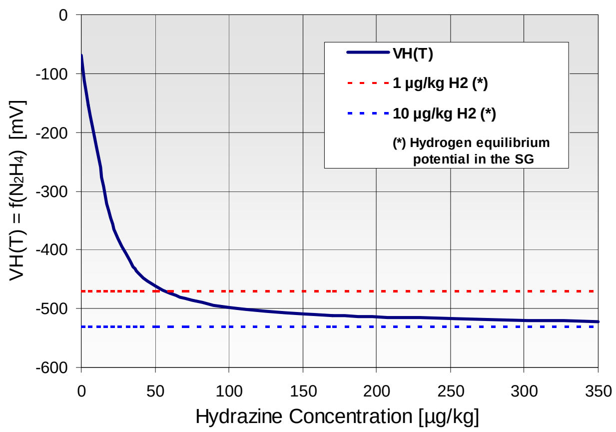
4.1.5.1.2 Establishment of reducing conditions

Besides the minimization of deposits, it is imperative to ensure reducing conditions in the SG environment. The major oxygen source is the air intake in the balance of plant (BOP) areas operating at sub-atmospheric pressure experienced in, for example the LP-turbine and condenser. A second source is the make-up water and other subsystems being recovered in the BOP. Copper/copper oxide is also considered to be an oxidizing agent. It can be found only in plants having copper in the BOP systems.

Redox potential measurements performed at several Siemens plants in the final feed water and inside the SGs (Figure 4.25) clearly show the need of maintaining a high N_2H_4 concentration.

The dotted lines indicated as 1µg/kg H_2 and 10 µg/kg H_2 in Figure 4.25 correspond to the hydrogen equilibrium potential in the SGs, which correspond to two different partial pressures of hydrogen taken arbitrarily.

According to these results, the target hydrazine concentration should be around 100 µg/kg, and not less than 20 µm.



VH(T) = f(N2H4) [mV] : Redox potential measured against normal hydrogen electrode at the operation temperature T, in mV, as a function of the hydrazine concentration.

The hydrogen equilibrium potential, corresponding to the chemical equation
$2H^+ + 2e^- \leftrightarrow H_2$
is given by the formula:
$E(H_2/H^+) = E^0(H_2/H^+) + (RT/F) \cdot \log [a(H^+)^2/p(H_2)]$
where $E^0(H_2/H^+) = 0$
$a(H^+)$: activity of hydronium ion (-log aH^+ indicates the solution pH)
$p(H_2)$: partial pressure of hydrogen in the system.

Figure 4.25. Influence of hydrazine concentration on the corrosion potential of Alloy 800 in steam generators (on-line plant measurements) [38].

For the steam generator pH at the moment of the measurement, two different partial pressures (corresponding to the concentrations of 1 µg/kg of H_2 and 10 µg/kg of H_2 respectively) were supposed and the corresponding hydrogen equilibrium potentials were calculated.

Since hydrazine decomposes thermally at operation temperature generating ammonia, both objectives (high pH, reducing conditions) are bonded together.

By maintaining sufficient reducing conditions, i.e. about 100 µg/kg of N_2H_4 in feedwater, considerable amounts of ammonia will be generated. The amount of ammonia produced having the required hydrazine concentration may be sufficient for achieving a sufficiently high pH in the steam water cycle as defined in the former section. In Figure 4.26 a typical calculation for a 900 MW(e) plant is presented, where the% hydrazine decomposition and ammonia production are estimated. Supposing a hydrazine ratio BD/FW of 1.3, the ammonia production estimated result in a $pH_{25°C}$ of 9.8, and a $pH_{190°C}$ in the wet steam film of 6.4, close to that needed for suppression of flow accelerated corrosion. The presence of ammonia cannot be avoided, since there is always a need of keeping a high hydrazine concentration in feedwater close to 100 µg/kg to ensure reducing conditions. Therefore, ammonia cannot be replaced by an ‘alternative’ amine.

This conditioning method (only hydrazine dosing) enables a simple and effective chemistry control. It is applicable only in Cu free plants.

4.1.5.1.3 Impurity control

Dissolved impurities in the secondary side are mainly involved in most steam generator corrosion processes and in a less extent the other secondary side systems. Impurities can be roughly divided into two groups, which are:

- Inorganic salts.
- Organic matter and CO_2.

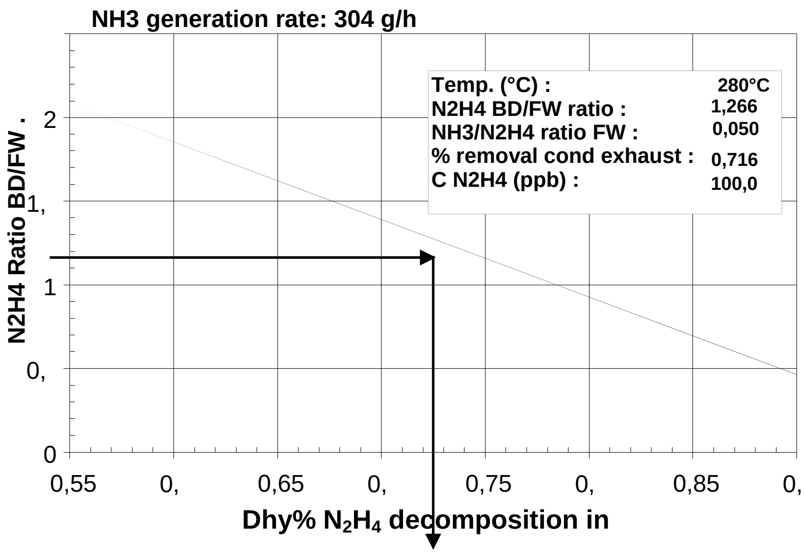


Figure 4.26. Hydrazine thermal decomposition% in the steam generators (typical).

Since the first ones are non or low volatile compounds, they can concentrate by evaporation being therefore of special concern for the steam generator tube degradation.

The second group can be of relevance for components like the turbine, but in the rule they are not detrimental for the steam generators.

A particular case is silica (SiO_2) which may be detrimental for SG, because it can concentrate in the SGs forming complex silicate forms, like alumina-silicates, some of them cement-like substances (e.g. xonotlite, augite) of very hard nature, which are believed to contribute to hardening of the deposits inside the SGS, especially tube sheet deposits. Silica is a common impurity in make-up water.

The sources for the impurities are the following:

- Condenser leakages
- Dissolved impurities in the make-up water and in the blowdown water treated by the blowdown demineralizers which returns to the cycle
- The steam generator blowdown demineralizers and the condensate polishing system ion exchange resins:
  - Resin/resin fine ingress
  - Reagents for regeneration, eluted by faulty regeneration.
- Impurities in chemical additives and consumables (like lithium hydroxide, boric acid, hydrazine etc.) during steady state operation
- Miscellaneous auxiliary products used during maintenance activities adhesives, markers, grinding material and assembly lubricants etc.
- Uncontrolled return of ‘clean’ condensates
- Organic compounds produced by decomposition of amines
- Oil ingress
- CO_2 entering at the condenser, or from thermal decomposition of organics
- Lack of cleanliness during outage maintenance activities.

Important is not only the amount of impurities transported into the system, but rather its composition.

Condenser leaks

It is clear that condenser leak is one of the most frequent causes of impurity ingress that may enter a system in a NPP and deserve a separate comment. It is important to take into account the improvement of condenser technology with respect to leak tightness and leak localisation capability. Then the type of cooling water is also very important in relation with the SG tubing material, as explained in other sections. Consequently, several situations may be considered.

In the 1970s most of the condenser had copper alloys and were not very tight, thus inducing frequent condenser leaks for which the threshold of localisation was ~10l/h. This was compatible with the operation with phosphate treatment buffering the condenser leaks acidity or alkalinity (see Section 5.1.2). In the case of AVT chemistry, condenser leak impurities can generate acidic or caustic, conditions by concentration beneath steam generator deposits, depending on the raw water composition.

Seawater is generating acidity, when magnesium compounds hydrolyse and precipitate at high temperature. Most of the river water generate more or less alkalinity (by $NaHCO_3$ decomposition into CO_2 and NaOH) although a very few fresh water are inducing a slightly acidic or almost neutral environment. The brackish or estuary water may be better with a more neutral resulting situation.

In these early times, for NPP with such condensers that were not tight enough, many PWR or WWER decided to add a condensate polishing plant (CPP) also called condensate polishing system (CPS) to eliminate the impurities entering the condenser especially for very small leaks that were not possible to locate and repair or just to increase the plant availability. The advantages and disadvantages are later assessed.

Different condenser design features have been later introduced, which are briefly summarized:

- Titanium tubing has been selected for many units cooled by seawater, since the chemistry specifications were only compatible with extremely low seawater leak that could not be localized by existing techniques.
- Stainless steel (or even titanium at the time this material was rather cheap) for river water-cooled units.
- Specific tube sheet design. Many different designs have been used, like for instance double tube sheet with intermediate demineralized flow water between the two tube sheets with the aim of reducing the leak impact in case of un-tight tube to tube sheet rollings with moderate results. Main drawback: permanent ingress of demineralized water.
- Condensers with tubes welded into tube sheet to avoid leaks in this area. This is a key point. In fact, the condenser is subjected to strong deformations between the operation condition (vacuum) and shutdown condition. This implies tensile or compressive tresses in the tubes, which are transferred to the tube to tube sheet joints, making them eventually leak. To avoid this, the only reliable solution is using welded tube to tube sheet joints as shown in Figure 4.27.
- Copper alloys were and are still selected a number of cases for either economical reasons, partial refurbishments or decision to keep a material that is preventing from amoebae development in closed circuits of cooling water with cooling towers.
- Hotwell steam sparging to avoid subcooled water (oxygen-containing) to be fed in the SGs at startup.
- Condenser cooling boxes with high flow rate draining possibility, to isolate the fastest possible a leak.

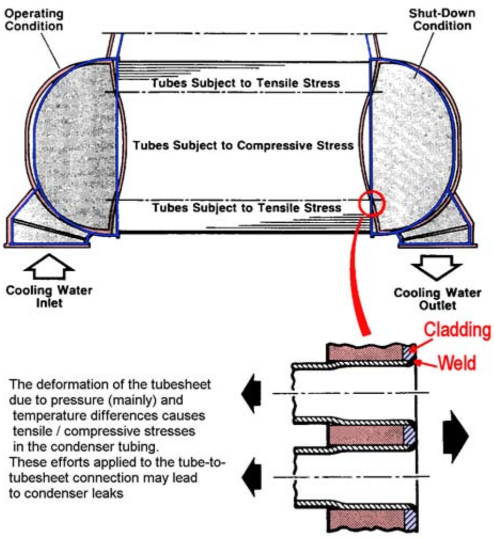


Figure 4.27. Main condenser design [39].

Then, progressively, significant progress has been made in leak detection (by cation conductivity or sodium in various sections of the condenser) and moreover in leak localisation. Many different techniques may be used depending on the leak rate:

- Visual pressure difference methods such as placing a foil on the tube sheet, a candle near the tube sheet.
- Helium detection, which belongs to the most sensitive and efficient method for rather small leaks. A helium pressure is put section-wise using covers on one side of the water chamber, while the gas is pumped on the shell side and sent to an analyzer giving the helium signal, when present in the gas, demonstrating the presence of a leak in the analyzed section. Large sections of the condenser tube sheet are first checked and then when one of these is identified as containing the leaking tube, smaller and smaller sections are progressively analyzed to identify the leaking tube (or a set of leaking tubes).
- Use of sulphur hexafluoride as tracer (SF_6). SF_6 is a colorless, odorless gas, which can be detected at extremely low concentrations (LD ~0.1 µg/kg), much lower than He, and has been also successfully applied.

With the new technology of condensers (material selection and tube sheet design), there is a drastic reduction of leaks that cannot be managed and eliminated when the need appears. In most cases, the situation is the existence of tight condensers that are more and more rarely leaking, provided they are properly maintained, with deposit elimination to avoid underneath corrosion.

This is explaining why an increasing number of units either do not have condensate polishers or keep them in by pass mode most part of the time.

Condenser polishers

With respect to impurity control, the operator’s philosophy can be oriented to:

- Emphasizing the prevention against impurity intake or,
- Implementation of cleaning facilities such as condensate polishers, i.e. condensate polishers system (CPS). The latter option can have a detrimental effect if not correctly applied. This technique is strongly depending on its design and operation modality, especially the regeneration technique:

- The risk of having a permanent small elution of free caustic or a sudden malfunction in operating the CPS. Considering that the corrosion processes affecting the SG tubing need as a prerequisite a concentration of impurities up to an aggressive level, the molar composition of the impurities which are entering to the steam generator is much more important than the absolute amount.
- The risk of intake of resin fines since this is the potential source of sulphides that are formed by thermal decomposition of sulphates in the steam generators.
- The risk of ingress regeneration solutions, i.e. pure caustic soda and/or sulphuric acid, inside the balance of plant and finally inside the steam generator.

Figure 4.28 shows the cation conductivity as well as sodium concentration in main-steam, heater-drains and SG-blowdown with and without operation of condensate polishing system. Due to caustic elution the lowest sodium concentration was measured when the condensate polishing system was not operated. Figure 4.29 shows also, that the sodium concentration is even higher during operation of CPS than during its out-of-service. The cation conductivity shows that operation of the CPS leads not necessarily to an improvement of the situation.

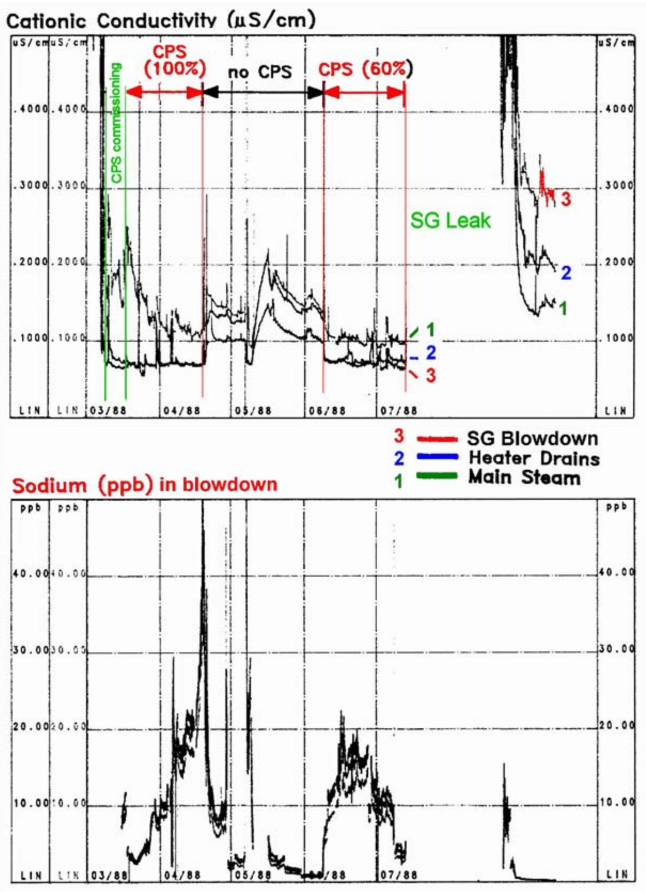


Figure 4.28. Behaviour of cation conductivity in main steam heater drains and SG blowdown, and sodium in SG blowdown with and without CPS operation (caustic elution).

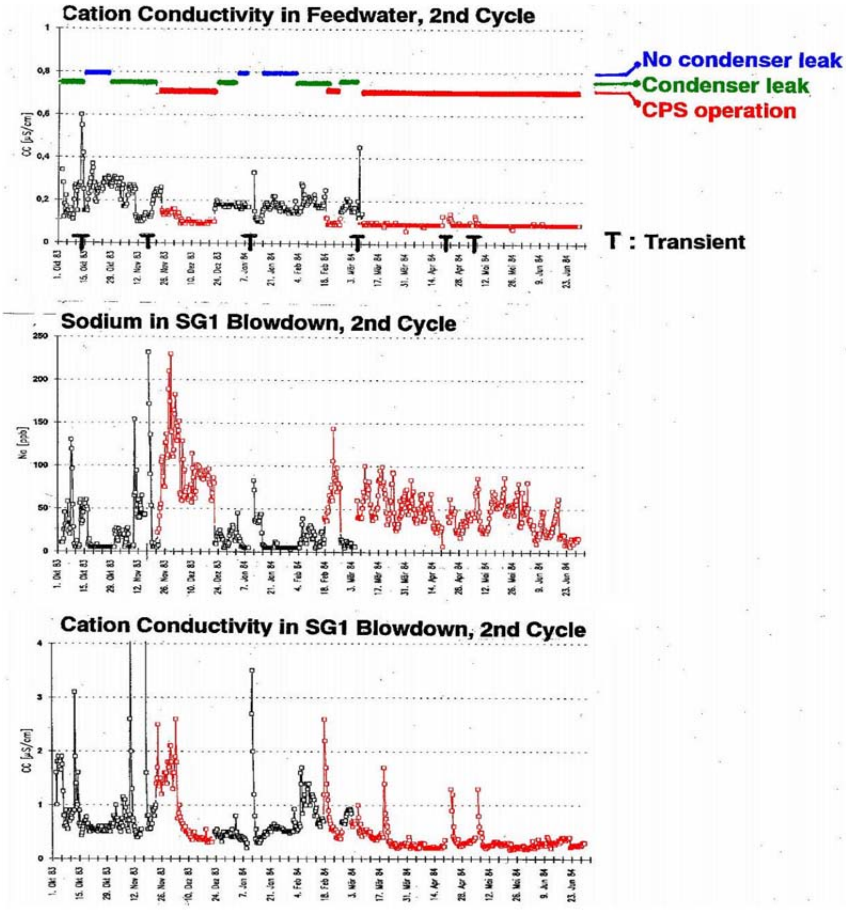


Figure 4.29. Behaviour of cation conductivity in feedwater and SG blowdown and sodium in SG blowdown with and without CPS operation.

Under undisturbed conditions, the make-up water being added to compensate fluid losses of the cycle (including SG blowdown when not recovered).

To reduce possible impurity ingress inside steam generators via the ***make-up water*** system it is recommended to tighten the steam water cycle as much as achievable to reduce the amount of make-up water during operation.

The ***recovery of SG blowdown*** permits a drastic reduction of the make-up coming from the demineralizing water plant. The quality of the water returned by the blowdown demineralizers is in the rule better than that of the make-up water plant, and oxygen free. Main drawback: in case of faulty operation, like bad regeneration, loss of resins, etc., there is a direct impact in the SGs (no buffering through intermediate storage).

Some plants use blowdown water to feed the demineralizing plant, decreasing the salt input and prolonging considerably the operation time between regenerations, resulting in a lower impurity input into the system.

A special attention should be turned on impurity ingress via ***auxiliary products*** (called also **consumables**) like adhesives, markers, grinding material and assembly lubricants, which are more or less temporally in contact with surfaces of systems and components during outages. Auxiliary products are regularly not designed for application in nuclear power plants, therefore, the high requirements regarding cleanliness and low impurity content are often not met.

Another possible reason for 'promoting' the ingress path via auxiliary products is that users select auxiliary products often only due to their generic properties and not based on impurities, which causes and/or enhances corrosion. Reason for this behaviour might be that the requirements for nuclear business are often not known or up to now this auxiliary product was used all the time or the generic properties of this product are excellent.

Both operators and manufacturers of nuclear power plants have developed and installed surveillance systems to scale down the ingress of impurities via this path. For example EDF installed the 'PMUC' standard for the French NPPs and AREVA NP developed the qualified product database ('QP-Database'), which is used by NPPs in five European countries.

Summarizing, the corrective measures for minimizing the impurity level are as follows:

- Ensure tight condensers and if condenser leakages occur: rapid and efficient localization and repair of any impurity in-leakage (helium leak test, online condenser monitoring).
- Avoid use of condenser polishers, or ensure adequate operation and regeneration due to risk of caustic elution.
- Minimize make-up water demand.
- Install quality surveillance programme of chemical additives and consumables as well as auxiliary products for maintenance and assembling.

The extent of the impact of impurity ingress into the cycle on the SG integrity will be strongly dependent on the retention (hideout) of impurities in occluded, overheated regions filled with corrosion product deposits. The chemistry supervision of impurities should not only point of reduction of the impurity concentrations, but mainly to establish the degree of hideout which is taking place. A steam generator cleanliness control strategy must be implemented to enable a situation-oriented maintenance programme (see Section 5.3).

4.1.5.2 Shutdown and startup conditions

Shutdown

The shutdown condition normally implies ingress of air into the systems. This, associated to incomplete draining, wet surfaces, moisture condensation, etc. will result in general corrosion of the carbon steels surfaces, and even localized corrosion, where anodic sites can be formed, preferentially in the presence of impurities, like for instance at the intersection between the metal, air and liquid as shown in Figure 4.30. Water and air are the pre-requisite.

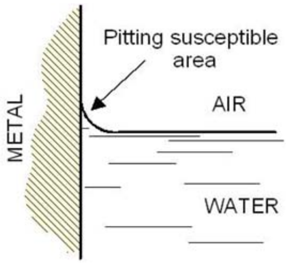


Figure 4.30. Shutdown corrosion: pitting at not completely drained locations.

A wet, aerated environment will cause not only damage to the components themselves, but it will increase the corrosion product ingress into the SGs in the startup phase. Besides, lack of cleanliness during and after the outage will cause also an undesired ingress of them into the SGs.

To avoid this, measures have to be taken by:

- Lay-up programme (see Section 5.3.3.9):
  - Dry lay-up: apply to empty systems
  - Wet lay-up: apply to filled systems.
- Chemistry control programme:
  - Control of consumable materials
  - Cleaning procedures after repair works.

Wet lay-up with conditioning agents eliminates oxygen thus impeding the corrosion process.

Dry lay-up to a dew point of < 10°C, or < 50% relative humidity (RH) eliminates water, also making the corrosion process not possible.

Concerning the steam generators, it is almost unavoidable to have wet and aerated conditions simultaneously, like during the tube sheet lancing. But the time at wet-aerated conditions has to be minimized through a good organization.

Oxidizing, wet conditions in the SGs during shutdown can promote tube sheet denting. In fact, during operation under reducing conditions denting is less probable, but it could be initiated after a long outage period where the tube sheet remains wet and the SG is kept open to air.

Startup transient

In this phase, all loose corrosion products as well as the impurities left in the system will be transported towards the SGs if they are not previously removed by an efficient flushing of the feed water train. The consequences of high Fe concentration in feed water at startup are made evident in the Figure 4.31. The integrated values of the Fe present in feed water permit the calculation of the magnetite ingress rate. About 50% of the magnetite ingress during 7 months of operation took place in two startup operations.

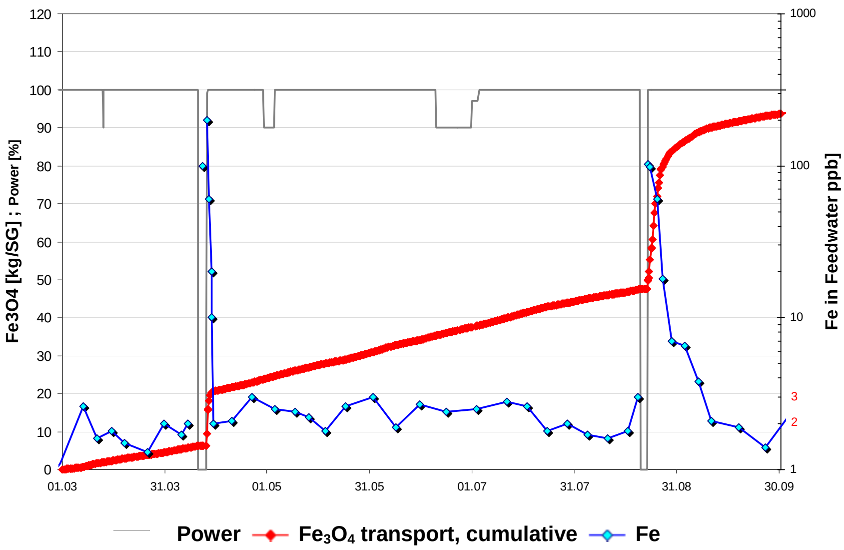


Figure 4.31. Ingress of corrosion products during startup.

4.1.6 Steam generator design

The relative impact of tube degradation mechanisms on overall PWR steam generator performance depends strongly on the plant and SG design. Inadequate geometries such as gaps and crevices promote the accumulation of corrosion products and this must be avoided at the maximum extent by design.

There are the three locations in the heat transfer areas of steam generators common to all steam generators together with the important features that affect the performance of such crevices (see Figure ***4.32***):

- Tube support structures or tube support plate (TSP).
- Top of tube sheet crevices at the tube to TS intersections (TTS).
- Sludge/deposits on tube sheet.

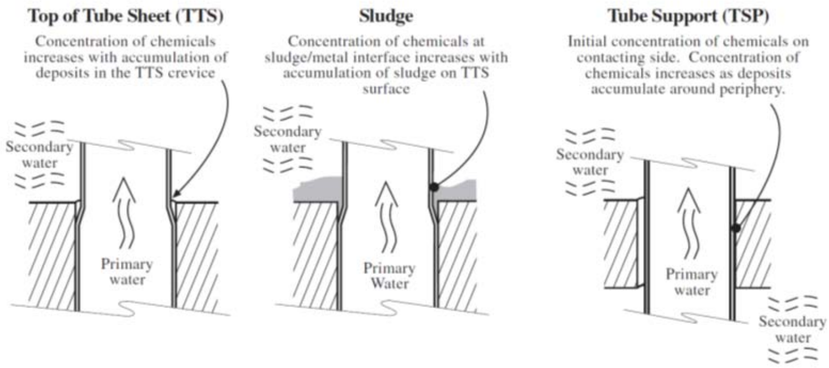


Figure 4.32. Geometries that produce heat transfer crevices involving tubing in steam generators [40].

The tube sheet (TS) deposits are the only that cannot be effectively decreased by design owing to the vertical design of the recirculation SGs. Therefore, the tube sheet is to be considered as the weakest point of the SG from the corrosion point of view and TS cleanliness is a high priority objective to retard SG ageing.

4.1.6.1 Tube support structures

The design of the tube support structures has been proved to be a key factor or a good SG performance. The majority of the reported SG tube corrosion problems after conversion to AVT - chemistry occurred in the tube to TSP crevices.

Basically there were three types of tube support devices (see Figure 4.33):

- Drilled hole tube support plates (DH-TSP).
- Broached trefoil and broached quatrefoil tube support plates (BH-TSP).
- Egg crate tube support grids (EC-TSG).

The evaluation of the different tube support plate geometries since the beginning of the nuclear business are summarized in Figure 4.34. The first used geometry was the drilled hole tube support plate designed by Westinghouse and Combustion Engineering in the early 1960s in USA. This tube support plate design was replaced later in 1970s and 1980s by the broached hole design in Westinghouse designed SGs and by the egg-grate structure in Combustion Engineering designed SGs. Babcock-Wilcox (USA) used only broached trefoil TSPs for their once through SGs, whereas Babcock-Wilcox (Canada) had started to use egg crate tube support structure in their recirculation SGs in 1990s. For Siemens SGs the egg crate design was the only tube support structure from beginning on in 1960s.

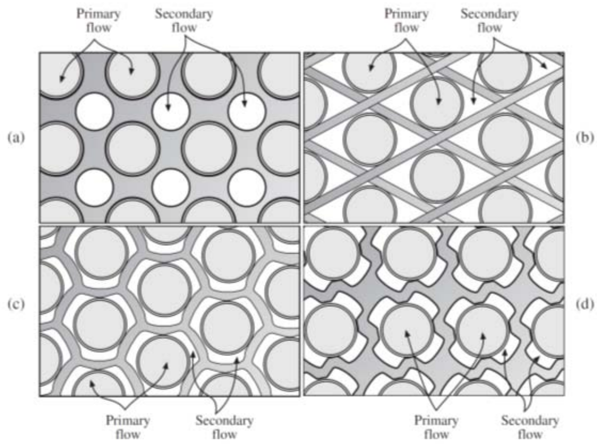


Figure 4.33. Geometries of tube supports: (a) drilled hole typical of early Westinghouse designs; (b) Egg crate typical of Siemens and Combustion Engineering; (c) broached trefoil typical of EDF and Babcock and Wilcox; (d) broached quatrefoil typical of later Westinghouse designs [40].

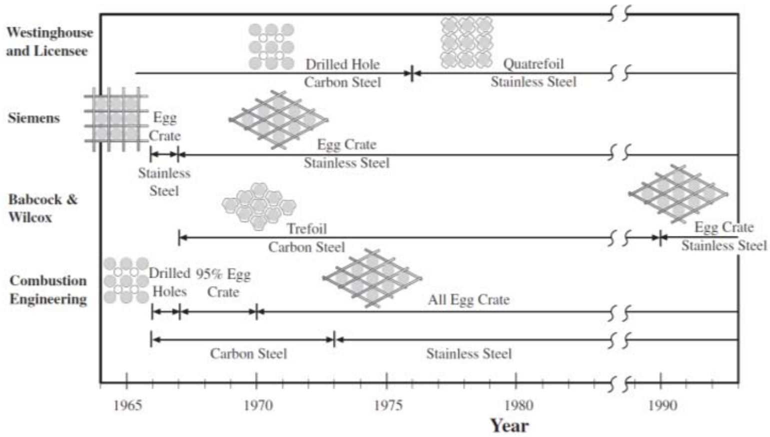


Figure 4.34. Evolution of tube support geometries and materials used by four nuclear steam supply system vendors for steam generators. [40].

As licensee of Westinghouse, Framatome (now AREVA SAS) and Mitsubishi Heavy Industry (MHI) have started to change to quatrefoil broached hole design in their SGs; whereas finally AREVA SAS moved to a trefoil broached hole design with convex tube lends, as shown in Figure 4.36.

Drilled hole tube support plates

They consist on a perforated plate with a thickness of about 20 mm where the holes diameters through which the tubes are inserted have a tolerance of +200 µm to +300 µm referred to the tube outer diameter (see Figure 4.35).

The drilled hole tube support plate is the worst design known and the main cause of tube degradation at tube support levels in the 80s and 90s. Corrosion product deposition inside the crevice will rapidly take place, causing:

- Strong increase of the local temperature due to lack of water circulation outer side of the tube.
- Local boiling conditions leading to dry-out of the area and enrichment of impurities in there.
- Corrosion.

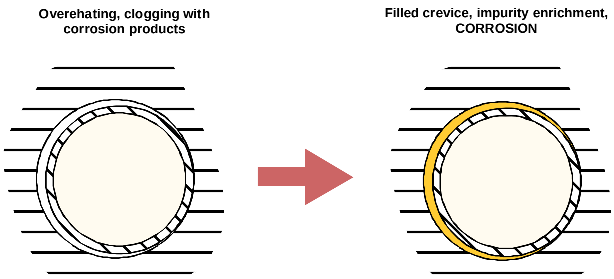


Figure 4.35. Drilled hole tube support plate design.

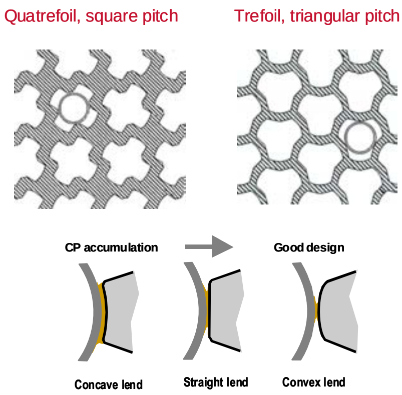


Figure 4.36. Broached hole tube support plate design.

Broach hole tube support plates

This design eliminates the local overheating and reduces the presence of crevices:

- Less or no enrichment of impurities.
- Better corrosion behaviour.

However, broach hole support plates have, depending on the design, more or less susceptibility to deposit accumulation and eventually clogging of the broached holes. The design features (quatrefoil or trefoil; Concave, straight or convex surfaces in contact with the tube) are described by Figure 4.36.

The main problem observed with this design is clogging of the broach holes as shown in Figure 4.37.

The clogging of the broached holes causes various difficulties:

- Perturbation of the SG internal hydrodynamics,
- Change of the recirculation rate,
- Increase of local flow velocities,
- Flow induced fretting,
- Flow accelerated corrosion (carbon steel plates).

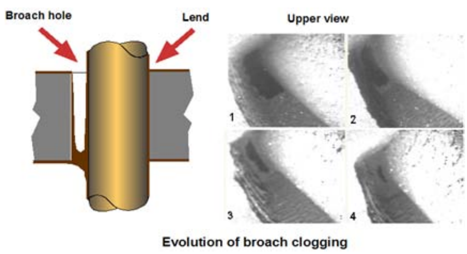


Figure 4.37. Broached hole clogging.

Tube support grids of the egg crate type

This design reduces at the maximum the overheating and crevice problem. The Siemens designed egg crates are made of stainless steel and its design principle is given by Figure 4.38. The egg crate design is from the chemistry point of view the best choice due to the following reasons:

- There are only two points in contact with the tube at a given level, with exception of the high bar intersections (only 4 tubes from 100 having a closed geometry around).
- The tube surfaces are better exposed to the SG bulk water, no overheating and/or deposit accumulation.
- No or negligible corrosion damage in more than 30 operation years is reported. Three plants report moderate initiation of OD damage after 31–34 years operation at the high bar intersections, i.e. affecting only a small fraction of the tubes.

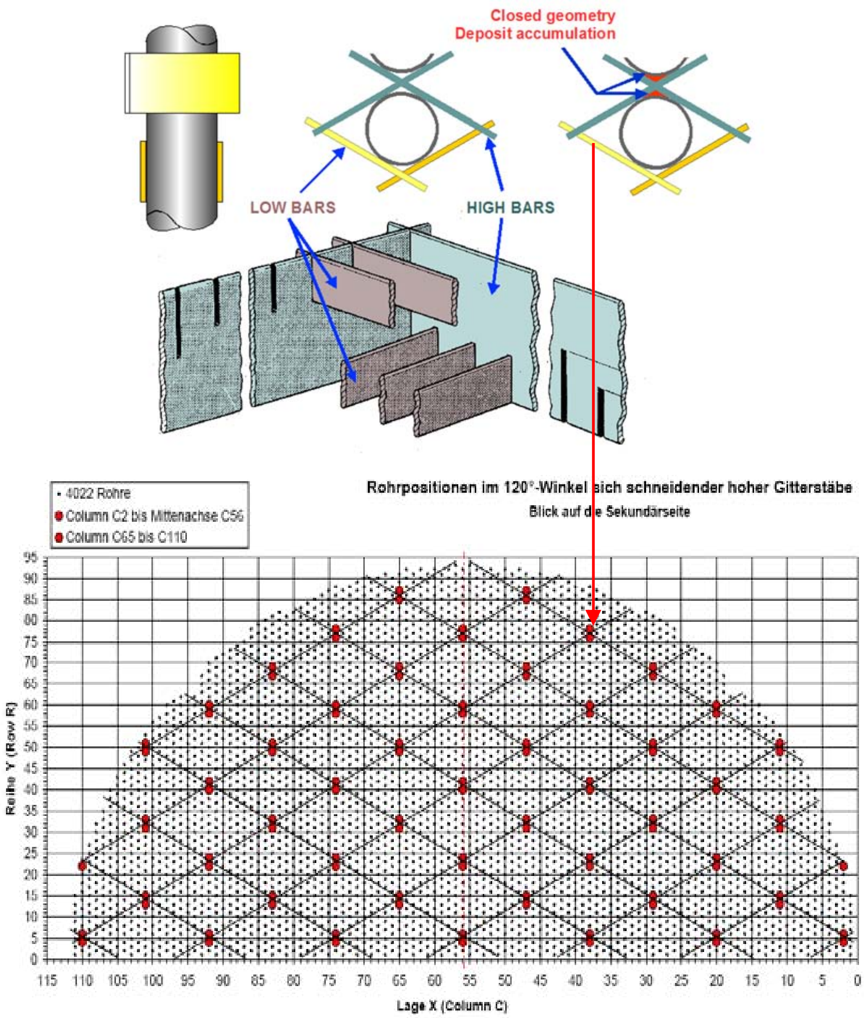


Figure 4.38. Siemens tube support egg crate design.

There is also another design type of egg crate grids designed by Combustion Engineering, which are made of carbon steel and have four contact points with the tubes at a given level (see Figure 4.39) [40]. In contrast to Siemens designed egg crates, this type of egg crate tube supports provides less recirculation round the tube resulting in less tube cooling and increased corrosion product deposits. In fact, SG tube corrosion was experienced at field within the crevices of tube to this type of egg crates.

4.1.6.2 Tube sheet design

The tube sheet area is the weakest point in the SGs of vertical arrangement. Corrosion products will eventually accumulate on the tube sheet surface. Accumulation of corrosion products on the tube sheet can be minimized by adequate design of the steam generator:

- Flow distribution baffle to maximize the radial flow velocity to reduce deposition of corrosion products at the maximum extent (see Figure 4.40). This device has a limited effect.
- Tube arrangement enabling efficient tube sheet cleaning. Once deposited, the corrosion products must be removed by high pressure tube sheet (TS) lancing each shutdown. A tube arrangement with square pitch cannot be cleaned as thoroughly as those arranged with triangular pitch (see Figure 4.41). In the latter case, with an adequate cleaning tool the perimeter of the tube can be cleaned almost completely.

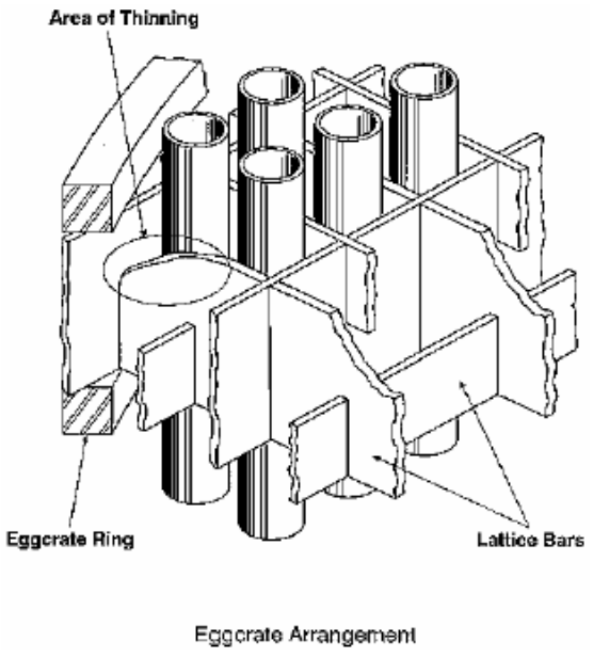


Figure 4.39. Combustion Engineering designed egg crate tube support grids [3].

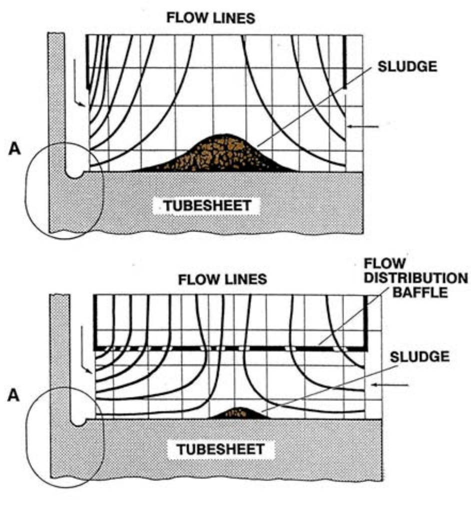


Figure 4.40. Flow distribution baffle to minimize the tube sheet deposits.

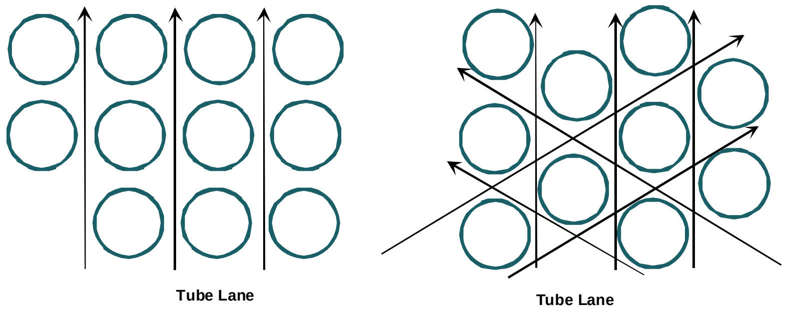


Figure 4.41. Influence of the tube arrangement on the tube sheet cleaning efficiency.

Tube to tube sheet intersections

The crevice between tube sheet and tube may represent a serious SG tube integrity problem.

Different techniques have been applied (see Figure 4.42). In the early years a mechanical expansion was performed only at the bottom, letting a deep crevice open towards the secondary side. This arrangement had as consequence the creation of differently aggressive local environments leading to numerous corrosion problems.

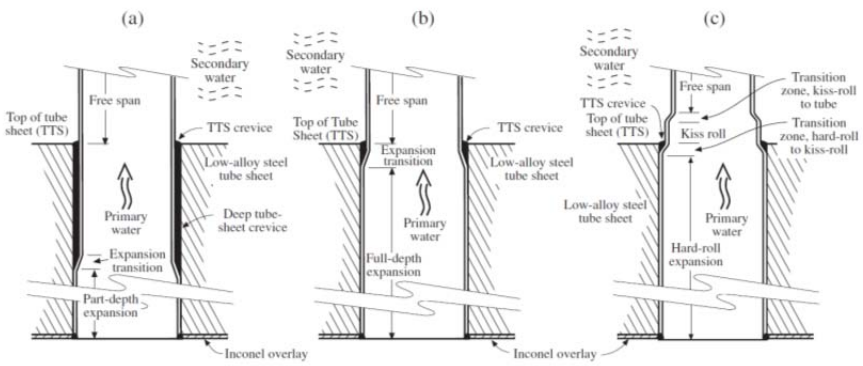
Fully expanded technique is now state of the art (see Figure 4.42 b, and Figure 4.43). A small crevice of 3 mm to 6 mm depth and a crevice having ~150 µm cannot be avoided for technical reasons (expansion tolerance at the top of tube sheet to avoid damage by over expansions).

The expansion technique can be hydraulic, mechanical, or a combination of both.

The minimization of the crevice depth becomes essential to avoid degradation problems like tube support denting and stress corrosion cracking.

If impurities accumulate in these crevices, oxidation of the carbon steel of the tube sheet will occur, generating less dense Fe oxides that, occluded inside the gap, will press and deform (dent) the tube (Figure 4.44).

This type of denting has been found under hard-caked deposits, and not necessarily implied later appearance of damage of outer diameter (Figure 4.45). In many cases the denting stopped its evolution after one or two cycles.



(a) partially expanded
(b) fully expanded
(c) fully expanded with ‘top kiss roll’

Figure 4.42. Tube to tube sheet geometries [3].

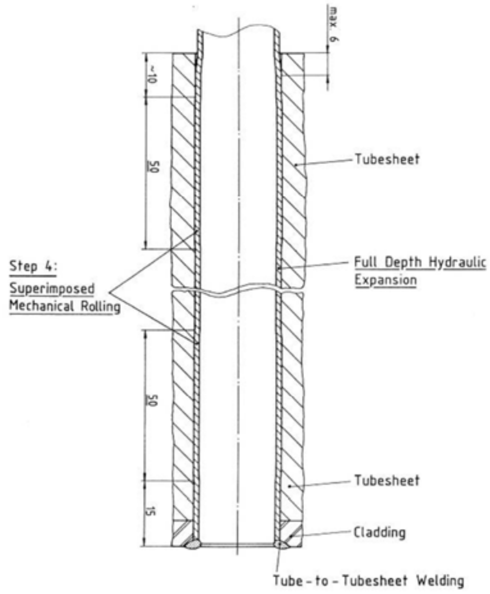


Figure 4.43. Advanced tube to tube sheet expansion technique.

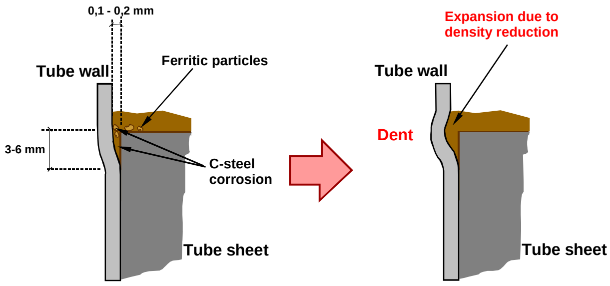


Figure 4.44. Tube sheet denting.

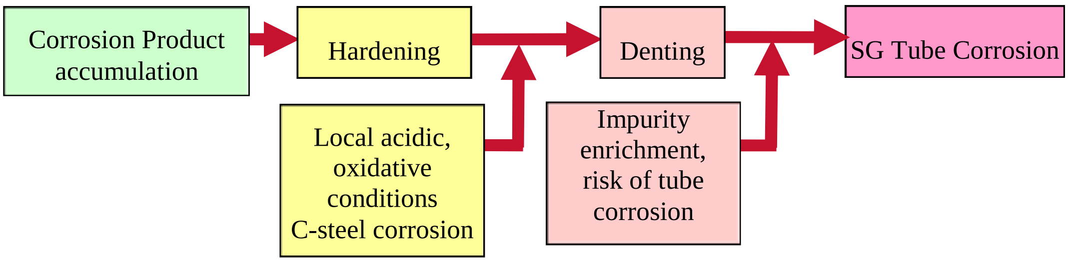


Figure 4.45. Damage of tube outer diameter following denting at top of tube sheet level.

4.1.6.3 Blowdown internal design

Two basic designs have been used:

- Blowdown collector pipes at the tube lane.
- Peripheral groove.

A typical design for collector pipe design is shown in Figure 4.46.

This is the most widely used SG blowdown design. The blowdown is taken from the middle of the SG and therefore it comes out very close to saturation. Saturated fluid may cause cavitation problems by pressure drop at the blowdown transport line outside the SG, requiring a rapid cool down or a tempering by mixing the blowdown with a small fraction of feedwater.

The design of the blowdown with perimetral groove (gutter) is shown in Figure 4.47. This design enables a better accessibility to the tube lane, and since it takes water from the periphery the water is subcooled because of the flow coming from the downcomer, which is mixed with feedwater.

The efficiency for removal of impurities and corrosion products is comparable.

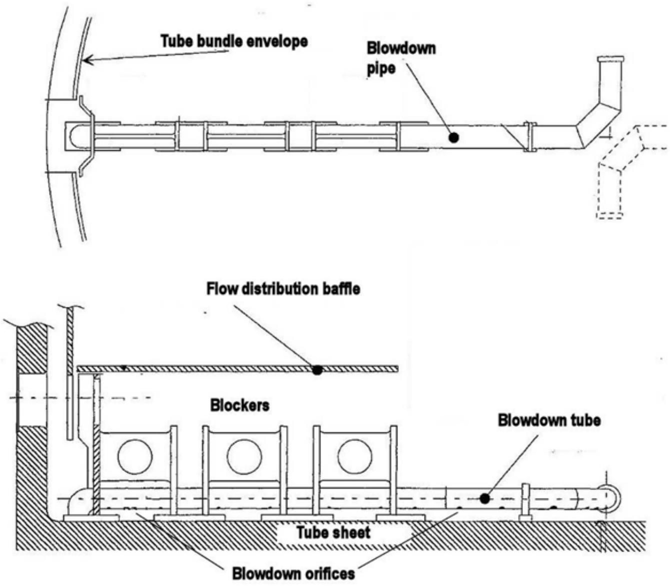


Figure 4.46. SG blowdown arrangement with internal perforated blowdown tubes (typical).

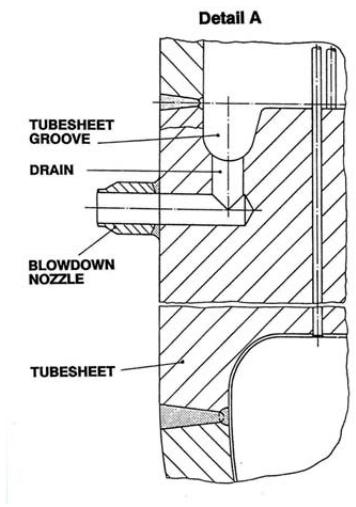


Figure 4.47. Blowdown with perimetral groove.

The external gutter provides the possibility of a better collection and removal of corrosion products being lanced towards the outer perimeter of the tube bundle during tube sheet lancing (easier aspiration of TSL waste).

4.1.7 Balance of plant design

The balance of plant (BOP) design has great impact on the corrosion product generation and transport inside the steam generator. As already pointed out minimizing the deposition of corrosion products inside the steam generators is the main goal to minimize corrosion problems and retard SG ageing, together with the maintenance of sufficiently reducing conditions in the steam generator.

Main BOP design features influencing SG performance:

1. **Absence of Cu alloys in the BOP** is a very important item.

The presence of copper in the BOP components represents a serious problem for SG integrity. In fact, Cu is responsible for two prejudicial situations:

- As indicated in Section 4.1.5 the presence of copper result in a limitation of the hydrazine concentration in the cycle due to the generation of ammonia. It obliges to reduce the ammonia concentration in the cycle to avoid corrosion of the Cu alloys (e.g. condenser tubes). Ammonia is a decomposition product of hydrazine, which is required for maintenance of reducing conditions in the SGs. The required amount of hydrazine is around 100 µg/kg. See Figure 4.25. The ammonia amount generated at this hydrazine concentration level is incompatible with copper bearing materials. So that the presence of Cu obliges to reduce the hydrazine concentration down to values that are often not sufficient to guarantee reducing conditions in the steam generators.
  Besides, Cu can act as oxidant ($Cu^{2+} + 2e \rightarrow Cu°$), which accelerates and/or promotes corrosion forms requiring locally oxidative conditions, like denting, and pitting.
- The reduction of hydrazine causes then indirectly also a limitation of the system pH, which is responsible for a higher generation of corrosion products, which will be transported into to the SGs increasing the risk of having impurity concentration sites in the SG accumulation zones. It forces the use of other Advanced Amines for alkalizing to counteract this negative effect.

That means, Cu has a negative influence on two of the three key parameters affecting SG corrosion performance: reducing conditions and corrosion product transport. Even if the pH in critical areas like HP turbine outlet and moisture separator reheaters (MSRs) can be improved by application of complementary, less volatile amines like Morpholine or ETA, the limitation of hydrazine subsists.

2. **Use of low alloyed Cr/Mo-carbon steels at areas susceptible to FAC** (e.g. HP turbine outlet, cross-under line, moister separator reheater)) is advisable for FAC minimization. The influence of material composition on FAC is shown in Figure 4.48.

3. **Low design flow rates**, smooth elbows, no high turbulence areas.

4. **Feedwater deareator** (Feedwater tank) is advisable especially for the startup transients. There, pre-heated, degassed water is made available before achieving criticality, so that at the moment of switching to the main feedwater pumps oxygen free water is available. Without deareator, the FW pumps take water from the condenser hotwells, which can hardly be kept oxygen free because they are under vacuum and it is difficult to avoid air ingress. If not available: condenser hotwell steam sparging can be implemented to reduce O_2 solubility during startup operation. A second advantage of a deareator is that it provides feed water at higher temperature in the subcritical phase of the startup transient, decreasing the risk of damage of the SG feed water nozzles by thermal shock/thermal stratification taking place by injection of cold auxiliary feed water.

5. **Tight condenser for impurity reduction.**

   Mainly achieved by using welded tube to tube sheet joints, and employing copper free tube materials, namely titanium or stainless steel. Not every stainless steel is resistant to seawater or brackish water conditions. A good selection is x2nicrmocu 25 20 5 (1.4539) or x2nicrmocu 2520 6 (1.4529), German standard [24]. Refer also to Section 4.1.5, Figure 4.27. The combination of welded tubes and with adequate selection of tube material and manufacture (e.g. Seamless tubes), ensure sufficient condenser tightness.

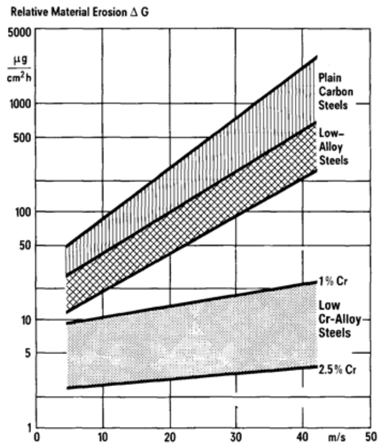


Figure 4.48. Influence of metal composition the FAC rate [35].

6. **Minimization of the make-up water amount by SG blowdown recovery through a mixed bed ion exchanger.**

   This technique reduces drastically the make-up water consumption. The blowdown demineralizers provide in the rule better water quality than the water treatment plant, reducing consequently the impurity ingress into the cycle. The main disadvantage is that any perturbation in this system has immediate impact on the cycle chemistry (no intermediate storage tank). Some plants use the blowdown water as raw water for the water treatment plant. This is a very good practice, prolonging the run time of the demineralising chains, and it results in a decrease of the impurity input. The water and steam leaks along the whole steam water cycle must be minimized. Target: less than 35 m^3/day, which can be achieved by adequate design of gaskets, valve types etc. Even recycling of water from the sampling system (0.5 to 1 m^3/h) is being practiced in a number of cases.

7. **No condenser polishers/**no condenser polisher operation during plant power operation, or very careful CPS design and operation. Refer to Section 4.1.5.

8. **SG blowdown recovery.**

   High capacity blowdown, with blowdown heat recovery, so that 0.7% blowdown are made possible on continuous basis, and doubled in case of need (startup, condenser leak).

   Plants not having thermal recovery are not only loosing energy, but also jeopardizing the SG performance by reducing the blowdown rate.

   Blowdown water recovery is advised to reduce the make-up water amount and consequently the impurity ingress. This happen in three different ways:

   - Using a regenerable mixed bed ion exchanger.
   - Using a non-regenerable ion exchanger.
   - Using the blowdown water as row water for the demineralizing plant. This indirectly implies an improvement of the demineralised water quality produced.

   The first alternative is used in most German plants. Disadvantage: possible accidental elution of regenerates into the system.

The second alternative is widely used, and implies the operation of the exchange, after amine breakthrough or in some cases forcing a reduction of the ammonia concentration to prolong the exchanger operation time, impacting negatively the corrosion product control.

4. **Controlled return of auxiliary condensates** to the system.

4.1.8 Analysis of the main steam generator tube degradation mechanisms

4.1.8.1 *Primary water stress corrosion cracking*

Recalling the Figure 4.11, Alloy 600MA is susceptible to pure water stress corrosion cracking, whereas, Alloy 690TT and Alloy 800NG are generally not susceptible. This is indicative of the susceptibility of Alloy 600MA to primary water stress corrosion cracking (PWSCC).

The occurrence of PWSCC of Alloy 600MA strongly depends on the absence of intergranular carbides. High mill-annealing temperatures (1065°C during final heat treatment) produce <u>inter</u>granular carbides, which make Alloy 600 HTMA tubes more resistant to PWSCC. In contrast, low mill-annealing temperatures produce <u>inter</u>granular carbides, which make tubes susceptible to PWSCC. PWSCC is a stress dependent process such that the damage rate increases as the stress to the fourth power. The exponent of four on damage rate is typical of stress exponents for creep and, thus, is consistent with modern models for PWSCC, which say that slow straining at the crack tip is an essential part of the cracking process. PWSCC is also a thermally activated process, which can be described by an Arrhenius relationship. A small decrease in steam generator operating temperature will significantly slow the initiation and growth of PWSCC at any location in the steam generator.

PWSCC occurs at locations on the inside surfaces of recirculating steam generator tubing with high residual stresses (normally introduced during fabrication and installation of the tubes). These locations are primarily the roll transition regions in the tube sheets, the U bend regions of the tubing in the inner rows (i.e. the tubes with a small bend radius), and any dent locations at the tube support plate, tube sheet, or sludge pile elevations. Section 4.1.5 discusses tube denting, e.g. deformation resulting in residual stresses due to build-up of corrosion products. PWSCC generally occurs on the hot leg side of the recirculating steam generations, however, cold leg PWSCC has also been observed.

Examinations of removed tubes affected by PWSCC and in situ inspection by rotating pancake coil eddy current test probes indicate that PWSCC cracks typically have the following patterns [41]:

- Cracks in U bends typically are axial in orientation, though occasional off-axial cracks have been detected.
- Cracks in standard roll transitions are mostly axial, though occasional short circumferential cracks occur between axial cracks. Rarely are isolated circumferential cracks detected. When the tube expansion is kiss rolled the crack is always axial and the growth rate decreases as crack length increases.
- Some large circumferential cracks have been detected in the sludge pile area of kiss rolled plants in France. In some cases, large circumferential cracks have been located at the same transition as multiple axial cracks. In other cases, large circumferential cracks have occurred without any axial cracks.
- Cracks at explosive transitions are typically circumferential in orientation, though occasionally axial PWSCC is noted by rotating pancake coil eddy current testing.
- Primary side cracks at dented tube support plate intersections are typically axial, though some circumferential segments have been noted.

- Cracks at dents associated with sludge pile deposits at the top of the tube sheet (observed in France) have been circumferential in orientation.

In the case of an axial crack, a leak will occur before the critical crack size (leading to tube rupture) is achieved. On the other hand, the evolution of circumferential cracks is not known. Consequently, a tube with a circumferential crack is usually plugged or sleeved immediately after detection to avoid possible tube rupture.

Already in the mid 1990s about 100 PWR plants worldwide had experienced significant PWSCC at the roll transition (tube sheet), dent, and/or U bend locations of the tubing, leading to extensive SG tube plugging or sleeving.

This degradation has occurred primarily at Westinghouse type plants (steam generators built by Westinghouse and by Westinghouse licensees in Europe and Japan) in Belgium, France, Japan, the Republic of Korea, Spain, Sweden, Switzerland, and the USA with Alloy 600MA tubing, typically expanded by hard rolling (which introduces high residual stresses at the roll transition and where rolling anomalies occurred). The most extensively degraded steam generators have had as many as 20% to 38% of all their tubes plugged as a result of PWSCC and have been replaced at a number of plants. However, similar steam generators (same model number) at other PWR plants have experienced only a few tube failures due to PWSCC. The explanation can be found in a lower operation temperature, and also the material characteristics.

Some units like Combustion Engineering plants with relatively high temperature mill annealed tubing initially reported significantly less PWSCC. However, after about several years of operation (10–20 years) PWSCC appeared, being the possible explanation the material sensitization of I600 MA at operation temperature (see Figure 4.49).

French plants with thermally treated Alloy 600 tubing have plugged tubes because of PWSCC at the roll transition region (PWSCC of thermally treated Alloy 600 tubing has occurred only in steam generators in which the tubes were mechanically rolled into the tube sheet.). However, the number of steam generator tubes involved (a total of 82) is rather small, in part, because the tubes were not plugged unless they also had dents (i.e. the possibility of circumferential cracking). As of December 1993, there had been no PWSCC of thermally treated Alloy 600 tubes in the USA or elsewhere outside of France and there had been no PWSCC of Alloy 690TT or Alloy 800NG tubing.

CANDU units using high temperature mill annealed Alloy 600 tubing, running at relatively low inlet temperatures, have not experienced PWSCC to date. The oldest running plant with Alloy 600MA tubing has over 20 effective full power years (EFPY) of operation with no evidence of this degradation mechanism. It is believed that the lower operating temperatures of the CANDU primary system and more resistant material may have contributed to the delay in onset of this type of cracking. The other tubing alloys used in the CANDU steam generators, Monel 400 and Alloy 800NG, are not susceptible to PWSCC.

Siemens SGs tubed with Alloy 800NG were also immune to his degradation type. No PWSCC reported. Alloy 800NG has the largest operation experience without PWSCC.

The evolution of PWSCC obliged some plants to reduce the operation temperature to slow down the degradation process [42] with the associated economical detrimental effect.

Alloy 600MA can be slowly sensitized at operation temperature (see Figure 4.49). This may explain the initiation of PWSCC after several years of operation. Alloy 800MA and Alloy 690TT (Figure 4.50), on the contrary, cannot sensitize at operation temperature during all the SG lifetime.

Therefore, the PWSCC problematic at the SG tubing is likely to have been solved at a great extent with the SG tube material replacement.

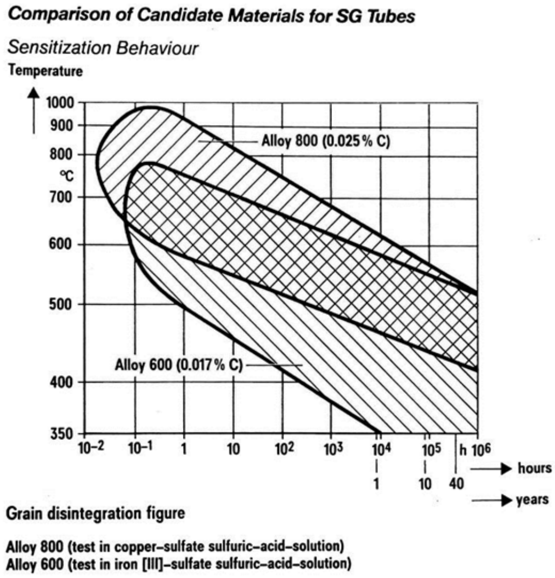


Figure 4.49. Sensitization time of Alloy 600 and Alloy 800 as a function of the temperature.

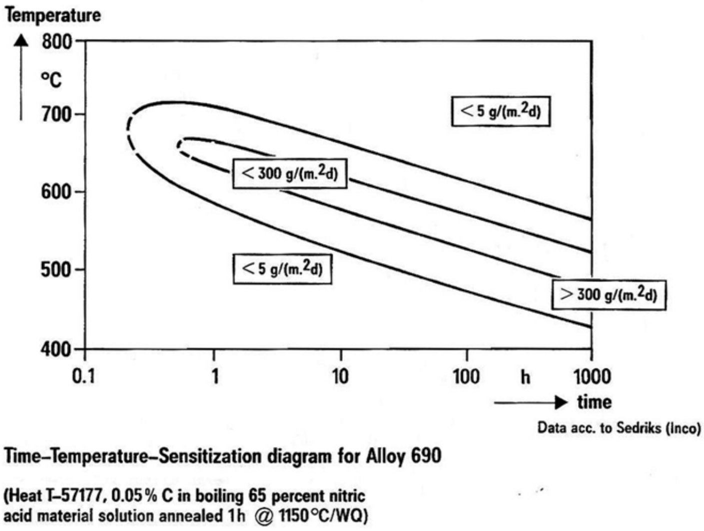


Figure 4.50. Sensitization time of Alloy 690TT as a function of the temperature.

4.1.8.2 Outer-diameter stress corrosion cracking

Outer-diameter stress corrosion cracking (ODSCC) is a degradation mechanism, which includes both intergranular stress corrosion cracking (IGSCC) and intergranular attack (IGA) on the outer surfaces of the tubing. Most of this degradation took place in the tube to tube sheet and tube to tube support plate crevices (drilled hole type). SCC has been also found beneath TS sludge pile.

IGSCC requires the same four conditions as PWSCC: tensile stresses, material susceptibility, high temperature and a corrosive environment (water containing aggressive chemicals). The corrosive environment is caused by enrichment of impurities that are present in the SG bulk water in zones of accumulation of corrosion product deposits (see Section 0).

IGSCC cracks occur along the grain boundaries, oriented normal to the maximum principal stress. IGA is characterized by local, corrosive loss of material on the grain boundaries, it does not require large tensile stress, but it is believed that stress accelerates initiation and growth of this mechanism. If the crack occurs through the grains, instead of along the grain boundaries, then it is called transgranular stress corrosion cracking (TGSCC).

ODSCC strongly depends on the concentration and composition of corrosive impurities at dry-out regions in the steam generator, mainly in crevices and beneath tube sheet deposits. A reduction of the impurity levels in the system can only delay the initiation of ODSCC. Plants having a very low impurity transport into the SGs will only delay the ODSCC initiation. The local impurity levels in the affected areas will be ruled by the presence of deposits, pre-requisite for impurity enrichment.

The impurity levels in the SG bulk water are highly variable, and are likely influenced by at least the following: cooling water type (fresh, brackish, sea), condenser leakage history, air in-leakage history, water treatment history, plant attention to secondary side chemistry, and types and application history of remedial measures.

ODSCC has occurred in the tube to tube sheet and the tube to tube support plate crevices and in the sludge pile region.

Free span ODSCC has been observed at some plants having thick deposit layers on the tubes. It occurred at a much lesser extent, and should be considered as exceptional.

ODSCC cannot be effectively controlled by impurity control only. The process is mainly dependent on SG geometry (crevices) and corrosion product accumulation.

Most outer-diameter stress corrosion cracks are primarily oriented in the axial direction, however, significant circumferential cracking has been observed in the roll transition region of the tubing in some steam generators and circumferential ODSCC is sometimes found near dents. For example, circumferential ODSCC at the roll transition region of the tubing had occurred in about 50% of the tubes in each of the three steam generators at Doel Unit 4 by the end of the eighth cycle.

In some cases circumferential OD cracking at top of tube sheet level has been found associated to previous occurrence of tube sheet denting (Refer to Figure 4.44 and Figure 4.45).

The axial cracks occur either singularly or in networks of multiple cracks, sometimes with limited patches of IGA shallow circumferential cracks may occur in the IGA affected regions producing a grid-like pattern of axial and circumferential cracks termed ‘cellular corrosion.’

ODSCC has been the main cause for tube plugging in plants provided with I600MA tubed steam generators.

The ODSCC damage recorded until 1995 serves to give a good impression of its rapid evolution.

As of December 1993 at least 89 PWR plants (44 US plants) with RSGs have experienced some degree of ODSCC in the tube sheet crevice, sludge pile, tube support plate intersection, or free span locations [43]. Approximately 14140 recirculating steam generator tubes with ODSCC at the tube support plate locations have been plugged at 63 PWR plants. Approximately 13860 recirculating steam generator tubes with ODSCC in the tube sheet crevice and sludge pile regions have also been plugged at 75 PWR plants (49 PWR plants have had both tube support plate and tube sheet ODSCC repairs). Tubes with ODSCC have also been sleeved at 25 plants. This degradation has occurred primarily in Combustion Engineering (eight plants) and Westinghouse type plants (79 plants) with Alloy 600MA tubing.

Only few CANDU plants have experienced some degree of ODSCC in the tube sheet crevice, sludge pile, tube support plate intersection, or free span locations. Tube material affected: Monel 400 and Alloy 600MA. The lower operation temperature of the SGs at CANDU plants is also responsible for a later initiation and slower evolution of the ODSCC damage.

Only one plant with thermally treated Alloy 600 tubing has reported ODSCC (Kori-2 has reported finding ODSCC assisted by lead (Pb) in the tube sheet region and plugging 125 tubes).

Only one tube with ODSCC had been found in the Siemens steam generators with Alloy 800NG tubing in the same period. This good result is attributed not only to the tube material, but mainly to the high pH - high hydrazine operation. Recently, some of the plants having RSGs of the Siemens type reported tube sheet denting exclusively at zones where hard-caked sludge had been previously formed. At one of these units 78 tubes were preventively plugged, and 2 in a second plant. The first OD indications at tube support started to appear in Siemens plants at two units after 31 operation years. Summary of OD indications at Siemens plants:

- 213 tubes plugged due to OD damage, from which 135 tubes correspond to 8 older plants.
- 43 tubes plugged due to OD corrosion at the grid tube support intersections, after ~ 31 operation years, at only 3 plants, initially operated with PO_4 and low AVT chemistry.

The only CANDU plant with extensive ODSCC has been Bruce-A2 where 1399 tubes failed (were plugged) due to lead assisted stress corrosion cracking. The most extensively degraded steam generators have had as many as 40 to 56% of all their tubes plugged or sleeved as a result of ODSCC and have been replaced at a number of plants. The degradation was severely aggravated in Bruce-A2 by contamination due to a lead blanket inadvertently left in one steam generator during maintenance activities. Cracking in the lead contaminated steam generators was typical of lead assisted cracking: mixed mode, transgranular and intergranular, ranging from 0–100% through wall. Lead shielding was also accidentally introduced into the Doel Unit 4 steam generator in Belgium and is believed to have contributed to the severe ODSCC, which subsequently occurred in that steam generator.

ODSCC has appeared in PWR steam generator tubes with both high and low mill annealed temperature, but generally not in thermally treated tubes, because, the thermally treated tubes do not have chrome depletion at the grain boundaries. Tests were conducted using high temperature electrochemical measurements to identify conditions leading to IGA [44]. The results of these tests indicate that in 10% caustic media at 320°C, IGA is commonly observed in Alloy 600 in the mill annealed condition. Thermally-treated material at 700°C shows definite improvement over mill annealed material in resistance to both IGA and IGSCC.

Because ODSCC can take several forms (short axial cracks, long axial cracks, circumferential cracking, cellular corrosion, etc.) and the ease of detection of these various kinds of ODSCC degradation varies considerably, the potential safety consequences of ODSCC at separate plants can be quite different. For example, ODSCC within the tube sheet is much more difficult to detect with a standard eddy current bobbin coil probe than PWSCC within the tube sheet or axial ODSCC at the tube support plates. However, it is possible to detect ODSCC within the tube sheet before it reaches a critical size and, therefore, make repairs before tube rupture. To date, there have been no tube ruptures due to undetected ODSCC in the tube sheet region. Axial ODSCC at the tube support plates can usually be readily detected with a bobbin coil probe, however, detection of circumferential ODSCC at the tube support plates requires special probes as does the sizing of ODSCC. Also, the evolution of the ODSCC depends significantly on the local environment within the crevice or under the crud, the details of which are often unknown. Therefore, the future crack growth rate cannot always be accurately estimated. However, some tube supports (and the tube sheet) can provide reinforcement in the event of a through wall crack, provided the support does not move relative to the tube during the event and the crack is within the support.

Free span IGA/IGSCC can occur if there are deposits on the tube, which concentrate impurities. The sensitivity of the eddy current signal is poor and a special analysis in absolute mode is needed to detect a free span flaw before the flaw achieves a critical size. Tube ruptures have occurred due to free span ODSCC.

4.1.8.3 Fretting, wear and thinning

These steam generator degradation types are broadly characterized as mechanically induced or aided degradation mechanisms. Degradation from small amplitude, oscillatory motion, between continuously rubbing surfaces, is generally termed fretting. Tube vibration of relatively large amplitude, resulting in intermittent sliding contact between tube and support, is termed sliding wear, or wear. Thinning generally results from concurrent effects of vibration and corrosion. However, thinning occurs at some locations, where flow induced vibrations are not expected, so it is not certain that tube motion is required for this mechanism, in some cases it may simply be the result of corrosion wastage. Fretting and wear makes tubes susceptible to fatigue crack initiation at stresses well below the fatigue limit, resulting in through-cracks or tube rupture.

The major stressor in fretting and wear is flow induced vibration. Initiation, stability, and growth characteristics of damage by these mechanisms may be functions of a large number of variables, including the support locations, the stiffness of the supports, the gap size between tube and support, secondary flow velocities and directions, and oxide layer characteristics.

Fretting may be caused by different factors. In general it will appear in zones of high linear flow velocities with a velocity component radial to the tubes. This occurs mainly in two zones:

- In the economizer of SGs provided with preheater chamber, where there is a flow perpendicular to the tubes
- In the U bend area of the tube bundle, where a divergent flow exists, that is, there is also a radial component.
- Broached hole clogging with corrosion products may also be responsible of recirculation flow perturbations resulting in considerably higher flow velocities in the areas not clogged, which can cause fretting.

Fretting/wear/thinning degradation was first identified as a problem in about 1973 and has been noted to some degree in all major PWR steam generator designs. This includes preheater and antivibration bar (AVB) wear/fretting in Westinghouse type RSGs, cold leg thinning in Westinghouse type RSGs, antivibration bar (diagonal support) wear/fretting in Combustion Engineering RSGs, and AVB wear/fretting in Siemens steam generators, causing in the Siemens designed PWR fleet plugging of 482 tubes in total. Faulty design of antivibration devices at the U bend area has been a major reason for fretting in the 70s and 80s.

As of December 1993, 116 plants with RSGs had experienced tubing failure due to AVB wear/fretting, 78 plants had reported wear/fretting failures due to loose parts damage, and 12 plants had reported wear/fretting failures associated with the steam generator preheaters [43]. 4633 tubes have been plugged because of AVB wear/fretting (920 tubes were preventatively plugged and the rest were plugged due to NDE indications), mostly in Westinghouse type steam generators. This damage has occurred in the more recent Westinghouse steam generator designs at 17 plants (Westinghouse models F, 44F, and 5IF and Mitsubishi Heavy Industries model 5IF) as well as in the earlier model steam generators. Steam generator tubes have also been plugged due to AVB (batwing or vertical strap) wear/fretting at, at least seven Combustion Engineering designed plants, three Siemens plants and one CANDU plant. At least 941 tubes have been plugged because of loose parts damage in 78 plants, although most of these plants (44 plants) have plugged less than ten tubes each. One plant did plug 176 tubes due to loose parts damage.

Fretting is occurring in CANDU steam generators with U bend supports made of staggered scalloped bars (the U bend support bar stack is split into two offset stacks as shown in Figure 4.51 and the tubes are held in semi-circular holes). This degradation is caused by flow induced vibration of the tubes which is due to U bend supports which were widely spaced and perhaps insufficiently rigid. Although tube fretting is severe and widespread, no tube failures have occurred in CANDU steam generators due to this degradation mechanism to date. There is evidence to indicate that the fretting rate in these steam generators is decreasing with time, suggesting that this mechanism is self-limiting.

Fretting caused by flow perturbations can be originated with the clogging of broach holes of tube support plates (refer to Figure 4.37). This has been observed in among others in French plants with quatrefoil type broached holes, causing a rapid fretting degradation in a limited number of tubes at the central region of the tube bundle (small U bends) at the height of the upper tube separator. The maintenance of clean broaches requires a reduction of the corrosion product ingress into the SGs, and periodical chemical cleaning operations as preventive or corrective measure.

Associated to the broach clogging, also internal flow perturbations may cause level oscillations of divergent nature, forcing to reduce power to restore stability.

A special case of this type of damage is loose parts damage. Loose parts and other debris have been found on the secondary side of the steam generators at a large number of PWRs over the years. These parts include tools (for example, a 152 mm flat file at Wolf Creek, a grinder wheel at Watts Bar Unit 1, a weld rod at Turkey Point 4, parts of a pocket knife at D.C. Cook Unit 1, and a 152 mm C-clamp at Point Beach), valve and pump parts (for example, a check valve pin at Turkey Point Unit 4), equipment used for previous inspections, broken steam generator material, debris left from previous modifications and repairs (for example, pieces of steel plate, copper tubing, weld material, wire, etc.), and other things. These loose parts have been implicated in at least two tube rupture events in operating plants in the USA. In addition to tube ruptures, loose parts in the secondary side of a number of plants have resulted in tube damage, and plugging.

One of the worst examples of this problem occurred at Ginna from 1975 to 1982. Foreign objects including various size pieces of carbon steel plate up to about 150 mm in length fell onto the tube sheet outside the periphery of the tube bundle during steam generator modifications performed in 1975 and later. This debris then impacted on the exposed peripheral tubes during subsequent operation and caused defects. The damaged tubes were plugged as a result of eddy current indications and/or small leaks. However, the debris continued to damage the plugged tubes and eventually caused the tubes to collapse and in some cases to become completely severed near the top of the tube sheet. The severed tubes and debris then interacted with the adjacent inboard tubes, resulting in fretting type wear of the adjacent tubes. These tubes, in turn, were plugged as a result of eddy current indications or leaks. However, damage continued until they also became severed. Eventually, an unplugged tube in the third row in from the outside row was subjected to fretting type wear over about 150 mm of length and burst. The wear removed about 84% of the wall thickness over about 100 mm of length, which caused a relatively long ‘fish mouth’ type burst. The peripheral tube damage mechanisms were primarily mechanical and included impacts, collapse, fatigue, fretting type wear, abrasion, and ductile overload and tearing.

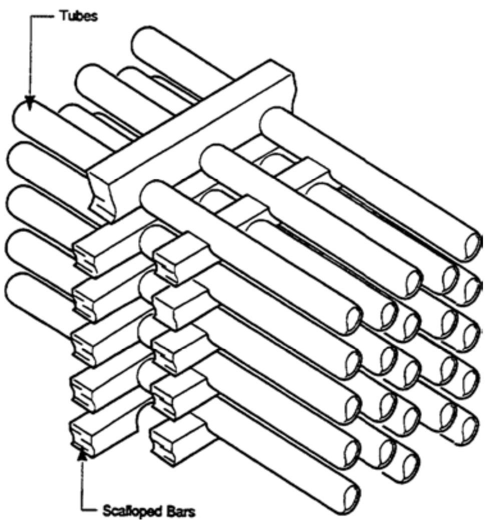


Figure 4.51. CANDU recirculating steam generators staggered scallop bar arrangement. (Courtesy of C. Maruska, Ontario Hydro).

Corrective measures included removing the debris and stabilizing (staking) and plugging nearby damaged tubes. USNRC Generic Letter 85-02 requested the US PWR owners to perform visual inspections in the vicinity of the tube sheet along the entire periphery of the tube bundle and the tube lane to identify and remove any foreign objects. Such an examination should be done after any secondary side repairs. Obviously, all tools and equipment going into a steam generator during an inspection should come out.

Although most loose parts damage has occurred on the secondary side of the steam generators, there have also been cases of primary side damage, mainly to protruding tube ends and tube to tube sheet welds.

4.1.8.4 Pitting

Pitting is a steam generator tube degradation type appearing as groups of small-diameter wall penetrations resulting from local corrosion cells, often promoted by the presence of chloride or sulphate acids under oxidizing conditions. Condenser leaks and leakage of beads, resin fines, or regeneration chemicals from ion exchangers can introduce impurities such as chlorides and sulphates, which result in local acidic conditions conducive to pitting.

Oxidizing conditions as the presence of copper and insufficient hydrazine are certainly promoting pitting attack. Under sufficiently reducing conditions pitting is suppressed in most of the cases. Copper free BOP and hydrazine as described in Section 4.1.5 ensure the necessary protection against this corrosion mode.

All candidate SG tube materials are susceptible to pitting under oxidizing conditions and concentrated impurities like chlorides.

Pitting generally occurs beneath the tube sheet sludge pile region or in the tube to tube support plate crevices. Pitting corrosion typically occurs in locally weak spots of the passive oxide layers on the surface of the SG tube. These susceptible locations may be the result of localized cold work of the metal, the presence of metal carbides, sulphides, or other secondary phase particles, or emergence of grain boundaries at the metal surface.

Significant pitting was first reported in an operating PWR steam generator about 1981. As of December 1993, only 11 PWR plants with RSGs had plugged tubes because of pitting and a few other plants had reported minor pitting degradation of 15% through wall depth or less [43]. However, a few plants have experienced significant pitting degradation including Indian Point Unit 3 (1290 tubes plugged because of pitting in the original steam generators and 3606 tubes sleeved), Kori Unit 1, which was replaced in 1998, (804 tubes plugged because of pitting and 1578 tubes sleeved for various reasons), and Millstone Unit 2 (1655 tubes plugged because of pitting in the original steam generators and 5164 tubes sleeved for various reasons). Most of this degradation occurred in the cold leg and cold leg sludge pile regions, however, pitting has also been found on the hot leg side of the RSGs [45–47]. In addition, most of the pitting has been associated with Alloy 600MA tubing exposed to severe secondary side chemistry incursions. However, 332 type 304 stainless steel steam generator tubes at the Yankee Rowe plant were also plugged because of pitting degradation.

Severe pitting has been experienced in CANDU units tubed with Monel 400 (1994 tubes plugged at one unit). This pitting is more accurately described as tube outer surface under-deposit corrosion and is caused by heavy secondary side deposits, both on top of the tube sheet and in the lower tube support areas. These deposits concentrate aggressive species such as chlorides and sulphides present due to condenser leakage and water treatment problems. One CANDU unit tubed with Alloy 800NG alloy has experienced a small number of tube failures due to pitting (under-deposit chloride pitting) at the first and second support plates. Early condenser tube leakage (seawater) and sludge deposits contributed to this degradation. At Siemens plants only two pits were reported at one SG in an old unit before conversion to high pH AVT.

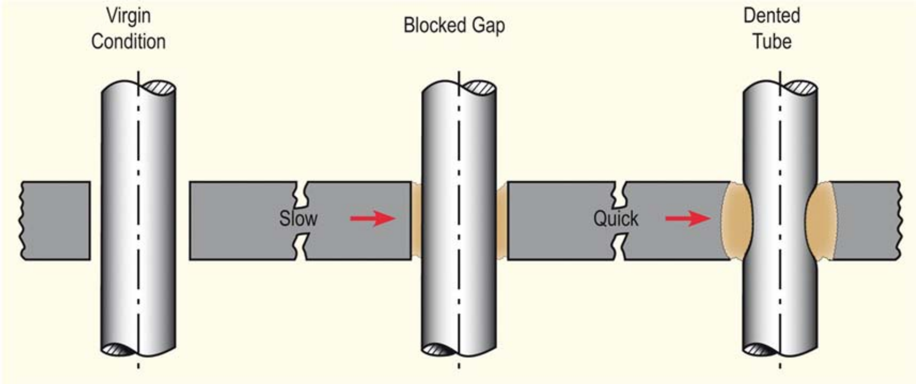
The incidence of pitting produced under power operation on SG performance is of less importance for plants built and operated according to the state of the art.

4.1.8.5 Denting

Denting describes the mechanical deformation or constriction of the tube at a carbon steel tube support plate intersection or at the top of tube sheet caused by the build-up of deposits and the growth of a voluminous corrosion product in the annulus between the tube and the support plate or tube sheet crevice if there is a gap at the top of tube sheet.

Denting started to occur mainly at the tube support plates made of carbon steel, drilled hole type, after the conversion from phosphate to AVT chemistry. This forced to replace the SGs at two PWRs (Surry and Turkey Point) in the USA. The problem has led in general to extensive tube plugging due to primary side cracking at supports and U bends and secondary side cracking at tube supports, resulting from the stressed induced by the tube plastic deformation. The TSP denting is schematically shown in Figure 4.52.

Tube sheet denting has been also reported as a consequence of the presence of carbon steel beads, in some case left at tube sheet after performance of shot peening (see Figure 4.44). For newer steam generators having stainless steel tube supports of the trefoil broached or grid type, TSP denting is practically excluded and TS denting remains the only kind of denting still possible to occur.



Accumulation of corrosion products
➔ overheating
➔ impurity enrichment
(Cl^-, SO_4^{2-}, Cu)

TSP carbon steel corrosion
➔ Expansion of oxides formed
➔ Tube deformation (dent)
➔ Stress ➔ later SCC

Figure 4.52. Schematic representation of the denting process.

TS denting have been experienced in few cases. Recently, five plants having replacement SGs of the Siemens type reported TS denting at moderate to large extent, after about 13 operation years. In one case, 80 tubes had to be plugged due to OD indications associated with denting. This TS denting appeared exclusively at areas where hard-caked deposits were present.

Dents do not themselves result in tube wall penetration or reduction in wall integrity. However, denting at some plants in the past has been sufficiently severe that it caused structural damage to the carbon steel tube supports of the drilled hole type. Denting is a concern because even small dents can induce tensile stresses above yield strength in the tube wall. As a result, these tubes may be subject to PWSCC or IGSCC at the dents during subsequent operation. In addition, severe denting in tubes with tight radius U bends has accelerated stress corrosion cracking in the U bends from distortion of the tube legs [4, 48]. Also, tubes with dents at the top tube support plate in the U bend region of the RSGs are more susceptible to high cycle fatigue failure.

The primary factors influencing denting are degree of superheat and bulk water chloride and oxygen concentrations under oxidizing conditions. Chlorides result in an acidic secondary water chemistry environment, which causes rapid corrosion of the carbon steel support plate when sufficient oxygen is present. Copper oxide may also play an important role as a supplier of oxygen to the carbon steel support plates. Sulphates (e.g. from condensate polisher leakage) are believed to cause denting in the same manner as chlorides, though the laboratory test database is not as extensive.

Denting was relatively uncommon when most plants used phosphate water chemistry, since the phosphates kept the crevice pH high.

Although modifications of the SG design (mainly elimination of the drilled hole tube supports) and attention to secondary side water chemistry have reduced denting to a lesser concern, denting is still considered a degradation concern because of its possible PWSCC consequences, particularly if a unit

(a) Has experienced one or more major secondary side intrusions of contaminants, or
(b) Is constructed with low temperature mill annealed tubing and is, therefore, susceptible to PWSCC even at small-size dents [4, 46, 48–50].

Denting of Alloy 600MA tubes at tube to tube support plate intersections was first identified as a significant steam generator degradation mechanism in about 1975, shortly after the time when many PWRs switched from phosphate to AVT secondary side water chemistry, and this degradation mechanism became the primary cause of steam generator tube plugging during the period 1976 through 1979. As of December 1993, 1471 RSG tubes at 41 plants (four Combustion Engineering and 37 Westinghouse type plants) had been plugged because of tube sheet and sludge pile denting and 9092 RSG tubes at 17 plants (four Combustion Engineering and 13 Westinghouse type plants) had been plugged because of support plate denting [43]. Significant support plate denting occurred at only five plants: Millstone Unit 2 (796 tubes), Surry Unit 1 (1996 tubes), Surry Unit 2 (1964 tubes), Turkey Point Unit 3 (1249 tubes), and Turkey Point Unit 4 (1835 tubes), all of the original steam generators at those plants have since been replaced. The majority of the support plate denting has occurred on the hot leg side at plants with seawater or brackish water for condenser cooling.

CANDU units with the older Alloy 600MA and Monel 400 steam generators with carbon steel supports have also experienced tube deformation due to deposit build-up in the tube support gaps and corrosion of the supports. However, tube cracking has not been detected in the deformed areas.

German plants never experienced tube support denting because SS tube supports of the grid type were used since the beginning.

4.1.8.6 High cycle fatigue

The combination of high vibration amplitude and low fatigue strength may lead to catastrophic fatigue failure. Vibration occurs in steam generators with high recirculation flow factors (causing flow induced vibrations in the U bend region) and improper antivibration bar support. A high mean stress (e.g. residual stress) significantly reduces the fatigue strength. Therefore, tubes with dents at the top tube support plate in the U bend region of the RSGs are susceptible to high cycle fatigue failure.

High cycle fatigue failures have occurred in the U bend regions of the North Anna Unit 1 and Mihama Unit 2 steam generators. Though high cycle fatigue from tube vibrations is not a general problem in PWR steam generators, tube ruptures, such as those at North Anna and Mihama Unit 2, are of particular concern because they were 360° breaks located high up in the steam generator where the leak location can more readily become uncovered by secondary water. This can allow escape of fission products from the primary coolant without partitioning in the secondary water. For example, upon failure of the Mihama Unit 2 steam generator A tube, the primary system leak rate rapidly escalated from a very low level to a value exceeding the normal capacity of the charging pumps. The ruptured tube eventually released about 55000 kg (55 t) of primary coolant to the secondary coolant system. Approximately 1300 kg (1.3 t) of steam, 0.6 Ci of radioactive noble gases, and 0.01 Ci of radioactive iodine subsequently escaped from the damaged steam generator's relief valve to the environment. The reactor core remained submerged owing to the operation of the high pressure injection system.

Most of the earlier tube failures in CANDU steam generators tubed with Alloy 600MA have been due to high cycle fatigue. These failures were initiated at either fret marks or more recently at stress corrosion cracks and are caused by flow induced vibration at the U bend area and at the seventh support plate. These failures continue to occur in the older CANDU steam generators.

High cycle fatigue is not reported by plants of the Siemens type.

4.1.8.7 *Wastage*

Phosphate wastage was the major cause of tube failures in PWR steam generators until about 1976. However it is no longer an active degradation mechanism in most of the PWRs because phosphate water chemistry is no longer used. The last plant applying phosphate treatment was Atucha I (PHWR) with a SG operation temperature corresponding to 44 bar steam pressure. This low temperature was responsible for a very slow development of SG tube wastage corrosion, which appeared after about 30 operation years.

4.1.8.8 *Tube support flaw assisted corrosion*

Flow accelerated corrosion has been reported by few CANDU plants having carbon steel, broached hole tube supports. Clogging of the broached holes at the hot leg caused a high flow rate through the cold leg, resulting in a serious degradation of the supports, requiring the replacement of the SGs.

4.2 PWR ONCE-THROUGH STEAM GENERATORS

Once through steam generators (OTSG) in the USA use the same Alloy 600MA tubing materials as RSGs, yet these steam generators have experienced substantially fewer tube failures. The lower failure rate is attributed to the differences in the steam generator design, manufacturing processes, and operation. Many of the chemical concentration processes do not operate in once through steam generators, as they do in RSGs. Table 4.4 lists once through steam generator tube degradation mechanisms, sites, stressors, failure mode and inspection methods. The most common tube degradation mechanisms are briefly discussed here. However, as noted below, even these mechanisms affect a very small percentage of the tubes in service.

4.2.1 Erosion-corrosion

In general, Erosion-corrosion results from dissolution of the protective oxide layers on the metal surfaces by high medium flows, which avoids the re-built of oxide layers. As a consequence, metal surfaces lose their protection against the metal dissolution by water, resulting in fast material removal on the surface. in the case of once through steam generators, this dissolution of the oxide layers on the tube surfaces can be promoted by impingement of the water droplets in the high velocity steam on tube surfaces. Inspection of removed tubes indicates that erosion-corrosion has occurred in once through steam generators on the outer surface of the tubes, principally around the fourteenth tube support plate at the periphery of the tube bundle.

The fraction of tubes for all once through steam generators affected by erosion-corrosion is small. Through December 1993, 1622 tubes (about 0.75% of the tubes in service) have been taken out of service due to erosion-corrosion. More than half (991) have been from one plant, hence, the mechanism is not occurring at the same rate in all once through steam generators.

TABLE 4.4. SUMMARY OF ONCE-THROUGH STEAM GENERATOR TUBE DEGRADATION PROCESSES

Rank[1]	Degradation site(s)	Stressors	Degradation mechanism(s)	Potential failure mode	In-service inspection methods
1	Outer surfaces of the tubes on periphery of the tube bundle near the 14th tube support plate	Velocities, sizes, shapes, impact angle and hardness of particles	Erosion-corrosion from impingement of particles	Wear of material	Eddy current testing
2	Tube outer surfaces near the upper tube sheet and the open lane or near the uppermost tube support plate and the open lane	Aggressive chemicals, vibration	Environmentally assisted high cycle fatigue	Circumferential cracks	Eddy current testing
3	Inner surface of tubes near the upper tube sheet roll transition and welds (primary side)	Sodium thiosulfate, air	Low temperature primary side stress corrosion cracking	Circumferential cracks	Eddy current testing

[1] Based on operating experience and number of defects.

4.2.2 High cycle fatigue

Through wall circumferential cracking has occurred in once through steam generator tubes at the top tube support plate (i.e. 15th tube support plate) and at the bottom of the upper tube sheet in the inspection lane region. The inspection lane region includes about three rows of tubes on either side of the inspection lane and a few additional rows at the periphery. The cracks initiated at the outside diameter of the tubes and propagated circumferentially in a transgranular mode. Tube samples revealed a serpentine band of metal loss in the areas near the upper tube support plate and just below the lower face of the upper tube sheet [4, 46]. Sometimes these metal loss areas contained micro-cracks that acted as the site for fatigue crack initiation. Laboratory tests indicate that the corrosive metal loss, including the micro-cracks, can be achieved with concentrations of sodium sulphate, silicates, and chlorides [51]. Thus, the degradation mechanism has been described as environmentally assisted high cycle fatigue.

The stressors for this corrosion fatigue cracking are believed to be deposits of concentrated impurities and cyclic vibration. Evaporation of the secondary side water in the lower elevations of the once through steam generators concentrates any contaminants or impurities into the remaining droplets. the steam flow then carries these droplets up to the open inspection lane to the upper tube sheet area, where the droplets impinge on the hot tubes around the inspection lane, dry out, and deposit the impurities. This process further concentrates the chemicals at selected locations on the steam generator tubes. Through December 1993, a total of 106 tubes (0.05% of the tubes in service) at six plants have been taken out of service due to this mechanism.

4.2.3 Low temperature primary side stress corrosion cracking

Stress corrosion cracking on the inner surfaces (primary side) was detected in the tubes of a once through steam generator at TMI-1 in 1981, where essentially all the tubes were affected and 1619 tubes plugged and 502 tubes sleeved [7, 52]. The incident is unique because the combination of conditions necessary to promote this type of attack is not expected to occur at other plants. Partially reduced sulphur species (e.g. sodium thiosulphate) had inadvertently been introduced into the primary system from the containment spray system. It is believed mat aggressive concentrations of sodium thiosulphate and oxidizing conditions developed in the failure area from dry-out and exposure to air. Most of the defects were circumferential in geometry and located in the upper part of the upper tube sheet near the weld heat affected zone or the roll transition. The main protection against recurrence of this type of incident in once through steam generators with sensitized tubing (due to heat treatment, see Section 3.2.1) is to avoid acidic oxidizing conditions by strict water chemistry controls and proper lay-up using strict procedure controls.

4.2.4 Outer diameter intergranular stress corrosion cracking and intergranular attack

As discussed in Section 4.1.8.2 above, intergranular stress corrosion cracking (IGSCC) requires tensile stresses, material susceptibility and a corrosive environment. IGSCC cracks occur along the grain boundaries, normal to the maximum principle stress. Intergranular attack (IGA) is characterized by local, corrosive loss of material along the grain boundaries. Both mechanisms require a concentration of corrosive impurities on the outer surface of the tubing.

Until 2006, 6664 tubes at seven plants were removed from service and 2726 were sleeved due mainly to IGSCC/IGA. The tube material was mostly Alloy 600SR. The damage primarily occurred near the upper tube sheet. At three units, the SGS were replaced by units tubed with Alloy 690TT. The plugging and sleeving rate is shown in Figure 4.53.

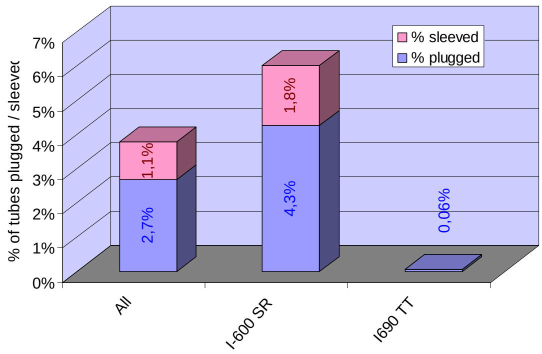


Figure 4.53. Tube plugging rate at once through steam generators in operation in the period 1978–2006.

4.3 WWER STEAM GENERATORS

The horizontal, U shaped tubing used in the WWER-440 and WWER-1000 reactors has been relatively trouble free. The main cause of damage has been outer surface stress corrosion cracking due to poor secondary side water chemistry, primarily chloride ion and oxygen excursions, but also low pH and the presence of various organic compounds. Secondary side chloride ion concentrations of several hundred to several thousand µg/kg have been reported for relatively significant times [53]. Also, the effects of the chloride ions on the stress corrosion rate have been accelerated due to the presence of porous crud deposits in quantities in excess of 150 g/m^2 (the recommended limit). The chloride ions tend to concentrate in the crud capillary structures by factors of 10^5 to 10^6 [54, 55]. At some WWER plants, the pH has dropped below 7.8 (the original lower limit, which has now been revised to 8.8 for the feedwater and 8.0 for the blowdown water as listed in Table 4.1) for up to 20% of the overall operating time, and to the range of 5 - 6 for up to 2% of the operating time. Also, up to 700 µg/kg of acetic acid (due to organic compound breakdown) has been found in the feedwater at several plants [56].

Status of the heat exchanging tubes at different units differs considerably. For the most of the SGs at WWER NPPs the status can be recognized to be satisfactory or to have improving tendency. However, at a number of Units there is a considerably degradation of heat exchanging tubes. This is caused by deficiencies in water chemistry due to imperfection of the main condensate system equipment resulting in considerable ingress of the impurities with feedwater into SG, and first of all of iron and copper oxides.

As of 2005, 1.8% of tubes were plugged from the total number of heat exchanging tubes at steam generators of Russian WWER-440 NPPs. It should be noted that most of the SGs of these Units are close to expiration of design service life, and four of them are operation beyond the design service life. At PGV-1000 steam generators 0.7% of tubes are plugged from the total number. Most of the tubes at these Units were plugged due to ECT indications.

Basic trends to improving the reliability of the existing SGs are related to improving the secondary side water chemistry: implementation of Morpholine and Ethanolamine water chemistry with pH value of feed water not higher than 9.2, and in replacing the copper-bearing tubes of the heat exchangers in the main condensate system with the stainless steel tubes – increase of feed water pH value for this water chemistry to 9.6–9.8.

Considerable ingress of corrosion products into SGs and their deposition on heat exchanger tubes results in the necessity to carry out the regular chemical cleaning. Delay in performing the chemical cleaning causes considerable difficulties in removing the deposits that have reached the critical sizes. In such cases a combination of chemical and mechanical cleaning methods is required.

4.4 TUBE RUPTURE EVENTS

4.4.1 Tube ruptures

The extensive tube degradation at pressurized water reactors (PWRs) with Alloy 600MA steam generator tubes has resulted in tube leaks, tube ruptures, and mid cycle steam generator tube inspections. This degradation also led to the replacement of Alloy 600MA steam generators at a number of plants and contributed to the permanent shutdown of other plants.

Most of the newer steam generators, including all of the replacement steam generators, have features, which make the tubes less susceptible to corrosion related damage. These include using stainless steel tube support plates with broach holes or egg crates to eliminate the likelihood of denting and new fabrication techniques to minimize mechanical stresses on tubes. Therefore, after the year 2002 the frequency of SGTR events decreased considerably.

The leak rate, degradation mechanism, rupture size, rupture location, and stressor and contributing factor information associated with twelve steam generator tube rupture events is summarized in Table 4.5 [57]. These ruptures have occurred over the last 20 years at a rate of about one every 2–3 years. The maximum leak rates have ranged from 470 I/min (125 gal/min) to 2880 L/min (760 gal/min). Maximum leak rates less than about 380 L/min (100 gal/min) are considered by the USNRC to be from tube defects rather than tube ruptures, since that amount of leakage is within the normal capacity of the charging systems. The highest possible leak rates calculated for a single tube rupture are on the order of 3800 L/min (1000 gal/min).

Five different tube degradation mechanisms caused the thirteen ruptures: three ruptures were caused by ODSCC, two ruptures were caused by high cycle fatigue, three ruptures were caused by loose parts wear, four ruptures were caused by PWSCC, and one rupture was caused by wastage. In the future, wastage as cause for tube rupture is very unlikely because only one PWR with heavy water is now still using phosphate water chemistry.

Future tube ruptures due to high cycle fatigue in Westinghouse type steam generators are less likely than a few years ago because most operators have inspected their steam generators to assure that the AVBs are properly placed and new steam generators are being more carefully fabricated with more and better AVB designs. However, the Indian Point Unit 3 experience suggests that such failures are possible even with proper AVB support. {A 456 L/h (120 gal/h) leak developed at Indian Point Unit 3 on 19 October 1988. Subsequent inspections identified a 250° circumferential high cycle fatigue cracks in the tube in Row 45, Column 51, just above the upper most support plate. The tube was dented at the support plate due to support plate corrosion, however, the Indian Point Unit 3 tube was properly supported by its AVBs.} *Loose* parts and other foreign objects continue to be left in some steam generators and additional ruptures of tubes due to loose parts wear are possible. Also, extensive primary water and outer diameter stress corrosion cracking has occurred in certain steam generators and more ruptures caused by those mechanisms in future are possible.

The rupture locations have generally been either just above the tube sheet (five ruptures), or in the U bend region (six ruptures). Only the McGuire rupture was near one of the lower support plates. The ruptures caused by loose parts wear have occurred just above the tube sheet, whereas the ruptures caused by high cycle fatigue have occurred just above the top tube support plate. Any future ruptures caused by those mechanisms will probably occur in the same locations.

The three ruptures caused by ODSCC appear to each have some unique contributing factors. The Fort Calhoun tube was subjected to high stresses caused by corrosion of the vertical batwing support bars. The McGuire rupture was located in a long shallow groove, which was probably created during fabrication. The Palo Verde rupture occurred in a tube with a susceptible (and abnormal) microstructure. However, excessive caustic impurities on the secondary side were part of the problem in all three cases.

Tube rupture by PWSCC at the inside of alloy 600 HTMA tube happened during a power reduction stage for refuelling in a Korean plant in 2002. Bulge during tube installation might induce high tensile stress inside of the tube. Destructive analysis showed that 80 mm long and 100% through wall PWSCC was developed and a guillotine rupture by vibration at the top end of the crack followed the PWSCC.

The plant transient information is summarized in Table 4.6 [57]. The operators were expected to:

- Maintain the primary coolant subcooled.
- Minimize the leakage from the reactor coolant system to the defective steam generator secondary side.
- Minimize the release of radioactive material from the damaged steam generator.

Timing is critical to the successful management of a steam generator tube rupture event. The key operator actions that must be accomplished in a timely manner include:

- Recognition that a steam generator tube rupture event is occurring.
- Control of the pressurizer level using the charging pumps and let-down line (if the rupture is small).
- Power reduction/trip.
- Isolation of the defective steam generator.
- Reactor coolant system cooldown including pumped flow to the intact steam generators and intact steam generator steam dumps to the condenser or atmosphere.
- Reactor coolant system depressurization, which generally requires throttling the safety injection and use of the pressurizer sprays or PORVs.

TABLE 4.5. SUMMARY OF THE LEAK RATE, DEGRADATION MECHANISM, RUPTURE SIZE, RUPTURE LOCATION, AND STRESSOR INFORMATION ASSOCIATED WITH TWELVE STEAM GENERATOR TUBE RUPTURES

Date	Plant	Maximum Leak Rate [gal/min]	Degradation	Size	Location	Stressors and contributing factors
1975-02-26	Point Beach-1 W-44	125	Wastage	2 adjacent ruptured bulges each about 20 mm long and wide	Slightly above the tube sheet, outer row on the hot leg side	Large sludge pile, ineffective cleaning
1976-09-15	Surry-2 W-51	330[a]	PWSCC	114 3 mm long axial crack	Top of U bend (apex) in Row 1, Column 7	High stresses and ovalization caused by inward movement of the legs due to support plate deformation
1979-06-25	Doel-2 ACE-44	135	PWSCC	100 mm long axial crack	Top of the U bend in Row 1, Column 24	High residual stresses due to ovalization during fabrication
1979-10-02	Prairie Island -1 W-51	336[a]	Loose Parts Wear	38 mm long axial fish mouth opening	Tube bundle outer surface, 76 mm above the tube sheet on the hot leg side, Row 4, Column 1	Sludge lancing equipment left in the steam generator
1982-01-25	Ginna W-44	760[a]	Loose Parts Wear, Fretting	100 mm long axial fish mouth opening	127 mm above the tube sheet on the hot leg side, Row 42, Column 55 (third row in from the bundle periphery)	Loose parts (baffle plate debris) left in the steam generator, wear of peripheral tubes, fretting of inner tubes
1984-05-16	Fort Calhoun CE	112	ODSCC	32 mm long axial crack (small fish mouth opening)	Horizontal run at the top, between the vertical batwing support bars on the hot leg side, Row 84, Column 29, the rupture faced down	Tube deformation caused by corrosion of the vertical batwing support bars, caustic impurities on the secondary side
1987-07-15	North Anna-1 W-51	637	High cycle Fatigue	360° circumferential break	Top of the 7th tube support plate on the cold leg side, Row 9, Column 51	High cycle vibration, denting, lack of AVB support
1989-03-07	McGuire-1 W-D2	500	ODSCC	95 mm long axial crack in a 645 mm long groove, 9 5 mm wide at the maximum point	711 mm above the tube sheet at the lower tube support plate on the cold leg side, Row 18, Column 25	Long shallow groove, possibly a contaminant
1991-02-09	Mihama-2 MHI-44	≈ 500	High cycle Fatigue	360° circumferential break	Top of the 6th (upper) tube support plate on the cold leg side, Row 14, Column 45	High cycle vibration, lack of AVB support
1993-03-14	Palo Verde-2 CE-80	240	ODSCC	65 mm long axial fish mouth opening in a 250 mm long axial crack	Free span region between the 08H and 09H tube support structures on the hot leg side, Row 117, Column 144	Tube to tube crevice formation, bridging deposits, caustic secondary water chemistry, susceptible material
1996-07-23	Tihange 3 ACE-E	167	Loose part wear	35 mm axial crack	At the top of tube sheet	Wear by foreign objects
2000-02-15	Indian Point 2	150 gal/min	PWSCC	No data	at the U bend area, tube apex	Small bend tube
2002-04-05	Ulchin 4	132 gal/min	PWSCC	80 mm axial crack, and guillotine rupture	Free span	Scratch, bulge induced PWSCC

[a] NRC estimates.

TABLE 4.6. SUMMARY OF PLANT TRANSIENT INFORMATION

	Point Beach-1	Surry-2	Doel-2	Prairie ls.-1	Ginna	Fort Calhoun	North Anna-1	McGuire-1	Mihama-2	Palo Verde-2
Maximum leak rate [gpm]	125	330	135	336	760	112	637	500	500	240
At power	Yes	Yes	No	Yes	Yes	No	Yes	Yes	Yes	Yes
First indication of rupture	Air ejector rad.	Pressure, air ejector rad.	Pressure	Air rejector rad.	Air rejector rad.	Pressure	Main steam line rad.	Main steam line rad.	Air ejector rad.	Pressure, MSL rad.
Time operators recognized SGTR	24–28 min	< 5 min	≈9 min	5–18.5 min	< 1 min	≈32 min	< 5 min	< 1 min	≈5 min	< 57 min
Second, Third charging pumps started [min]	2, 19	5 (2nd)	1.8, < 15	9, 10	1, 2.5	0,0: increased flow, 18 min	-	4 (2nd)	5 (3rd)	2 (3rd)
Letdown line isolated	8 min	5 min	2.4 min	-	3 min	24 min	3 min	5 (reduced)	-	6 min
Load reduction started	30 min	7 min	N/A	7 min	1.5 min	N/A	3 min	4 min	7 min	No
Manual reactor trip	47 min (at 25% power)	10 min (at 70% power)	N/A	No	No	N/A	5 min	8/9 min	No	13 min
Automatic reactor scram	No	No	N/A	10.15 min	3 min	N/A	No	No	10 min	No
Automatic safety injection	No (blocked at 54 min)	No, manual SI at 11 min	19.2 min	10.23 min	3 min	No	5.3 min	No (blocked at 23 min)	10.1 min	13.2 min
Defective steam generator isolated	**58 min**	**18 min**	**9.4 min**	**27 min**	**15 min**	**40 min**	**18 min**	**11 min**	**22 min**	**2 h 54 min**
main steam isolation valve closed	48 min	18 min	closed	27 min	15 min	40 min	16 min	≈11 min	22 min	2 h 54 min
main feedwater valve closed	58 min	11 min	closed	10.15 min	3 min	closed	5 min	≈9 min	12 min	13 min
auxiliary feedwater flow	None	18 min	41–50 min	-	3–7 min	0–32 min	5.3–16 min		12 min	
feed to Terry turbine	No	-	No	-	4–7 min		0–18 min		8 min	
safety valve open	No	No	No	No	54, 63, 114,		No	No	-	
atmospheric dump valves open	No	No	No	1-2 sec at scram	132 min		No	No	39, 49, 59 min	
RCS cooldown started	**51 min**	**21 min**	**41 min**	**1 h 36 min**	**2 min**	**41 min**	**19 min**	**14 min; 3.5 h**	**22 min**	**2 h, 47 min**
RCP on defective steam generator tripped	66 min	11.5 h	17.4 min	12 min	4 min	42 min	43 min		46 min	13 min (one)
RCP on intact steam generators tripped	No	19 min (One)		13 min	4 min	43 min	43 min (one)		47 min	13 min (one)
RCP on intact steam generators restarted	N/A	No		7 hours	116 min				1 h, 17 min	
intact steam generator steam dumps	51 min	Yes		-	2–3, 2–5, 75 min	41 min	19 min	19 min	22–37 min, 62–94 min	
RCS depressurization started	**51 min**	**16 min**	**68-88 min**	**42 min**	**2, 73 min**	**30 min**	**16 min**	**14 min**	**54 min**	**1 h 30 min**
safety injection throttled	Yes (61 min)	Yes (16 min)			2 h 47 min	No		N/A		
safety injection stopped	N/A	16 min*	68 min	42, 52 min	73 min	N/A			57 min (two)	
pressurizer spray used	1 h 40 min	Yes	28 min	No	No	Yes (72 min)	Yes		54 min[b]	
pressurizer PORV open	No	No	blocked	Yes (43 min)	42–44 min	No	34 min		No (tried)	
charging pumps stopped	73, 79 min	21 min			3 min	27 min (2)		37 min (1)	-	
Reactor coolant system and defective steam generator secondary pressure equal	≈ 7 h	~ 1 h	?	61 min	3 h 2 min	?	34 min	47 min; 10 h 37 min	1 h 8 min	3 to 4 h
RHR in operation	3 h 5 min	~ 11.5 h	3 h 15 min	16 h 26 min	21 h 35 min	3 h 47 min	5 h 49 min	17 h	8.5 h	6 h
Excessive level in defected steam generator	Yes	No	No	No	Yes	Yes	No	No	No	No

a The high head safety injection pumps are also the charging pumps, one remained in operation..

b The auxiliary spray was started at 54 minutes, stopped at 1 hour, 8 minutes, and then set partially open at 1 hour, 19 min.

It should be noted that based on the training that reactor operators receive prior to licensing, a steam generator tube rupture is normally easily recognizable. The operators have several indicators that can be referred to that point to the fact that a tube rupture is occurring. The steam line radiation monitors and the air ejector radiation monitors are the prime indicators and are used as Emergency Operating Procedure entry conditions. The operating procedures that are utilized to combat the transient assume that the plant is at power and that the systems are aligned properly.

The success of the operators, as indicated by the times these activities started or finished in Table 4.6, is mixed. For example, the Point Beach, Fort Calhoun, and Palo Verde operators took a relatively long time (up to 28, 32, and 57 minutes, respectively) to realize (or prove to themselves) that a steam generator tube rupture had occurred. The result was that they were slow to start reducing power (30 minutes at Point Beach where the maximum leak rate was relatively low, 13 minutes at Palo Verde where the leak rate and the initial pressure drop were larger) and slow to isolate the defective steam generators (58, 40, and 174 minutes, respectively). By contrast, the Ginna, North Anna, McGuire, Surry, and Mihama operators recognized that a steam generator tube rupture event was happening within a few minutes of the first alarm Their load reductions started within 1.5, 3, 4, 7 and 7 minutes, respectively, and their defective steam generators were isolated within 15, 18, 11, 18, and 22 minutes, respectively. The defective steam generator at Mihama would have been isolated at 15 minutes, had the main steam line isolation valve worked properly. It should be noted that it is harder for the operators of a plant at or near hot standby (Doel and Fort Calhoun) to detect a steam generator tube rupture. But the operators at Point Beach, Palo Verde, and probably Prairie Island, should have been able to recognize and identify the event much faster.

Also, a significant drop in pressurizer level should signal the operators to start and set the second and third charging pumps at full flow as well as reduce or isolate the let-down flow, and that happened in most cases. However, the third charging pump did not start at Doel until about 15 minutes, the second and third charging pumps did not start at Prairie Island until 9 and 10 minutes, and the charging pumps at Fort Calhoun were not at full flow until 18 minutes. Adequate charging flow can prevent safety injection (for smaller ruptures) and allow the pressurizer to be used to help control the early depressurization. It is realized that in some instances the third charging pump may be a low volume, high discharge pressure pump that is normally utilized for make-up and is ineffectual in supplying large quantities of water in an emergency.

Another area where timely actions were important is the cooldown and depressurization of the primary system. It is very important to get the reactor coolant system pressure down to a value below the defective steam generator secondary side pressure and keep it there (slightly below, but not so far below that the backflow will significantly affect the primary system boron concentration) while at the same time keeping the reactor coolant system fully subcooled. Reactor coolant system pressures above the defective steam generator secondary side pressure for long periods of time result in overfill of the steam generator secondary side and unnecessary radioactive material releases to the environment. The North Anna, Surry, Prairie Island, and Mihama reactor coolant system pressures were reduced to their defective steam generator secondary pressures in 34, 60, 61, and 68 minutes, respectively, and there were no defective steam generator overfill problems. The Point Beach, Ginna, and Fort Calhoun, reactor coolant system pressures were held well above the defective steam generator secondary side pressures for considerably longer times (about 7, 3, and an unknown number of *hours*, respectively) and the defective steam generators overfilled. The McGuire depressurization also took a very long time (10 hours, 47 minutes), but the defective steam generator at McGuire was not overfilled because of releases to the condenser and through the condenser vent, to atmosphere.

Despite these variations in timing, it should also be noted that in all cases the plants were properly cooled down and the radioactive material releases were small and well below regulatory limits. Also the operator performance was sometimes hampered by inadequate Emergency Operating Procedures (Palo Verde, for example) or by defective equipment (Mihama, for example). At other times the operator was hampered by plant conditions that did not allow rapid employment of Emergency Operating Procedures. There are still numerous reasons for (a) continued operator training on steam generator tube ruptures and (b) training on the recognition of events based on the indications that are available. Neither training method should be utilized by itself. It appears that the majority of actions that were carried out were accomplished in accordance with the published procedures. Deviations from procedures appeared to be thought out in advance.

4.4.2 Incipient tube rupture events and steam generator tube leakages

Seven incipient tube rupture events, which occurred in the USA during the period of 1988 to 1993 are summarized in Table 4.7 [57].

TABLE 4.7. RECENT INCIPIENT STEAM GENERATOR TUBE RUPTURE EVENTS IN THE USA

Plant	Date	Maximum Leak Rate	Defect Size	Defect Location	Degradation Mechanism
Braidwood Unit 1	1993-10-23	≈ 47 L/h (12.5 gal/h)	330 mm (1.3 inch) crack	Above the top tube support plate near AVB	ODSCC
Arkansas Nuclear One, Unit 2	1992-03-09	57 L/h (15gal/h)	Circumferential through wall crack	Hot leg side of the tube in Row 67, Column 109, 4.8 mm above the tube sheet in the explosive transition region	ODSCC
McGuire Unit 1	1992-01-16	37 L/h (10 gal/h)	250 mm long axial crack	Cold leg side of the tube in Row 47, Column 46, 130 mm above the lower tube support plate	ODSCC
Maine Yankee	1990-12-17	318 L/h (84 gal/h)	100 mm long axial crack	Top of the U bend of the tube in Row 6, Column 43	ODSCC
Three Mile Island Unit 1	1990-03-06	≈ 115 I/h (30 gal/h)	360° circum-ferential crack	Peripheral tube A77-1 next to the open inspection lane, bottom of upper tube sheet	High cycle fatigue (environ-mentally assisted)
Beaver Valley Unit 2	1989-06-21	80 I/h (21 gal/h)	97% through wall wear, small rupture	Hot leg side of the tube in Row 31, Column 16, 25 mm above the tube sheet	Loose parts damage
Indian Point Unit 3	1988-10-19	456 I/h (120 gal/h)	250° circum-ferential crack	Tube in Row 45, Column 51, just above upper support plate	High cycle fatigue, denting

For some of these incipient steam generator tube rupture events, the operators were able to quickly shut down the reactor and isolate the detective steam generator. In other cases, the cracks stopped growing for unknown reasons. These actions limited the contamination of the secondary coolant and may have prevented actual tube rupture. Also, some of these events demonstrated how quickly very low leak rates can increase as the crack grows. Leak rate monitoring programmes that provide close to real time information can limit the frequency of steam generator tube ruptures. "At some sites, data from the air ejector radiation monitors is continuously displayed in the control room. At other sites, main steam-line radiation monitors promptly detect increases in nitrogen-16 activity. When combined with appropriate alarm set-points and operational limits, this information can quickly alert operators to implement response procedures to monitor increases in leak rates or to shut down the reactor and isolate the affected steam generator" [58].

Steam generator tube leakages have occurred also at considerable extent in the period until end of the 1990s, and decreased in the following years. In Table 4.8 the NRC statistic until 1998 is shown. The statistic of forced outages due to tube leaks in USA (Figure 4.54) shows a considerable improvement.

TABLE 4.8. STEAM GENERATOR TUBE LEAKAGE- NRC USA STATISTICS 1990–2000 [59]

No	Date	Plant	Leak Rate L/d	Cause
1	Jan. 1990	St. Lucie 1	**11**	Foreign Object
2	Mar. 1990	TMI 1	**5451**	Fatigue
3	May 1990	Millstone 2		Cracked Plug
4	Aug 1990	North Anna 2	**151**	Cracked Plug
5	Nov. 1990	Oconee 2	**492**	Fatigue
6	Nov. 1990	Shearon Harris	**189**	Loose Part
7	Dec. 1990	Maine Yankee	**5451**	PWSCC
8	Apr. 1991	San Onofre 1	**568**	Sleeve Joint
9	Apr. 1991	Millstone 2	**265**	U bend SCC
10	May 1991	Millstone 2	**265**	Tube Sheet Circumferential Crack
11	Jan. 1992	McGuire 1	**946**	Free span Crack
12	Mar. 1992	ANO 2	**1363**	Tube Sheet Circumferential Crack
13	Mar. 1992	Prairie Island 1	**545**	Roll Transition Zone Axial Crack
14	May 1992	McGuire 1	**19**	
15	Sep. 1992	Prairie Island 1	**329**	
16	Nov. 1992	McGuire 1	**946**	
17	Nov. 1992	Trojan	**757**	Sleeve Weld Circumferential Crack
18	Mar. 1993	Palo Verde 2	**908**	Upper Bundle Freespan Inter Granular Stress Corrosion Cracking
19	Jun. 1993	Kewaunee	**379**	Leaking Plug
20	Aug. 1993	McGuire 1	**700**	Sleeve failure
21	Sept 1993	Palo Verde 3	**397**	Free span crack
22	Oct 1993	McGuire 1	**700**	Circ. crack in sleeved tube
23	Oct. 1993	Braidwood 1	**1136**	Free span Cracks
24	Nov. 1993	San Onofre 3	**189**	Loose parts degradation and leaking welded plugs
25	Nov. 1993	Farley 2		
26	Jan. 1994	McGuire 1	**379**	Leaking Sleeve
27	Mar. 1994	Oconee 3	**545**	Fatigue
28	Mar. 1994	S. Texas	**606**	Leaking Plug
29	Mar. 1994	Zion 2	**5451**	Tubesheet Crevice Inter Granular Attack OD
30	Jul. 1994	Oconee 2	**545**	Fatigue
31	Jul. 1994	Maine Yankee	**189**	Circumferential Crack
32	Feb. 1996	Zion 1		Foreign object
33	Aug. 1996	Byron 2	**454**	Loose Part
34	May 1996	Vogtle 1		Foreign object
35	Nov. 1996	ANO 2	**246**	Axial Crack
36	June 1997	McGuire 2	**250**	ODSCC at TSP
37	Nov. 1997	Oconee 1	**1514**	2 Welded Plugs
38	Dec. 1998	Farley 1	**341**	2 Free span Cracks

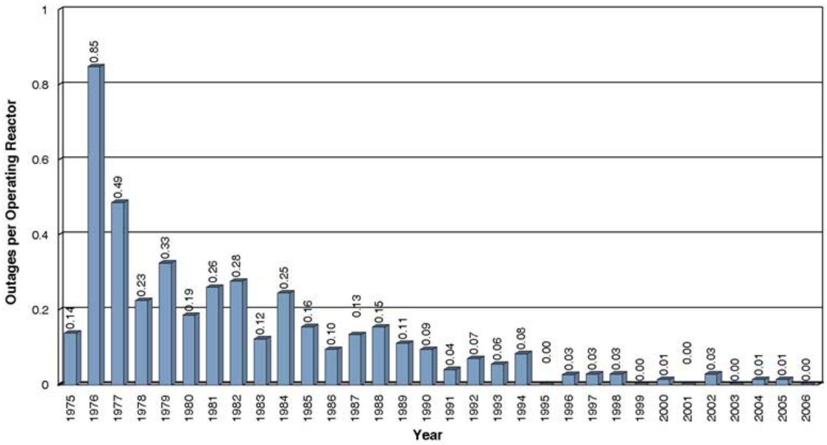


Figure 4.54. Tube leak forced outages in the USA plants.

4.5 PWR STEAM GENERATOR SHELL, FEEDWATER NOZZLE, DRAIN NOZZLE AND TUBE SHEET

This section discusses degradation mechanisms in steam generator shells, feedwater nozzles and drain nozzles. Corrosion fatigue, high cycle thermal fatigue, and stress corrosion cracking have caused cracking on the secondary sides of the PWR steam generator shells. PWR primary side degradation has not been observed and there has been no PWR tube sheet or CANDU shell, nozzle, or tube sheet degradation reported.

Thermal fatigue and erosion-corrosion are responsible for most of the ageing degradation that has occurred in PWR feedwater nozzles and the nozzle-to-pipe weld regions. Ageing degradation may cause leakage but probably not failure, however, it may also so weaken the system and reduce the safety margin that another event, such as a pressure pulse or a water hammer, could be the final cause of a rupture. Primary side divider plate damage has occurred at some CANDU units.

Table 4.9 lists and ranks by importance the degradation mechanisms, sites, stressors, failure modes, consequences, and inspection methods for the PWR feedwater nozzles and the steam generator shells. The feedwater nozzle is ranked highest, because a break at this point would cause a much larger leak than from a steam generator shell crack and might not be isolated from the steam generator, thus leading to rapid blowdown of the steam generator. Such a break would challenge the integrity of any severely degraded tubes.

4.5.1 Corrosion fatigue

4.5.1.1 Steam generator shells

high amplitude, low frequency cyclic stresses combined with coolant containing oxygen and copper oxides have caused corrosion fatigue damage to the upper girth weld, i.e. upper shell to transition cone weld, in about seven recirculating steam generator shells in the USA (Note that significant concentrations of copper oxides are associated with copper alloys in the feed train.) The presence of oxygen and copper oxides probably contributes to the formation of surface pits, which act as stress raisers, and therefore, as sites for fatigue crack initiation in the steam generator shell. During a few transient events, the water level in the steam generator drops below the girth weld region, and the incoming feedwater impinges on the girth weld and produces rather high stresses [60]. Also, fluctuations in the steam generator water level will impose thermal fatigue cycles on the steam generator shell. Circumferential cracks have been observed in the girth weld under the feedwater nozzle, mainly in the heat affected zone, with little penetration in the base metal. This suggests that the fracture toughness of the heat affected zone was substantially lower than that of the base metal, and that the stresses were large enough to drive the cracks through the heat affected zone but not through the base metal [61].

TABLE 4.9. SUMMARY OF DEGRADATION PROCESSES FOR PWR FEEDWATER NOZZLES AND STEAM GENERATOR SHELL

Rank [1]	Degradation site(s)	Stressors	Degradation mechanism(s)	Potential failure mode	In-service inspection method(s)
1	Feedwater nozzle and nozzle-to-piping weld.	Flow velocity, O_2 content and pH level in feedwater, impurities, stratified flows, thermal shocks, water hammer, plant transients.	High and low cycle fatigue, erosion-corrosion.	Rupture from wall thinning, leakage through fatigue cracks, rupture from water hammer.	Ultrasonic testing radiography.
2	Steam generator shell girth welds.	Plant transients, oxygenated coolant containing copper oxide, in-leakage of brackish water through condenser tubes, residual stresses.	Corrosion fatigue, stress corrosion cracking.	Leakage through fatigue or stress-corrosion cracks.	Ultrasonic testing radiography.
3	Feedwater nozzle bore, blend radius, shell inside surface beneath the nozzle.	Leakage of feedwater through the nozzle thermal sleeve joint causing turbulent mixing of cold feedwater and hot steam generator coolant.	High cycle thermal fatigue	Leakage through fatigue cracks.	Ultrasonic testing radiography.
4	J tubes and feedring	Flow velocity, O_2 content and pH level in feedwater, impurities.	Erosion-corrosion	Damage caused by loose parts, thermal fatigue to shell.	Problem remedied, inspection unnecessary.

[1] Currently performed but not included in the in-service inspection requirements.

4.5.1.2 *Feedwater nozzles*

Failures were observed in horizontal feedwater pipes and SG feedwater nozzles, in the form of cracks concentrated on the lower piping halves. The cause was identified as thermal fatigue cracking [62, 63], originated in cycling stressing due to thermal stratification. The intensity and velocity of this type of failure is strongly influenced by the stress amplitude, which depends on the existing temperature difference originated as described below and the frequency of the cycling stressing.

Under low feedwater flow conditions, typically during hot standby, when the feedwater is supplied by the auxiliary feedwater system, the relatively cool feedwater tends to flow along the bottom of the horizontal sections of the piping adjacent to the feedwater nozzle, with the top portion containing hot water. This thermal stratification may lead to two different stressors, which cause fatigue damage:

cyclic local stratification and 'thermal striping.' Cyclic local stratification stresses, caused by small auxiliary feedwater flow fluctuations and subsequent changes in elevation of the interface between the hot and cold layers, can produce significant stress changes at a point in the pipe cross-section. Thermal striping, due to turbulent mixing at the interface of the hot and cold layers, can produce high cycle fatigue crack initiation, generally a surface effect. Thermal striping does not propagate cracks, however, cyclic thermal stratification may propagate shallow cracks caused by thermal striping. The stress concentration at the sharp transition from the smaller thickness nozzle to the larger thickness feedwater pipe near the nozzle/pipe weld counterbore can also promote cracking in this region [64].

On 25 June 1979, the USNRC issued Bulletin 79-13 requesting examinations of the feedwater nozzles and adjacent piping in the USA to address the safety concerns raised by fatigue cracking [65]. The resulting inspections revealed pipe cracks in the vicinity of the feedwater nozzles at 18 of the 54 facilities inspected [64]. All cracks were corrosion fatigue cracks caused by cyclic thermal stratification, except the cracks at one plant, which were identified as stress corrosion cracking [65]. Recently, feedwater fatigue cracking has again been observed at several US plants, including a through wall crack at one unit. This cracking appears to have been caused by high stresses at the counterbore and fluctuations in the auxiliary feed water flow, water chemistry may also have played a secondary role.

Both carbon steel piping material and low alloy steam generator shell material are susceptible to corrosion fatigue if they contain sulphur inclusions, such as manganese sulphides [66, 67]. The morphology and distribution of the sulphides can cause the crack growth in low alloy pressure vessel steels to differ by a factor of two, depending on the crack plane orientation [68]. Environmental effects appear highest for steels with medium-to-high concentrations of sulphur (>0.015 wt%) in highly oxygenated water, environmental effects may be negligible in low sulphur (0.010 wt%) steels in deoxygenated water. This kind of degradation is strongly influenced by three factors:

- SG feedwater nozzle and feedwater distribution design.
- BOP design.
- Operation modality.

These are explained in the following:

Steam generator feed water nozzle and feed water distribution design

A design avoiding a two phase flow in the nozzle, as shown in Figure 4.55, and a distributor provided with J tubes are state of the technique to minimize thermal shock/thermal stratification since mid of the 80s [62, 63, 69]. Different suppliers have developed advanced designs to minimize this risk, as shown in Figure 4.55.

Balance of plant design

Plants having a feed water (Deareator) tank can feed water at a higher temperature during the startup phase. This reduces the temperature difference between auxiliary feed water and SG temperature.

Other designs offer the possibility of back purging to reduce the cold water impact when starting the main feedwater pumps (see Figure 4.56). The calculation of the number of thermal cycles as a function of the temperature jump according to ASME fatigue curves is typically shown in Figure 4.57. Having available feed water at ~150°C the temperature jump is about 130°C whereas using cold auxiliary feedwater it results to be of the order of 240°C. Roughly, the number of thermal cycles increases about 10 times (10^4 to 10^5).

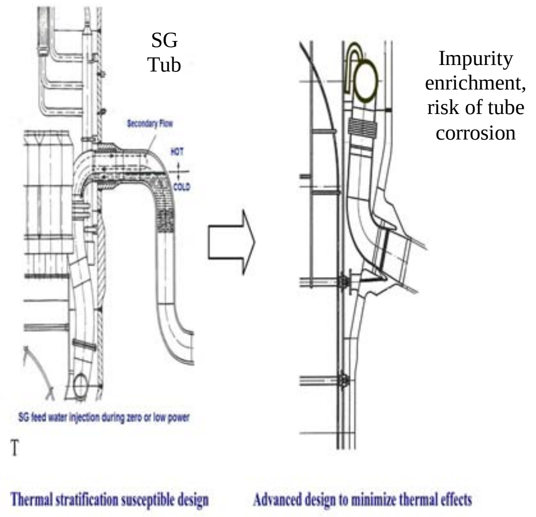


Figure 4.55. Steam generator nozzle design evolution.

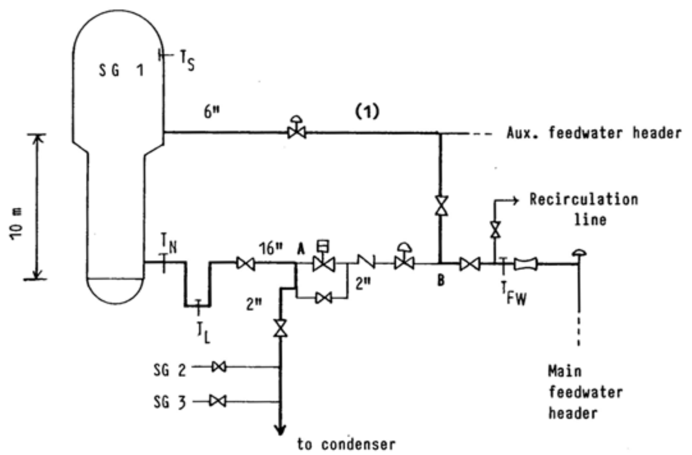


Figure 4.56. Schematic arrangement for feed water back-purging to reduce thermal shocks during startup operation.

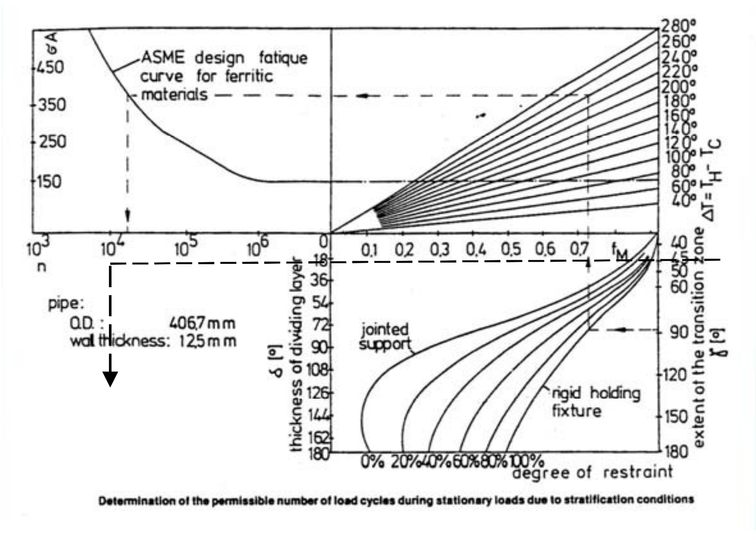


Figure 4.57. Determination of the number of load cycles during stationary loads due to stratification conditions.

Operation modality

Under zero or low power conditions (hot standby, startup), the feedwater flow is very low if compared with the full power flow rate. In such conditions, the flow in horizontal feedwater pipe sections takes place unevenly over the flow cross-section. The feedwater, which is relatively heavier because of its lower temperature, tends to flow beneath the hot water present, generating a transition zone, where an abrupt change in temperature occurs generating strong temperature gradients in the inner side of the tube walls. In Figure 4.58 a typical temperature radial profile (measured values) is shown. This transition area can be permanently changing its position by fluctuations of the feedwater flow rate. In fact, if uncontrolled, variable flow of cold water takes place, the level of the cold to hot fluid interface will oscillate within the horizontal pipe, being able to generate stress cycles leading eventually to thermal fatigue cracking. This process occurs usually in the auxiliary feedwater nozzles during startup. Also in the main feedwater line thermal stratification can occur, for instance in the case of untighten feedwater valves, or the corresponding bypass.

If the number of temperature oscillations per unit time is very high, like in the case of Figure 4.58 (b) and Figure 4.59, the resulting high number of thermal cycles, which generate the associated mechanical cyclic stresses, can lead to fatigue cracking after a certain period of operation. In Figure 4.58 (a) on the contrary, there is almost no thermal cycling.

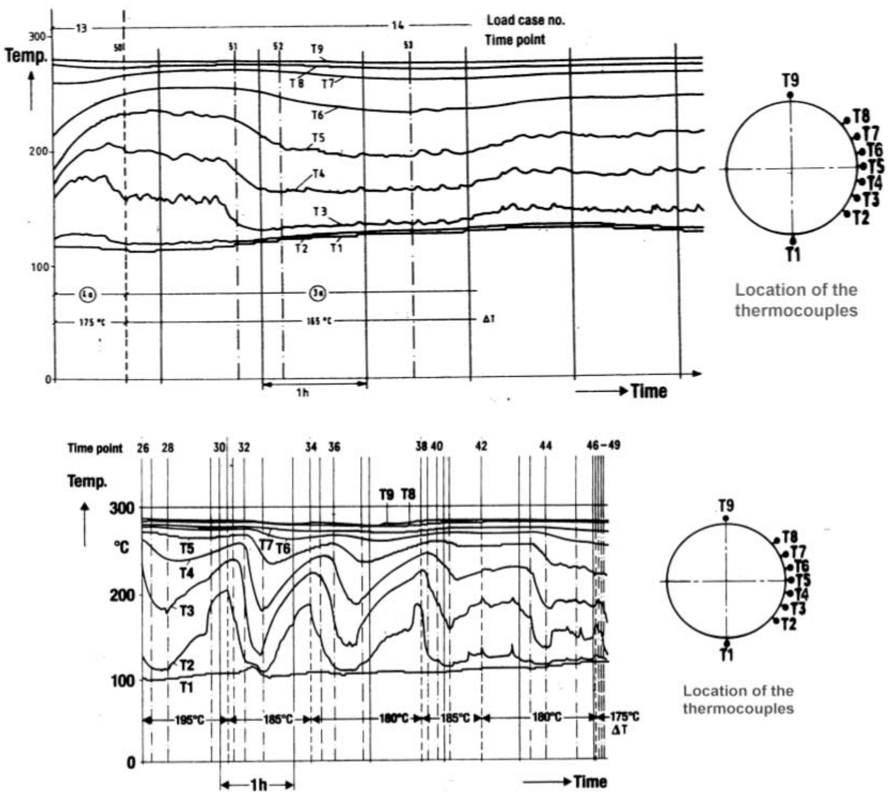


Figure 4.58. Temperature measurements on the feedwater nozzle during continuous and intermittent injection of auxiliary feedwater.

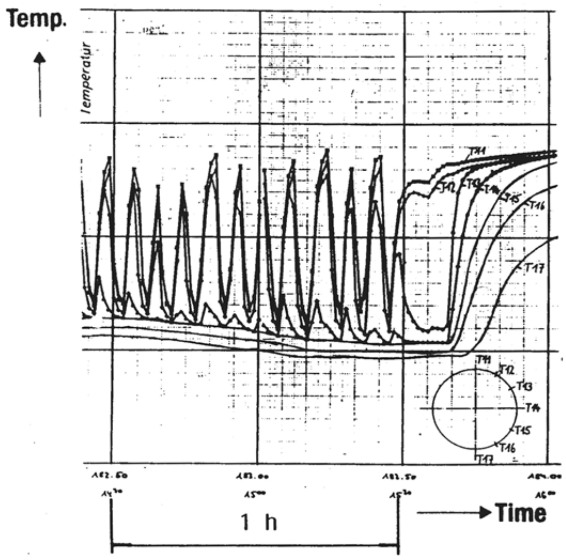


Figure 4.59. Temperature measurements on the feedwater nozzle showing a high thermal cycling rate (bad operation conditions).

The startup procedure should be optimized to ‘softer’ startup:

- Avoiding strong variations of the feed water flow rate.
- Minimizing the temperature differences when switching to main feedwater line. The temperature difference between the pipe and feedwater nozzle walls and the SG saturation temperature corresponding to the temperature during the whole startup process shall be minimized. For that, the feedwater line temperature, nozzle temperatures, feedwater temperature and SG saturation temperature could be drawn as a function of power and/or time to visualize if there are any operative improvements possible.
- Minimize the number of feedwater flow interruptions (manual SG water level control).
- A minimum feedwater flow rate should be defined to ensure plug flow in the line thus avoiding stratification. Minimum linear flow velocity necessary to reach this condition is 0.25 m/s.

4.5.2 Transgranular stress corrosion cracking

Steam generator shell material subjected to high tensile stresses and oxygenated secondary coolant containing copper oxides is susceptible to transgranular stress corrosion cracking. High tensile stresses include both weld residual and operating stresses. Transgranular stress corrosion cracking and corrosion fatigue are differentiated by their load histories. Transgranular stress corrosion cracking occurs when the applied stresses are constant or have a very small fluctuation, i.e. the ratio of the minimum to maximum stress intensity factors is close to one. Corrosion fatigue occurs when the applied stresses are cyclic and the ratio of stress intensity factors is smaller than about 0.95.

Circumferential cracks and linear indications have been detected on the inside surface of the girth welds in 18 steam generators in the USA, all of which are Westinghouse models 44 and 51 with a feed ring design [70]. This type of cracking was first observed in 1982 when a girth weld of a steam generator leaked at a US plant [71]. Linear indications have also been detected at least in one non-US plant. In most of these cases, the girth weld region was predominantly subject to static loads and the cracking was caused by transgranular stress corrosion cracking.

Leak-before-break analyses show that a stress corrosion crack will grow through the shell wall and produce a measurable leak before it exceeds the critical flaw size and the vessel ruptures [10]. Field experience to date supports this analysis. Inspection port holes in the steam generators have also experienced cracking, most likely stress corrosion cracking, on the inside surface. Grinding of the inspection porthole might have introduced the residual stresses needed for stress corrosion cracking.

4.5.3 High cycle fatigue

High cycle fatigue degradation can be caused by cyclic thermal stratification, thermal striping, and turbulent mixing of leaking cold feedwater (if any) with hot steam generator coolant (see Section 4.5.1). Any leakage of the feedwater through the feedwater nozzle-thermal sleeve joint can cause thermal stratification, turbulent mixing, and thermal shocks in the feedwater nozzle. These thermal stresses can promote fatigue damage in the nozzle bore, nozzle blend radius, and the inside surface of the shell. At one PWR plant in the USA, the feedwater nozzle bore region, blend radius, steam generator shell inside surface beneath the nozzle (see Figure 3.6), and feedring support bracket welds have all experienced cracking, probably due to both thermal fatigue and stress corrosion.

4.5.4 Flow accelerated corrosion

Flow accelerated corrosion (FAC) also known as erosion-corrosion (EC) is a degradation mechanism that affects carbon steel (CS) piping carrying single phase, subcooled feedwater and steam lines carrying wet steam. The damage caused by erosion-corrosion is higher than damage attributed to erosion or corrosion alone. Carbon steel feedwater piping corrodes during normal operation, forming a thin layer of iron oxide, mostly magnetite (Fe_3O_4), on the inside surface. This layer protects the underlying piping material from the corrosive environment, and in the absence of erosion, limits the corrosion rate. However, if stressors causing erosion are present, the layer of iron oxide will dissolve and the uncorroded metal surface will again be exposed to the corrosive environment, and piping corrosion will continue. Thus, the continuous process of oxide growth and dissolution leads to thinning of the pipe wall and ultimately to a catastrophic failure, when the pipe is subject to a pressure pulse of large magnitude.

FAC occurs under high flow rates, if the protective oxide layers on the surface of CS components and pipes cannot be built. The protective oxide layers are built on the CS surface by the reaction of iron ions, which are dissolved from the metal, with water at high temperatures. If these protective layers dissolve in an iron unsaturated fluid medium at the metal-fluid interface, or if iron ions released from the CS surfaces are immediately removed by a high flow, the protective layers cannot be built, and this results in the FAC degradation of CSs.

Figure 4.60 presents a simple model describing the phenomena occurring during erosion-corrosion [72]. The FAC mechanism, their stressors and parameters having influence on the development of FAC are well described in [31–33].

FAC will depend on the nature of the protective layer, which is dependent on the base material composition, the surrounding chemistry conditions and temperature. It has to be well understood that FAC is a two phase process: metal and water. In the case of steam flow, it can produce FAC following the above described mechanism only if a water film forms and flows on the metal surface (annular flow). The high steam velocities of typically 30 m/s ‘push’ the water film, increasing the velocity of the streaming water film on the metal surface. This is represented in Figure 4.61. Although the water film has a lower velocity than steam, it results higher than the usual linear velocities at pipes with single phase (liquid) flow. In the single phase-system a characteristic scalloped or orange skin shape surface appear whereas in two phase system a very thin oxide layer and the ‘tiger striped’ surface (Figure 4.62) are observed.

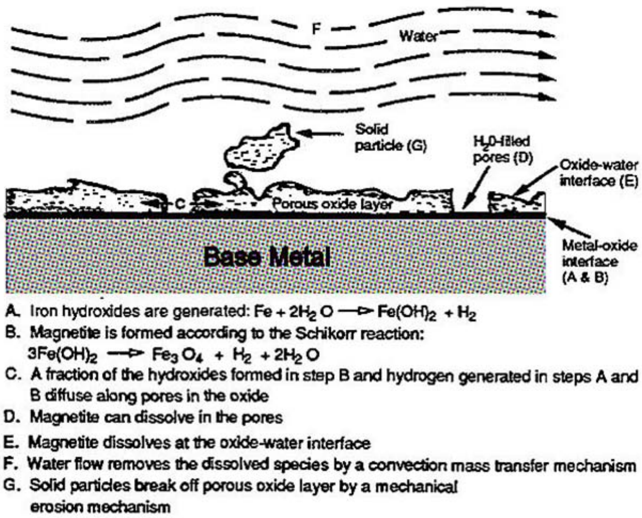


Figure 4.60. Phenomena occurring during erosion-corrosion [72].

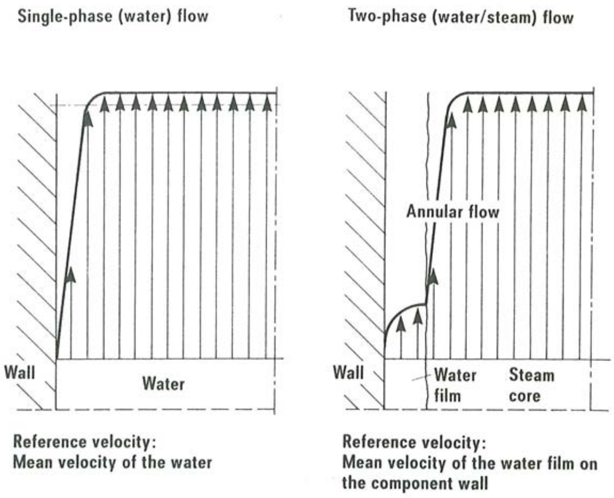
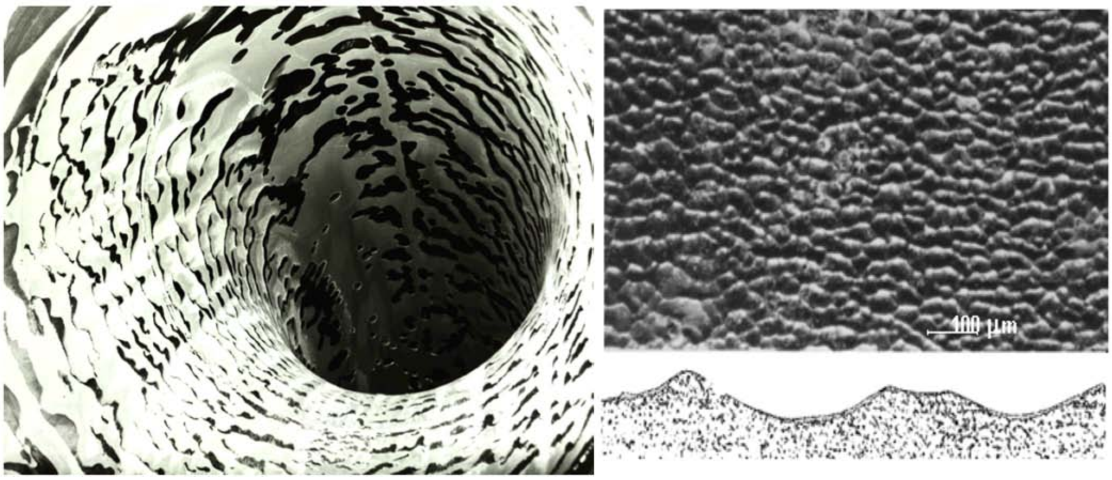


Figure 4.61. Flow velocity profiles in single phase and two phase FAC [31].



Local acidic, oxidative conditions

Carbon steel corrosion Denting

Figure 4.62. Flow accelerated corrosion: pipe surface appearance.

The factors affecting the erosion-corrosion rate are then the following:

- Piping and/or component material.
- Bulk water flow velocity.
- Piping configuration, geometry related flow perturbations (local flow velocity, turbulence).
- Feedwater and/or condensate temperature.
- pH value.
- Oxygen content.
- Moisture content (two phase FAC).

Carbon steel components with less than 0.1 weight per cent Cr are susceptible to erosion-corrosion damage being the Cr-Mo alloys with 2–2.5% Cr highly resistant. The characteristics of these alloys require careful welding procedures and extensive radiographic examinations, what makes the use of these alloys more expensive.

By replacing carbon steel pipes and components with low allowed steel the flow accelerated corrosion (FAC) will be reduced significantly (Figure 4.63). See also Figure 4.48 of Section 4.1.7. Stainless steel is not susceptible at all.

The influence of pH and temperature is of crucial importance and has been also discussed in detail in Section 4.1.5. (See Figure 4.64) updated from [30–32].

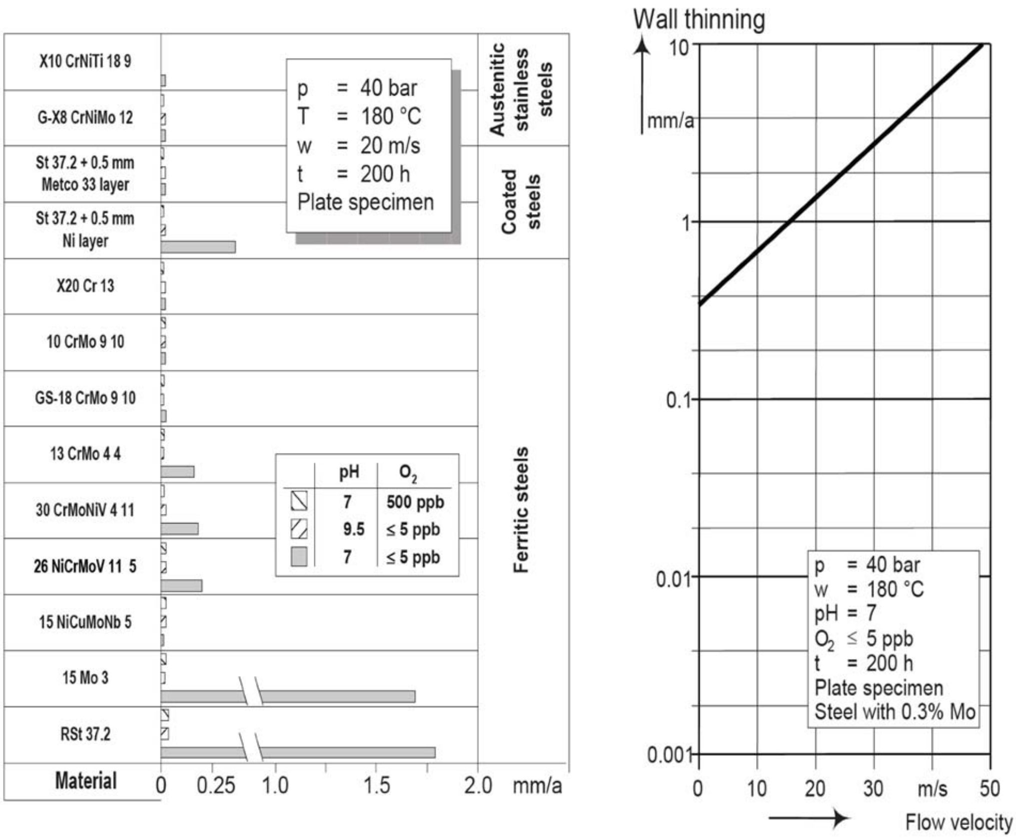


Figure 4.63. Parameters influencing FAC: Material type (left side) and flow rate (right side) [31,32].

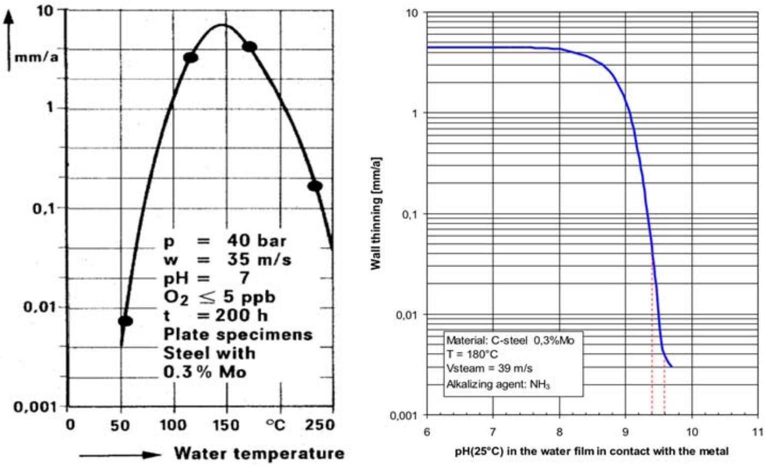


Figure 4.64. FAC rate as a function of temperature (left), Ammonia concentration and pH required to suppress FAC (right).

For a $pH_{25°C}$ > 9.5 in contact with the metal, using ammonia as alkalizing reagent, a drastic FAC reduction is expected. In fact, the pH at the operating temperature is important. As established in Section 4.1.4, the corresponding $pH_{190°C}$ for steam systems results in > 6.5.

The combined effect of temperature and material is shown in Figure 4.65. This temperature range of 100–200°C with a maximum close to 180°C automatically defines the areas of the steam water cycle with the highest susceptibility, where the material selection must be carefully considered.

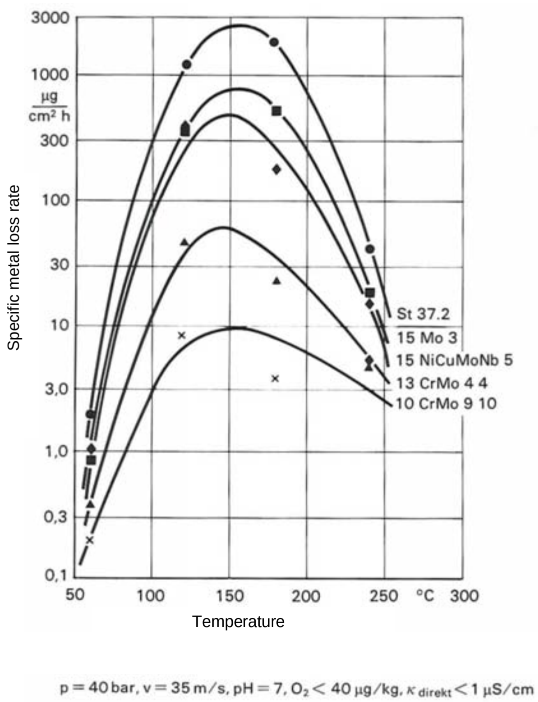


Figure 4.65. Parameters influencing FAC: Combined effect of temperature and material [31, 32].

Oxygen contributes to form a very stable hematite (Fe_2O_3) as oxide layer is generated on the carbon steel surfaces. Being hematite less soluble than hematite, it provides a barrier against FAC, as described in Section 4.1.4 and clearly shown in Figure 4.23.

At the beginning of 2000s, partial oxygen injections were introduced in several PWRs, to counteract local FAC problems occurring under extremely high flow conditions. It is described in detail in Section 5.3.2.1.

Inadequate geometries (e.g. low radius elbows, etc.) associated to high linear velocity of the fluid in contact with unalloyed carbon steel will result in enhanced FAC.

The influence of the design could be well described by Keller [73, 74], defining a dimensional geometry factors for each configuration of piping. The geometry factors acc. to Keller (Figure 4.66) permit to assess the relative influence of the geometry on FAC rate. The low the factor value is the more slightly is the wall thinning. For example, by choice of enough large bend radius or by using y-pipe instead of t-pipe or such like for the purposes of better flow quality, the influence of these design factors on corrosion rate could be reduced

Whereas a straight pipe has a factor of kf~0.04, a low radius elbow (kf=0.5) will be subjected to a FAC rate of about 10 times higher, being the absolute values a function of the other relevant parameters.

type of exposure			reference velocity w	k_c
stagnation points of primary flow		at pipes	impact velocity	1.00
		at blades		1.00
		at plates		1.00
		in divergent branches and behind orifices		0.75
				0.60
stagnation points of secondary flow		R / d = 0.5 in bends and outlet diffusors	flow velocity	0.52
		R / d = 1.5		0.30
		R / d = 2.5		0.23
		behind convergent branches		0.15
stagnation points after separation vortices		behind pipe inlets (sharp - edged)		0.16
		at and behind obstructions		0.16
without stagnat. points		in straight pipes		0.04
		in leaky joints	velocity for ideal total head	0.08
complicated cases		in labyrinths		0.05
		at and above blades at annular water traps	mean blade tip velocity of stage	0.20

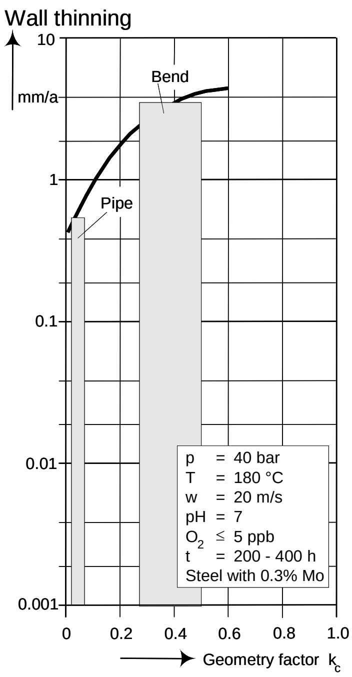


Figure 4.66. Geometry factors according to Keller for assessment its influence on FAC rate [73, 74].

Since downstream a flow perturbation (valve, elbow, etc.) there is some distance where the flow has not yet recovered the normal flow profile, the areas close to the perturbation are still influenced, and if two components are too close to each other that located downstream will have an enhanced metal loss rate.

These complex interdependences between material, chemistry and hydrodynamics have been successfully modelled in the form of computer codes allowing perform estimations and predictions leading to a safer and more economical operation, like COMSY [75] or CHECKWORKS.

The FAC rate can be predicted by calculations using codes like the WHATEC code (today COMSY), as shown in Figure 4.67 and Figure 4.68 [29, 33]. The calculated predictions fit very well with the field experience. Such programmes are integrated in the plant surveillance programmes, enabling the identification of susceptible areas an orienting/rationalizing the UT inspection programmes.

Single phase FAC at the feed water line caused various severe accidents [36] and has been extensively studied over the last thirty years. The first fatal accident in western PWRs due FAC occurred on 9 December 1986 at an 18 inch (approx. 460 mm) elbow immediately downstream of a T-fitting in the condensate system at Surry Unit 2 (see Figure 4.69). The flow accelerated corrosion attack caused a local reduction of the original wall thickness from 12.5 mm down to 1.5 mm. A plant transient caused a pressure increase inside the pipe, initiating the respective pipe rupture. Due to the sudden occurrence of the break, the persons working in the turbine hall had no opportunity to escape. Therefore four workmen were killed and several more were seriously injured [13].

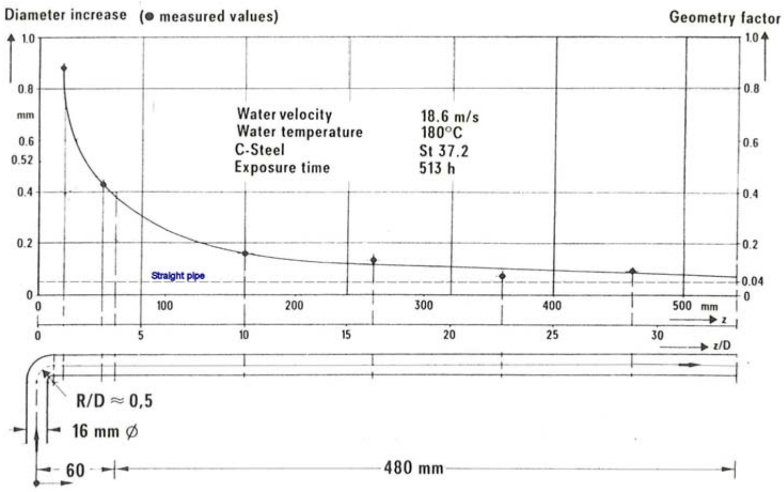


Figure 4.67. Calculated and measured FAC rate at a horizontal pipe downstream a bend.

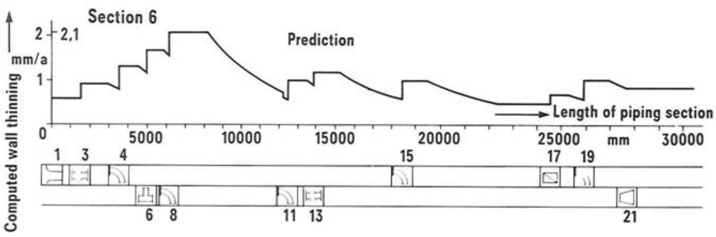


Figure 4.68. Calculated FAC rate at pipe section having different low perturbations.

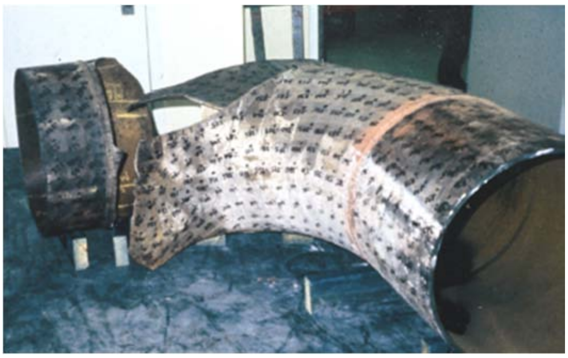


Figure 4.69. Ruptured elbow at Unit 2 of NPP Surry [16].

Millstone Unit 3 is a PWR at what was originally a three unit station located on the Long Island Sound in Connecticut, USA. In December 1990, two 6 inch (approx. 170 mm) lines downstream of level control valves in the moisture separator drain system failed catastrophically.

Post-accident investigation revealed that while the lines that failed should have been included in the single phase FAC programme, a miscommunication between the analyst at the corporate office and the engineer at the plant caused these lines to be omitted from the analysis and inspection efforts.

Figure 4.70. Damaged Pipe at Unit 3 of NPP Millstone [16].

On 9 August 2004, a large pipe break in a secondary side line at the NPP Mihama Unit 3 nuclear power station [29] killed five workers. The incident was caused by a degraded pipe in the condensate system, located in the turbine hall. The respective 22” pipe was suffering from flow accelerated-corrosion attack. The ruptured pipe was located behind an orifice plate. The flow accelerated-corrosion attack caused a local reduction of the original wall thickness from 10 mm down to 1.4 mm. This local wall thickness reduction caused the respective pipe rupture, which occurred while workers were preparing for a routine outage.

Figure 4.71. Pipe rupture at Unit 3 of NPP Mihama. (The orifice flange is barely visible on the right hand side of the right picture).

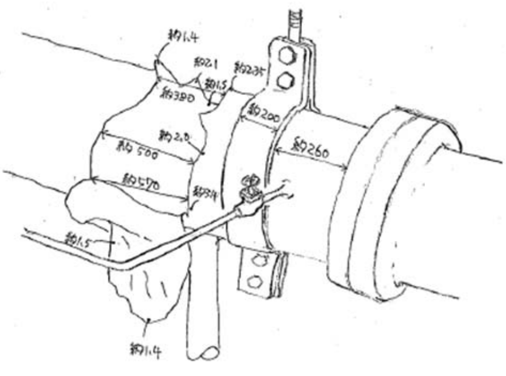


Figure 4.72. Sketch of ruptured pipe at Unit 3 of NPP Mihama.

At this time, most parametric influences are reasonably well understood. A code like COMSY could predict the events at Surry and Mihama with due anticipation, as shown in Figure 4.73 [29, 76].

The chart at Figure 4.73 indicates the predicted progress of wall thinning versus the operating time of the plant. Line No. 3-4 marks the minimum required wall thickness of the pipe for the given stress conditions. The red line indicated the wall thinning rate computed by the FAC code whereas the dashed line marks the wall thinning rate which was actually experienced. The lifetime prediction chart indicates the performance of a wall thickness inspection for the year 1991 and predicts the pipe rupture for the year 1999.

Figure 4.74 illustrates a lifetime prediction chart generated by the FAC code for the Surry 2 pipe break location. The red line indicated the wall thinning rate computed by the FAC code. The computed rate correlates well with the wall thinning rate actually experienced. The predictive result indicates the performance of a wall thickness inspection for the year 1981 i.e. five years before the occurrence of the catastrophic pipe break.

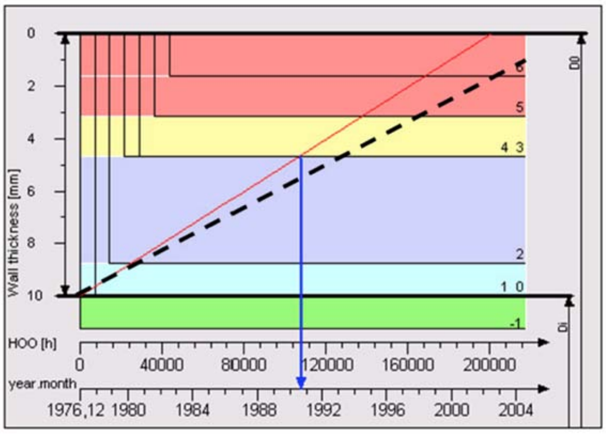


Figure 4.73. Lifetime prediction chart Mihama 3 [29, 76].

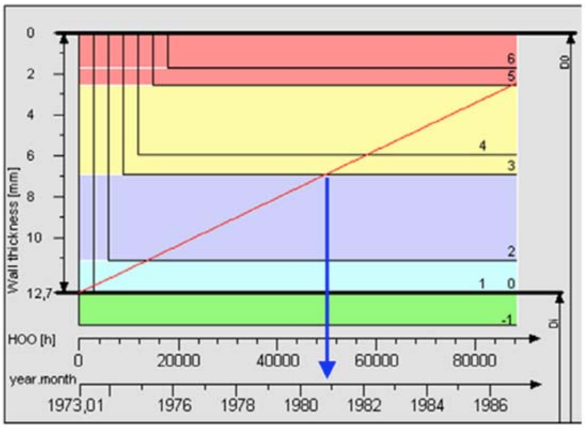


Figure 4.74. Lifetime prediction chart Surry 2 [29, 76].

Although erosion-corrosion is a greater concern in PWR feedwater piping, steam generator components have also experienced direct damage from this mechanism. Erosion-corrosion of the thermal sleeve at Diablo Canyon Unit 1 was recently reported [77]. The carbon steel J tubes and feedrings within RSGs have also experienced significant erosion-corrosion induced wall thinning. The affected J tubes have been repaired or replaced with Alloy 600 J tubes.

Erosion-corrosion damage has been reported to some of the carbon steel primary side divider plates in the CANDU steam generators, as well as fatigue damage to the carbon steel divider plate bolts. (The primary side divider plate is located below the tube sheet in the lower plenum of the RSGs.) The erosion-corrosion of the plate and fatigue of the bolts caused increased divider plate leakage and excessive bypass flow, which decreased somewhat the performance of the steam generators. Fatigue of the bolts may also lead to loose parts damage to the tube sheet.

Besides direct SG damage, FAC is an important indirect contributor to SG tube corrosion, as explained in Section 4.1.5, increasing the inventory of corrosion products and creating the adverse local conditions leading to damage tube outer diameter.

4.5.5 Stress corrosion cracking in steam generator primary inlet and drain nozzles

Stress corrosion cracking in SG primary inlet nozzle, hot leg, in Japan has been reported by the Nuclear and Industrial Safety Agency (NISA), occurring in 11 steam generators at 5 PWR plants (see Figure 4.75).

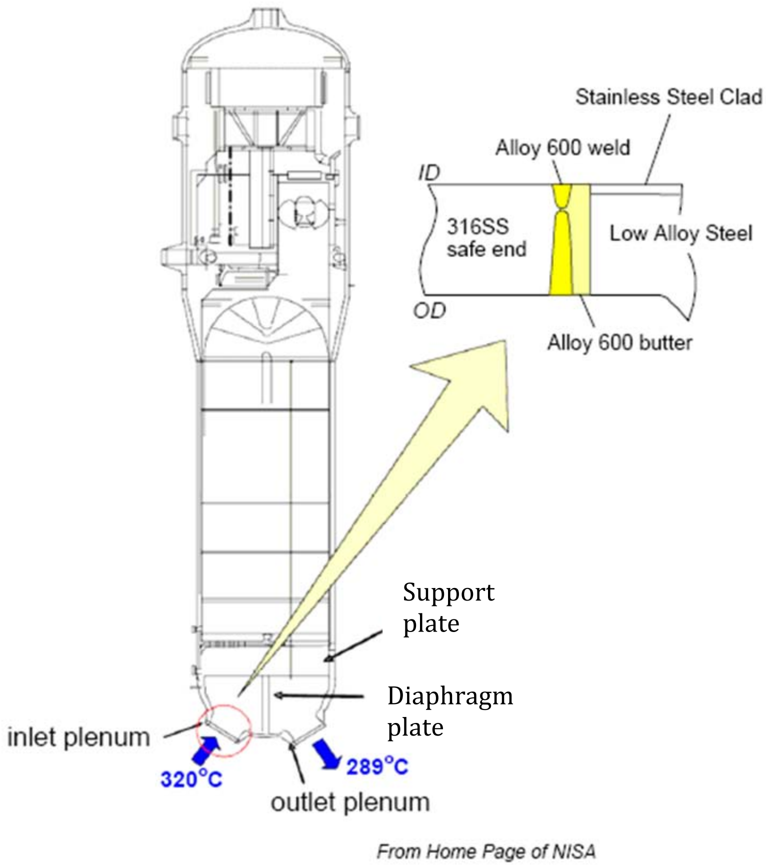


Figure 4.75. PWSCC at welds on the steam generator inlet plenum.

The cracks were found by ECT on the inner diameter of the inlet nozzle at the inner Alloy 600 weld. Axial cracks. Material of the loop piping is 316 SS, SG side is SS-cladded low alloyed carbon steel.

In one known case the cracks appeared in SGs that had been replaced in1994. In 2007, cracks measuring 6 mm and 8 mm in maximum depth were found in the welds on the primary coolant inlet nozzle stubs in two of three SGs. All of them had used nickel based Alloy 600 for welding their nozzle stubs. Ti is presumed that during the production of replacement SGs, the inner surfaces of their inlet nozzle stubs were machined to remove asperities, a combination of strong residual stresses generated on such surfaces during this process and stresses applied during subsequent plant operation caused primary water stress corrosion cracking (PWSCC) and led to the growth of cracks.

Countermeasures: Flaws to be removed through machining. Verification of flaw removal by liquid penetrant testing, measurement of the machining depth, if needed, coating by build-up welding using nickel based Alloy 600. Following this, the surface of the circumferential weld is to be coated around the entire perimeter by build-up welding using nickel based Alloy 690, which is highly resistant to corrosion. The areas subjected to build-up welding will then be surfaced through buffing (surface polishing) as a precaution in order to reduce residual stress.

Stress corrosion cracking in SG drain nozzle in some plants including Korean plant was reported. The nozzles were made of Alloy 600 base material and welded with alloys 82 and 182 to the SG shell. Carbides were distributed at the grain boundaries, but no grain boundary Cr-depletion was observed. Circumferential cracks were developed at the root of an inside the thick wall pipe. Axial cracks were distributed at the root of the J weld with a length around 6 to 10 mm long. All the cracks were initiated from the inner surface of the pipe. Some more shallow cracks were also observed, but they were not detected by the field non-destructive examination with ECT and UT. Two out of the 12 cracks penetrated through the wall, primary water leaked out during operation. The high tensile stress region calculated by using a commercial FEA code, ABAQUS coincided with the crack locations. The highest tensile stress region was at the root of the J weld, judging from metallography and residual stress analyses. Residual tensile stress after a welding process was considered as the main contributor to the stress.

4.6 WWER COLLECTOR, SHELL, AND FEEDWATER DISTRIBUTION SYSTEM

Although the WWER tubing has been relatively trouble free, stress corrosion cracking of the WWER-440 collectors and WWER-1000 cold collectors and erosion-corrosion of the WWER feedwater distribution systems has occurred. The stress corrosion cracking of the collectors is discussed first, followed by a brief discussion of the feedwater problems.

4.6.1 Stress corrosion cracking of the WWER-1000 collectors

In contrast with the vertical tube bundles and horizontal flat tube sheets used in the West, the WWER steam generator tube bundles are horizontal and are attached to the walls of two vertical cylindrical collectors or headers. Primary coolant from the reactor core region enters through the inlet (hot) collector, passes through the U shaped tubing, and leaves through the outlet (cold) collector. The WWER-1000 collectors are fabricated from low alloy steel and clad on the inside with austenitic stainless steel. The hot and cold collectors are similar with normal operating temperatures at 320°C and 290°C, respectively. The inner diameter of the WWER-1000 collectors is 834 mm and the wall thickness is 171 mm.

Higher than normal radioactivity levels were observed in the secondary system of South Ukraine Unit 1 in late 1986. It was determined that three adjoining ligaments in the cold collector of one of the four steam generators had developed through wall cracks resulting in failure of the tube to collector inside surface cladding welds and significant leakage of primary coolant into the secondary system [78]. This steam generator had been in operation for less than one year. As of July 1993, 33 steam generators at eight WWER-1000 plants had been replaced because of failure or the potential of failure of the cold collectors [78, 79]. These replacements occurred at only 3-25% of the design lifetime (240 000 h). Two of SGs were repaired.

Cracking and potential rupture of the WWER collectors is of concern not only because of the economic losses associated with repairing or replacing these steam generators, but also because of public safety. Radioactive primary coolant could be discharged to the environment via the main steam atmosphere dump valves if they stick open. Worst case calculations suggest that about 200 tonnes of primary system, steam generator, and emergency core cooling water might be released. Also, long term cooling might be lost if the atmospheric dump valves do not close properly because there are no isolation valves on the atmospheric dump valve lines [80].

Metallographic examination of failed collector material "showed that the cracks were corrosion induced, mechanical in nature, initiating and propagating from the secondary circuit side, at first via an intercrystalline and then via an intergranular mechanism" [78]. The maximum crack length (as a sum of the lengths of the affected ligaments) on the secondary side was about 1000 mm. The maximum through wall crack length on the primary side was about 10–15 mm. To date, cracks have been found only in the cold collectors. However, 'indications' have also been reported for the hot collector [80]. Three types of cracks have been observed: satellite cracks with widths up to 0.1 mm and lengths up to 1 mm; planetary cracks between two adjacent holes with widths up to 0.5 mm, lengths across the ligament, and depths up to 30 mm; and arterial cracks through several (up to 30) holes with lengths up to 1000 mm, widths more than 0.5 mm, and depths through the wall (171 mm). The maximum crack propagation rate was six ligaments within one operating cycle (approximately 18 months).

The metallographic examinations also showed that the cracks usually started at a crevice between the collector hole and a non-expanded tube, near the non-perforated zone (V configuration) of the collector. The cracks start at pits and grow across the ligaments first, further growth occurs through the wall. The wall is penetrated only after cracking of several ligaments. Ductile cladding failure occurs after the cracks penetrate the collector wall.

Investigation and analysis of the design, fabrication, operational loads, and water chemistry conditions led to the following findings [78, 81]:

- The tubing in the steam generators with collector cracking had been explosively expanded into the collectors using 'rigid' charges. This procedure led to deformation of the collectors, seizure of the upper part of the collector in the steam generator vessel flange, and residual stresses near yield in the collector ligaments.
- The collector hole drilling techniques coupled with the explosive tube rolling led to the formation of a layer of embrittled, highly cold work material on the inside surface of the collector holes, which was sensitive to cracking.
- Crevices with depths up to 20 mm were present due to under-expansion of the tubes. These crevices collected impurity deposits, which promoted stress corrosion cracking. The deposits in the cold collector crevices tended to be porous, whereas the deposits in the hot collector crevices were generally dense enough to prevent water ingress.
- The low alloy steel used for the WWER-1000 collectors undergoes strain ageing at about 290°C. It is also more susceptible to stress corrosion cracking at temperatures below 280°C than at higher temperatures.
- Abnormal secondary water chemistry conditions accelerated the cracking process, especially a drop in pH to acid conditions (as low as 4.3), and significant periods, when the chlorine ions ranged from a few hundred to a few thousand µg/kg rather than the specified less than 150 µg/kg [82], [56], [53, 56, 82]. Excessive oxygen due to aerated auxiliary feedwater and copper from the condenser tubes may also have contributed to the problem [80].

- The steel fabrication process may have created MnS inclusions, which acted as sites for crack initiation.

To improve the performance of steam generators already in operation, the following changes were made: release of the collector upper racks, low temperature heat treatment (450°C) of the collector perforated zone, and improvements in secondary water chemistry. These changes helped but were not fully effective.

For new steam generators a high temperature heat treatment at 650°C was conducted along with full depth hydraulic expansion of the tubes using a hydraulic expansion process, which minimized the residual stresses and crevices. For the collector material improved type 10GN2MFA low alloy steel is used. It is electro slug melted or doubly vacuum treated to minimize the gas concentrations and secure a homogeneous chemical composition. The phosphorus and sulphur contents were reduced. For new units water chemistry sufficiently improved, excluding copper from secondary side systems.

The new WWER-1000U design will probably use titanium stabilized austenitic stainless steel in the perforated regions of the collectors rather than low alloy steel and the tubes will be expanded hydraulically.

4.6.2 Erosion-corrosion of the feedwater distribution system

As discussed in Section 4.5.4, erosion-corrosion is a flow accelerated corrosion mechanism, where damage caused by erosion-corrosion is higher than damage attributed to erosion or corrosion alone. The factors affecting the erosion-corrosion rate include piping configuration, feedwater temperature, pH value, bulk water flow velocity, turbulence, oxygen content, impurities and material.

A current issue involves the erosion-corrosion of the WWER-440 and WWER-1000 feedwater distribution systems. The WWER-440 feedwater distribution system is shown in Figure 4.76 and consists of a feedwater pipe which enters the steam generator vessel on the side opposite the hot collector in the steam region, travels across half the tube bundle, and then travels down to about the centre of the tube bundle, where it connects via a tee joint with a horizontal manifold. The horizontal manifold is equipped with a number of nozzles directed down, through which sub-cooled feedwater is injected into the corridor between the two sides of the tube bundle to mix with the saturated liquid. The system was originally fabricated with mild carbon steel. Flow accelerated corrosion of the nozzles has occurred at a number of plans including Dukovany, Paks, Loviisa, and Rovno. The damage has ranged from modest wall loss to complete nozzle destruction (the nozzles closest to the tee tend to be more damaged). Erosion-corrosion of the tee joint has also been observed, which could lead to cold feedwater spray onto the hot collector.

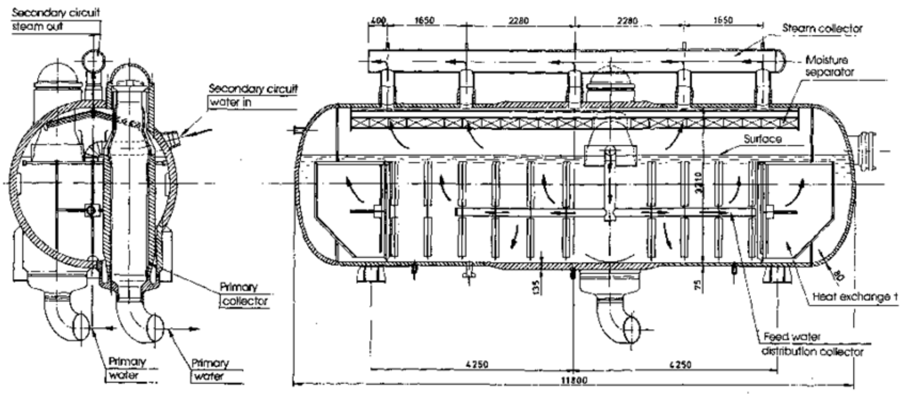


Figure 4.76. WWER 400 steam generator – feedwater distribution collector.

Loss of the feedwater distribution nozzles is not considered a major safety issue because experiments conducted at OKB Gidropress have shown that the feedwater flow distribution is still adequate. However, the missing parts may cause fretting damage to the steam generator tubes or damage the valves in the blowdown lines (only 2 of the 13 missing feedwater distribution nozzles at Paks have been found). Also, continued erosion-corrosion of the system will eventually destroy the tee joint.

In response to this problem, OKB Gidropress has designed a new WWER-440 feedwater system, which has similar geometry but is made of titanium-stabilized austenitic stainless steel. This new system has been installed in the Rovno and Paks steam generators. Another retrofit design prepared by Vítkovice in the Czech Republic is characterized by a manifold above the water level and feedwater distribution through long down-comers into mixing boxes situated at the level of the previous feedwater manifold. This design has been installed in the Dukovany steam generators (16 steam generators) and one Bohunice steam generators. A slightly different upper feedwater system was installed in another Bohunice steam generators. The tee joints were repaired at Loviisa in 1989-1990. Later, on finding extensive damage to the feedwater distribution nozzles, a programme of feedwater system piping replacement was performed at Loviisa. Replacement design differs to avoid possible water hammer phenomena because of cold feedwater supply, which is specific feature of Loviisa NPP.

Erosion-corrosion of the WWER-1000 steam generator feedwater distribution systems may also be a problem, and alternate designs and materials are being evaluated by OKB Gidropress. This problem lead to replacement programme performed also at WWER-1000 steam generators.

4.6.3 Failure of collector cover bolts

The WWER steam generator collectors are sealed at the top with covers (plates), which are bolted to thin flanges around the top of the collectors (see Figure 2.8 and Figure 2.9). On 24 January 1982 all twenty bolts holding the cover on the hot collector in steam generator number 5 at Rovno Unit-1 broke during a reactor power increase from 75% to 82%. The cover blew off (lifted), creating a break area around the collector circumference with an equivalent diameter of about 120 mm. The primary coolant system pressure dropped rapidly and the reactor was automatically scrammed at 12 seconds. All three trains of emergency core cooling started shortly thereafter. At 13 minutes, the operators shut down the reactor coolant pump on Loop 5 and attempted to close the isolation valve but it would not fully close (the primary coolant pressure was about 40 atmospheres).

Between 30 and 39 minutes the operators were able to improve the leak tightness of the Loop 5 isolation valve, but also noted that Loop 3 was leaking. Eleven of the twenty bolts on the hot collector cover in steam generator number 3 were later found to be broken. The operators shut down the Loop 3 reactor coolant pump and tried to close the Loop 3 isolation valve. It initially closed only 50% of the way. The result of these actions (full isolation of Loop 5 and partial isolation of Loop 3 and full emergency core cooling flow) was that the primary system pressure increased to 105 atmospheres at 39 minutes and then all twenty bolts on the cover of the hot collector in steam generator 1 broke. (Also, four of the twenty bolts on the cover of the hot collector in steam generator 4 broke at some point.) The primary coolant system pressure then dropped back about 40 atmospheres within about 1 minute. At 65 minutes, there were indications that some of the steam generators were overfilled and there was water in the steam lines. Eventually, all four defective steam generators were isolated and the plant was cooled using Loops 2 and 6 only. Altogether, about 1100 tonnes of primary coolant and emergency core cooling water was lost to the secondary side and about 20 tonnes were released to the environment along with about 17 Cis of radioactive material [83].

Inspection of the bolts after the accident determined that the failures probably occurred as a result of corrosion fatigue damage. The bolting material chemical and mechanical properties were within specification, however, there was some non-uniformity in yield strength (56-67 kg/m^2) and hardness (19-27 Rockwell). Forty per cent of the fracture surfaces had a clearly visible striated structure characteristic of fatigue damage. There were differences in grain size and carbide inclusions. The "character of the fracture surfaces was brittle" with numerous inter- and trans-granular micro-cracks. The breaks occurred in the transition region from the threaded to non-threaded material or in the first few threads. Some of the micro-cracks appeared to have been present for a considerable period of time.

Due to wear of the top cover seals, there had been primary to secondary coolant system leakage from the hot collector covers in steam generators 1, 3, 4 and 5 and the bolts had been screwed down very tight the previous year, creating high tensile stresses. Other possible reasons for the bolt cracking include water level oscillations and splashing on the secondary side which caused thermo cycling and fatigue damage and may have caused an accumulation of impurities in the bolt region, a poor choice of bolt lubricant, and high chloride levels on the secondary side [83, 84].

Corrective measures at Rovno and other units included a new procedure for tightening the bolts, a change in the stud lubricant from molybdenum sulphide to copper-graphite, a change in the secondary side chloride limits from 500 ppm to 50 ppm, and better secondary side water level control. Also, the bolts and covers on all the Rovno steam generator collectors were replaced. Other WWER-440 plants have also implemented nitrogen-16 monitoring on the main steam lines in response to this accident [84]. Implementation of expanded graphite gaskets instead of nickel allows to drastically decreasing stresses in bolts to avoid cracking.

Problems with the primary collector bolts occurred also at Bohunice and Dukovany NPPs, but without rupture. Periodically inspected and defective bolts with indications were changed. The problem was completely eliminated using a different type of sealing (camprofile gasket), which does not require high level of initial assembling pre-stress.

4.7 SUMMARY OF CURRENT WORLD EXPERIENCE

The status of the western PWR steam generator tubing degradation has been updated using information from [18, 19, 85] in Section 0.

Refer to Figure 4.3. Until 1994 about one half of the PWR nuclear power plants in the world were plugging steam generator tubes in any given year. This implies that about one half of the PWR plants were operating with tubing defects near or beyond the national limits in any given year. In the 1990s, the percentage of tubes plugged per year has been about 0.30–0.34% (of a total steam generator tube population which topped 3.4 million in 1994). The total number of steam generator tubes plugged per year during the first half of 1990s has ranged from about 8000 to 10 000 tubes. In addition, more than 55 000 steam generator tubes had been sleeved as of December 1993 and about 30 000-40 000 tubes were sleeved in 1994 and 1995.

Although an average plugging rate of 0.25–0.3% per year may seem acceptable, over a 40 year steam generator life this amounts to about 10–12% of the available tubes plugged. Also, not all steam generators are degrading equally. The causes of steam generator plugging on a worldwide basis are shown in Figure 4.2. As discussed above, the relative impact of the various tube degradation mechanisms on overall steam generator performance has dramatically changed over time. In 1993, PWSCC (22%), ODSCC (41%) and fretting (5%) accounted for about 68% of all the tubes plugged. The diversity and persistence of the damage mechanisms suggested that no one remedy will resolve all the problems and effective remedies are not easily found. However, the consequently applied improvements resulted in a significant decrease of the SG degradation, mainly due to replacement of the damaged SGs (see Figure 4.4) replacing them by units provided with Alloy 800NG or Alloy 690TT tubing material (see Figure 4.5), associated to back-fitting operations like elimination of Cu bearing materials from BOP systems, as well as operative measures mainly (but not exclusively) chemistry related modifications as described in former sections.

The widespread tubing degradation that has occurred in some PWR steam generators had led to spontaneous single tube rupture events, which have occurred at a rate of about one rupture every two years. In addition, incipient tube rupture events have been occurring at the rate of about once a year in 1990s, which was decreased drastically in 2000s. Steam generator tube ruptures due to loose parts damage, PWSCC and ODSCC are expected to decrease in number, mainly due to the drastic reduction of SG tube PWSCC associated to the change of tube material, and the improvements leading to a reduction of the OD corrosion damage (older plants) and the drastic diminution in newer plants or plants with new SGs, even though it remains a major concern owing to the gravity of such event.

Simultaneous rupture of a number of steam generator tubes is very unlikely unless induced by a design basis accident such as a main steam line break. There have been no main steam line breaks or other design basis accidents, which might cause multiple steam generator tube ruptures. However, such accidents are possible. Sophisticated analysis of such transients in PWRs indicates that effective operator intervention and actions to throttle the emergency core cooling injection and actuate the residual heat removal system will result in a successful recovery from a main steam line break with up to about 15 induced steam generator tube ruptures. More than about 15 induced steam generator tube ruptures produces a system response, where the reactor coolant system sub-cooling cannot be recovered prior to exhaustion of the normally available emergency core cooling water (which in some plants can be replenished from outside sources). Some seven hours of emergency core cooling are available for a main steam line break with one induced tube rupture, whereas only about two hours of emergency core cooling are available for a main steam line break with 15 induced tube ruptures. (These are typical numbers for a Westinghouse type three-loop plant and assume optimum throttling of the emergency core cooling injection.) Clearly, the reactor operator actions must be prompt and effective: This was not always the case during the previous single spontaneous steam generator tube ruptures. If the reactor operators do not properly throttle the emergency core cooling injection or replenish the storage tank during a main steam line break accident with 15 induced steam generator tube ruptures, the emergency core cooling water supply will be exhausted within an hour and the core will be uncovered and start to melt in about seven hours.

Units having SG tubing of a material other than Alloy 600 MA experienced a better behaviour. These were mainly the CANDU and Siemens Units, having SGs with Alloy 800NG. Beside the SG tube material, the CANDU units operate at lower temperatures, which make them not fully comparable with other PWRs.

In the particular case of the Siemens plants, the tube failure rate due to corrosion under comparable operation conditions has been negligible. The plugging rate accounted to less than 0.6% for all units, and less than 0.2% considering the plants in operation since 1978, and there was no need of SG replacement to now (exception: NPP Obrigheim, the original SGs with Alloy 600MA tubing, had to be early replaced in 1982) The first units having been decommissioned arrive to their end of life without noteworthy SG damage. This successful experience is attributed to the adequate, systematic harmonization off the plant system and component design, materials and applied chemistry as described in Section 4.1.3.

To summarize, there have been a number of PWR steam generators operating with tube defects at or near the national limits at any given time. Spontaneous single tube ruptures have and will probably continue to occasionally occur. The radioactive material releases associated with these events have and will continue to be small and well below regulatory limits. A design basis accident such as a main steam line break might induce some multiple tube ruptures. It is likely, but not certain, that the reactor operators can successfully cope with the transient.

Since mid of 1980s, a series of measures to counteract SG tube degradation have been implemented to reduce and/or control the impurity amounts/composition in the SGs, like more stringent chemistry guidelines, boric acid treatment, in most of the cases with less or no success, since the problem was mainly design related. Efforts were also made in some cases to eliminate copper from the secondary system to enable sufficient reducing conditions (high hydrazine) and high pH operation reducing the corrosion product transport into the steam generators, among other measures like the use of alternative amines to improve the pH of wet steam areas, with more or less success depending also on SG design. Steam generator replacement was initiated in most of the cases of severe ageing, Alloy 690TT and 800NG were selected as tube material, and stainless steel tube supports of advanced trefoil broached hole or egg crates were used. Also improvements in the design of FW nozzles contributed to palliate thermal shock/stratification problems. The SG performance has been since then considerably improved.

However, in order to improve the SG lifetime and performance of the SGs, not only new SG material, better SG design and adaptions in the chemistry are necessary, but also a number of design/material/chemistry incompatibilities in the secondary cycle with negative influence on the SG performance need yet to be solved in operating plants.

WWER steam generators: In contrast with some of the PWR steam generator tubing, the tubing has been relatively trouble free until end of the 1990s. Due to relative thick tube of WWER, associated to a lower operation temperature, tube rupture is very unlikely.

Regarding collector cracking, it is justified also that this event is very unlikely, providing proper in-service inspection. However, the collectors in the WWER-1000 steam generators have been a problem As of July 1993, 33 steam generators at eight WWER-1000 plants had been replaced because of failure or the potential of failure of the cold collectors. Unfortunately, many (most) of the replacement steam generators are not significantly different from the original equipment so additional collector cracking is expected. The collector cracks can be large and the crack propagation rates high. Cracks up to 1000 mm in length have been found and crack propagation rates up to six ligaments per operating cycle have been observed.

Perspective for the future

The experience gained up to date is being well recycled and it results in a significant improvement of the life expectancy of the steam generators. However, existing plants having still material/design/chemistry incompatibilities may not arrive to end of life without replacement of a steam generator.

For new plants there is a promising perspective, provided that the lessons learned as described in this document are consequently applied in their design.

5 STEAM GENERATOR AGEING MANAGEMENT: OPERATIONAL GUIDELINES

This section describes a set of operational guidelines which are aiming to help nuclear power plant operators prevent, or at least minimize, steam generator ageing degradation and thereby maximize component life. Implementation of these measures is expected to be considerably less costly than repairing or replacing steam generators and may provide the additional assurance required to operate some steam generators for additional time.

The steam generator ageing processes require a deep analysis and a very good understanding of the involved mechanisms, following the approach of Figure 5.1 below.

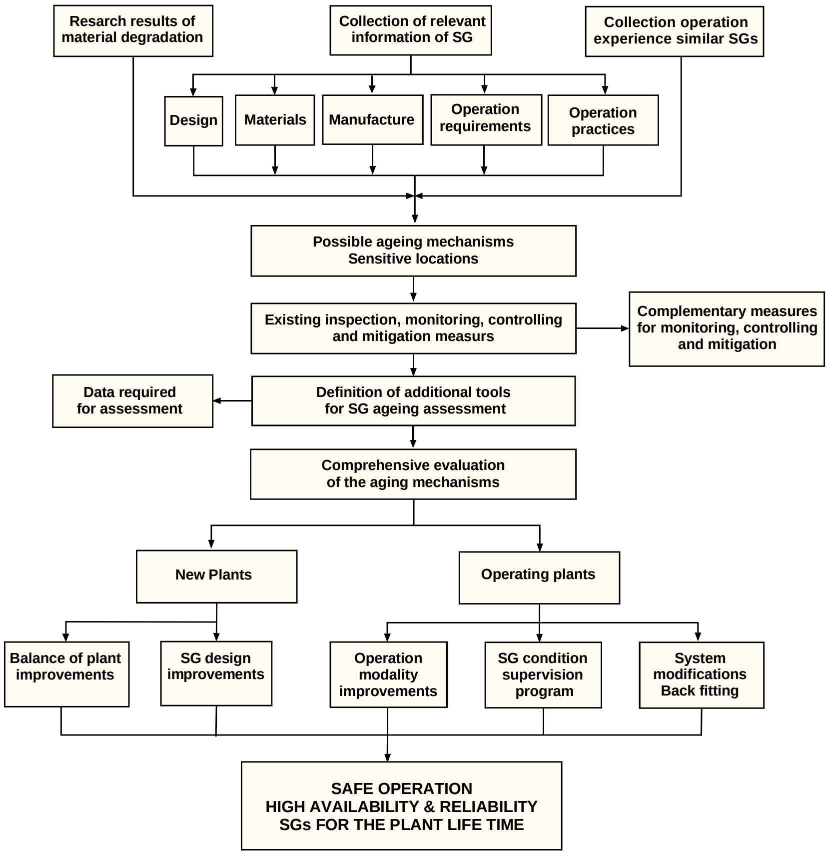


Figure 5.1. Analysis of the ageing mechanisms and continuous improvement.

For a given steam generator and balance of plant, the operation requirements and operation modality play a significant role and are those able to be improved more easily.

Ageing of steam generators is strongly influenced by chemical related degradation phenomena. For that reason, the fundamentals of the corrosion related degradation processes and the interactions between chemistry, materials and design have been extensively treated in Section 4. A suitable chemistry concept is therefore an important countermeasure to minimize steam generator degradation.

The chemistry related operational procedures are grouped into the following topic areas:

- Secondary side water chemistry control and diagnostic parameters *adapted to the SG and BOP system characteristics*, as stated in Section 4, Section 4.1.5.
- Measures to control steam generator deposits.
- Measures to ensure reducing conditions.
- Measures to control secondary side impurity incursions.
- Measures to remove secondary side impurities.
- Primary coolant system water chemistry.

Although this section provides general guidance, detailed operating procedures must be developed to suit the specific conditions and requirements of specific plants. Given the variety of materials, system and component design and environmental conditions encountered in practice, the detailed operating procedures will vary considerably from plant to plant.

A very important aspect of steam generator ageing management is the use of a comprehensive inspection and monitoring programme and appropriate fitness for service guidelines to assess the current and future safety state of these components. These topics are discussed in Sections 6 and 7 of this report. Anyway, since the chemistry related aspects have the bigger impact on SG performance, affecting not only the SG integrity but also the thermal performance (fouling), a long term supervision and management programme must be established and carried out to assess the SG condition and recognize at the earliest possible the need of preventive measures and enable a condition-oriented maintenance.

5.1 SECONDARY SYSTEM WATER CHEMISTRY CONTROL

5.1.1 Objectives

A secondary system water chemistry programme should be established that ensures the steam generator chemistry key conditions:

- Corrosion product transport to the SGs as low as possible.
- Sufficiently reducing conditions (avoidance of oxidizing conditions).
- Limited transport of impurities into the SGs is properly controlled.

The programme should identify a reduced number of key parameters categorized as control parameters, and also the necessary complementary diagnostic parameters.

Control parameters relate directly with SG integrity, and they must be correspondingly limited by establishing action levels for fault-finding and corrective measures, as well as operation restrictions to protect the SGs.

Diagnostic parameters relate indirectly with the control parameters and shall serve to complete the information for fault finding and corrective measures.

The programme should also define all the required continuous and grab samples, specify the accuracy and frequency of the measurements.

5.1.2 History of applied secondary side chemistry

5.1.2.1 Recirculating steam generators

Refer also to Section 4, Section 4.1.2, for steam generator degradation history.

In the past two general approaches to water chemistry in steam generators have been used and these have been directed primarily toward minimizing corrosion in heat transfer crevices:

- Phosphate chemistry treatment.
- All volatile treatment (AVT).

Historically, based on fossil fired unit experience, most of the PWR units were using the phosphate treatment, since such a treatment is able to buffer contaminants entering the system and concentrating in the SG. The reason for this is that condenser tubes were historically made of copper alloys, for their high thermal conductivity, but were not always tight. In the early 1970's (under phosphate chemistry treatment) SG tubing material Alloy 600 MA started to suffer from corrosion, characterized as caustic induced stress corrosion cracking (SCC) or wastage (basically acidic mechanism) of the SG tubing. Na/PO_4^{3-}-ratios have been successively modified to try to avoid both types of corrosion such as so-called coordinated and congruent phosphate chemistry [3] but without success. In fact even both environments were able to coexist in different local parts of the SG and it became obvious that it was impossible to avoid corrosion of Alloy 600 MA tubes, whatever the Na/PO_4^{3-} molar ratio in the SG bulk water that was in the range of 2.0 to 2.6.

However, one plant, Doel Unit 4, started operation with an all-volatile treatment and was operated intermediately in mid 1990s under phosphate chemistry with the hope to counteract ODSCC, after they have experienced severe lead induced ODSCC (PbSCC). One Spanish plant, Jose Cabrera, started with phosphate in 1968 until end of the service life and one Argentine plant, Atucha-1, started with phosphate in 1974 until to conversion to high AVT chemistry treatment in 2009.

Most of the PWR with Alloy 600 MA tubing effectively moved to all volatile treatment (AVT) chemistry in the 1970s and 1980s. AVT chemistry typically involves using ammonia (NH_3) to raise pH and hydrazine (N_2H_4) to scavenge oxygen to establish reducing concentrations in the SGs. Due to copper still present in the secondary circuit, the ammonia concentration had to be kept low. Since ammonia is generated by thermal decomposition of hydrazine, the hydrazine was indirectly also limited jeopardizing the reducing conditions of the steam generator (see also Section 4.1.5).

But at the time of phosphate treatment, utilities were used to operate with rather high impurity levels, much higher than what they are now, particularly for seawater-cooled plants. The transition to AVT required a drastic lowering of the impurity ingress. The lack of sufficiently reducing condition associated with high impurity ingress has been the cause of several different corrosion mechanisms like pitting and denting beside IGA and SCC. The AVT chemistry, without any buffering effect, was unable to neutralize the acidity or alkalinity of cooling water ingresses or other pollutions, when they concentrate in the SGs. The above mentioned denting phenomenon induced extremely quick and severe degradation, requiring urgent steam generator replacements (SGR) in several PWR units in the USA, particularly at seawater cooled PWR units. Also an improvement of the chemistry control became necessary.

Since the early 1980s the chemistry guidelines of the secondary side have revised and improved several times tending mostly to limit the impurity ingress into the steam generator.

The different plant suppliers/plant owners adopted different strategies concerning chemistry control, resulting in different guidelines.

In USA (and in a number of other countries regularly owners of plants of American plant manufactures) the water chemistry control guidelines were those developed by the EPRI Steam Generator Owners' Group requiring continuous (or daily) monitoring of cation conductivity, chloride, sodium, sulphate, pH, ammonia, dissolved oxygen, hydrazine, copper, and iron [86–88]. The Steam Generator Owners' Group also established very low levels of acceptability for impurities because the water chemistry at an all-volatile treatment plant is more sensitive to small quantities of impurities than the water chemistry at a plant using phosphate.

EDF adopted somewhat different guidelines for the primary and secondary water chemistry than recommended by EPRI, any way also stressing on impurity reduction.

A different approach was followed by VGB (German large power station owners group) which stressed on reducing corrosion product ingress into the steam generators, based on the following: when there is an on-going process of enrichment under deposits the chemistry will locally shift unbuffered into concentrated aggressive environments, as explained in Section 4.1.4 and schematically shown in Figure 4.16 [14]. In-leakage of seawater or brackish water due to condenser tubing defects, impurities in the feedwater, impurities released from the condensate polishers, and resins released by the condensate polishers can all cause upset conditions. To avoid such impurity enrichment processes it becomes necessary to reduce the input of corrosion product in the steam generators.

The first VGB Water Chemistry Guideline was issued in 1973, which was revised two times with the final revision in 2006.

The obtainable pH_T applying the low AVT was not high enough to be a countermeasure to flow accelerated corrosion in main steamlines for example (refer to Section 4.1.5, [26]). Because of limitations of the ammonia concentration due to the presence of copper alloys in the BOP system, there has been a trend away from using ammonium hydroxide toward the use of Morpholine (C_4H_8ONH), which is somewhat less volatile, in conjunction with hydrazine even though in some cases at hydrazine levels, which were insufficient to ensure reducing conditions. Later, other amines like Ethanol-Amine (ETA), 3-methoxy-propyl-amine (MPA), 5-Aminopentanol or Di-Methyl-Amine (DMA) were also considered, from which Ethanol-Amine (ETA) is the mostly accepted. This results in even higher pH_T especially in wet steam areas of secondary side systems leading to a reduction of erosion-corrosion. This, in turn, reduces sludge build-up in the steam generators. By the end of 1990, about 30% to 40% of the US PWRs and 75% of the French PWRs were converted to a Morpholine All-Volatile treatment.

In various western countries different measures, like boric acid treatment (BAT) and/or molar ratio control (MRC) [3, 13], (see also Section 4.1.3) were implemented to improve secondary side chemistry. A few US plants have converted to a combination of boric acid and Morpholine, because boric acid causes a drastic decrease of pH in wet steam areas due to its volatility, increasing the FAC rate. However about 30% of the Japanese PWRs are converted to boric acid without Morpholine.

Boric acid can be added during normal plant operation and also during tube sheet crevice flushing operations performed during shutdown. The process had been qualified for compatibility with steam generator components by several providers. By the end of 1990, 32 power plants had accumulated a total of about 60 years of operating time with boric acid. It worked well in to palliate the denting degradation (stopped the carbon steel corrosion at TSPs).

Laboratory studies indicated that the addition of boric acid might prevent denting and caustic IGSCC/IGA initiation in alkaline environments that would otherwise cause damage [89]. Further findings indicated that adding boric acid after crack initiation in alkaline environments might reduce the rate of crack propagation by a factor of 8 to 10. The operational practice showed afterwards that even though boric acid was able to palliate denting, it was unable to effectively stop the IGSCC processes, mainly because of the volatility of boric acid do not permit to concentrate on the SG tube surfaces while at operation. Anyway, some French plants reported a positive result with boron soaking at high concentration at the level of the tube sheet [13].

Another approach mainly applied in USA and Japan, was the technique known as molar ratio control (MRC), consisting on trying to balance the molar ratio of anions to cations at values >1 in the crevices, thereby preventing the formation of highly alkaline or acidic conditions. The practice of molar ratio control is based on the assumption that the crevice pH can be modified by controlling the ratio of strong acid anions and strong bases. Such an approach involves a variety of unknowns (e.g. hideout fractions) that must be estimated from previously analysed data, like hideout return. There are limited data that suggest MRC may have some effectiveness. The application of molar ratio control was covered by EPRI Guidelines [88]. Nevertheless, the revision 6 of the secondary side guideline [26] mentioned that the effectiveness of molar ratio control has not been proven. Additionally the addition of chloride to secondary side water, generate fear regarding corrosion. Following the ALARA concept it might be better to avoid pollution than adding it.

The first PWRs in Germany started commercial operation in 1969. This plant had Alloy 600MA SG tubing with stainless steel egg crates. In all other Siemens designed PWRs SG with Alloy 800NG tubing materials with stainless steel ‘egg crate’ tube supports were used. All old Siemens designed PWRs having Alloy 800 NG SG tubes, which went into service in the early 1970s started also with phosphate chemistry in their SGs and low pH AVT ammonia chemistry in their entire secondary side, because of copper tubing in their condensers. The low feedwater pH conditions caused insufficiently controlled FAC and consequently high feedwater iron transport so that deposits occurred within the SGs of these German PWRs. Under such deposits phosphate compounds were able to concentrate and finally the first wastage corrosion was reported at the end of the 1970s.

As a consequence German Utilities decided to terminate the phosphate treatment and introducing high pH AVT treatment having feedwater $pH_{25°C}$ values > 9.8 instead of the low $pH_{25°C}$ feedwater about 9.1 or alternative amines followed by most of the plants worldwide. These high $pH_{25°C}$ > 9.8 in final feedwater using ammonia as alkalizing medium requires the elimination of copper alloys in the BOP systems, which took some several years. In the meanwhile low AVT or low phosphate was applied. Also some plants in the USA started later to operate with elevated hydrazine concentrations (greater than 100 µg/kg).

All of the Siemens plants are operating with high hydrazine concentrations (typical values of 80–200 µg/kg) and high feedwater $pH_{25°C}$ values (greater than 9.8 specified and typical values of 10.0). The copper alloy condenser tubing in the older Siemens plants was replaced with either stainless steel or titanium tubing when the plants were converted to high hydrazine, high pH water chemistry. The good harmonization between SG design (egg crate tube supports), BOP design (absence of copper, feedwater tank, Cr-Mo low alloyed carbon steel with ~2.5% Cr in FAC susceptible areas) resulted in a significantly reduced risk of impurity enrichment locations and low fouling rate in the SGs. This permitted a considerable relaxation of the chemistry guidelines concerning impurity control. The Siemens approach resulted in the lowest incidence of chemistry on the SG performance worldwide for plants operating at comparable conditions, e.g. temperature, (see also Section 4, Section 4.1.2.).

5.1.2.2 Once through steam generators

All once through steam generators use AVT water chemistry. Phosphate chemistry has never been used in the once through steam generators, so phosphate wastage has never been a problem. However, the once through design is susceptible to impurity concentration around the upper support plates close to upper tube sheet (super heating area), which caused in some plants tube outer diameter stress corrosion cracking (ODSCC). In addition, some of the once through steam generators (OTSGs) have experienced sludge build-up around the lower tube support plates in the broached flow holes that restrict the feedwater flow. Such flow restriction has forced some Babcock & Wilcox plants to power reduction by as much as 30% at times.

Because of the operating characteristics of the OTSG, secondary plant water chemistry requirements differ from those of a recirculating steam generator. This is particularly true during power operation (i.e. >15% reactor power) since there is no blowdown from an OTSG. In addition, most of the impurities transported to the OTSG via the feedwater are concentrated in the upper region of the OTSGs (close to upper tube sheet) and insignificant amount is transported out of the OTSG by the superheated steam, due to extremely low steam volatility of the salt impurities. This requires the BOP cycle and equipment design is appropriate for the OTSG system (i.e. full-flow condensate polishers, etc.).

5.1.3 Current secondary side chemistry guidelines

5.1.3.1 EPRI secondary side chemistry guideline for recirculating steam generators

The following section deals with the EPRI Pressurized Water Reactor Secondary Water Chemistry Guidelines - Revision 6 issued in 2004 [26]. The objective of this PWR Secondary Water Chemistry Guideline is to provide guidance on determining and implementing a set of plant-specific water chemistry requirements for the secondary cycle of PWRs.

These guidelines intend to cover many plants having in some cases fully different characteristics, which makes difficult or impracticable the establishment of common chemistry rules.

Considering this, the Section 4 of the EPRI guidelines establishes three important concepts:

1. The application of the ALARA principle to the chemistry control: ALARA chemistry is recommended, but it is recognized that this alone cannot stop but only delay corrosion processes if there are flow occluded crevices and other regions where impurities can concentrate, even though without directly referring to the accumulation of corrosion products as priority main concern.

   As part of their optimized water chemistry programme, a number of utilities have adopted lower impurity concentration targets than the action level 1 values given in Section 5 of the EPRI Guidelines. Examples of these target values are given in Table 5.1 respectively. Each utility is encouraged to establish target or normal operation impurity concentrations below action level 1 values consistent with the ALARA concept, with efforts to identify the cause of an abnormal condition initiated well before action level 1 values are approached.

2. The need of customization of the guidelines, adapting them to each particular case, based on the individual plant design, taking into account the susceptibility and reliability of each system/component, and analysing the impact of the chemistry on both criteria. Based on this analysis a plan-tailored chemistry is to be defined, including the use of different chemistry tools like molar ratio control (MRC), boric acid treatment (BAT), high hydrazine, advanced amines, etc., for which separate guidelines have been prepared.

3. The introduction of the concept of integrated exposure of impurities, which had been already suggested as diagnostic parameter in the Rev. 5 of the EPRI Guidelines.

Guideline Values:

The tables contained within Section 5 for recirculating steam generators (RSGs) and Section 6 for once through steam generators (OTSGs) include chemistry monitoring requirements (control parameter) and recommendations (diagnostic parameter).

Control parameters are those parameters that have a demonstrated relationship to steam generator degradation. Plant operations should support actions required to maintain these parameters within the specified values.

TABLE 5.1. EXAMPLES OF PLANT SPECIFIC CHEMISTRY TARGETS FOR RSGS PRIOR TO EXCEEDING 30% POWER

System	Parameter	Target Value
	Sodium	< 5 µg/kg
Steam Generator Blowdown	Chloride	< 10 µg/kg
	Sulphate	< 10 µg/kg
Power Operation		
	Parameter	**Target Value**
	Sodium	< 1 µg/kg
	Chloride	< 2 µg/kg
Steam Generator Blowdown	Sulphate	< 2 µg/kg
	Iron	< 3 µg/kg
	Copper	< 0.1 µg/kg
Feedwater	Hydrazine	> 50 µg/kg

TABLE 5.2. RECIRCULATING STEAM GENERATOR HEAT-UP/HOT SHUTDOWN AND STARTUP (RCS > 200°F (> 93°C) TO < 30% REACTOR POWER), FEEDWATER SAMPLE (FROM STEAM GENERATOR FEED SOURCE) [26]

CONTROL Parameters				
Parameter	**Frequency**	**Initiate Action**	**Value Prior to Power Escalation >5%**	**Value Prior to Power Escalation >30%**
pH 25°C	daily	See [26]	-	-
Dissolved O_2 [ppb]	daily/continuous	> 100	≤ 100	≤ 10
Hydrazine [ppb]	daily	< 20 or < 8 × [O_2]	≥8 × [O_2] and ≥ 20	≥8 × CPD[O_2] and ≥ 20
Diagnostic Parameters				
		Frequency		**Normal Value**
Startup		daily		≤ 100
Hot standby/Reactor critical <5% Power		daily		≤ 10

TABLE 5.3. RECIRCULATING STEAM GENERATOR HEAT-UP/HOT SHUTDOWN AND STARTUP (RCS > 200°F (> 93°C) TO < 30% REACTOR POWER) SG BLOWDOWN SAMPLE [26]

CONTROL Parameters			
Parameter	**Frequency**	**Value Prior to Power Escalation > 5%**	**Value Prior to Power Escalation > 30%**
Sodium [ppb]	continuous	≤ 100	≤ 10
Chloride [ppb]	daily	≤ 100	≤ 20
Sulfate [ppb]	daily	≤ 100	≤ 20
If sodium, chloride, or sulfate exceed 250 ppb, **OR** exceed 50 ppb for an interval of 100 hours while the plant is > 5% reactor power, then the plant must return to < 5% reactor power as quickly as safe plant operation permits.			
Diagnostic Parameters: boron [ppm], cation conductivity [µS/cm 25°C], pH 25°C, Hydrazine			

TABLE 5.4. RECIRCULATING STEAM GENERATOR POWER OPERATION (≥ 30% REACTOR POWER), FEEDWATER SAMPLE [26]

CONTROL Parameters				
		Action level		
Parameter	**Frequency**	**1**	**2**	**3**
pH Agent	daily	See [26]	-	-
Hydrazine [ppb]	continuous	<8 × CPD [O_2] or < 20 ppb, whichever number is larger	See [26]	See [26]
Total Iron [ppb]	weekly	> 5	-	-
Total Copper [ppb]	weekly	> 1	-	-
Oxygen [ppb]	continuous	> 5	> 10	-

Diagnostic Parameters	
Parameter	**Consideration**
pH 25°C	Continuous indicator of pH additive concentrations
Cation Conductivity [μS/cm 25°C]	Semi-quantitative indicator of organic acid concentrations
Metal oxide species ECP	Assessment of corrosion product impact on steam generator tubing
Integrated Corrosion Product Transport	Periodic assessment of corrosion product mass transport to the steam generator using integrated samples. (See Section 7.6.2)
Lead	As obtained on a plant-specific intermittent basis from integrated samples. (See Section 7.3)

TABLE 5.5. RECIRCULATING STEAM GENERATOR POWER OPERATION (≥ 30% REACTOR POWER), SG BLOWDOWN SAMPLE [26]

CONTROL Parameters				
		Action level		
Parameter	**Frequency**	**1**	**2**	**3**
Cation conductivity [μS/cm 25°C]	continuous	-	> 1	> 4
Sodium	continuous	> 5	> 50	> 250
Chloride, ppb	daily	> 10	> 50	> 250
Sulfate, ppb	daily	> 10	> 50	> 250

Diagnostic Parameters	
Parameter	**Consideration**
Molar Ratio	As specified in site-specific chemistry programme.
Boron	As specified in site-specific chemistry programme.
pH 25°C	Continuously monitored. Refer to references [9–11] for pH optimization.
Specific conductivity and pH Agent	Refer to Section 7: reasonable consistency between values of pH, ammonia, amine, boric acid, conductivity, etc. should be achieved.
Hideout Return Evaluation	Perform each planned shutdown. See Section 7 for evaluation techniques.
Silica	Crevice chemistry, steam quality, and impurity source consideration.

Diagnostic Parameters are important to monitor the programme effectiveness, identify programmatic problems, or assist in problem diagnosis.

Action levels have been defined for taking remedial actions, when monitored parameters are outside the specified operating range. Deviations from chemistry concentrations normally achieved at a given station should be investigated. Action levels prescribe values of a parameter above which long term system reliability may be jeopardized.

Action level 1: Objective: To promptly identify and correct the cause of an out-of-guideline value without power reduction.

Actions: Corrective actions should be implemented as soon as possible to return parameter to below action level 1. If parameter is not below the action level 1 value within *one week* following confirmation of excursion, go to action level 2 for those parameters having action level 2 values.

Action level 2: Objective: To minimize corrosion by operating at reduced power while corrective actions are taken.

Actions: Take immediate actions to reduce power to a plant-specific level (typically approximately 30%) and achieve that power level within eight hours of entering action level 2, or as quickly as safe plant operation permits. Return parameter to below action level 1 value within *100 hours* of exceeding an action level 2 value or go to action level 3 for those parameters having action level 3 values.

Action level 3: Objective: To correct a condition, which is expected to result in rapid steam generator corrosion during continued operation.

Actions: Shut down as quickly as safe plant operation permits and clean up by feed and bleed or drain and refill as appropriate until normal values are reached. Regardless of the duration of the excursion into action level 3, the plant shall be taken to < 5% power.

In the following the values for the control and diagnostic parameters for startup as well as power operation defined in the mentioned EPRI Guideline for recirculation SG are listed.

5.1.3.2 VGB secondary side chemistry guideline

The VGB Guidelines were issued in 2006 [90] in succession to second revision dated 1988. This revision of the previous Guideline became necessary, because based on the gained field experience (especially on the secondary side) the plant chemistry programme was changed significantly from the one specified in this previous Guideline. The major change in secondary side water chemistry for all VGB PWRs was the change from phosphate chemistry in steam generators with relatively low pH values in the entire secondary side (due to copper bearing materials used for condenser tubes) to the so called ‘High AVT’ chemistry consists of high pH values.

The revision 2006 of the VGB Water Chemistry Guidelines covers not only the reactor coolant system but also the Secondary Side of the PWRs and for both systems similar definitions are used with respect to chemistry parameters, which can be categorized in Control and diagnostic parameters. For the establishment of the chemistry guidelines chemistry parameters must be defined. The chemistry guideline parameters are classified into two categories:

- Control parameters.
- Diagnostic parameters.

Control parameters are selected as key parameters, which are considered to determine the overall water chemistry for optimal plant operation. In case of reactor coolant system the target is to control the radiation build-up and the corrosion performance whereas for the secondary side systems only the control of corrosion performance is considered. The control parameters are chosen not only for their prime importance basing on research and extensive field experience but also based on the availability of good detection methods according to the state of the art as to reliability, sensitivity and accuracy.

For the control parameters following values are defined:

Normal operating values: They define a margin for chemical values, which are readily achievable under normal undisturbed trouble free plant operating conditions.

Tolerated values: They define the range deviated from the normal operating values up to action level 1. Based on field experience these values, although higher than the expected, do not cause a risk for the plant and are still consistent with long term plant reliability. But a penetrating into tolerated range should motivate evaluation of the cause aiming to correct the deviation for best chemistry practice. This enables earliest possible identification of a beginning of chemistry anomaly and helps to decrease the probability of reaching action levels.

Action levels: Action levels define chemical values that require immediate evaluation and corrective measures. Besides the initiation of remedial actions also operation limitations like their maximum allowed duration and also plant power limitations are established according to the degree of the deviation. There are three action levels for reactor coolant system and secondary Side systems. The definition of these action levels is selected based not only on research results and but mainly on extensive field experience:

Action level 1: Covers the range of the chemistry values, within which according to expertise long term corrosion problems cannot be excluded. Actions: Return parameter into its allowed range within 28 days (four weeks) from confirmation of excursion. This may be varied in singular cases upon judgment of the overall situation.

Action level 2: Covers the range of the chemistry values, within which according to expertise short term corrosion problems cannot be excluded. Action: Return parameter into its allowed range within 14 days (two weeks) from confirmation of excursion, with a power reduction on 30% if dissolved impurities are the cause of the excursion. In case of primary side water chemistry deviations, power reduction is not required due to lack of concentrating mechanism in the primary side of SGs.

Action level 3: Defines the range of the chemistry values, within which according to expertise a further *plant operation is no* more *advisable.* Action: Initiation of plant shut down according to Operation Manual within 12 hours.

Limit Values**:** The limit values are the maximum acceptable value for a control parameter. Overriding a limit value implies the consequence of short term corrosion damage, accordingly it is not allowed to exceed or violate these values. Few limit values are defined only for plant startup operation.

Diagnostic parameters complement the overall picture of the controlled water chemistry. They do not impose any kind of restrictions on plant operation. The diagnostic parameters help to describe the entire operating chemistry and serve to perform root cause analysis in case of deviations of control parameters. A direct or indirect link of diagnostic parameters with control parameters can considerably support evaluations and implementation of counter measures in case of chemistry anomalies.

With respect to water chemistry parameters the VGB Guideline defines the plant status in three modes considering the thermal and hydraulic conditions and their effects on chemical environment:

Cold shutdown/lay-up: Covers the annual outages and refuelling period.

Startup operation: Covers the period of T > 120°C up to criticality for reactor coolant system, and up to five days after power operation begin for the secondary side systems.

Power operation: Covers the time after startup operation as described above.

The Secondary Side Guideline values for startup phase are summarized in the following tables.

TABLE 5.6. FEEDWATER CONTROL PARAMETERS FOR PLANT STARTUP OPERATION [91]

Control Parameter	Limit value
Oxygen [µg/kg]	0.1

TABLE 5.7. STEAM GENERATOR DIAGNOSTIC PARAMETERS FOR PLANT STARTUP OPERATION [91]

Diagnostic Parameter	Normal operating value
pH [25°C]	> 9.5
Cation conductivity [µS/cm]	< 2.0 [a)]
Sodium [mg/kg] [b)]	< 0.1
Hydrazine [mg/kg]	> 0.1

[a)] Cation conductivity caused only by strong anions and not by organics or CO_2.
[b)] In case sodium > 0.5 mg/kg, (AL3 value for power operation) a further plant heat-up is not allowed, plant should be shut down for corrective actions.

The Guideline values for power operation are shown in the subsequent tables.

TABLE 5.8. FEEDWATER CONTROL PARAMETERS FOR POWER OPERATION [91]

Control parameters	Normal operating values	Action level 1	Action level 2	Action level 3
pH [25°C]	> 9.8	< 9.8	-	-
Cation conductivity [µS/cm] [a)]	< 0.15	> 0.2	-	-
Oxygen	< 0.005	> 0.005	> 0.02 [b)]	> 0.1

[a)] Caused by only strong anions, organics and CO_2 are not to be considered.
[b)] Power reduction is not required.

TABLE 5.9.STEAM GENERATOR CONTROL PARAMETERS FOR POWER OPERATION [91]

Control parameters	Normal operating values	Action level 1	Action level 2	Action level 3
Cation conductivity [µS/cm] [a)]	< 0.2	> 1.0	> 2.0	> 7.0
Sodium [mg/kg]	< 0.005	> 0.05	> 0.1	> 0.5

[a)] Caused by only strong anions, organics and CO_2 are not to be considered.

TABLE 5.10. FEEDWATER DIAGNOSTIC PARAMETERS FOR POWER OPERATION [91]

Control parameters	Normal operating values
Hydrazine [mg/kg]	> 0.02
Cation conductivity [µS/cm]	> 15.0

TABLE 5.11. STEAM GENERATOR DIAGNOSTIC PARAMETERS FOR POWER OPERATION [91]

Control parameters	Normal operating values
pH 25°C	> 9.5
Chloride [a)] [mg/kg]	< 0.01
Sulphate [a)] [mg/kg]	< 0.01

[a)] To be analysed in case of deviation in cation conductivity value for root cause analysis.

TABLE 5.12. MAIN CONDENSATE DIAGNOSTIC PARAMETERS FOR POWER OPERATION [91]

Control parameters	Normal operating values
Oxygen [mg/kg]	< 0.02
Cation conductivity [µS/cm]	< 0.2

TABLE 5.13. REHEATER STEAM DIAGNOSTIC PARAMETERS FOR POWER OPERATION [91]

Control parameters	Normal operating values
Cation conductivity [µS/cm]	< 0.2

5.1.3.3 EDF secondary side chemistry guideline

The main objective of the secondary water chemistry specifications of EDF have been established to cope with 3 main objectives:

- Low erosion-corrosion rate of carbon steels.
- Limited stress corrosion cracking of SG tubing.
- Low deposits on the tubes, which would decrease the heat transfer capability.

The selection of feedwater treatment is indicated in Table 5.14.

TABLE 5.14. PH AND CHEMISTRY TREATMENT IN SECONDARY SIDE IN EDF PLANTS [92]

Parameter	Expected Value	Limit Value	Copper used?	Chemistry
pH [25°C]	9.1–9.3	9.0–9.4	Yes	Morpholine treatment
Morpholine [mg/kg]	4–6	4–8		
Hydrazine [mg/kg]	> 10	> 5		
pH [25°C]	9.5–9.6	9.2–9.8	No	Morpholine treatment
Morpholine [mg/kg]	6	4–8		
Hydrazine [mg/kg]	100	> 50		
pH [25°C]	9.6–9.8	9.5–10.0	No	Ammonia treatment
Ammonia [mg/kg]	2–5	-		
Hydrazine [mg/kg]	100	> 50		

In France 23 units of a total number of 58 NPPs had still copper alloys present in the BOP. Therefore the $pH_{25°C}$ at low temperature in the condenser and the low pressure heaters was limited to 9.2 in order to avoid copper corrosion. Consequently these 23 units were operated with Morpholine chemistry treatment. In the 35 units without copper alloys the $pH_{25°C}$ in the condenser and in the low pressure heaters was increased up to about 9.7. The pH was adjusted by using ammonia (8 units) or Morpholine (27 units). The application of ethanolamine in French NPPs was under discussion in 2002. The limit of $pH_{25°C}$ < 9.7 in all ferrous plants was due to economical and environmental reasons. It was mentioned by EDF that above such a pH, the efficiency of resins for SG blowdown purification would quickly drop and the resin may not be operated a long time after exhaustion with the conditioning reagent.

Sodium and cation conductivity are the two parameters selected for deciding if the unit has to be shutdown, when the steam generator is polluted. Chemical specifications for these two parameters are shown in Figure 5.2 and Figure 5.3 respectively for units cooled by river water or sea/estuary water [92].

Sodium as well as cation conductivity are measured on-line and the values are transmitted into the control room, with alarms associated to zones 3, 4 and 5. In case of evolution of the cation conductivity (zone 2 or higher), grab sample analysis of chloride, sulphate, and organic acids is required to help the chemist to identify the exact type and origin of the ingress and to initiate countermeasures. The expected values for chloride and sulphate are respectively < 5 and < 10 µg/kg.

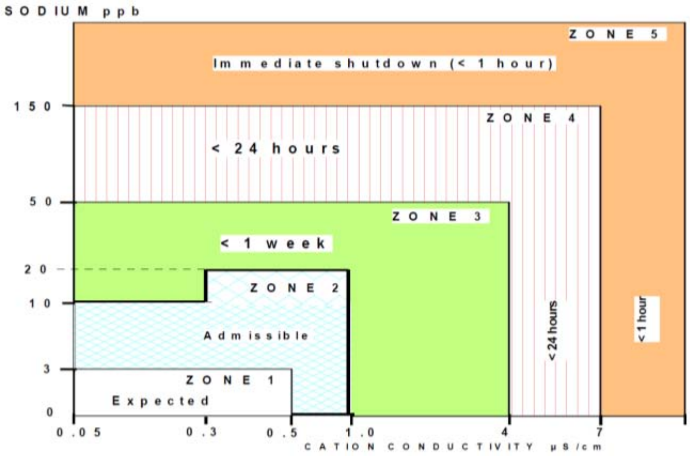


Figure 5.2. SG blowdown limits at nominal power > 25% for river water cooled units [92].

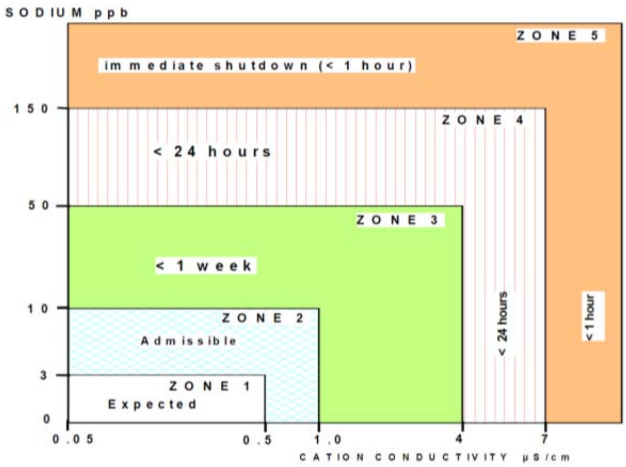


Figure 5.3. SG blowdown limits at nominal power > 25% for sea water cooled units [92].

Eleven units operating with Morpholine chemistry treatment were in 2002 also treated with boric acid addition in the secondary system to mitigate IGA/SCC of Alloy 600MA SG tubing. In this case, the specified feedwater $pH_{25°C}$ is approximately 0.3 pH units lower than the values indicated in Table 5.14. The difference in specification limits for these units is mainly concerning the upper values of cation conductivity for zones 1 and 2.

The operational practice of the EDF plants in 2000 is summarized in Table 5.15.

TABLE 5.15. SECONDARY CHEMISTRY OPERATIONAL RESULTS OF FRENCH NPPS IN 2000 [92]

Parameter	**Sampling point**	**900 MW 34 units**	**1300 MW 20 units**	**1450 MW units**
Oxygen	Condensate water	3 [µg/kg]	1.8 [µg/kg]	1.6 [µg/kg]
Sodium	SG blowdown	1.6 [µg/kg]	1.4 [µg/kg]	2.3 [µg/kg]
Chloride	SG blowdown	5 [µg/kg]	4 [µg/kg]	3 [µg/kg]
Sulphate	SG blowdown	5 [µg/kg]	4 [µg/kg]	4 [µg/kg]
Parameter	**Sampling point**	**Ammonia w/o copper**	**Morpholine with copper**	**Morpholine w/o copper**
Cation conductivity	SG blowdown	0.16	0.34	0.39
$pH_{25°C}$	Feedwater	9.7	9.2	9.4

5.1.3.4 CANDU secondary side chemistry

CANDU steam generator chemistry control is generally All Volatile: Advance Amines or Morpholine and hydrazine (N_2H_4) for plants with copper alloys in the feed train, NH_3/N_2H_4, for all ferrous plants.

One CANDU station uses only Morpholine and no hydrazine, another station used a combination of phosphate and Morpholine/N_2H_4 and recently phosphate was abandoned. The latter is also the only CANDU plant with a full-flow condensate polisher.

Most of the CANDU units operate with a deaerator to reduce dissolved oxygen. One CANDU station used boric acid to mitigate corrosion of the carbon steel tube supports, in particular, the U bend supports. Corrosion of these supports has contributed to the 'growth' of the entire structure, creating high local stresses leading to extensive stress corrosion cracking in the U bend region. The initial operating experience with boric acid has been good and the impact on other chemical parameters small.

The chemistry guidelines for CANDU reactors of the 600 MW(e) series foresee in general a Morpholine – Hydrazine treatment for Cu free BOPs, and low hydrazine with limitation of the ammonia concentration to avoid Cu corrosion. The basic chemistry concept is shown in Table 5.16.

The operation ranges for CANDU plants are typically those shown in Table 5.17 [93]. At this plant, FAC at the steam generator tube support plated (broached holes, quatrefoil, carbon steel) was the reason for later use of ETA instead Morpholine. The chemistry guideline values corresponding to power operation for a 600 MW(e) plant are partially transcribed in Table 5.18 to Table 5.20.

The guideline values are categorized as follows for interpretation of the guideline value tables:

TABLE 5.16. GENERIC CONCEPT FOR SECONDARY CHEMISTRY GUIDELINE VALUES FOR CANDU PHWR 600

FLUID	CONTROL PARAMETER	DESIRED CONDITION	CONTROLLED BY
Condensate	pH (all-ferrous systems)	9.8	Adding ammonia [a)]
	pH (ferrous/copper systems)	9.1	Adding morpholine [a)]
	Dissolved O_2	ALARA	Minimizing air inleakage. Degassing in the condenser. Deaerator removes O_2 Adding hydrazine [b)]
	Sodium (a diagnostic parameter)	ALARA	Monitoring to detect and minimize effects of condenser tube leaks.
Feedwater	Dissolved O_2	ALARA	Minimizing air inleakage. Deaerator removes O_2 Adding hydrazine [b)]
	Total Iron Total Copper	ALARA	Maintaining desired pH and low dissolved O_2 Blowdown.
	Hydrazine	Slight Excess	Addition control in response to chemical analysis.
Boiler Water	Cation conductivity	ALARA	Using high purity make-up. Blowdown.
	pH (all-ferrous systems)	9.6	Adding ammonia [a)]
	pH (ferrous/copper systems)	9.1	Adding morpholine [a)]
	Chloride Sodium Silica Sulphate	ALARA	Minimizing condenser tube leaks. Using high purity make-up. Blowdown.

[a)] The addition point for morpholine/ammonia is downstream of the CEP discharge.
[b)] The hydrazine addition point is between the deaerator and the deaerator storage tank.

TABLE 5.17. SECONDARY CHEMISTRY GUIDELINE VALUES FOR CANDU PHWR 600 (TYPICAL)

Parameter	**Feed water**	**SG blowdown**	
pH	9.2–9.6	9.2–9.6	Plant with Cu bearing materials Plants without Cu : $pH_{25°C}$=9.8 in FW
Morpholine [mg/kg]	5–20	5–20	Plants without Cu: same concentration
Hydrazine [mg/kg]	1–10	1–10	Plants without Cu: 60–80 µg/kg N_2H_4
Oxygen [µg/kg]	< 5	-	
Ammonia [mg/kg]	< 0.8	< 0.8	Plants without Cu: according to N_2H_4 decomp.
Specific conductivity [µS/cm]	4–8	4–8	
Cation conductivity [µS/cm]	0.3–0.4	1.5	
Sodium [µg/kg]	< 1	< 5	
(ETA [mg/kg])	4–7	15	In some plants.

TABLE 5.18. BOILER BLOWDOWN CHEMISTRY GUIDELINE VALUES FOR CANDU PHWR 600

BOILER BLOWDOWN
CONTROL PARAMETERS

Parameters (units)	**Admin Limit**	**Control specifications**		
		Action level I	**Action level II**	**Action level III**
Sodium (mg/kg)	< 0.005	> 0.010	> 0.100	> 0.250
Chloride (mg/kg)	< 0.005	> 0.020	> 0.100	> 0.250
Sulfate (mg/kg)	< 0.005	> 0.020	> 0.100	> 0.250

DIAGNOSIS PARAMETERS

Parameters (Units)	**Normal Range**	**Concern and/or required action**
Hydrazine (mg/kg)	2 × FW	TREND from on-line data. Ratio of blowdown hydrazine to feedwater hydrazine should be 2.0–3.0, indicative of conditions inside boilers.
Silica (mg/kg)	less than 0.500	Make-up water quality from WTP can be improved. IF boiler silica levels are significant, MONITOR individual boilers for hideout trends.
Organic Acids (mg/kg)		MONITOR organic acid formation from morpholine decomposition. Organic acid levels will contribute to background cation conductivity indications.
Bulk Water Equivalent Ratios	Increasing toward 1.0	Trending parameter to evaluate potential boiler crevice chemistry.
pH	9.2–9.5	Trending parameter.
Corrosion Product Morphology (oxidation state)	> 95% reduced	Results are indicative of oxygen control and hydrazine effectiveness.
Cation Conductivity (mS/m)	Trend Not Increasing	This is the only on-line indicator of anionic impurity increase. INCREASE anion sample frequency to assess if the cause is impurities for which there are control specifications.
Phosphate (mg/kg)	< 0.010*	Trending parameter to evaluate potential boiler crevice chemistry.

TABLE 5.19. FEED WATER CHEMISTRY GUIDELINE VALUES FOR CANDU PHWR 600

FEED WATER
CONTROL PARAMETERS

Parameters (units)	**Admin Limit**	**Control specifications**		
		Action level I	**Action level II**	**Action level III**
Morpholine (mg/kg)	20–30	> 15.0	None	None
Hydrazine (mg/kg)	0.020–0.050	< 0.020	None	None
Total Iron (mg/kg)	< 0.005	> 0.010	None	None
Total Copper (mg/kg)	< 0.002	> 0.003	None	None
pH	9.3–9.7	< 9.3 or > 9.7	None	None
Dissolved Oxygen (mg/kg)	< 0.005	> 0.005	None	None

DIAGNOSTIC PARAMETERS

Parameter (units)	**Normal Range**	**Concern and/or Required Action**
Caution Conductivity (mS/m)		Only on-line indication of anion contaminants (e.g. Cl, SO_4). INVESTIGATE any increasing trend, CORRELATE with changes in organic acid levels.
Corrosion Product Morphology (oxidation state)	> 95% reduced	Results are indicative of oxygen control and hydrazine effectiveness. A minimum of 30 days of plant operation should occur before sending samples for analysis.

TABLE 5.20. CONDENSATE CHEMISTRY GUIDELINE VALUES FOR CANDU PHWR 600

CONDENSATE SYSTEM
CONTROL PARAMETERS

Parameters (units)	Admin Limit	Control specifications		
		Action level I	Action level II	Action level III
Sodium (mg/kg)	Non-Detectable	> 0.00025	None	None

DIAGNOSTIC PARAMETERS

Parameter (units)	Normal Range	
Corrosion Product Morphology (oxidation state)	> 95% reduced	Results are indicative of oxygen control and hydrazine effectiveness.
Cation Conductivity (mS/m)	TBD	TREND relative cation conductivities and sodium levels for all three condenser hotwells and IF one is higher than the others, INITIATE condenser leaksearch procedure.
Sodium (mg/kg)	Non-Detectable	
Ammonia (mg/kg)	TBD	MONITOR ammonia levels CORRELATE to system hydrazine levels as baseline indicator of hydrazine thermal decomposition rates.
Specific Conductivity (ms/m)	TBD	Conductivity should be correlated to system morpholine and ammonia levels. Decreasing trend indicates make-up requirement for morpholine.
Total Iron (mg/kg)	< 0.005	Higher than normal iron levels indicate poor amine distribution in drains piping. CHECK morpholine and hydrazine levels in drains samples and CONSIDER programme adjustment.
Total Copper (mg/kg)	< 0.002	Indicated too high ammonia levels in condensers. CHECK morpholine and hydrazine levels - REDUCE to lower part of range.
Dissolved Oxygen (mg/kg)	< 0.020	Trending parameter for correlation with CPT results. INSTITUTE a search for source of air ingress and TAKE STEPS to return DO_2 levels to normal range.

Administrative limits are limits or ranges that prescribe off-normal conditions, but are not considered to be indicative of corrosive conditions in the system. Compliance with this limits are considered to provide a conservative mode of operation.

Action levels (ALs) are limits or ranges for a parameter outside of which remedial actions must be taken to restore chemistry control. ALs are categorized as follows:

AL1: corrosive conditions may exist such that long term operation is not permitted. Action is required to return the parameter(s) below this limit within 7 days. If the parameter is not returned within this time, action level 2 takes force. If there is no AL2 specified for the given parameter, an engineering justification must be prepared for extension of the operation at full power.

AL2: corrosive conditions are known to exist such that full power operation is no longer permitted. Immediate actions to return the parameter within AL 1 shall be initiated. If the parameter is not returned to normal within 4 days, consider declaration of AL3 under assessment of the particular situation and approval of the superintendent.

AL3: corrosive conditions are known to exist such that continued operation would result in rapid SG corrosion. The plant must be shut down as quickly as safe operation permits to minimize SG degradation. Depending on the nature of the event, the chemistry department must determine whether a hot or cold shutdown is required. An engineering justification is to be prepared to permit return to power operation.

CANDU reactors present a good approach for shutdown condition and startup following long outages [94].

Steam generator lay-up

A boiler wet lay-up loop has been retrofitted at Canadian CANDU-6 reactors to isolate the SGs from the rest of the steam cycle following cooldown, during lay-up, and prior to startup. Using this boiler wet lay-up loop, water is removed from each of the SGs through the blowdown lines and returned at a convenient location, i.e. feedwater or reheater drains line. The system permits chemical sampling, and addition of chemicals for pH and dissolved oxygen control.

A combination of a nitrogen cover gas above the SG water line and dosing of the water with hydrazine maintains the concentration of dissolved oxygen below detection limits in the SG during lay-up. This measure was taken because long outages are planned for retubing works at the reactor. Long term dry lay-up of the steam generators is problematic because it is difficult to completely drain the water, therefore:

- The time that each steam generator is exposed to air will be minimized, e.g. work will be performed on one steam generator at a time, and the others will be protected to ensure that none are exposed to air except when being inspected or maintained.
- Efforts to completely drain the steam generator to avoid exposing the steam generator internals to moist air, e.g. vacuum out water that may remain on tube sheet and other internal surfaces would be beneficial.
- The water used for refilling the steam generators should be injected appropriately.

Steam cycle dry lay-up

The feedwater, condensate and steam systems are initially open to the turbine-building atmosphere because it is not possible to seal the condenser, and other parts of the system, without main steam. The steam cycle systems (e.g. condensate and feedwater including the tube and shell side of the low pressure and high pressure heaters) is drained and water removed from any low spots or dead legs. Dryers are used to maintain the carbon steel steam cycle components under an atmosphere of dried air during long term lay-up, to enhance the removal of any residual water. It becomes necessary to set up several systems to circulate dried dehumidified air through the entire steam cycle.

Restart

The aim of any long term lay-up strategy is to protect the systems and components during the lay-up and to prepare these for their return to service. In the case of the steam generator and steam cycle it is important to:

- Minimize the transport of iron oxides to the steam generator at restart.
- Maintain good chemistry control as the station moves from the lay-up specifications to those for full power operation.
- Minimize the concentration of soluble species in the steam generator and ensure that these provide balanced water chemistry.

There will be accumulation of ionic impurities in the water in the steam generator from hideout return, and accumulation of corrosion products on the steam cycle components resulting from corrosion, during the dry lay-up. For these reasons it is advisable to fill and drain those portions of the steam cycle exposed to water during normal operation, and to drain and refill the steam generator, prior to startup.

Feedwater recirculation lines have been retrofitted at Canadian CANDU-6 stations to avoid transporting water with high concentrations of suspended solids to the steam generators at startup, water pumped to the feedwater system is returned to the condenser. If available, this recirculation line will be used to condition the water (i.e. get the pH and concentration of hydrazine in specification) in the condensate and feedwater systems prior to startup. It is recommended, in this case, to recirculate the water in the condensate and feedwater systems, sample for suspended solids, and remove these solids by full-flow filtration, or by feed (dosed with hydrazine and Morpholine) and bleed. At re-start, it is not possible to remove dissolved oxygen until main steam is available. Therefore, until the deaerator becomes functional and there is a vacuum in the condenser it can be assumed that the water in the system is saturated with air, and a stoichiometric excess of hydrazine should be present in the condensate and feedwater systems. Once the removal of oxygen is proceeding, the concentration of hydrazine can be reduced to that specified for normal full power operation.

Based on operational experience, the behaviour of the system, including the ability to remove impurities through blowdown, is expected to be different following a long refurbishment outage. Care should therefore be taken to maintain the impurity concentration low during reactor restart. During startup, hold periods of high blowdown flow should be included to allow for the removal of impurities introduced by feedwater, if necessary.

5.1.3.5 EPRI secondary side chemistry guideline for once through steam generators

The EPRI chemistry guidelines for once through steam generators (OTSGs) reflect the same fundamental technical bases defined for RSGs.

The secondary side chemistry requirements of once through steam generator (OTSG) differ from those of recirculating steam generators due to operating characteristics of OTSG. This is particularly true during power operation (i.e. >15% reactor power) since there is no blowdown from an OTSG in this status. This means that impurities transported to the OTSG via the feedwater are mostly concentrate in the upper super-heated region of the OTSG due to insignificant volatility of the salt impurities in steam, and less are transported out of the OTSG by the superheated steam. Therefore this requires extremely pure feedwater.

The startup conditions require considering that when increasing power, moisture separator drains (MSD) should be routed to the condenser for cycle clean-up. When at full power, a fraction of the moisture separator drain flow is routed forward at an amount depending on the chemistry goals. Because of the high concentrations of impurities in the moisture separator drains, treatment (demineralizing) or blowdown of a portion (~20%) of these drains is a suitable measure to improve feedwater quality. In this way. larger amounts or even the entire MSD flow may be pumped forward without degrading the feedwater purity.

One point to outline is that plants with OTSGs are mostly operated with a condenser polisher. High ammonia concentrations resulting from the thermal decomposition of hydrazine, can lead to premature exhaustion of the cation resin in condensate polishers operated in the hydrogen-form and cause higher sodium leakage from powdered resin systems operated in the ammonium form.

The EPRI Guideline for OTSGs considers four plant status modes defined relative to the thermal and hydraulic conditions within the steam generator:

- Cooldown/hot soaks.
- Cold shutdown/wet lay-up (RCS < 200°F) - modes 5 and 6 of standard technical specifications.
- Startup, hot standby, and reactor critical at <15% reactor power (RCS > 200°F, < 15% reactor power) - modes 1, 2, 3 and 4 of standard technical specifications.
- Power operation (> 15% reactor power) - mode 1 of standard technical specifications.

For the status modes b) to d) the guideline contains three subchapters regarding the technical justification, parameter justification and corrective actions. The control and diagnostic parameters for *Startup, hot standby, and reactor critical at <15% reactor P*ower are summarized in the following tables.

Guideline Values

The definitions applicable to the guideline values (*control parameters, diagnostic parameters, and action levels*) are basically the same as for RSGs.

The guideline values are shown in Table 5.21 to Table 5.25.

5.1.3.6 WWER secondary side chemistry guideline

As in the western PWRs one of the most important objectives of the secondary water chemistry treatment of WWER-1000 is to minimize the rate of erosion-corrosion wear of the secondary side equipment and pipelines in order to decrease the ingress of corrosion products into the SG. Ammonia and/or hydrazine water chemistry initially used on the secondary side of the majority of WWER steam generators. History of WWER secondary water chemistry shows constantly stringing requirements. Now requirements are different at different units and in different countries for WWER owners.

TABLE 5.21. STARTUP/HOT STANDBY/REACTOR CRITICAL AT < 15% REACTOR POWER: FEEDWATER SAMPLE – OTSG [26]

CONTROL parameters		
Parameter	**Frequency**	**Initiate Action**
pH 25°C	3/day	a)
Dissolved O_2 [ppb]		
Startup	continuous	> 100 b)
Hot standby	continuous	> 10 b)
Reactor critical at < 15% Reactor Power	continuous	> 5 b)
Hydrazine c) [ppb]	3/day	< 8 × [O_2[b), d) < 50 ppb b)
Suspended Solids [ppb]		
Startup	3/day	> 100 b)
Hot standby/Reactor critical < 15% Power	daily	> 10 b)
Diagnostic Parameters e)		
Parameter	**Justification**	
Silica [ppb]	Minimization of impurity ingress to the steam generators.	
Sodium [ppb]	Minimization of impurity ingress to the steam generators.	
Sulfate [ppb]	Minimization of impurity ingress to the steam generators.	
Chloride [ppb]	Minimization of impurity ingress to the steam generators.	
Cation Conductivity [μS/cm at 25°C]	Minimization of impurity ingress to the steam generators.	

a) Consistent with site specific pH control programme.
b) Return to normal value within 8 hours or consider a startup/power hold.
c) Alternatives to hydrazine may be used if qualified by the utility. Appropriate limits for any hydrazine alternative should be substituted.
d) Oxygen concentration measured at condensate pump discharge.
e) Since the OTSG is operating as a recirculating steam generator at powers <15% (control and assessment of impurity ingress is based on OTSG blowdown impurity concentrations).

TABLE 5.22. STARTUP/HOT STANDBY/REACTOR CRITICAL AT < 15% REACTOR POWER: BLOWDOWN SAMPLE – OTSG [26]

CONTROL Parameters				
Parameter	**Frequency**	**Initiate Action (Modes 2 - 4)**	**Initiate Action (Modes 1, 0 - 15% Power)**	**Value Prior to Power Escalation > 5%**
Sodium [ppb]	continuous c)	>100 b)	>250 d)	≤100
Chloride [ppb]	3/day	>100 b)	>250 d)	≤100
Sulfate [ppb]	3/day	>100 b)	>250 d)	≤100
Diagnostic Parameters				
Parameter	**Justification**			
pH 25°C	Demonstrate consistency with feedwater pH			
Hydrazine [ppb]	Assess oxidant control programme			
Cation Conductivity [μS/cm at 25°C]	Monitor organic acid concentrations and large increases in anionic contaminant			

a) Although the tube sheet drain sample will be diluted by feedwater and therefore not be representative of water in the tube bundle, it is the preferred sample location. If the shell side drain sample rather than the tube sheet drain sample is employed, the water level must be maintained above the elevation of the shell side drain line penetration. It should be noted that dilution of the tube sheet drain sample with feedwater is expected.
b) Return to normal value within 8 hours or consider a startup/power hold.
c) Alternate monitoring of the two steam generators is acceptable.
d) If limit is exceeded during power escalation, be in hot shutdown within 4 hours and clean up by feed and bleed or drain and refill as appropriate.

TABLE 5.23. POWER OPERATION (≥ 15% REACTOR POWER): FEEDWATER SAMPLE – OTSG [26]

CONTROL Parameters				
		Action level		
Parameter	**Frequency**	**1**	**2**	**3**
pH Agent	daily	[a]		
Hydrazine [b] [ppb]	daily	≤8 × CPD [O_2] or < 20 ppb	[c]	[c]
Sodium [e] [ppb]	continuous	1	3	5 [h]
Chloride [e] [ppb]	daily	3	5	10 [h]
Sulfate [ppb]	daily	1	3	5 [h]
Silica [d] [ppb]	3/week	10	20	-
Total Iron [f] [ppb]	weekly	5	-	-
Oxygen [ppb]	continuous	5	10	-

Diagnostic Parameters	
Parameter	**Consideration**
pH	Assess consistency with measured pH agent concentration.
Cation Conductivity	Monitor organic acid concentrations and large increases in anionic contaminant.
Organic Acid Anions (acetate, formate, etc.)	Resolution of cation conductivity observations.
Fluoride	Fluoride transport assessment, resolution of cation conductivity observations.
Copper [g]	Copper/copper oxide transport assessment.
Lead	Lead transport assessment.
Magnetite Fraction	Assessment of corrosion product impact on OTSG tubing ECP.
Integrated Corrosion Product Transport	Periodic assessment of corrosion product mass transport to the steam generator using integrated samples. (See Section 7.6.2).

[a] Consistent with site specific pH control programme.
[b] Alternatives to hydrazine may be used if qualified by the utility. Appropriate limits for any hydrazine alternative should be substituted.
[c] In event of loss of hydrazine feed that is not restored within 8 hours, commence shutdown as quickly as safe plant operation permits. If hydrazine feed is restored, then the plant can return to full power.
[d] Parameter included for turbine performance. Silica is not considered to impact steam generator integrity, and is therefore a recommended parameter outside of NEI 97-06 requirements.
[e] The preferred method of monitoring final feedwater concentrations of sodium and chloride is by calculating them from moisture separator drain concentrations using a mass balance approach.
[f] This limit applies to steady state operation after a stabilization period. Integrated sampling should be initiated at approximately 30% power. The action level response time begins when the analysed data becomes available, e.g. within 1 to 2 weeks of sample collection.
[g] Even though most OTSGs have an all ferrous secondary cycle, establishment of a baseline level should be considered.
[h] Plant shutdown required only if action level 3 value is exceeded for > 2 hours, or if at any time for any duration the parameter exceeds 20 ppb.

TABLE 5.24. POWER OPERATION (> 15% REACTOR POWER): CONDENSATE SAMPLE OTSG [26]

CONTROL/Diagnostic parameters [a]				
		Action level		
Parameter	**Frequency**	**1**	**2**	**3**
Dissolved O_2 [ppb]	continuous	>10	30 [b]	-

[a] If an appropriate feedwater oxygen monitoring system is available (see Section 7), condensate oxygen can be considered a diagnostic rather than a control parameter and indicated action levels do not apply.
[b] Reduce power to site specific power level consistent with determining source of in-leakage.

TABLE 5.25. POWER OPERATION (> 15% REACTOR POWER): MOISTURE SEPARATOR DRAIN SAMPLE – OTSG [26]

Diagnostic Parameters	
Parameter	**Expected Value/Justification**
Sodium [ppb]	Feedwater Concentration × CF [a)]
Chloride [ppb]	Feedwater Concentration × CF [a)]
Sulfate [ppb]	-
Cation Conductivity [µS/cm]	-
Organic Acids	Demonstrate consistency with cation conductivity.

[a)] CF = Concentration factor given by ratio of steam plus liquid to liquid phase flow rates at inlet of moisture separator.

Presence of copper in BOP equipment (e.g. in the condenser tubing and the low pressure heaters at the first generation of WWER-1000) in Russia and Ukraine is the limiting factor for water chemistry improvement. Therefore secondary water chemistry with addition of hydrazine and ammonia was limited to a feed water $pH_{25°C}$ 8.8–9.2. This $pH_{25°C}$ is not sufficient to suppress properly the erosion-corrosion in wet steam and two phase flows of equipment and pipelines in the condensate and feedwater path made of carbon steels. Nevertheless, both countries launched programmes of reconstruction on copper exclusion. In Finland and Czech Republic plants operated without copper from the very beginning with excellent SGs tubing performance results.

Additionally, the presence of anions of strong acids in the SG water leads to a considerable acceleration of the SG tube corrosion. As a countermeasure feedwater is periodically alkalized with LiOH at operating Russian WWER-1000 with hydrazine-ammonia secondary water chemistry since 2000 in order to neutralize the effect of strong acid anions in the SG water. The purpose of this procedure is to exceed the total concentration of strong acid anions and maintain the pH_T not less than 5.64 at operating temperature. Since 2003, SG water is alkalized continuously (the actual $pH_{25°C}$ of SG water at alkalization is 8.5–9.2).

Since the middle of 2005, Rostov NPP Unit 1 was switched over from hydrazine-ammonia to Morpholine secondary water chemistry and beginning with September 2006 Balakovo NPP Unit 2 was switched over to Ethanolamine (ETA) water chemistry. In March 2008, Balakovo NPP Unit 3 was switched over to ETA water chemistry and it was planned that by the end of 2008, the other two units at Balakovo NPP would have been switched over to ETA water chemistry. Morpholine water chemistry allows keeping the feedwater $pH_{25°C}$ 8.9–9.3 (Morpholine concentration is 2500–4500 µg/kg) and the SG blowdown water $pH_{25°C}$ 8.9–9.1. The feedwater $pH_{25°C}$ with ETA water chemistry is 9.0–9.2 (Ethanolamine concentration is 800–1200 µg/kg), and the SG blowdown water $pH_{25°C}$ is 9.0–9.5. [95].

In 2008 the Russian WWER-1000 type reactor were operated under one of the following secondary water chemistries:

- Hydrazine-ammonia water chemistry with feedwater alkalization using LiOH resulting in a feedwater $pH_{25°C}$ 8.8–9.2 and a SG blowdown water $pH_{25°C}$ 8.5–9.2 (Kalinin NPP Units 1, 2, 3, Novovoronezh NPP Unit 5, Balakovo NPP Units 1 and 4).
- Morpholine water chemistry with a feedwater $pH_{25°C}$ 8.9–9.3 and a SG blowdown water $pH_{25°C}$ 8.5–9.4 (Rostov NPP Unit 1).
- ETA water chemistry with feedwater $pH_{25°C}$ 9.0–9.2 and a SG blowdown water $pH_{25°C}$ 9.0–9.5 (Balakovo NPP Units 2 and 3).

The WWER secondary side chemistry guidelines are summarized in the subsequent tables:

TABLE 5.26. WWER FEEDWATER SPECIFICATIONS FOR HYDRAZINE-AMMONIA AND MORPHOLINE CHEMISTRIES [96]

Parameters	**Hydrazine-ammonia**	**Morpholine**
pH value at 25ºC	8.8–9.2	8.9–9.3
Cation conductivity [µS/cm]	≤ 0.3	≤ 0.3
Hydrazine [µg/kg]	≥ 20	≥ 10
Morpholine [mg/kg]	-	2.5–4.5
Copper [µg/kg]	≤ 3.0	≤ 2.5
Iron [µg/kg]	≤ 15	≤ 10
Dissolved oxygen [µg/kg]	≤ 10	≤ 10
Oils [µg/kg]	≤ 100	≤ 100

TABLE 5.27. WWER STEAM GENERATOR BLOWDOWN SPECIFICATIONS [97]

Parameters	Limit value
pH value at 25ºC	8.0–9.2
Cation conductivity [µS/cm]	< 5.0
Sodium [µg/kg]	< 300
Chloride [µg/kg]	< 100
Sulphate [µg/kg]	< 200

TABLE 5.28. WWER CONDENSATE WATER SPECIFICATIONS [97]

Parameters	Limit value
Cation conductivity [µS/cm]	< 0.35
Sodium [µg/kg]	< 2
Chloride [µg/kg]	< 100
Oxygen [µg/kg]	< 30

At the present WWER-1200 (AES-2006) is being designed in Russia. The secondary side tubes of low and high pressure heaters as well as turbine condensers are going to be made of stainless steel. The ETA water chemistry was accepted for the secondary system of NPP AES-2006. The quality parameters of steam generator feedwater and blowdown water for operation of NPP AES-2006 during power operation are shown in Table 5.29 [95].

WWER plants having Cu- free secondary side started to change to high pH AVT in 2000–2010.

5.1.3.7 Comparison of secondary side chemistry guidelines

As outlined in Section 4, a proper control of the water chemistry is indispensable for the high performance of the PWR plants. Depending on the selected materials and different plant designs of different vendors different water chemistry guidelines are used worldwide to control the chemistry treatment. In this section the secondary side chemistry guidelines of EPRI, VGB and EDF are compared as for available by published information.

TABLE 5.29. QUALITY PARAMETERS OF STEAM GENERATOR FEEDWATER AND BLOWDOWN WATER FOR OPERATION OF NPP AES-2006 AT POWER LEVELS >50% N_{NOM} (COMBINED AMMONIA-ETHANOLAMINE WATER CHEMISTRY)

Parameter	**Feedwater**	**Blowdown water from ‘salt’ compartment**
	Reference levels	
Cation conductivity [μSm/cm], not more than	0.3 [a)]	1.5 [a)]
pH value	9.3–9.7 [b), c)]	9.4–9.7 [b)]
Oxygen concentration [μg/dm³], not more than	5	-
Sodium concentration [μg/dm³], not more than	-	30 [a)]
Chloride-ion concentration [μg/dm³], not more than	-	30 [a)]
Sulfate-ion concentration [μg/dm³], not more than	-	30 [a)]
Iron concentration [μg/dm³], not more than	5 [b)]	-
Hydrazine concentration [μg/dm³], not more than	10 [b)]	-
Ethanolamine concentration [μg/dm³]	300–800 [b)]	-
Ammonia concentration [μg/dm³]	800–3000 [b), d)]	-

a) Control parameter.
b) Diagnostic parameter.
c) With mixed beds of condensate polishing connected, the recommended pH upper limit is not more than 9.5.
d) With mixed beds of condensate polishing connected, the recommended ammonia concentration is not more than 1500 μg/dm³.

Even all these guidelines have similar requirements for the water chemistry control and similar structure with respect to corrective actions like Action levels (EPRI and VGB Guidelines) or specified operating zones (EdF Guidelines), they have some differences in their requirements. These water chemistry control requirements are based on the field experience gained by the Vendor-Utility organizations. Accordingly the differences in the Guidelines are based on the different field experienced gained due to different plant system designs and materials used. Concerning the VGB Water Chemistry Guidelines in comparison with other Guidelines one major difference regarding the secondary side chemistry are the action levels for power operation to limit the impurity exposures (requirements regarding the time and concentration). These differences in the guideline requirements are due to different plant system designs and field experience including plant chemistry measurements performed during plant startup operations or during abnormal operating conditions caused by impurity transients.

The three mentioned guidelines have similar requirement structure with respect to corrective measures, i.e. it is allowed for a limited time period to operate at certain impurity concentrations in SGs. The only difference between these Guidelines is the definition of the criteria for corrective measures. Whereas EPRI and EDF Guidelines allow shorter operation time with low impurity concentrations in SGs due to their experience with sensitive SG tubing material Alloy 600MA, VGB Guidelines allows longer operation time with even higher impurity concentrations based on their good experience with SG tubing material Alloy 800NG (see Table 5.30 to Table 5.32).

In order to have a clearer assessment of the differences between the three guidelines the total possible impurity ingress associated to the above sodium concentration levels, the products of the allowed Na concentration and max allowed time [mg/kg × h] representing the maximum amount of sodium transported into the steam generator are shown in Table 5.33.

TABLE 5.30. COMPARISON OF SG BLOWDOWN CONTROL PARAMETER OF EPRI, VGB AND EDF SECONDARY SIDE CHEMISTRY GUIDELINE. PART 1.

Guideline		Time duration	Parameter		Value
EPRI	AL 1	7 days	Sodium	[µg/kg]	> 5
			Chloride	[µg/kg]	> 10
			Sulphate	[µg/kg]	> 10
			Cation conductivity	[µS/cm]	-
EDF	Zone 3	7 days	Sodium	[µg/kg]	> 20
			Chloride	[µg/kg]	> 30
			Sulphate	[µg/kg]	> 20
			Cation conductivity	[µS/cm]	> 1.3
VGB	AL 1	28 days	Sodium	[µg/kg]	> 50
			Chloride	[µg/kg]	*)
			Sulphate	[µg/kg]	*)
			Cation conductivity	[µS/cm]	> 1.0

*) indirectly limited by cation conductivity.

TABLE 5.31.COMPARISON OF SG BLOWDOWN CONTROL PARAMETER OF EPRI, VGB AND EDF SECONDARY SIDE CHEMISTRY GUIDELINE. PART 2.

Guideline		Time duration	Parameter		Value
EPRI	AL 2	100 hours	Sodium	[µg/kg]	> 50
			Chloride	[µg/kg]	> 50
			Sulphate	[µg/kg]	> 50
			Cation conductivity	[µS/cm]	> 1.0
EDF	Zone 4	24 hours	Sodium	[µg/kg]	> 50
			Chloride	[µg/kg]	-
			Sulphate	[µg/kg]	-
			Cation conductivity	[µS/cm]	> 4
VGB	AL 2	14 days	Sodium	[µg/kg]	> 100
			Chloride	[µg/kg]	-
			Sulphate	[µg/kg]	-
			Cation conductivity	[µS/cm]	> 2.0

TABLE 5.32. COMPARISON OF SG BLOWDOWN CONTROL PARAMETER OF EPRI, VGB AND EDF SECONDARY SIDE CHEMISTRY GUIDELINE. PART 3.

Guideline		Time duration	Parameter		Value
EPRI	AL 3	Immediate shutdown	Sodium	[ppb]	> 250
			Chloride	[ppb]	> 250
			Sulphate	[ppb]	> 250
			Cation conductivity	[µS/cm]	> 4.0
EDF	Zone 5	Immediate shutdown	Sodium	[ppb]	> 150
			Chloride	[ppb]	-
			Sulphate	[ppb]	-
			Cation conductivity	[µS/cm]	> 7.0
VGB	AL 3	Shutdown (according to plant Procedure) within 12 hours	Sodium	[ppb]	> 500
			Chloride	[ppb]	-
			Sulphate	[ppb]	-
			Cation conductivity	[µS/cm]	> 7.0

TABLE 5.33. PRODUCT OF THE ALLOWED NA CONCENTRATION AND TIME REPRESENTING THE MAXIMUM AMOUNT TRANSPORTED INTO THE STEAM GENERATOR

Action levels	EPRI	EDF	VGB
AL 1/Zone 3	0.84 [mg/kg × h]	3.4 [mg/kg × h]	33.6 [mg/kg × h]
AL 2/Zone 4	5.0 [mg/kg × h]	1.2 [mg/kg × h]	33.6 [mg/kg × h]
AL 3/Zone 5	3.0 [mg/kg × h]	1.8 [mg/kg × h]	6.0 [mg/kg × h]

The limitations established as limit values, action levels, etc. by the different suppliers or operators as defined in the former sections and summarily represented in Table 5.30 to Table 5.32 are considered to be general minimum requirements for protection against corrosion of steam generator secondary side in cases of deviations from normal operation conditions. Theoretical considerations and experience gained with SGs and plants of different types have shown that operation with impurity concentrations above these levels and time periods might lead to corrosion damage.

However, a long term SG degradation cannot be fully excluded even at lower values, especially if the steam generators have sensitive tubing material. In fact, the field experience worldwide clearly showed that especially SG Alloy 600MA tube degradation of chemical origin (corrosion) had also occurred at plants operating within specified limits having as pre-requisite the concentration of impurities at local areas where deposits, mainly corrosion products, accumulate enabling the local enrichment of impurities up to aggressive levels by boiling. The nature of the local aggressive environment formed depends on very complex interactions, which are not always quantifiable in full. This impurity concentration process will eventually occur, at a speed dependent of the impurity burden present in the feedwater and consequently in the steam generator bulk water, and the presence of concentration sites, i.e. accumulation of corrosion products.

The experience gained showed also clearly that it is not possible to have a uniform chemistry guideline for all plants, forgetting the essential interaction between chemistry, design characteristics and material concept of the different units. A customization of the chemistry control strategies becomes unavoidable.

The concepts exposed in Section 4 on the analysis of the root causes and degradation mechanisms described, defining the state of the art and knowledge, permit to establish a common concept for future plants as well as improving the chemistry strategies at operating plants.

5.2 PROPOSAL OF CHEMISTRY & DESIGN CONCEPT

The following proposal bases on the analysis of the root causes and degradation mechanisms described in Section 4, which define the state of the art.

5.2.1 Chemistry

5.2.1.1 Basic approach

Based on this, the philosophy associated with the chemistry guidelines is that the guideline limit values and action levels shall not be understood as threshold values below which corrosion cannot occur. These values are set for regulation in front of clearly abnormal situations. Therefore, the guideline values have to be observed together with four main additional requisites to guarantee long term SG integrity:

- **Application of the ALARA Principe for impurities and corrosion product transport** towards the SGs at any plant condition. Based on the arguments formerly given, the impurity levels in feed water and SG bulk water below which long term corrosion damage is fully prevented cannot be precisely established. The integrated amounts of corrosion product transported to the SGs as well as the integrated exposure to impurities must be kept as low as achievable. Careful supervision of the chemistry condition under operation as well as during shutdown periods and startup transients is required.
- **Minimization of the corrosion product transport** towards the SGs at any plant condition is the essential step to ensure a good SG performance.
- **Adequate maintenance** to keep the SGs clean of deposits, particularly at the tube sheet, avoiding the formation of hard deposits.
- **Implementation of the necessary tools** and methods to achieve and supervise successfully these objectives:
  - Adequate monitoring systems/equipment.
  - Adequate organization and treatment of chemistry data, diagnosis tools.
  - Work procedures, action plans.

In a more detailed listing, a state-of-the-art chemistry supervision must fulfil the following aspects:

- Observance of the guideline values:
  - No transgression of limit values.
  - Observance of the operation restrictions and conditions imposed by the action levels.
- Application of the ALARA principle for impurities and corrosion product transport:
  - No transgression of cycle integrated allowances (see below).
  - During all periods at undisturbed operation conditions, operation should be close to the lower range of the expected values.

    - Fastest possible recovery of the expected operation condition in case of deviations within the tolerated range (between expected values and AL1). This means, the upper values of the expected range shall be considered as an unsatisfactory condition able of being improved.
- Adequate maintenance of the RSGs by keeping cleanliness especially at the tube sheet by periodic cleaning:
    - SG cleanliness supervision programme. Target: avoidance of formation of hard caked deposits.
    - Mechanical cleanings (tube sheet lancing, HP tube sheet lancing if necessary) on routine basis.
    - Visual inspections for verification.
    - Chemical cleanings (soft/hard chemical cleaning), condition-oriented.
- Quality assured chemistry supervision:
    - Plant chemistry related documents must be available and kept updated as per Plant QM:
        - Chemistry guidelines
        - Chemistry handbook
        - Operation manual
        - Work procedures
        - Procedures for handling of abnormal situations
        - Maintenance procedures.
    - Procedural compliance with the a.m. documents
    - Adequate organization for handling of chemistry data:
        - Chemistry management system (LIMS) according to the state-of the art.
        - Adequate computer aided diagnosis systems [76, 98, 99].

The minimization of the corrosion product accumulation is, as said, the first main goal to be pursued to minimize the risk of SG tube corrosion. This can be achieved:

- By design, avoiding the presence of gaps and crevices.
- By operation at high pH thus reducing the corrosion product input.

The advanced SGs have a tube support design, which considerably reduces deposit accumulation, and a much less susceptible tubing material. This, associated with high pH, ensures a long time of trouble free operation at the tube supports. However, the accumulation of deposits above the tube sheet cannot be effectively influenced by design. Consequently, **the top of tube sheet remains the area most susceptible to tube damage**. Therefore, periodic maintenance (cleaning) of the tube sheet is a fundamental requisite for achievement of long term SG integrity.

Together with the strict maintenance of reducing conditions, the minimization of the impurity concentration levels is therefore the second main goal to be pursued to minimize the risk of SG tube corrosion.

5.2.1.2 Integrated allowances

In order to contribute to forcing the application of the ALARA principle, integrated allowances can be established, and added to the guideline values with the character of complementary control parameters.

An integrated allowance is defined as the time integration of a control parameter along one pre-defined time interval, typically one operation cycle. For the integrated allowance, expected values and maximum tolerable values can be established. The most suitable control parameters selected for integration in the case of RSGs are:

- Cation conductivity.
- Sodium concentration in SG blowdown.

The basic criterion to define the max tolerable values for these control parameters is that in one cycle the accumulated impurity ingress into the SG shall be reasonably less than the impurity amounts which would ingress if the plant were continuously operated at the upper level of the range expected for these parameters under undisturbed operation conditions. The expected range can be taken from extensive field experience.

The integrated allowances represent the integration over one cycle of the blowdown cation conductivities and the sodium concentrations, corrected by plant power, expressed as:

$$X_{int,m} = \frac{1}{P_{100}} \int_{t=0}^{t=t} X\, P\, dt$$

The integrated allowances can be practically calculated as the product of the average cation conductivity and the average sodium concentration in a certain operation period multiplied by the corresponding operation time and affected by the factor $P_{av}/P_{100\%}$, where P_{av} is the average power in the considered operation period.

The average cation conductivity and the average sodium concentration in SG blowdown are to be determined daily and a running total (integrated) value is to be calculated. The integrated values (Na, CC) can be calculated at regular intervals, e.g. every day. Computerized numerical integration methods can be used, if available. The final objective pursued is to obtain the area below the curve as accurately as possible. It is the task of the chemist to perform this calculation in such a way that the integrated allowance results as close as possible to the mathematical integral value. An example of such calculation is shown in Figure 5.4.

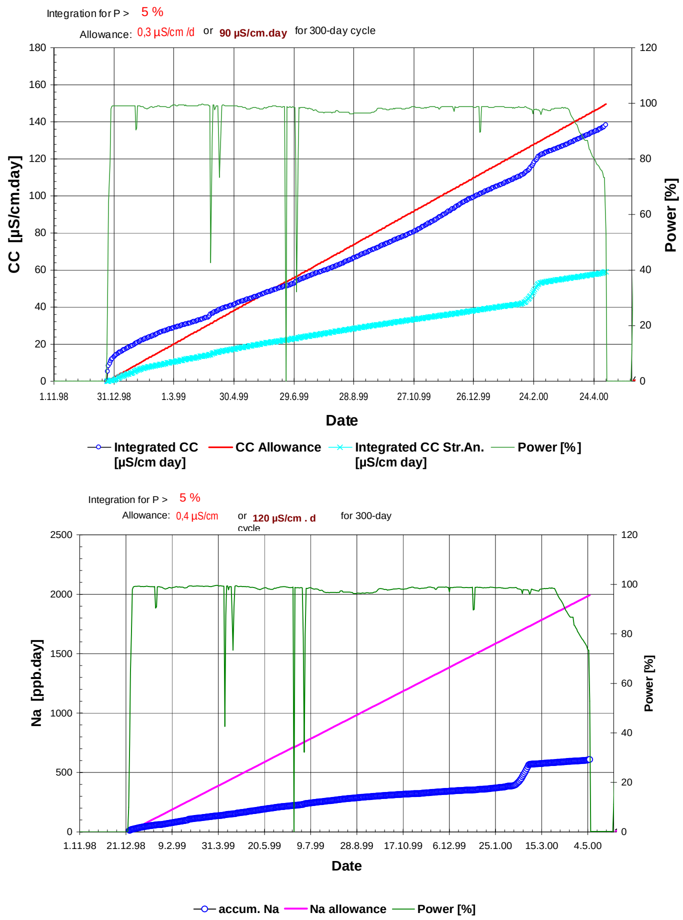


Figure 5.4. Sodium and cation conductivity integrated values (typical).

5.2.1.3 *Steam generator condition assessment*

One very important aspect is to ensure an adequate control of the SG condition introducing a steam generator cleanliness supervision programme based on a long term trend analysis of selected data and observables to be assessed as a whole, providing a rational method for evaluating as quantitatively as possible the ageing situation of steam generators [100]. The evaluation shall be assisted by a systematic approach to evaluate the major steam generator operation data, with following targets:

- Early recognize an evolution outside the expectancies, affecting the thermal performance and/or the component integrity.
- Gather sufficient information for root cause analysis of the possible reasons for worse-than-expected behaviour of the steam generators.
- Perform a condition-oriented maintenance.

The lifetime of SGs is basically determined by two main parameters:

1. The **thermal margin** given by the available heat transfer area.
   - Tube scaling (fouling)
   - Tube degradation:
     - Corrosion
     - Fretting (wear).

2. The **degradation of the pressure envelope.**
   - Fatigue of the main feed water nozzle.
   - Integrity of the SG shell.

In the following, the method how AREVA GmbH assesses the steam generator condition is described.

Thermal performance

By rational selection and evaluation of selected parameters, a so-called *fouling index* can be conformed accounting for the thermal performance of the SGs. The indicators to be considered are of different nature. The required data and information are gained during power operation, as well as during startup/shutdown transients and shutdown periods. Without intending to make a complete analysis (which must be tailored to each particular case) these are, among others:

Power operation:

- Systematic determination of the fouling factor, calculating the actual heat transfer capacity, departing from the operational data such as steam pressure, feed water flow rate, primary temperatures.
- Feed water chemistry:
  - Corrosion product mass balance, integrated amounts, inventory in SG.
  - Impurity transport, integrated exposure, mass balance, source analysis (trend).
  - Analysis of impurity sources with concentration models (e.g. MULTEQ), if possible.
  - Hydrazine ratio SG/FW (correlation with fouling).
  - Analysis of transients and abnormal conditions.
    (e.g. hideout evaluation in case of high increase of FW impurities).

Shutdown periods:

- NDT inspection results (ECT):
  - Tube integrity

- Deposits on tube sheet
  - Corrosion product mapping, oxide thickness determination.
- Visual inspections:
  - Tube sheet (extension, height, consistency and appearance of the deposits)
  - Tube supports (deposit accumulation)
  - Shroud supports.
- Tube sheet lancing results:
  - Trend
  - Amount
  - Composition of oxides
  - Impurity content in deposits by analysis of:
    - Oxide deposits
    - Impurities redissolved in lancing water (trend)
- Measurement of oxide deposits on SG tubes (trend at accessible locations).

Shutdown/startup transients:

- Hideout return of impurities during plant cooldown:
  - Composition, ionic balance.
  - Analysis with concentration models.
- Corrosion product transport during startup.
- Blowdown startup chemistry analysis (indirect hideout estimation).
- Redox conditions during startup transient.

It results obvious that many of these parameters considered separately will not enable any conclusive assessment, owing to the uncertainty associated to them, which will not be discussed here. But all them together, analysed with expertise will give plausible trends indicative of the SG condition, lifetime, and need of preventive/corrective maintenance measures, as well as facilitating the fault-finding in cases of abnormal development. The necessary expertise can be made available in the form of computer codes helping 'quantifying' the expert knowledge in the following steps:

- Each indicator evaluated by the expert receives a note based on the data collected.
- Each indicator has a weighing factor attributed, with which the note given is processed. This weighing factor establishes the relative significance of the indicator considered in front of the other.
- The absence of indicators is also weighted (no data = higher uncertainty).
- Generation of a condition index, indicative of the SG condition. Action levels can be associated to it, having in this way the possibility of carrying out a condition- oriented maintenance.

Pressure envelope

The parameter, which may restrict SG lifetime through degradation of the pressure envelope, is the feed water nozzle fatigue (see Section 4, Section 4.5.1.2). Due to the large temperature difference between the saturated water in the downcomer and the cold feed water, the material is subject to possible loadings resulting in thermal fatigue. A good practice is then to monitor the temperatures on significant locations in the nozzle area, and evaluate the measurement results with the aid of specific codes [62, 101]. In particular, the FAMOS code is being used at almost all German plants [102]. From these measurements, feeding concepts, which minimize the nozzle fatigue, are adapted to the plant's requirement.

5.2.1.4 Long term trend evaluation

For the implementation of an effective life cycle management the combination of the major parameters Fouling Index, Plugging Index and feed water nozzle fatigue in combination with a long term condition monitoring is essential in order to achieve information of the appropriate maintenance actions. On a yearly basis the relevant parameters and analysis results are recorded and evaluated to achieve a comprehensive data base for the development of the component condition, as above described.

Depending on the results actual trends can be observed and appropriate measures can be planned condition-oriented in due time. As a consequence, damages can be minimized, outage times are reduced and the lifetime of the component can be extended.

5.2.1.5 Quality assured chemistry supervision

The chemistry supervision is one of the most difficult, owing to the associated uncertainties and the complexity of the mechanisms involved. The right interpretation of acquired chemistry data and their associated process data require:

1) An adequate data acquisition and administration system, also known as Laboratory Information Managements System (LIMS)
2) A well implemented system to enable the correct diagnosis in front of out of normal conditions, by well established logic linking/concatenation of the observed symptoms, which require expert knowledge.

Data Management System

A number of software packages for water chemistry control are available. Most of these computer programmes have to be considered as **data acquisition and analysis programmes**. Some of them require manual data input (Laboratory Information Management Systems), some of them are capable to perform a full automated data acquisition and validation of data. The data validation is performed by means of numerical methods. Such computer aided systems are necessary for a rapid:

- Validation of data (plausibility analysis, error exclusion)
- Calculation of derived parameters
- Visualization of data
- Trend analysis
- Correlations between parameters
- Check procedural compliance, etc.

This enables the analysis by the expert, which is responsible for the interpretation of all collected data, performing:

- Data validation (or verification, if previously made by the system)
- Gathering of additional data upon need
- Interpretation of data
- Source analysis
- Predict course of events, establish a diagnosis
- Initiation of necessary actions.

This kind of data analysis systems expects a long working experience and specific skills by the plant chemistry operator, and/or a very precise procedural establishment of all the elements necessary to perform a diagnosis based on the analysed data, establishing what to do in front of a wide variety of possible scenarios. As a matter of example a source analysis draft is shown in Table 5.34.

TABLE 5.34. SOURCE ANALYSIS IN CASE OF INCREASE OF FEED WATER CATION CONDUCTIVITY

Cation Conductivity in Feed Water - Source Analysis			
Source	**Cause**	**Symptoms/Checks**	**Actions**
Cooling water leak (main condenser)	Salts, organics	- Increase in CC due to strong anions - Some increase of total organic carbon - All CC measurements increase, including HD and MS (at lower extent) depending on organics content - Sodium in BD and MC increase - Chloride in BD increases (seawater) - Different Na concentration and CC in hotwells (between hotwells and with respect to reference sample) - Concentration ratio of impurities in leaking hotwell and in SGBD follow a specific pattern (BD/HW ratio ~ 25 for 0.5% blowdown) - No worsening of make-up water observed - No or very low oxygen increase of MC - High increase rate possible, can reach high CC values	VERIFY… CORRELATE … ADDITIONAL INFO REQUIRED… FOLLOW TREND … INITIATE … APPLY PROCEDURE No. …
Make-up water	Salts, regenerant (sulfuric or hydrochloric acid)	- CC mostly due to strong anions - Associated to worsening of make-up water (DWST) quality - Associated to worsening of DW plant product - Predominant SiO_2 increase of BD and make-up water indicative of regeneration problems/exhaustion of DWP mixed bed filters - Increased CC and Na level in hotwell corresponding to the section where make-up water injection takes place - Significant increase of SO_4 (Cl) without associated Na increase indicative of contamination with regenerants - pH decrease without change in hydrazine/ammonia concentration in FW also indicates H_2SO_4 HCl ingress. - No increase of CC in MS and HD - No increase of oxygen concentration in MC - No worsening of water quality in BD downstream demineralizers	VERIFY… CORRELATE … ADDITIONAL INFO REQUIRED… FOLLOW TREND … INITIATE … APPLY PROCEDURE No. …

Cation Conductivity in Feed Water - Source Analysis

Source	Cause	Symptoms/Checks	Actions
Make-up water	Organics	- No increase of CC due to strong anions - Associated to organics concentration increase of DWST and DWP product - Increase in CC in MS and HD - Increased CC level in hotwell corresponding to the section where make-up water injection proceeds, no associated Na increase - No increase of oxygen concentration in MC - May depend on the season (increase of summer)	VERIFY… CORRELATE … ADDITIONAL INFO REQUIRED... FOLLOW TREND … INITIATE … APPLY PROCEDURE No. …
Make-up water	CO_2	- CC due to strong anions does not change - Associated CO_2 concentration increase of DWST - Increase in CC in MS, less in HD - Some CC increase of hotwell corresponding to make-up water injection, no Na increase - Slight increase of oxygen concentration in MC possible	…
Blowdown demineralizer	Resin ingress	- Increase of sulphate, over-proportionally to chloride - Increase of TOC in the system (SGBD, HD) - Possibly resin beads in SGBD sample - Increased CC and SO4 in hotwell associated with blowdown return - Decrease of pH in SG (big resin ingress) - Mixed bed has lower delta P (big resin ingress) - organics/carbon present in a SGBD filter sample	…
Blowdown demineralizers	Salts	- Increase in CC downstream demineralizers with respect to upstream - CC in SG mostly due to strong anions - No associated worsening of make-up water quality - Increased CC and Na in hotwell associated with blowdown return - No associated oxygen increase of MC	…
Blowdown demineralizers	Regenerants (anion elution)	- Increase in CC downstream demineralizers with respect to upstream - CC in SG mostly due to strong anions, being the regenerant anion (SO4, Cl) the cause - No associated worsening of make-up water quality - Increased CC in hotwell associated with blowdown return - No associated Na increase - No associated CC increase in HD-Drains and MS - No associated oxygen increase of MC	…

Cation Conductivity in Feed Water - Source Analysis

Source	Cause	Symptoms/Checks	Actions
Condensate Polishers	Salts	- Not necessarily a big increase of FW CC (CO_2 and organics may be still well retained by the CPS compensating the increase of salts) - increase of CC downstream polishers - CC in SG mostly due to strong anions - No associated worsening of make-up water quality - No associated oxygen increase of MC	…
Condensate Polishers	Regenerants (anion elution)	- Not necessarily a big increase of FW (CO_2 and organics are well retained by the CPS) - increase of CC downstream polishers - CC in SG mostly due to the acid used for regeneration - No associated worsening of make-up water quality - No associated oxygen increase of MC - increase of SG BD of the anion used for regeneration - no sodium in SG BD	…
Condensate polishers	Resin ingress	- Increase of sulphate, over-proportionally to chloride - Increase of TOC in the system (SGBD, HD) - Possibly resin beads in SGBD sample - Decrease of pH in SG (big resin ingress) - One mixed bed has lower delta P (big resin ingress) - organics/carbon present in a SGBD filter sample	…
Air inleakage in turbine/condenser area	CO_2	- CC due to strong anions does not change - No associated CC increase of DWST - Increase in CC in MS, less in HD - Same CC and Na concentration in all hotwells, no increase of Na concentration - Increase in oxygen concentration in MC	…
Impurities carried in with hydrazine dosing	Salts, (organics less probable)	- Responsible for slight CC increases only - Chloride concentration increase probable - Probably no sodium increase - Associated quality worsening of dosing solution - No symptoms corresponding to volatile organics	…

Cation Conductivity in Feed Water - Source Analysis

Source	Cause	Symptoms/Checks	Actions
Oil leak	Organics	- Increase in CC in MS and HD, much less in MC - Increase in suspended solids in SG blowdown, other than corrosion products possible - CC due to strong anions remains unchanged - Evidenced by visual observation of sample filters possible (oily and/or dark brown appearance) - Same CC and Na level in all hotwells	…
Clean drains condensate (clean cond. tank)	Salts	- Increase in CC and Na in hotwell corresponding to clean cond. tank return - Increased Na in clean cond. tank sample - No increase of CC in MS and HD - Increase in CC due to strong anions - CC and Na oscillations, corresponding to discharge periods - Possibly associated oxygen increase of MC, oscillating in regular intervals corresponding to clean cond. tank discharges	…

Diagnosis System

Diagnostic systems are many steps ahead this approach. Nowadays, advanced computer aided diagnosis systems have been developed [98, 99, 100, 103]. They contain the capability of data interpretation and derivation of specific diagnoses, combined with an explanation component of how the diagnoses were derived. Furthermore, diagnostic systems are able to give specific recommendations of how to proceed to reach the normal operational behaviour as soon as possible.

Some of them like the DIWA use fuzzy logics to better represent the expert's language in a quantifiable form, and enable using the logic rules necessary for diagnosis with an associated ‘confidence level’ quantifying how precise (or not) the diagnosis is. Simplified examples of ‘fuzzification’ of the expert's knowledge and the generation of diagnosis by means of logic rules applied to symptoms having an associated confidence level (credibility) are shown in Figure 5.5 and Figure 5.6. The interface system/user should be so that the pre-programmed expert knowledge can be corrected, updated and/or extended by the user itself, pouring in this way their own knowledge in the system taking the necessary time and care, increasing in this way the confidence system/user.

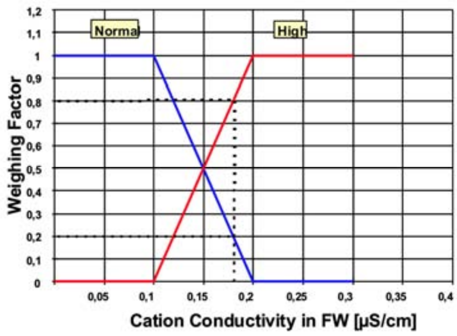


Figure 5.5. Expert assessment as fuzzy output.

Such systems are increasing the quality of the chemistry supervision, and should be considered as the state of the art.

Explanation of the expert assessment using fuzzy logic in Figure 5.5:

Expert assessment: *Normal cation conductivity in feedwater is around 0.1 µS/cm, by > 0.2 µS/cm it has to be considered as too high.*

Fuzzy output: *by 0.18 µS/cm cation conductivity is considered high with a weighing factor of 0.8, and normal with a weighing factor of 0.2.*

The weighing factor is a measure of the assertion’s credibility. The system architecture is drawn in Figure 5.7, and an example of the integration of the diagnosis system in the plant I&C is shown in Figure 5.8.

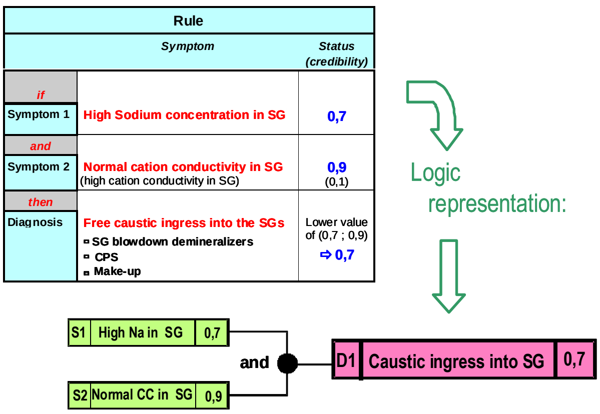


Figure 5.6. Simplified example of a diagnosis based on fuzzy expressed symptoms and logic rules.

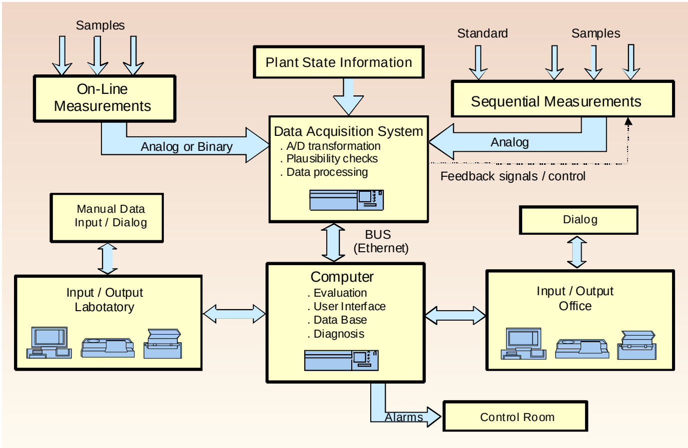
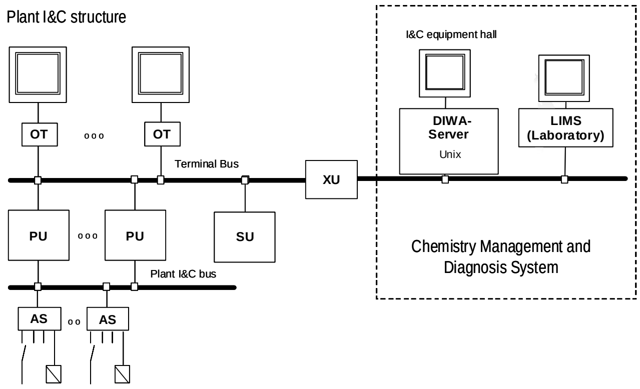


Figure 5.7. Chemistry Management and Diagnosis System Architecture.



OT: operating terminal *PU: processing unit*
XU: external gatewaySU engineering workplace

Figure 5.8. Integration of the Chemistry Management and Diagnosis System in the Plant I&C.

5.2.2 Design

For the design description of the SGs and BOP, refer to Section 4, Sections 4.1.6 and 4.1.7.

Steam generator design

A summary of the conclusions regarding SG design is listed here:

- Tube material for recirculation, vertical SGs: both Alloy 690TT and Alloy 800NG can be considered equivalent.
- Alloy 600MA should not be used for SG tubing, including primary nozzle welds.
- Feedwater nozzle design avoiding thermal shock and thermal stratification, and installation of temperature sensors, associated with a supervision system for analysis and optimization of the operation modality.
- SG shell. No major modifications identified.
- Stainless steel tube supports: In order of preference regarding the field experience acquired, the design for new SGs it is recommended to use:
  - Grid supports.
  - Trefoil broach holes with convex lends.
- Welded channel head divider plate.

- Blowdown internal design enabling a subcooled condition of the water:
  - Peripheral gutter (chamfer).
  - Internal blowdown pipe plus tube sheet drain line.
- No economizer (feedwater preheater). The experience gained show that the benefits of the economizer (smaller SGs for a given power) were negatively compensated by problems like fretting, making this alternative less attractive.
- High capacity blowdown, with blowdown heat recovery, so that 0.7% blowdown are made possible on continuous basis, and doubled in case of need (startup, condenser leak). Back-fitting is economically rentable and it should be considered state of the art.
- Recovery of blowdown water to reduce the make-up, using a mixed bed ion exchanger/regenerable, or non-regenerable, or using the blowdown water as row water for the demineralizing plant.

5.3 MEASURES TO CONTROL AND IMPROVE SECONDARY SIDE CHEMISTRY

Refer also to Section 4, Sections 4.1.3 to 4.1.5.

Measure for control and improvement of the secondary side chemistry are based on three main topics:

- Corrosion product transport.
- Redox potential conditions.
- Impurity control.

The basic aspects concerning these points have been discussed in detail in the Section 4, Section 4.1.5.

5.3.1 Control of corrosion product ingress into the steam generators

5.3.1.1 Reduction of the flow accelerated corrosion

Evaluation of field experience shows that an important source of the corrosion products entering the steam generators is the flow accelerated corrosion (FAC) at the wet steam areas of the steam water cycle. It is a process assisted by fluid dynamic mechanisms, which results in wall thinning of piping, vessels and equipment made of carbon steel and occurs only under certain conditions of flow, temperature, chemistry, geometry and material. The influence factors are discussed in Section 4.1.5.1 and 4.5.4.

Basic measures:

- Increase pH in the system. Target: to achieve a $pH_{Tws} > 6.5$ where T_{ws} is the temperature of wet steam at HP turbine outlet- cross under- moisture separator.
- By increasing ammonia concentrations until achieving a $pH_{25°C}$ close to 10.0 in final feed water. Hydrazine can supply partly or totally the ammonia required. Copper elimination from BOP systems is required.
- By applying advanced amines, if ammonia are not sufficient or not applicable.
- Pipe replacement with low alloyed materials having a composition with more than 2.5% Cr content.

5.3.1.2 Removal of the copper materials from the secondary coolant system

The reasons for copper replacement are described in Section 4.1.7.

Copper bearing materials corrode under the presence of ammonia and oxygen. This will happen especially at (but not limited to) the air exhaust sections of the main condenser at condensers tubed with copper bearing materials. Therefore, the ammonia concentration has to be maintained low in systems having Cu alloy surfaces in contact with the fluid. Therefore, the presence of copper bearing materials in the secondary side limits the operational pH-value in the final feed water, which adversely affects the corrosion product control, leading to a continuous increased ingress of corrosion products into the steam generators, promoting impurity enrichment and corrosion.

Besides, copper limits indirectly the hydrazine concentration, which produces ammonia by thermal decomposition, adversely affecting the reducing conditions necessary in steam generators.

Copper can also act as oxidant, promoting corrosion mechanisms like pitting or TSP/tube sheet denting.

As a consequence, the long term integrity of the SG tubing cannot be guaranteed unless frequent steam generator cleaning such as sludge lancing of the tube sheet area and/or chemical cleaning of the tube bundle is practiced, in order to keep the steam generators clean.

Less generation of corrosion products due to erosion corrosion in the steam systems will also beneficially influence the operational performance of the secondary systems (suppression of erosion corrosion) and will reduce inspection and repair work in this area.

The replacement of copper bearing materials from the secondary side is not mandatory. However, it is recommended because in this way the safety margin against possible corrosion phenomena can be additionally increased and steam generator fouling performance can be improved.

5.3.1.3 Minimization of corrosion product and impurity ingress during startup transients

See fundamentals in Section 4.1.5.2.

After the outage at the beginning of the startup process before the heat-up starts, efforts should be made to minimize the inventory of corrosion products in the feedwater system, which could be transported to the SGs together with impurities, which may have been introduced into the feedwater train and various parts of the secondary system during annual outages. Consequently, it is important to carefully eliminate them before startup.

- Otherwise, the corrosion product input can represent a significant part of the SG inventory.
- Impurities that may be harmful for SG tubing must be eliminated before they hide out during power operation (concentration of impurities), which becomes significant above about 25% of nominal power.

It is important to purify the secondary system:

- By feed and bleed of the feedwater train before startup, if recirculation line with condensate polishing systems or mechanical filters are not considered in the design.
- Afterwards by the steam generator blowdown system.

This can be done by recirculation of water from the effluent of the high pressure heater to the condenser and purification. Sufficient startup time should be allocated to accomplish SG and feedwater clean-up. Corrosion products transported during startup are generally more oxidizing than those transported during normal operation, because of potential exposure to oxidizing conditions during lay-up, particularly for those plants, which do not use nitrogen blanket during lay-up. For these reasons, it is important to pay attention to minimize the transport of corrosion products into the SGs during startup and to make efforts to reduce the oxidation state of the corrosion products that enter the SGs.

The feed and bleed of feedwater train is a good way for early elimination of ionic impurities before they enter the SG, if condensate and feedwater cannot be purified by Condensate Polishing System (CPS) using recirculation line. Then SG blowdown will be used before increasing the power. The objectives of chemistry during shutdown and startup operations are to keep a good water quality in order:

- To decrease the quantity of demineralised water that will be used to rinse the feedwater train during startup for reaching the specified values.
- Thus to decrease the volume of liquid effluents containing chemicals.
- To decrease time spent during startup for reaching the specified values.

5.3.1.4 Follow-up of corrosion product transport

By a follow-up of the system pH an indirect control of the corrosion product is performed.

This control is carried out measuring the $pH_{25°C}$ directly, and/or the amine concentration. The pH measurement is not very reliable and requires a careful calibration. The specific conductivity (SC) is almost exclusively function of the amine concentration, providing a very reliable way to follow up the alkalinity in the system, especially when only ammonia is used the SC measurement can replace the pH measurement. A comparative pH determination is shown in Figure 5.9. When Advanced Amines are used, the only alternative monitoring way is the direct measurement of the amines.

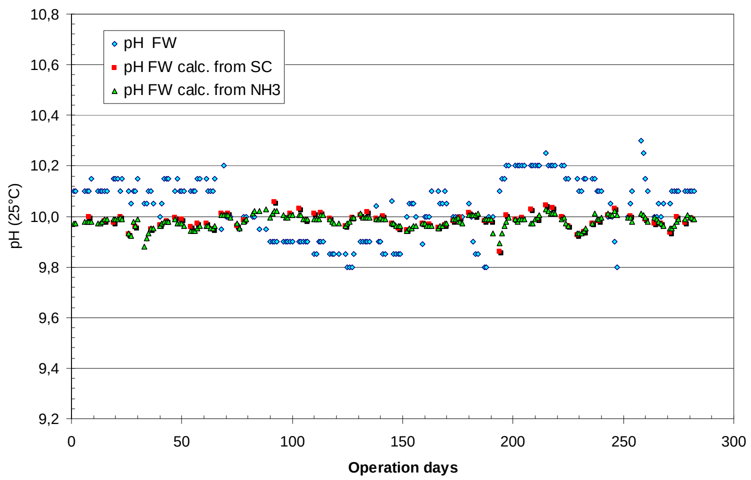


Figure 5.9. Accuracy of feed water pH measurements.

The estimation of the corrosion product inventory is important to assess the SG condition and decide about remedial actions such as chemical cleaning. This issue has been often disregarded, when the importance of corrosion product transport is not recognized.

A reliable measurement of the corrosion product at least in feedwater is necessary, and whenever possible in all relevant streams transporting corrosion products (main condensate, heater drains) especially in plants having a high CP input (low AVT)

The sampling of suspended solids represents a problem requiring well designed sampling nozzles, sampling lines, sampling point and sampling (filtration) equipment as well as specific sampling procedures.

The factors influencing the behaviour of particles submerged in a fluid are widely described in the literature [104, 105]. The main influencing factors are inertial forces (flow direction changes, sedimentation), thermophoresis, electrostatic precipitation, impaction (impingement), Brownian diffusion [106]. From these, the inertial forces are of major concern, followed by the electrostatic precipitation, which plays a role in case of small oxide particles (colloidal forms).

Sampling nozzles: isokinetic probes are sometimes used. However they are not required under the feedwater sampling expected conditions [13].

Making an analysis of the drag forces[5] to which a particle submerged in a moving fluid and considering the terminal velocities of the particles under the sampling conditions (temperature, particle diameter, density of the liquid and the particle, Reynolds number) [104, 105]. It results evident that if the flow velocity of the sampling stream is 1 to 2 m/s (linear flow velocity recommended by ASTM: 1.8 m/s [107, 108]), particles of ~ 3 µm in diameter will tend to drift out of the flow line at a terminal velocity of only about 1% of the fluid velocity at 300°C, and even lower at 50°C. That means, if the fluid changes direction, the particle will 'follow' well the fluid stream and a representative sampling of such particles is possible.

Anyway, the nozzle must have a design avoiding wall effects, like that shown in Figure 5.10.

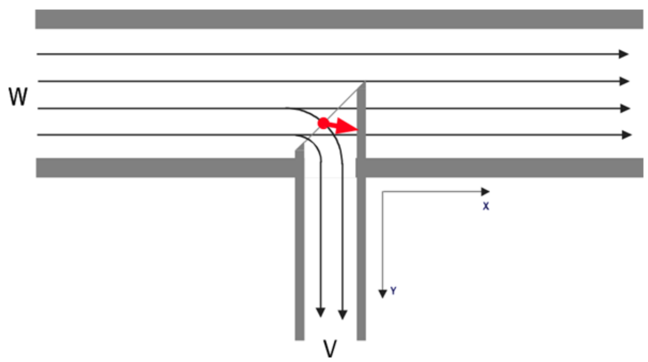


Figure 5.10. Sampling nozzle of 'inclined face' type for corrosion product sampling (DIN).

Sampling lines: turbulent flow with (Re = Dvp/µ > 8000) is required. This corresponds with a linear flow rate of 1 m/s in a DN6 line. A common mistake is to use too big lines at low flow rates. The lines must be short (<10 m) to avoid perturbations. This makes necessary to implement local sampling points, not centralized. Horizontal lines must be avoided to prevent deposition.

Sampling point should be chosen sufficiently far away from flow perturbations like elbows, valves. Sampling devices must ensure a continuous uniform sample flow. The sample analysis is performed in many different ways, not being the limiting factor.

[5] The drag force represents the 'resistance-to-movement' of the particle relative to the surrounding fluid. A high value of Fd means that the particle will tend to have a high resistance to inertial forces, like for example those derived from the change of direction of the fluid. The drag force ('friction' force) will be bigger for higher fluid density and viscosity, keeping al the other parameters constant.

5.3.2 Redox potential conditions in secondary circuit

5.3.2.1 Oxygen control

Besides the minimization of deposits, it is imperative to ensure reducing conditions in the SG environment. This prerequisite is achieved by adding hydrazine to secondary circuit[6]. Fundamentals about the system redox potential condition requirements are given in Section 4.1.5.1. Nevertheless, due to difference in design of the BOP of several OEMs, some characteristics have to be considered. See also Section 4.1.7. Two main design concepts can be recognized being the major difference in the feedwater supply.

The first one has no feedwater deaerator in its design due to cost reduction reasons and supplies the feedwater during plant startup operations either from the ‘auxiliary feedwater tank’ (AFT) or from the ‘condensate storage tank’ (CST). This concept is used typically in USA PWRs but also in many other countries like in some EDF plants in France. In this concept the oxygen control is performed by hydrazine injection for all operation modes including plant startup operations by airtight sealing of the AFT and CST.

The second design concept considers the use of feedwater deaerator tank or feedwater tank. This concept has the advantage of supplying the SGs with oxygen free hot feedwater during all operation modes including the startup operations. All Siemens-KWU PWRs, Japanese and the new EPR™ are using this secondary side concept. Feedwater dearators are also used in other PWRs, like all Japanese PWRs, many CANDU plants and several other PWRs like several EdF plants in Europe.

The rate of the reaction between hydrazine and oxygen is very slow at low condensate temperatures and starts to accelerate at temperatures above 150°C. The rate of the reaction above 150°C is more than 300 times faster than at temperatures below 100°C [91]. The reaction is also a catalytic reaction with corrosion products. Therefore the reaction rate is accelerated especially in the tube bundle area of the feedwater heat exchangers, where huge amount of surface area covered with corrosion products is exposed to hydrazine and oxygen containing water (Figure 5.11).

In the feedwater line, the surface area is relatively smaller, accordingly, the reaction rate is also remarkably slower than at the tube bundle area. This fast oxygen removal by hydrazine in the tube bundle of the HP feedwater heat exchangers can also be confirmed by visual inspection of the surface colours at the inlet und outlet of the heat exchangers. Red colours indicate still presence of oxygen, whereas the black colours confirm the oxygen free reducing conditions. The amount of hydrazine to be injected for the oxygen control is plant specific depending on the air leak tightness of the secondary side.

It has to be noted, that hydrazine is used to ensure reducing conditions in the steam generator not in the feedwater line. As mentioned before in Section 4.1.5.1, red oxide colour indicates hematite (Fe_2O_3) whereas the black one is magnetite (Fe_3O_4). Hematite is less soluble than Magnetite, which leads to a less corrosion product ingress into the steam generators. Several organizations, like Siemens and Japan Atomic Power Company (JAPC), have started to investigate several years ago the possibility of establishing local oxidizing conditions by oxygen injections into secondary side without affecting the reducing conditions in the SGs. These investigations confirmed that one of the most important issues is the monitoring of the oxygen in the effected system areas and especially in the final feedwater up-stream SGs, in order to ensure the reducing conditions for SGs.

6 The replacement of hydrazine by other components is being searched, owing to the carcinogenic nature of this reagent, but there is still no equivalent, qualified alternative.

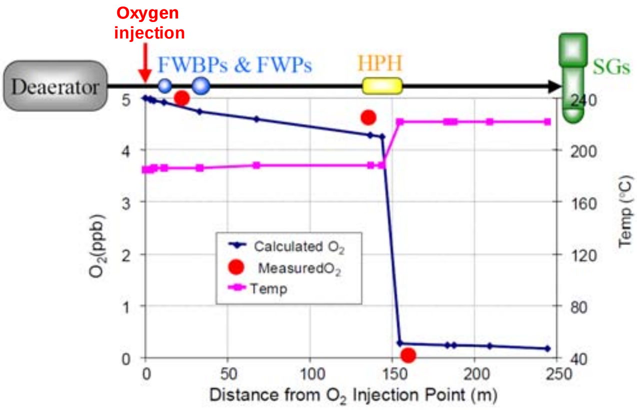


Figure 5.11. Measured oxygen profile along feed water train (Initial levels of O_2 = 5 ppb and N_2H_4 = 100 ppb, pH 9.8) [109].

The formation of hematite can be achieved by only a small increase of the redox potential by 100 mV, which yields to a decrease of the iron solubility by factor 10. Figure 5.12 shows the calculated iron solubility as a function of the redox potential at constant pH of 6.39 at 280°C. Therefore it is rather recommended to obtain 'red surfaces' in the feedwater system. Only small amount of oxygen is needed to achieve this (Figure 5.13).

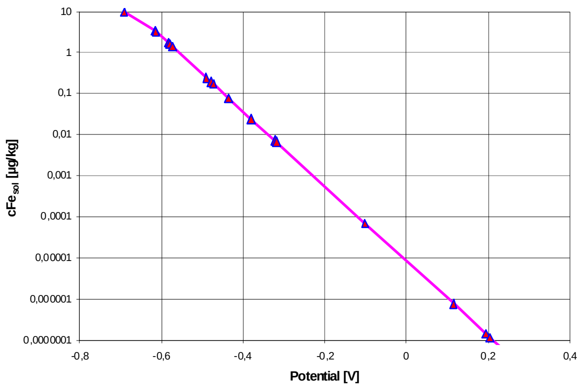


Figure 5.12. Iron solubility as a function of redox potential at a constant pH (280°C) = 6.4 [110].

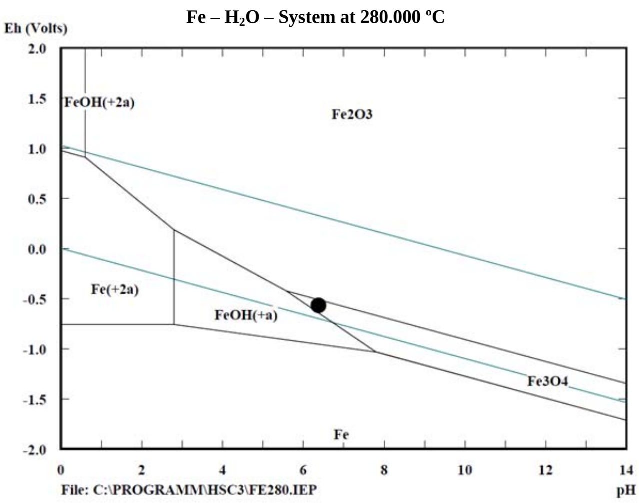


Figure 5.13. Pourbaix-Diagram for the system Fe-H_2O (280°C) [110].

The first known published feedwater oxygen treatment in a PWR was performed in 1984, at the Biblis-B plant in Germany [111]. At that time, the plant was operating under low pH AVT conditions with a feedwater $pH_{25°C}$ < 9.5, due to existing copper bearing tubes in the condensers. In this plant, two separate feedwater lines are feeding two SGs separately from the feedwater tank. During the annual inspection, it was discovered that one of these feedwater lines was black coloured and the other was red coloured. The black coloured line had significant FAC damage on the carbon steel flow deflecting grids in the HP feedwater heater, whereas the red one had no damage, see Figure 4.23.

Obviously, the feedwater oxygen removal was not homogenously in the large sized feedwater tank (500 m^3 longitudinal tank). As a temporary measure to counteract FAC, the utility had decided to inject oxygen with aerated make-up water into the feedwater line up-stream feedwater pump. This oxygen treatment was successful to stop the FAC in the HP feedwater heater in the black feedwater line.

In Japan oxygen injection treatment has been also considered at the Tsuruga-2 PWR unit due to carbon steel FAC damage at a limited location. Before introduction of the so-called oxygenated water chemistry (OWC) treatment, JAPC has performed detailed preparatory work and a demonstration test at Tsuruga-2 [109, 112, 113]. The objective of these investigations was to confirm that the reducing conditions in the SG would not be affected. After finalizing the preparatory work, JAPC performed a demonstration test at Tsuruga-2 PWR.

During this demonstration test, oxygen was injected up-stream the feedwater booster pump with an injection rate to achieve < 5 μg/kg O_2 in the feedwater. The hydrazine injection was adjusted to maintain a feedwater $pH_{25°C}$ of 9.8 and a hydrazine concentration of 100 μg/kg. The test was monitored by oxygen, ECP, and iron concentration measurements up-stream and down-stream HP feedwater heaters. The ECP measurements at Tsuruga 2 plant confirmed the protection of carbon steel surfaces against FAC by oxygen injection. Based on these results, JAPC is planning in the next future to implement oxygen injections (OWC treatment) in combination with high AVT. The concept of this chemistry is illustrated in Figure 5.14.

As described the operational experience showed that even if oxygen is dosed in the secondary circuit the prerequisite of reducing conditions in SGs is achievable. Nevertheless, the plant specific behaviour has to be considered.

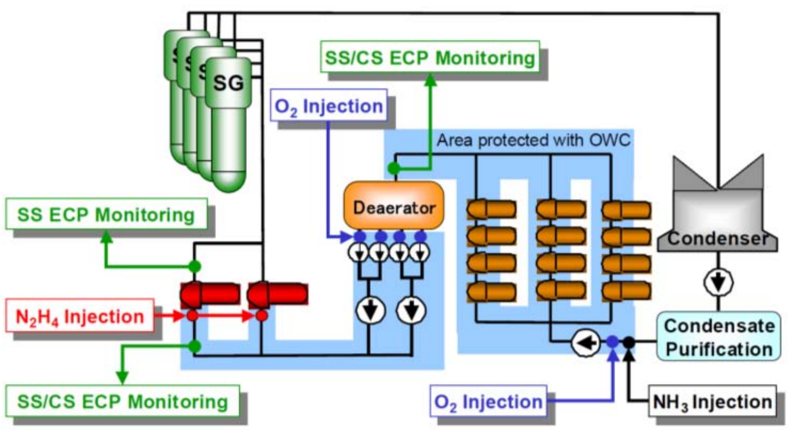


Figure 5.14. Full scale OWC concept planned for Tsuruga-2 [109].

5.3.2.2 Follow up

O_2 measurements represent also a problem. Long sampling lines transporting sample at high temperature will result in a lower oxygen concentration than that actually existing in the feedwater line (see Figure 5.15).

In principle, as for corrosion products, it would be better having a short line, or at least having the sample cooler close to the sampling point and not in the central sampling panel as commonly found.

A better alternative to a direct O_2 measurement is an on-line redox/corrosion potential measurement [114, 115].

The electrochemical potential on-line measurements started to be performed in the 1980s and since then it has been adopted as control parameter of reducing conditions. The Figure 5.16 clearly shows the lack of sensitivity of the oxygen on-line measurement in feedwater using the centralized plant sampling system (curve 6), showing almost no response even if the concentration in main condensate achieved the order of 40 ppb caused by air in-leakage (curve 5). The redox potential measurement directly in feedwater (curve 2) shows a variation following the oxygen concentration in feed water, as well as the corrosion and redox potentials measured inside the SG using provisory electrodes adapted to a SG inspection hole. Redox potential should be seriously considered as the most suitable method for follow up of reducing conditions.

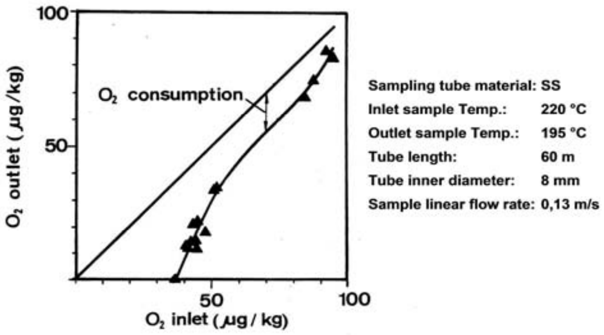


Figure 5.15. Influence of the sampling line length on the O_2 measurement.

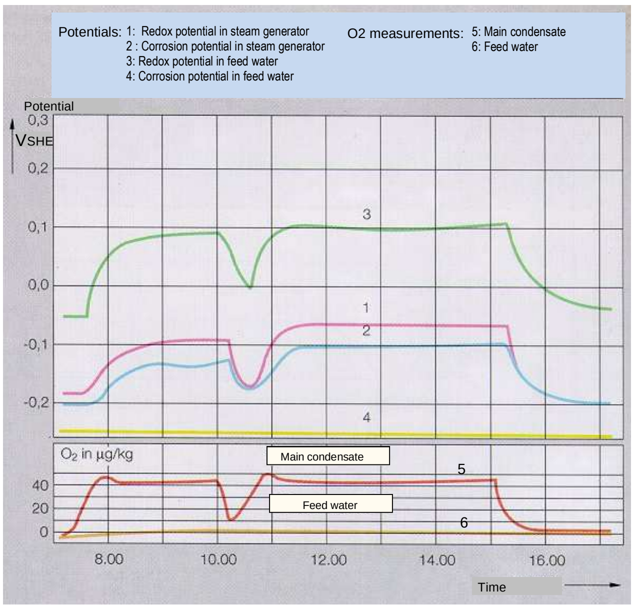


Figure 5.16. Redox and corrosion potential measurements in the SGs and feed water of a PWR. Comparison with oxygen measurements.

5.3.3 Impurity control

The fundaments of impurity control have been well described in Section 4, Section 4.1.5.1.

A first goal for operating plants is clearly the reduction of the impurity sources. They are basically:

During normal operation:

- Condenser leakages.
- Dissolved impurities in the make-up water and in the blowdown water treated by the blowdown demineralizers ,which returns to the cycle.
- The steam generator blowdown demineralizers and the condensate polishing system ion exchange resins:
  - Resin/resin fine ingress.
  - Reagents for regeneration, eluted into the system in case of faulty regeneration.
- Uncontrolled return of 'clean' condensates.
- Organic compounds produced by decomposition of amines.
- Oil ingress.
- Impurities in chemical additives and consumables (hydrazine, amines, boric acid, etc.) during steady state operation.
- CO_2 entering at the condenser, or from thermal decomposition of organics.

During shutdown, later transported to the steam generators:

- Miscellaneous auxiliary products used during maintenance activities, montage aids, welding electrodes, adhesives, markers, grinding material, lubricants etc.
- Lack of cleanliness during outage maintenance activities.
- Lack of cleanliness control prior to restart the plant.

Important is not only the amount of impurities transported into the system, but rather its composition.

The basic philosophy shall be to implement a well-organized management to:

- Prevent the ingress.
- Adequate corrective actions to minimize their effects.

5.3.3.1 Condenser

Condenser tightness
Refer to Section 4, Sections 4.1.5.1, and 4.1.7.

Condenser tightness supervision
For a correct supervision, a harmonized leak detection and leak localization infrastructure must be available.

Leak detection
The most sensitive indication of a possible condenser leak is the impurity concentration evolution in SG blowdown by Cation Conductivity and sodium (CC, Na) monitoring. Even if, other impurity sources may be responsible for that, the first suspect must be the condenser.

The hotwell supervision shall consist on individual Na and CC measurements, being the sensitivity of the Na measurement higher than that of CC. Owing to the nature of the Na on-line measurement, differences between hotwells can be measured due to electrode shift, requiring a careful and well-implemented maintenance. For bigger leaks, the CC offers a trouble free, reliable indication. One solution to avoid Na concentration differences due to calibration is the use of a single Na monitor sequentially switching from one hotwell to the next, in this way systematic calibration errors are compensated. The measurement of Na in the reheated-steam condensate as reference value is advisable, because due to the low volatility of Na at this point the Na concentration is surely zero, and this measurement can be used as zero reference. A possible arrangement is shown in Figure 5.17.

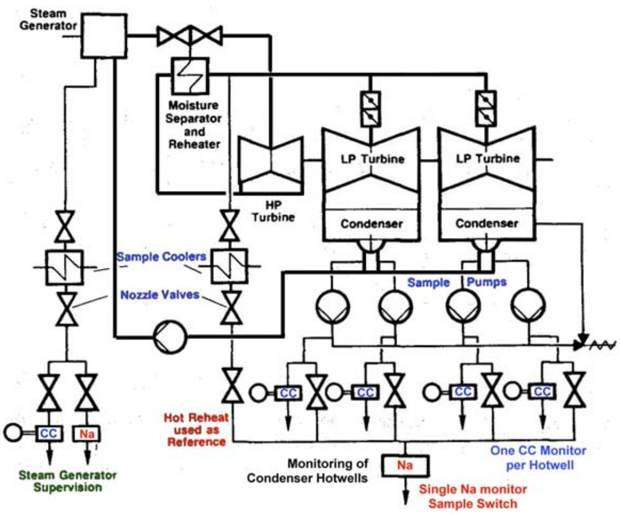


Figure 5.17. Advanced condenser hotwell supervision system.

Seawater plants have a rapid response in front of a leak, and an immediate isolation of the leaking section must proceed. The correlations between leak rate and Na, CC are shown in Figure 5.18 for sea water cooled condenser, confirming that very low leaks are detectable and the leaking hotwell can be identified, posing a difficulty for later localization and repair of the damaged tube.

River water cooled plants may be confronted with the opposite problem: a leak can be recognized by SG blowdown, but it results difficult to identify the leaking section. Lowest possible detection limits are then required, achievable with a concept like that of Figure 5.17.

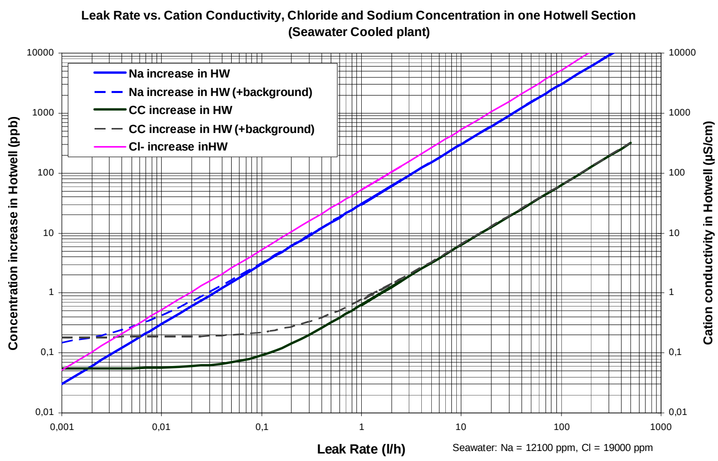


Figure 5.18. Cation conductivity and sodium concentration in hot well vs. leak rate for a seawater-cooled plant.

Leak localization
Refer to Section 4, Section 4.1.5.1.

Basic philosophy: leaks, which are detected, must be localizable.

Seawater cooled plants: Sensitive leak localization methods are mandatory to ensure the localization of the leaks that can be detected by the supervision system.

Plants having softer water may have the problem of not being able to detect a leak by hotwell measurements, risking a continuous plant operation with a mini leak causing a significant integrated exposition of impurities to the SGs. This requires a 'blind' search to localize the failure.

State of the art is therefore the helium or sulphur hexafluoride detection techniques.

5.3.3.2 Condensate polishing system

As formerly described in Section 4 Section 4.1.5.1, there exist two philosophies in managing impurity control. On the one hand the operator emphasise the prevention against impurity intake or, on the other hand, on the implementation of cleaning facilities. A condensate polishing system (CPS) is installed for purifying the water coming from the condenser, which, after the feedwater train, will be the feedwater for the SG. It consists in a series of ion exchange resin (IER) beds and/or filters with powdered resins, to eliminate corrosion products and ions present in condensate water. The purpose is to avoid the impurity transportation toward the SG, where they may deposit and concentrate, induce corrosion of SG tubing, (or even potentially the turbine) or decrease the heat transfer. The greatest efficiency to purify the feedwater would require installing the CPS in the final feedwater, but this may not be considered since the IER cannot operate at high temperature and the thermal balance would be unacceptable.

In almost of the US PWRs and in all Japanese PWRs CPS is considered for the impurity control. Recently, in some Japanese PWRs, where high AVT chemistry is introduced, CPS is used only during startup operation, i.e. it is bypassed during power operation. In contrary, in European PWRs condensate polishing systems are not so widely used, e.g. none of the EdF PWRs CPS is considered. Siemens-KWU has designed CPS only in three German PWRs, due to special request of the owner Utility. Based on its own field experience this utility does not use the CPS during normal power operation any more. All the other Siemens-KWU designed PWRs have no CPS in their secondary side [116]. The reason not using the CPS is the concern that CPS operation affects the SG performance due to reduced feedwater pH resulting in poor corrosion product control as well as the risk of residual impurity and resin release into steam generators. In the Republic of Korea, when switching Kori 1 to ETA in 1998 in order to decrease suspended solids and sludge in SG, a condensate polishing system (anionic resins) fouling have been observed and mitigated. Here again, the condensate polishing system was designed for NH_3 at pH 9.0. With ETA, without condenser leak, it has been decided to keep the condensate polishing system with partial flow (13%) or in bypass (98% flow) mode.

The presence of condensate polishing system on WWER is mainly explained by the lack of tight copper alloy condensers. Several units switched to amines treatment (Morpholine, ETA) to decrease quantity of sludge due to pH 9 with NH_3 and associated corrosion of SG tubes. This treatment has been the opportunity to improve secondary water chemistry quality: Tightening condensers, condensate polishing system bypass, SG blowdown resins operating once saturated with amine. This gave satisfactory results and a decrease of transfer of corrosion products and SG primary to secondary leak [96, 117].

With new materials, condensate polishing system (CPS) is finally more a burden and a pH limitation than an opportunity to eliminate pollution. Laboratory studies and plant experience have shown that decomposition products of resin fines, giving reduced sulphur compounds, or with sodium hydroxide throw, may constitute a very detrimental hazard for SGs integrity. Since reliable condensers exist and low leak detection with helium is carried out, it looks more desirable to avoid continuous operation of condensate polisher, which can constitute a higher risk of contamination than a purification method. It appears that the feedwater corrosion product transport is finally higher in units with CPS than without. The CPS operation is hardly compatible with a sufficiently high pH (regeneration frequency, liquid wastes, and costs) and its benefit does not compensate the inconveniency of this lower pH values. If CPS is present, it is highly advisable to keep it in by-pass mode, ready for use only in case of need for a limited period of time (condenser leak, startup). A cheaper option is to only have a lower flow rate system specifically aimed at eliminating contaminants before and during startup.

Consequently the following recommendation can be given regarding the condensate polishing system:

- **Existing PWR or WWER in operation, having installed condensate polishing system:** Consider using CPS only in case of pollution for a limited time.
- **NPP with leaking condenser:** Consider condenser replacement on the short term instead of eliminating the pollution with CPS operation.
- **New NPP:** Consider either no CPS, partial flow polishers only (startup) or with full flow if 100% availability needed. Also a condensate mechanical filtration system can be considered.

As an overall conclusion of the necessity of CPS it can be stated: With new materials, CPS is rather a source of pollution with associated corrosion risk, of high cost and wastes (more and more undesirable), of chemistry option restrictions, than an opportunity to save time and eliminating pollution.

5.3.3.3 Steam generator blowdown purification

The principle for SG blowdown purification deals with issues similar to CPS, since both are using ion exchange resins with their specific characteristics. There are a few differences between SG blowdown and CPS with an impact on the options:

- The SG blowdown flow rate to be treated is about 0.5 to 1% of feed water flow, whereas the flow rate of CPS is 55 to 70%. This explains that in some countries SG blowdown was directly released without any treatment, which looks completely unacceptable nowadays, on a friendly environmental point of view.
- The low flow rate allows to decide if resins should be regenerated or should be disposed (solid wastes) when they become inefficient for purification.

Most of the countries regenerate their resins and use a cationic bed for conditioning reagent elimination, thus frequently regenerated (depending on the operating pH and the type of conditioning reagent) followed by a mixed bed, as a polisher (explaining the use of ‘polishing’ term) i.e. eliminating the final traces of impurities in a neutral environment.

For the better elimination of the impurities traces, it is mandatory to have a cationic bed for eliminating the conditioning reagent and operating in a neutral environment [118] on the mixed bed downstream. This is the option if ultrapure quality water is expected starting from already good quality water. With the necessity to operate at a pH higher than before (see Section 4), the regeneration frequency becomes unacceptable for the frequency of manipulation, the costs of reagent and the liquid effluents from regeneration. More and more, particularly with new SG material highly resistant to corrosion and compatible with slightly higher impurity concentrations, the resins operate after saturation with the reagent, up to the point where regeneration is required by another criterion, like sodium break through, rather than resin saturation. However, this option looks possible if the pH/reagent selection allows to keep a satisfactory water quality at ion exchange resign outlet, which is depending on the relative affinity of ions (Na^+ and NH_4^+, Amine-cations) on the cation resin. The decreasing order of affinity is $NH4^+ > Na^+ > H^+ >$ ETA-cation > Morpholine-cation. This means that for a defined molar concentration of amine, the operation of ion exchange resign after amine breakthrough is more feasible with Morpholine or ETA than with ammonia. Consequently, such an operating mode allows to more optimizing the pH with all the important associated advantages, if a frequent regeneration is undesirable for the associated burden. Moreover, a slightly higher presence of some impurities may be still compatible with corrosion resistant SG tubing.

A Swedish approach was developed to get rid of all the regeneration chemicals and associated liquid wastes [119]. At NPP Ringhals the SG blowdown system is designed without regeneration and it is not intended to operate with ammonia-saturated resins, which would induce a lower quality of water at resin outlet. Therefore with H-AVT chemistry treatment the blowdown system lifetime was short and annual resins cost high, in addition to an important workload for resin replacement and important impact on the environment. In 2001–2003, about 20% (5 m^3/h) of the SG blowdown was by-passed and treated through electro-deionization (EDI). EDI is an electrical potential driven ion separation process (electro dialysis) that integrates ion exchange bipolar membranes in combination with IER as shown in Figure 5.19. No chemicals are needed for regeneration of the cell and much lower volumes of wastes are produced as compared to ion exchange resigns regeneration. It was reported, that the operating costs are also much lower than resin replacement. In 2005, a full scale EDI (20–30 m^3/h) has been installed to be used for SG blowdown purification (except in case SG leak) after a filtration resin bed (inert resin or saturated cation) and before a mixed bed as a polisher for insuring a high water quality. The only concern of EDI is the potential risk of compartment fouling which has not been a problem during this trial period at NPP Ringhals [119].

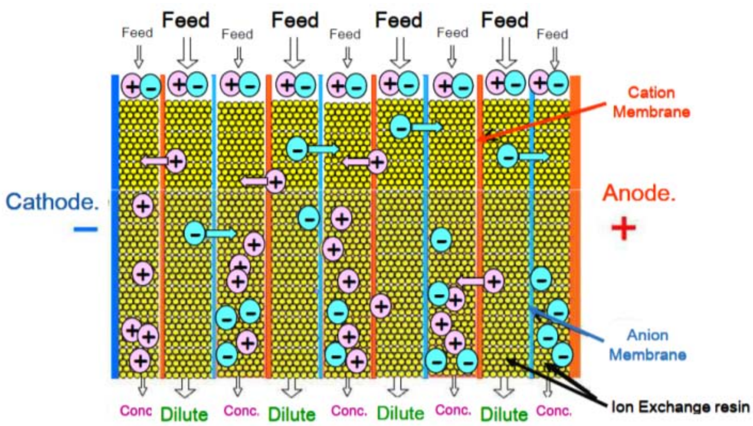


Figure 5.19. Principle of electro de-ionization [119].

Blowdown recovery is, as explained in Section 4 Section 4.1.7, is tightly related to blowdown heat recovery. By recovering the heat, there is no economical need of reducing the blowdown rate. As a consequence, higher flow rates can be adopted, resulting in lower SG bulk water concentrations and improving the steam generator water chemistry.

In plants having ammonia as alkalizing agent, about 75% of the ammonia present will be flashed back to the feed water train, and reducing the amine loading of the blowdown demineralizers.

5.3.3.4 *Control of lead. Contamination.*

Lead has been implicated in the accelerated stress corrosion cracking of Alloy 600MA steam generator tubing at a number of utilities. Of particular interest are two of the oldest French stations at Fessenheim and Bugey, where cracking has been related to possible chronic lead problems, rather than lead source contamination as in Bruce A Unit 2 and Doel Unit 4. Lead is typically found at comparatively low levels in steam generator deposits having been transported there from the secondary system.

Laboratory studies have also revealed the presence of lead accelerated stress corrosion cracking of not only Alloy 600MA, but also for Alloy 800NG and Monel 400 even for Alloy 690TT [120–124]. All the alloys tested corroded in aqueous lead contaminated environments. However, the Alloy 600MA material was most susceptible. The most severe environment in the French studies [121] was a lead contaminated caustic solution. However, the Spanish studies show that these materials have a higher susceptibility for cracking in a lead contaminated AVT environment [122].

A laboratory test showed that 1 mg/kg of lead might cause the lead induced cracking in alloy 600MA [125].

At present there is no quantitative correlation between the feedwater or blowdown lead concentrations and the cracking susceptibility of steam generator tubes under a given set of generating conditions (e.g. constant stress and other water chemistry parameters). Therefore, the lead contamination levels in operating steam generators should be kept as low as possible until more information is available and some ‘safe’ level is defined. Effective operating procedures should be used to prevent and control both acute and chronic sources of lead contamination.

5.3.3.5 *Minimization of make-up*

Fundamentals: See Section 4, Section 4.1.7.

Careful make-up water chemistry control is also needed to control the chloride content in the SG secondary side water (in addition to controlling the in-leakage of raw water through the condenser). Organic impurities in the make-up water decompose at steam generator temperatures and produce additional chlorides, through decomposition products of organic-chlorinated components like chloroform, which may be formed during the pre-treatment of raw water. Since they are non-ionic, they are not detected by conductivity measurement. These ‘hidden’ chlorides may be introduced into the steam generator at amounts larger than indicated by an ordinary chemical analysis of the make-up water, unless the water sample is subjected to high temperatures and pressures before the analysis. Some plants have installed counter current absorption columns to get rid of light chlorinated organics. One of the approaches to reducing the chloride and impurity input through the make-up water is to reduce the quantity of make-up water used. A blowdown recovery system will purify and recycle blowdown water that is cleaner in terms of chlorides and organic impurities than the usual supply of make-up water.

5.3.3.6 *Consumables and auxiliary products*

As already mentioned in Section 4, even small amounts of impurities could be concentrated in crevices and might cause severe steam generator damages. Therefore, a reliable quality assurance system is of utmost importance to ensure a stable quality level of chemicals applies to reagent injected in the secondary system (ammonia, amine, and hydrazine). Not only surveillance of chemicals or chemical products themselves is necessary, but also auxiliary products like adhesives, markers, grinding material and assembly lubricants, which are more or less temporally in contact with surfaces of systems and components during outages and maintenance work.

These products are usually not especially designed for nuclear power plants and consequently they might not fulfil the requirement of the nuclear business. Both operators and manufacturers of nuclear power plants have developed and installed surveillance systems to scale down the ingress of impurities via this path. For example EdF installed the ‘PMUC’ standard for the French NPPs and AREVA NP developed the qualified product database (‘QP-Database’), which is widely used by NPPs in several European countries [126].

The issue of surveillance of consumables and auxiliary product cannot be covered by the chemistry staff of a NPP only. To ensure safe conditions it is rather recommended to include beside the technical personal (chemistry and maintenance department) also the commercial staff and consider the purchasing process of such products [127].

5.3.3.7 Clean condensate recovery

Several plants do not have a clean condensate collection tank. All returns are driven to the condenser, increasing the number of connections and decreasing the air-tightness.

A clean condensate tank enables a controlled return of clean condensates, and the possibility of dumping bad quality returns by analysis.

5.3.3.8 Follow up of impurities

The supervision of impurities is a very complex matter which can only be mastered by strictly following the concepts established in Sections 4.1.5.1, 5.1.3, 5.2.1, 5.3, stressing on:

- Quality assured chemistry supervision, for operation and shutdown periods.
- Clear procedures (normal and abnormal conditions).

Particularly a long term follow-up of the hideout/hideout return is considered important to assess the SG condition with a view to impurity enrichment, pre-requisite for SG corrosion degradation. Predictive and check tools, like advanced mass balance codes and tools for developing and optimizing chemistry programmes (e.g. ChemWorks), chemistry impurity concentration models (e.g. MULTEQ), computer aided diagnosis systems (e.g. DIWA) have to be considered state of the art an consequently applied.

5.3.3.9 Lay-up

The preservation of the both steam generators and BOP systems during shutdown periods is a requirement to prevent not only direct corrosion of the considered components, but also to reduce the generation of corrosion products that later will be transported into steam generators.

The lay-up condition (conservation and protection of components against corrosion during shutdown) will depend on several criteria:

- The material in presence (carbon steel, stainless steel, nickel base alloy, copper alloys).
- The duration of the lay-up, when the component will stay in the defined condition.
- The other maintenance activities that may apply either to the component or to other ones in interaction, such as in service inspection (non-destructive examination), repair, sludge lancing etc. that may require to drain the component.

- Radiation protection. For example, SGs are usually wet laid-up due to radiation field. During the period, when the SGs are dry due to maintenance activities, additional shielding measures needs to be considered to protect the maintenance personnel.
- The authorized methods (e.g. use of nitrogen or not).
- The available systems and devices (e.g. drying systems, dry air).

Still stand corrosion affects mainly the carbon steel surfaces, and it occurs in an aerated (oxygen) AND wet (water) environment.

Depending on the formation or not of anodic sites, it may cause general corrosion as well as localized corrosion (pitting), as schematically shown in Figure 5.20.

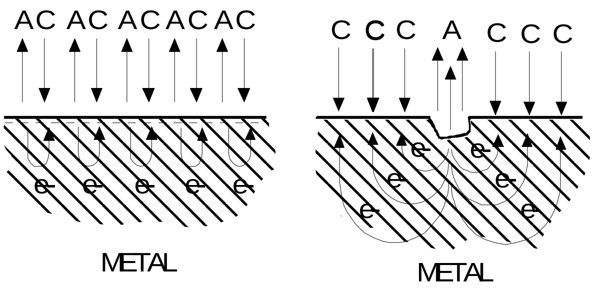


Figure 5.20. Still stand corrosion of carbon steels (schematic).

There are two lay-up methodologies: Dry lay-up (exclusion of water), or wet lay-up (exclusion of oxygen).

Dry lay-up consists in completely draining the water from the component that will be kept in dry condition. Drying is achieved by blowing dry air free of oil and dust through the component or system. To dry the systems, either hot air (ventilator + heater) and/or dry air (regenerative air driers) are used. The basic requirement for dry lay-up is

- Air renewal rate: > 1 system volume per hour
- Relative humidity level: <50%, based on 20°C (Figure 5.21)
- Absolute humidity: <7.2 g H_2O/kg air
- Dew point: 9°C

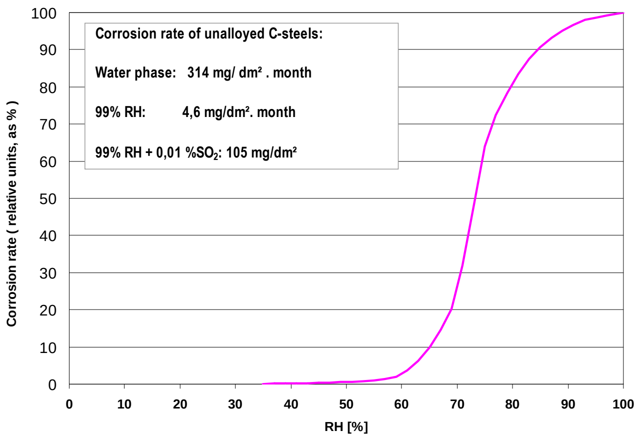


Figure 5.21. General corrosion of carbon steel as a function of relative humidity.

The system sections should be selected based on the capacity of the driers available, in order to replace the system volume at least once per hour.

For long term lay-up, under closed circuit condition, a humidity limit of 30% based on 20°C is required. Dry lay-up is to be used mainly in the BOP systems. Systems usually concerned:

- Steam and extraction systems
- HP and LP turbines
- Condensate and feed water systems
- Condenser.

Dry lay-up requires being included in the outage maintenance planning, to solve possible interferences with maintenance works. Basically, the steps for the implementation of dry lay-up of the secondary system are:

- Divide the secondary system in suitable sub-systems able to be dried independently. An example is shown in Figure 5.22. With a reduced number of drying units, the complete BOP can be covered, giving also the possibility of changing the arrangement according to the different maintenance works being performed (e.g. opening of the turbine, etc.). The number and size of the driers should be selected based on the system section volumes, in order to ensure the adequate air renewal rate.
- Definition and preparation of air inlet/air outlet connections
- System draining at elevated temperatures
- Valve positioning
- Connection of drying equipment
- Humidity control.

Target: to start dry lay-up conditions in less than 3 days following shutdown.

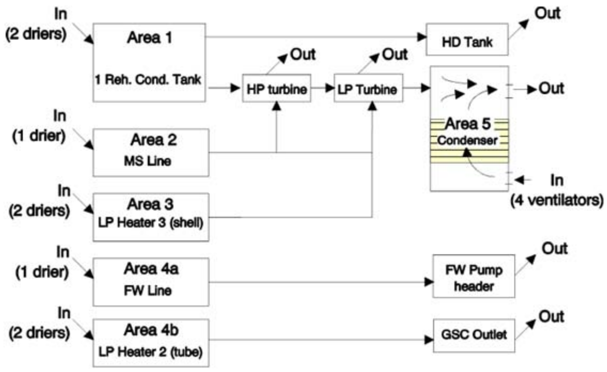


Figure 5.22. Dry lay-up arrangement for preservation of BOP systems.

Dry lay-up of SGs: For still stand periods where the SG has to be kept closed and empty, it is recommended to use nitrogen to prevent contact of the SG water with oxygen, if SG has Alloy 600 MA tubing material and carbon steel tube support plates. If nitrogen is not used for safety concerns (risk of anoxia) a dry lay-up should be maintained with the complete absence of humidity and remaining water in some parts of the components. This can mainly be achieved by proper water draining when the component is still at a temperature as high as permissible, in order to get it dry in a short time. This issue is important to avoid/prevent tube sheet denting among others.

Wet lay-up consists in filling the component and/or systems with chemically treated water. Protection is provided by a proper concentration of ammonia/amine and hydrazine to keep an alkaline and reductive environment. Wet lay-up is commonly used in:

- Condensate and feed water systems
- Steam generators
- Auxiliary boilers
- Intermediate cooling systems.

The easiest way of wet lay-up is the use of operating medium, which is alkaline and under reducing condition. For this purpose, during the plant shutdown operation, after the plant cooling-down is switched from SGs to Residual Heat Removal System (RHRS), the secondary systems that are not scheduled for maintenance activities can be isolated with the operating medium. For this type of wet lay-up it is recommended to add some hydrazine during the shutdown to achieve 10–20 mg/kg of hydrazine in the operating medium. In addition, it is mandatory to keep wet lay-up conditions free of highly corrosive elements, such as chloride or sulphur. The Japanese and then the French adopted a target value for hydrazine concentration depending on the duration of the wet lay-up. The rationale is to have the minimum value of 75 mg/kg of hydrazine at the end of the wet lay-up. Thus, hydrazine concentration must be greater than 75 + (7 × d) mg/kg where d = number of wet lay-up days.

SG wet lay-up

At temperatures below about 100°C, the steam generators should be filled with de-oxygenated (<100 µg/kg 0_2), chemically treated water to minimize corrosion. An amine should be used to keep the $pH_{25°C}$ above 9.8 and a hydrazine concentration above 75 mg/kg should be used to maintain a protective oxide film and a reducing environment. The sodium, chloride and sulphate concentrations should be below 1000 µg/kg during wet lay-up and below 100 µg/kg prior to heat-up. If desired and allowed, a positive nitrogen overpressure could be maintained during filling, draining, and cold shut down to minimize oxygen ingress. However, the use of nitrogen is not mandatory. The steam generator water should be mixed and sampled three times per week until the parameters are stable, and weekly thereafter. Corrective actions should include feed and bleed operations or draining and refilling the steam generator with deoxygenated make-up water of the proper purity [88].

During heat-up (reactor coolant system temperature above 100°C and reactor power below 5%), the dissolved oxygen in the feedwater should be as low as possible and below 100 µg/kg before exceeding 5% power. The hydrazine in the feedwater should be greater than three times the oxygen concentration and 100 µg/kg. The blowdown cation conductivity should be below 2 µS/cm and the sodium, chloride and sulphate concentrations in the blowdown samples should remain below 100 µg/kg each. In general, the heat-up period should be used to reduce impurity levels in the steam generator and prepare the secondary coolant system for power operation.

If copper alloy condenser material is used on the secondary side, the excess hydrazine should be removed prior to heat-up. Some of the hydrazine will thermally decompose to ammonia during heat-up, which at high concentrations will accelerate the copper alloy corrosion and rapidly exhaust the condensate polisher resin. Also, the thermal decomposition of the hydrazine will increase the pH therefore, it is recommended to control an upper limit of $pH_{25°C}$ 9.2 prior to heat-up for systems with copper alloy material [88]. Once more, the presence of copper in the system forces to worsen the SG reducing condition during plant transient like condenser leaks, where reducing conditions are indispensable, especially if there is no feed water tank providing oxygen free water.

5.4 MEASURES TO MINIMIZE SG DEPOSITS AND IMPURITY INVENTORY

5.4.1 Steam generator cleanliness programme

As already stated, high steam generator performance is a prerequisite for high plant availability and for possible lifetime extension. The major opponent to that is corrosion and fouling of the heating tubes. The most effective ways of counteracting all degradation problems and thus of improving the steam generator performance is to keep them in clean conditions or if necessary to plan cleaning measures such as mechanical tube sheet lancing or chemical cleaning.

The questions of the necessity of a steam generator cleaning is usually discussed and answered by original equipment manufacturers (OEM) of steam generators, who has expertise on SG performance and usually can also provide cleaning technologies as service activities. Nevertheless, it would be very useful for the utilities to have some tools, which can support their decisions whether corrective measures have to be planned. These decisions require an evaluation of the actual SG cleanliness condition. If the trend of the SG condition has been monitored over the past operating years, corrective measures can be planned more reliable and in due time, before their implementation. In order to gain a complete picture of each steam generators cleanliness condition in a plant or its evolution, all suitable plant operational and SG inspection data should be evaluated together. These data serve as 'fouling indicators', which may be categorized as follows:

1. Water Chemistry Data

- Corrosion product mass balance
- Hydrazine thermal decomposition
- Impurity ingress (sulphate, chloride and other salts resulting in Out of Specification Conditions, e.g. condenser leaks)
- Calculation of local conditions (hide-out and hide-out return).

2. Inspection Results

- Visual inspections
- Tube sheet lancing results
- Tube scale thickness measurements.

3. Steam generator heat transfer calculation

- Design data (heating surface, number of plugged tubes etc.)
- Process parameter (mass flow rates, temperature, pressure).

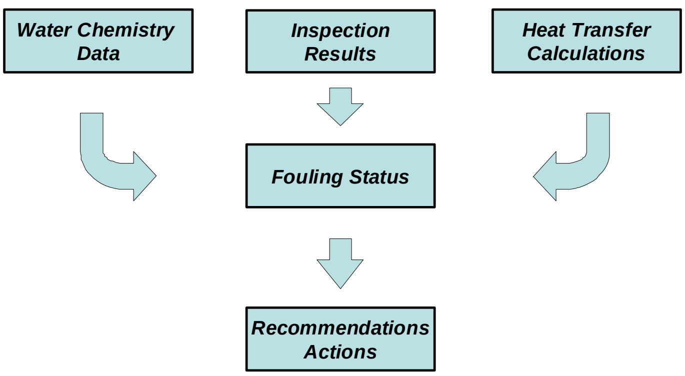


Figure 5.23. Steam generator cleanliness criteria [116].

The objectives of secondary side cleaning are to remove the sludge and the various chemical impurities and corrosion products located in and under the sludge, and to remove the chemicals concentrated in the tube/tube sheet crevices as well as in the tube/tube support plate crevices.

5.4.2 Mechanical steam generator cleaning

5.4.2.1 Tube sheet lancing

Lancing uses high pressure jets to mechanically remove sludge from the tube sheet surface to alleviate IGSCC and IGA. By periodic sludge lancing, the depth of accumulated sludge can be kept below the height necessary to cause dry-out and concentration of impurities.

Inspection and lancing equipment has been developed and tube sheet lancing is nowadays a worldwide proven and established method. It is applied by several suppliers and can be subdivided into:

- Standard tube sheet lancing (1 Step).
- Enhanced sludge lancing (multiple steps).
- Inner bundle lancing (see Figure 5.24).

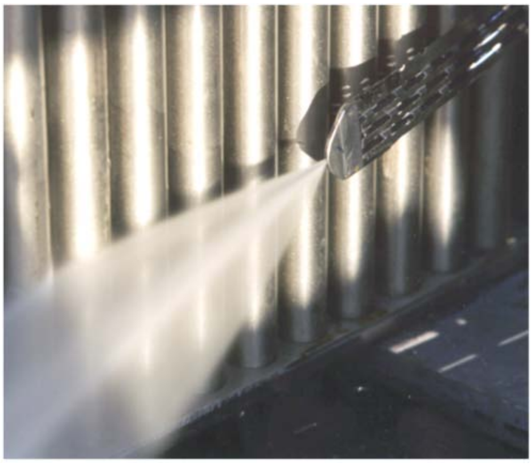


Figure 5.24. Inner tube bundle lancing tool.

Tube sheet lancing is normally associated with a visual inspection of the steam generators. It is conducted either every, or every other inspection period in France and Japan and every inspection period in Spain, Switzerland, and Belgium.

5.4.2.2 Pressure pulse and water slap

The other mechanical cleaning processes, like pressure pulse and water slap are applied by periodically injection and release of pressurized nitrogen at the bottom of the tube bundle. The nitrogen produces upward movement of the water mass in the steam generator, thereby dislodging deposits from the tube surfaces and from the tube sheet and tube support plate regions. The pressure pulse and water slap processes have been proven somewhat effective in removing corrosion products. However, in contrast to chemical cleaning, the use of these processes can remove very small amount of deposits and accordingly has only resulted in short term improvements.

5.4.2.3 *Steam generator flush*

As discussed in Section 4, impurities can concentrate in the tube sheet crevices and in the tube to tube support plate crevices, in the sludge pile, and beneath free span crud (bridging) deposits. These concentrated chemicals have caused extensive ODSCC, pitting, and other damage in certain plants. One procedure that may help control this problem is crevice flushing, which is accomplished by heating the fluid in the crevices, then depressurizing the steam generator secondary side so that boiling occurs in the crevices. The process is repeated a number of times (more than four). Steam bubbles formed within the crevices (or in porous crud) tend to expel the impurity-containing water, thereby cleaning the crevice. The crevices can be heated (especially on the hot leg side) by running the primary coolant pumps. The mechanical energy of the pumps is translated into an increase in the primary coolant temperature, which heats the crevices. Steam generator flushing has been tried at a number of temperatures, the most common of which is 150°C. Sludge lancing should be performed before crevice flushing so that impurities are not washed down into the crevices during the flushes. Flushing steam generator crevices by depressurizing the secondary side appears to remove most of the sodium, some of the sulphate, and not much of the chloride. Also, depressurization without a nitrogen overpressure is about as effective as using a nitrogen overpressure [128].

5.4.2.4 *Steam generator soaks*

Although it has been suggested that removing the impurity source from the feedwater and then running the plant at full power for a time or reducing the power periodically without shutdown might flush some of the impurities from the crevices, neither has been effective. In fact, hot soaks at temperatures of 90°C to 150°C without heat flux have been found to be the most effective simple means of promoting impurity releases (hideout return) from the crevices. Both laboratory experiments and field experience indicate that the amount of trapped impurity release by soaking is comparable to removal by depressurization, although a longer time is required for soaking. However, removal of aggressive chemicals from the tube sheet crevices is hindered by sludge on the tube sheet. Therefore, hot soaking is recommended to be carried out after sludge cleaning [128].

5.4.2.5 *Upper bundle hydraulic cleaning*

In the mid of 1990s, under contract to the EPRI, Forster-Miller Inc., together with R. Brooks Associates, Inc. (Brooks), have developed an enhanced system for SG upper bundle hycraulic cleaning (UBHC) [129]. The overall UBHC system layout is shown in Figure 5.25a. The system consists of:

- Bulk cleaning head (BCH) from Foster-Miller (see Figure 5.25b and c), which delivers HP water jets between tube columns to remove sludge from the tube and TSP surfaces.
- Vertical deployment system (VDS) from Brooks (see Figure 5.25a), on which the BCH is mounted, that positions the BCH for cleaning.
- Control and sludge processing system (see Figure 5.25a).

UBHC is designed to clean the SG with TSP having flow slots in their TSP designs, which allow access for the upward movement of the equipment, mainly for Westinghouse SGs (for example model 51). The CE or Siemens designed SGs with egg crate tube supports cannot be cleaned with this equipment because they do not have such openings in their egg crates.

The BCH and VDS are installed through the secondary side hand holes at the TS level and extended in vertical position (see Figure 5.25b) upwards through the flow slots in the TSPs. Once positioned vertically, the BCH sweeps to its horizontal operating position (see Figure 5.25c). The cleaning process begins at the top of the SG and moves downwards. HP jets remove deposits from the tubes, TSP (and broached holes also claimed by the vendors), flushing them downwards as the cleaning head moves lower in the steam generator. The cleaning is completed with a standard sludge lancing to ensure that the deposits are removed from the TS region.

The UBHC system can be rapidly installed. Approximately four hours is needed to uncrate, assemble and install the system in the SG. Complete cleaning at all TSP levels of the upper bundle can be completed within approximately two days. This time can be reduced by cleaning only selected areas based on the results of a visual inspection performed prior to cleaning. For Westinghouse model 51 SGs, the VDS provides access to all TSPs at a vertical travel rate of 5 ft/min (1.5 m/min). The BCH delivers 70 gpm (265 liter/min) of water through 10 jet pairs (20 nozzles) at 2500 to 3000 psi (180 to 215 bars). The camera on the BCH provides visual record of all operations. Once installed in the SG, system control is through a computer interface at a remote location. Personnel are required near the SG hand hole only during installation and vertical repositioning.

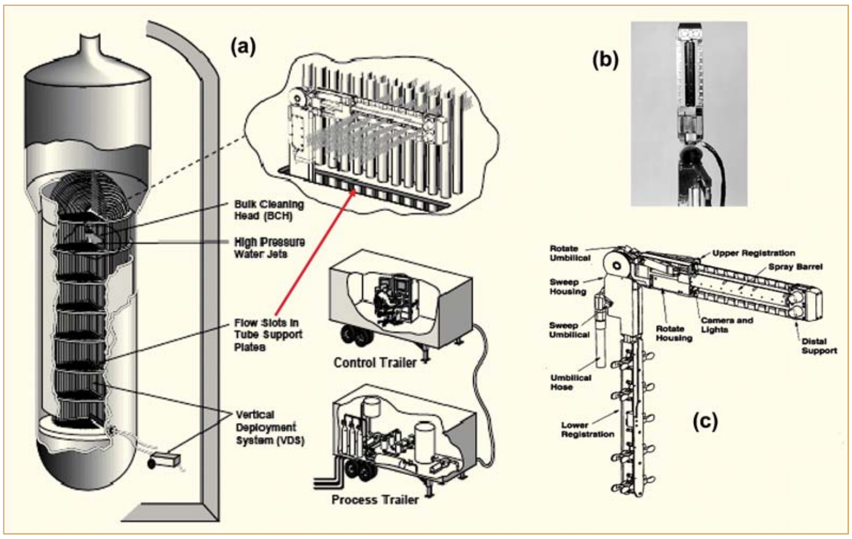


Figure 5.25. SG upper bundle hycraulic cleaning (UBHC) [129]: (a) Overall UBHC system (b) Bulk Cleaning Head (BCH) in deployment position (c) BCH in cleaning position.

5.4.3 Chemical cleaning

Presently, there exist two main application procedures with respect to temperatures for the SG chemical cleaning processes. These are applications at low and high temperatures. Both procedures may have advantages as well as disadvantages for the individual specific applications: The ‘high temperature processes’ need shorter application time as advantage due to fast reaction kinetic. However they are fully in the ‘critical path’ of the plant outage, especially when the primary side plant heat is used. This may become a disadvantage for short annual outages. On the other side, the ‘low temperature processes’ have longer application duration, which may be a disadvantage. However, they can be applied every time during the annual outage so far it fits to the outage schedule. This may in return be an advantage. The utilities are considering these aspects of the processes always for their decision to select the cleaning process.

In addition to these ‘hard or full scale chemical cleaning’ processes, which were developed in the past, several organizations started to developed also so called ‘soft or maintenance chemical cleaning’ processes in the 1990s and 2000s. Whereas the ‘hard cleanings’ are applied usually as active cleanings to remove huge amount of deposits and/or hard top of tube sheet and tube support plate crevice deposits, the purpose of 'soft cleanings' is usually to remove periodically portions of the SG deposits for preventive reasons.

According to manufacturer of the WWER SGs chemical cleaning should be performed when deposit rate exceed allowable 150 g/m^2.

5.4.3.1 EPRI SGOG Process

This process is applied worldwide by different vendors (e.g. AREVA Inc. or Westinghouse) on a licensing base. Main intention during the development of the process was the reduction of corrosion products in the crevices of drilled hole TSP to mitigate denting effects. The EPRI SGOG solvent for a full scale chemical cleaning consists of three EDTA based cleaning solvents, i.e. a magnetite solvent, a copper solvent and a crevice solvent. The process generally ends with a passivation step. Prior to the application, between the process steps and after the end of the process several rinsing step (full volume and partial volume rinsings) are required, resulting in an according amount of liquid waste.

TABLE 5.35. EPRI SGOG PROCESS PARAMETERS [130]

Process parameters	Magnetite solvent	Copper solvent	Crevice solvent	Passivation Step
EDTA	10 wt.%	5 wt.%	20 wt.%	-
Hydrazine	1 wt.%	-		0.03%
Hydrogen peroxide	-	2–3 wt.%	-	-
$pH_{25°C}$	7 (NH_4OH)	9.5 (EDA)	6 (NH_4OH)	10 (NH_4OH)
CCI-801 Inhibitor	0.5–1 vol.%	-	1 wt.%	-
Temperature	190–205°F	90–110°F	245–255°F	195–205°F
	88–96°C	32–43°C	118–124°C	91–96°C

The process duration is normally in the range of several days, depending on the actual SG situation and the actual required numbers of applications steps. Hence usually external heaters and recirculation equipment is used. To mitigate carbon steel corrosion caused by the long contact time of active chemicals with SG internals the sulphur-containing inhibitor CCI 801 is applied, thus requiring a thorough rinsing to remove detrimental inhibitor residuals. The inhibitor ensures low general carbon steel corrosion, where the surfaces are inhibitor wetted.

5.4.3.2 EDF process

EDF has developed and patented its own SG chemical cleaning process in the 1980s. This process is designed to use a single cleaning solvent to dissolve iron oxides and copper. A combination of gluconic and citric acid is used for the iron removal step. A sulphur containing inhibitor, P6 from Multiserve, is used for the control of the carbon steel corrosion. Ammonia is also used to adjust the pH of 3.3 at ambient temperature of 25°C (77°F). The process application temperature is 85°C (185°F) and during the application a nitrogen blanket is used in the SGs to exclude oxygen. It was found that 170 hours of iron solvent application is sufficient for the effectively cleaning of the entire tube bundle and of the TS. However, it was also confirmed that tube to drilled hole TSP crevices could not be cleaned at all.

This process was applied three times at EdF PWR plants in 1980s, since then it is no more applied.

5.4.3.3 High temperature chemical cleaning (AREVA)

This process is a high temperature process, using the primary side as heat source. Depending on the plant design characteristics and restrictions high temperature chemical cleaning (HTCC) can be applied during the shutdown phase of the plant, thus having a minimum impact on the critical path. Since chemical reactions rates are enhanced by higher temperatures the overall duration of the magnetite dissolution step is the lowest of all chemical cleaning processes, being in the range of some 10´s of hours per SG. Furthermore the ratio of magnetite deposits dissolution to carbon steel dissolution is shifted towards deposit dissolution at process temperature around 160°C. Therefore the addition of an inhibitor, which contains in most cases sulphur (e.g. CCI 801), is not required. Thus preventing the ingress of impurities into the SG which are detrimental with regards to localized SG tube crevice corrosion issues.

The process comprises of several injections of the applied chelating chemicals, followed by filling the SG to pre-calculated levels (e.g. above certain TSP or TSG) with demineralized water. Mixing and enhanced solvent agitation is realized by venting (i.e. controlled opening of the SG pressure relieve valves) and simultaneous inert gas injection (see Figure 5.26). By this injection strategy an optimum chemistry concentration is ensured to obtain the maximum magnetite dissolution, while keeping the carbon steel corrosion at a minimum. The process can be followed and controlled by measuring the amount of unsaturated chelating agent and by measuring the ratio of nitrogen to hydrogen in the off gas, which is a measure for carbon steel dissolution. An additional control parameter is the amount of reducing agent. If required an additional injection of the reducing agent is performed, thus ensuring reducing conditions during the whole process. After draining the SGs the process can be followed by a copper removal process and usually is followed by a tube sheet lancing to remove loose remaining particles.

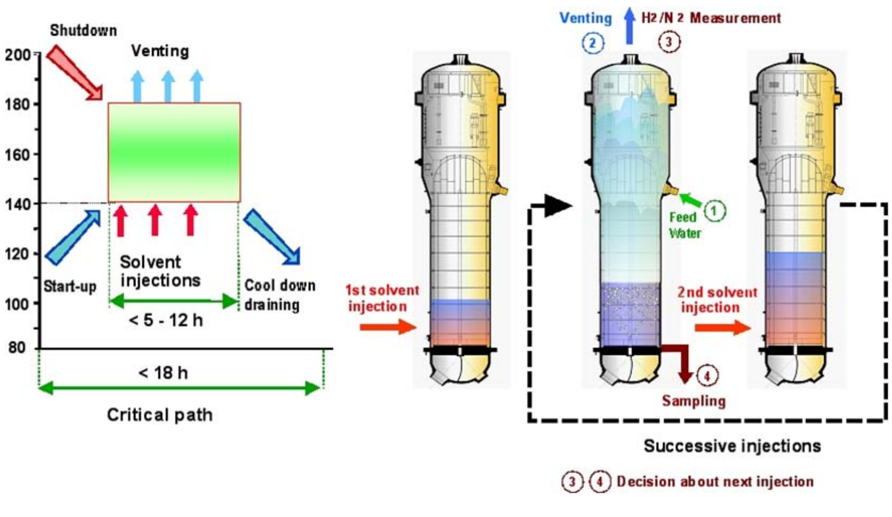


Figure 5.26. Principle of the AREVA NP high temperature chemical cleaning process.

The process, which is the most often one applied, has proven its capability of removing deposits fast and effective in more than 62 applications in more than 250 SGs worldwide from all vendors (e.g. KWU, W/C, B&W, FRA, CE, W, MHI and WWER). During the recent cleaning activities in France in 2007/08 huge amounts of deposits have been removed, ranging from 2950 kg to 3450 kg of removed deposits per SG [131]. After the cleaning operations a visual inspection has been performed on the bottom part of the SG, proving that the tubing, tube sheet, flow distribution baffle and tube support plates were satisfactorily clean and no deposits could be seen in the tube to TSP crevices [131].

Long term experience showed also that a chemical cleaning can improve the corrosion situation in SGs. Based on sodium ingress ODSCC was observed in one plant, leading to 371 plugged tubes [14]. By removal of concentrated impurities (i.e. detrimental ions) in deposits during HTCC the progress of the corrosion phenomena could be stopped. The number of tubes, which had to be plugged in the cycles following the HTCC, was reduced during the outages after the cleaning. Thus field experience showed that HTCC can improve SG corrosion situation, but also showed that, once the corrosion process has made considerable progress, cleaning processes cannot remove the impurities from the deep cracks. Hence it is recommended not to delay the cleanings once the corrosion process has started.

5.4.3.4 Deposit accumulation reduction technology (DART HT)

DART HT is a maintenance cleaning process, to dissolve a part of the magnetite inventory, usually applied to remove up to 1200 kg magnetite per SG. This process is mainly used as maintenance cleaning method for older SG´s to reduce their magnetite deposit load. The process is based on the well-known HTCC process, applied also at temperatures of around 160°C. Its effectiveness to clean the tube support structure (i.e. blocked broach holes) as well as hard sludge from the tube sheet is less than the HTCC process. The main difference between those two processes is the concentration of the chemicals, whereas the DART HT is performed at an under-stoichiometric ratio of complexing agent and expected magnetite. Corrosion of carbon steel is prevented by a stringent control of free complexing agents; hence, no process control is required.

5.4.3.5 Deposit accumulation reduction technology (DART LT)

This soft cleaning process is a low temperature version of the above-mentioned DART HT process, applied at a temperature range of 80–120°C. To control carbon steel corrosion an (AREVA proprietary) sulphur free inhibitor is to be applied. The applied inhibitor has the advantage of being sulphur free hence preventing the ingress of detrimental impurities into the plant system.

5.4.3.6 Deposit minimization treatment (DMT)

This process is designed as a maintenance cleaning method with a negligible corrosion of carbon steel to be applied on a regular basis, maintaining the steam generator in clean conditions. The design base is to remove up to 500 kg of magnetite per SG (including subsequent sludge lancing). The process can be applied with a minimum impact and requirement of plant systems, since the chemicals are injected already mixed to the appropriate concentration and preheated to the reaction temperature by supplier equipment and tools. The process is based on oxalic acid as chelating agent building a soluble ferric iron oxalate complex. Innocuousness with regards to SG base material is ensured by the self-inhibiting characteristic of the applied cleaning solution. An insoluble ferrous oxalate complex is formed directly on the surface of the carbon steel, generating a tightly adhering film. This film acts as a protective film on the carbon steel surfaces thus limiting the general corrosion of carbon steel. After draining the DMT dissolution solvent a conversion step is performed. The conversion solvent turns very low soluble ferrous oxalate in a highly soluble ferric oxalate complex, which will be removed by draining of the conversion solvent. Simultaneously a protective iron oxide layer (e.g. Fe_2O_3) is formed on carbon steel surfaces. All liquid waste components can be easily decomposed thermally or electrochemically, thus allowing a significant waste reduction. The DMT process has been applied successfully in the USA and is currently under qualification for the French NPP fleet, where the applications are scheduled to start in beginning of 2011.

5.4.3.7 Advanced scale conditioning agents (ASCA)

Westinghouse developed a second new maintenance cleaning process called 'advanced scale conditioning agent (ASCA) technology [132]. ASCA solvent promotes some dissolution of the overall deposit inventory, which enables in some extent the penetration of the chemicals into internal regions of the deposits. As of today, there are four types of ASCA treatments available to address specific deposit management requirements, [133]. They include 'full bundle maintenance cleaning', 'top of tube sheet (TTS) treatment', 'copper/lead removal ASCA', and 'thermal hydraulic recovery and maintenance ASCA'.

The solvent used for these purposes is a chelate based solution (usually EDTA with the concentration in the range of about 0.3 to 1.0%) containing amines, a reducing agent, and a surfactant. The solvent is designed for a capacity to dissolve corrosion products, which may be transported by feedwater into SGs within one to three cycles. Carbon steel corrosion limits are established in order to allow the repeated applications of the process over the life- time of the plant.

The one of the specific goals of the maintenance ASCA cleaning process is to increase the porosity of the existing tube scales as an enhancement to heat transfer. However it should be considered that the porous oxide surfaces that enhance the nucleate boiling can also accelerate the impurity concentration mechanism by HO. Therefore it is highly recommended to follow up the HO behaviour of the impurities by HOR measurements during the plant shutdowns after applying ASCA treatment.

The TTS ASCA treatment uses also chelate basis solvent and its main goal is to soften or weaken the TTS hard scale collars by dissolution so that they may be removed more easily by TSL using CECIL.

The copper ASCA treatment solvent consists of lower concentrated chelate solution, applied at a higher pH with a mild oxidant. It is designed to remove metallic copper in the magnetite deposits.

5.5 PRIMARY COOLANT CHEMISTRY CONTROL PARAMETERS

The purpose of the PWR primary coolant chemistry programme is to protect the fuel rod cladding from excessive oxidation and crud build-up, to minimize the radiation field at out-of-core areas and provide reactivity control for the reactor. PWR primary coolant system water chemistry, which meets these objectives, has no effect on steam generator degradation except on SGs having Alloy 600MA tubing material, where primary coolant chemistry can have effect on PWSCC of Alloy 600MA tubes. Nevertheless, the PWR primary coolant water chemistry control parameters are discussed in this section for completeness.

5.5.1 Primary side conditions for PWR steam generators

The primary coolant in the RCS serves as a *moderator* and is a medium for *transporting heat* from the core to the steam generators. Hence, it must not endanger plant operation by the corrosion of materials and consequences thereof. Beside of the function as a moderator, the task of water chemistry can be divided into the following main points:

- Metal release rates of the structural materials should be minimal.
- The occurrence of localized forms of corrosion should be counteracted.
- The transport and deposition of corrosion products must be influenced in such a manner, that contamination of the primary coolant system is kept low.
- The deposition of corrosion products on heat transfer surfaces, particularly on fuel assemblies, should be prevented as far as possible.
- Radiolytic formation of oxygen should be suppressed.

Historically, the starting point for all discussions about the correct pH in PWR primary coolant can be found in the work of Sweeton, et al. [134], who have reported measurements of the solubility of Fe from magnetite (Fe_3O_4). These data suggested that under the conditions of a PWR primary system the optimum pH should be pH 6.9 at 300°C. At these conditions magnetite iron solubility is at a minimum and thus the transport of iron based crud should also be a minimum. Furthermore, 2 mg/kg of lithium were sufficient to achieve a pH of 6.9 at begin of cycle, BOC (≈ 900 mg/kg B for an annual cycle). This 2 mg/kg lithium was also considered to be low enough to avoid any corrosion attack on the fuel elements.

However, later on it was recognized, that the contribution of nickel is much more important to the primary side corrosion product inventory than the iron. Further on it was found, that nickel ferrite is a major constituent. Consequently the solubility behaviour of nickel ferrite was investigated and it was found, that a pH of 7.4 at 300°C should be the solubility minimum. However, a pH of 7.4 could not be adjusted at BOC since 2 or 2.2 mg/kg lithium was at the upper specified limit in order to prevent lithium induced corrosion of the fuel element cladding.

Boron is added in the form of boric acid (H_3BO_3) as a neutron absorber for reactivity control. The boric acid concentration is changed throughout a reactor cycle to compensate for other changes in reactivity and is not varied independently. The boron levels are relatively high (1000 to 2000 mg/kg using natural boric acid) at the beginning of the fuel cycle. Then, they are gradually reduced by ~100 mg/kg per month. The concentration of lithium hydroxide (LiOH) is co-ordinated with the boric acid concentration to achieve the desired pH.

At field different B/Li chemistry treatments were and are still applied:

- Coordinated lithium/boron chemistry
- Modified lithium/boron chemistry
- Elevated lithium/boron chemistry
- Constant elevated lithium/boron chemistry.

Initially most of the PWRs were operated with coordinated B/Li chemistry treatment, i.e. the pH_{300} was kept constant at 6.9 during the cycle. The second mode is the modified lithium/boron chemistry, where at the begin of cycle in annual cycles a concentration of 2–2.2 mg/kg Li is used and kept constant till reaching a desired pH_{300} of e.g. 7.4 and then the pH_{300} 7.4 line is followed by the appropriate Li/B-coordination. The third alternative is to operate with an elevated lithium/boron chemistry where a level of 3.5 mg/kg Li is used at begin of cycle till reaching a pH_{300} of e.g. 7.4. At this pH the Li/B coordination is adjusted to stay at pH_{300} = 7.4 till the end of the cycle. The fourth alternative is the constant elevated lithium/boron chemistry where at the beginning of cycle a high Li-level of e.g. 5 mg/kg is adjusted and during the cycle a Li/B-coordination keeps the pH constant throughout the cycle. Nevertheless in all cases the fuel vendor stipulates the maximum lithium concentration.

The application of enriched boric acid (B-10 fraction of ~30%) was introduced due to changes in the core design (so called ‘high duty cores’) to achieve the criteria for reactivity control. The use of B-10 has the advantages that the target pH_{300} = 7.2 to pH_{300} = 7.4 is achieved earlier than using natural boric acid.

The key component concerning primary coolant water chemistry is therefore given by restrictions due to the fuel elements and dose rate reduction issues, and not the steam generators, except for Alloy 600MA SG tubes. The restrictions imposed due to the above mentioned issues are then automatically given for the SGs and sufficiently restrictive. The only steam generator problem arising from the primary side has been PWSCC, which can mainly be completely solved by material replacement (i.e. replace of Alloy 600MA).

Cracking on the primary side has occurred in areas where tensile stresses existed at the inner side of the tube. Such locations have been eliminated in the design of replacement steam generators. In addition, Alloy 690TT and Alloy 800NG seem to be immune against PWSCC. Regarding the corrosion resistance of the materials used up to now in steam generators it seems based on results of EPRI [135], that Alloy 690TT might have a better corrosion resistance than Alloy 800NG for some (but not all) secondary side extreme environmental cases. The slightly better corrosion resistance of Alloy 690TT is compensated by the longer operation experience of Alloy 800NG. Primary water stress corrosion cracking of Alloy 600MA and Alloy 182/82 weld metal seem to be the biggest challenge currently faced by the PWR Industry. These materials are widely used in the RCS of PWRs (see Figure 5.27, Figure 5.28, Figure 5.29) and the incidences of cracking have increased sharply in recent years. The well-known incidences for such cracks are V.C. Summer, Oconee 1 and Davis-Besse [136].

In order to get a better control about such incidents, EPRI is managing a Materials Reliability Program (MRP) [137]. This programme addresses the following aspects:

- **Accessibility.** Many of the susceptible locations are very difficult to access.
- **Consequences.** Safety and operability assessments are not available for many of the susceptible components.
- **Inspection.** Procedures and capabilities need to be defined for many of the susceptible components.
- **Assessment.** Crack growth data for these materials show a lot of scatter, the origins of which are not well understood.
- **Mitigation.** Stress reduction methods are available but need to be adapted for the susceptible components. No fully qualified chemistry mitigation method is available.
- **Repair/replacement.** Resistant materials are known and some components can be replaced, but repair options need to be defined and qualified for many of the susceptible components.

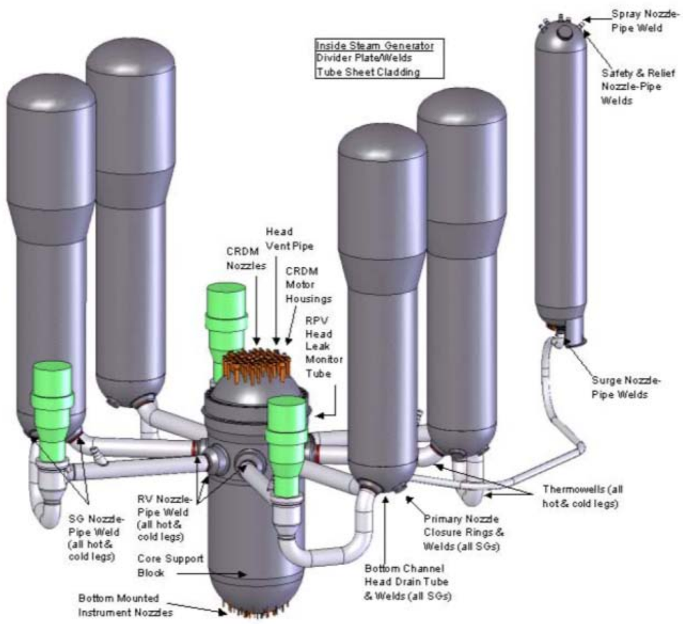


Figure 5.27. Typical Alloy 600 locations in Westinghouse plants [137].

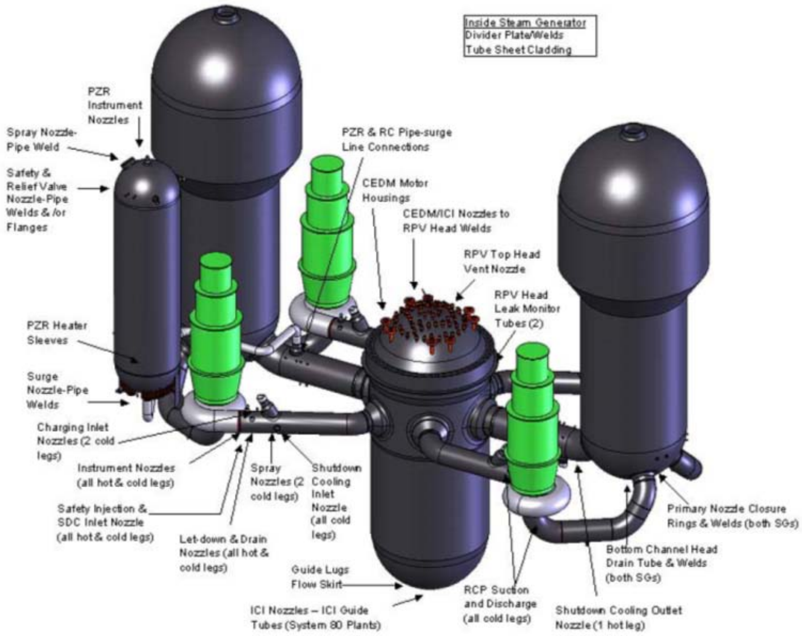


Figure 5.28. Typical Alloy 600 locations in Combustion Engineering plants [137].

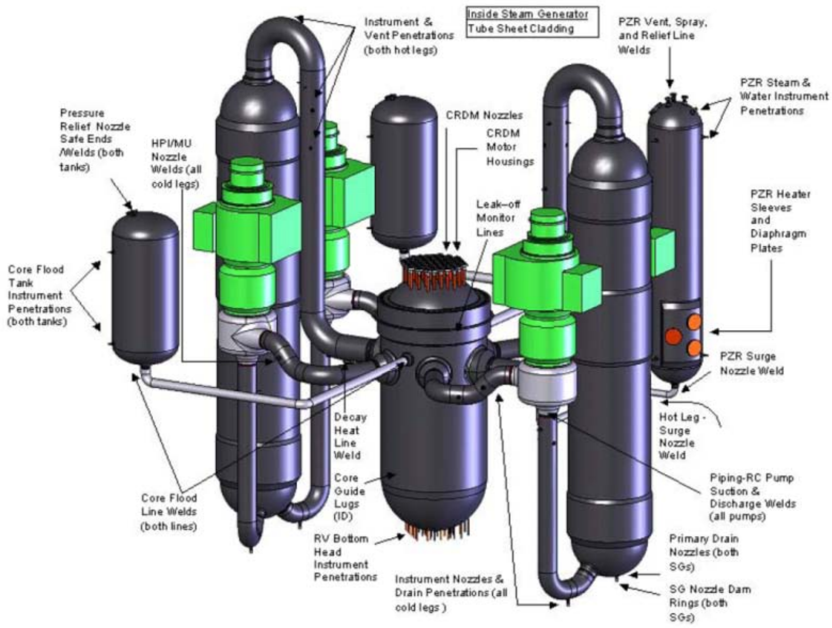


Figure 5.29. Typical Alloy 600 locations in Babcock&Wilcox plants [137].

In view of such issues, an effective water chemistry mitigation option would be highly appreciated. Zinc addition appears to be the most promising possibility for the time being. At higher concentrations (typically 15 to 40 µg/kg) Zn has palliative effect against PWSSC, by providing more stable protective layers thus reducing the influence of tensile stresses in the corrosion process. Nevertheless, up to now it is the only chemistry related measure available to counteract PWSCC. Based on laboratory and field experience with SG Alloy 600MA tubes, it is confirmed that, zinc definitely mitigates the RWSCC initiation. However, its influence on PWSCC crack growth rate is somewhat not conclusive: Even though, mitigating effect of zinc on PWSCC crack growth rate of Alloy 600MA SG tubing material was observed at field (e.g. Diablo Canyon unit 1&2), its clear beneficial effect for reactor pressure vessel (RPV) Head penetrations could not be confirmed. Even though, mitigating effect of zinc on

PWSCC crack growth rate of Alloy 600MA SG tubing material was observed at field (e.g. Diablo Canyon unit 1&2), it is clear beneficial effect for reactor pressure vessel (RPV) Head penetrations could not be confirmed. Recently, based on the results of materials reliability programme (MRP), EPRI concluded that zinc addition, due to inconsistent and limited effect of zinc on thick walled Alloy 600MA and Alloy 182 weld metal, is not a reliable way to mitigate stress corrosion crack growth in thick walled nickel alloys [138].

Recently, based on international laboratory tests, it was found that coolant Dissolved Hydrogen (DH) concentration influences significantly the PWSCC of Alloy 600MA. Based on investigations sponsored by EPRI, PWSCC crack growth rate is at maximum in the range of 20–30 cc/kg DH concentration. At DH concentrations either less than 15 cc/kg or above 40 cc/kg, the PWSCC crack growth rate decreases. In addition to these experiences, Studvik test results confirmed that the PWSCC initiation is insignificant at DH concentrations below 15 mg/kg, however, it increases with increasing DH concentrations. Therefore, the intended strategy regarding the DH concentration to mitigate PWSCC of Alloy 600MA, Alloy 182/82 welds is contradictory: Whereas, EPRI recommends to increase the DH concentration to about 60 cc/kg [138] based on the assumption that PWSCC cracks already exist, Japanese PWR industry intends to decrease the DH concentration below 25 cc/kg (lower specification value) to avoid the PWSCC initiation. All these strategies are still under discussion and a clear common strategy is not established yet.

Although zinc was injected in the beginning to suppress the PWSCC risk, it was found, that low concentrations of approximately 5 µg/kg in the primary coolant reduces the dose rate build up. Zn injection results in incorporation of zinc into oxide layers (see Figure 5.30). Thus zinc can delay the incorporation of activated products (e.g. radio-cobalts) in the system surfaces, and even displace already embedded nuclides out of the oxide layer, which is corroborated by an increase of radionuclide concentration in the coolant associated with start of Zn injection. Many units nowadays use zinc as a dose rate reduction measure.

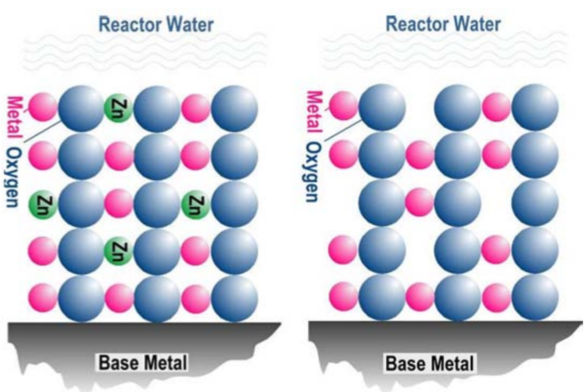


Figure 5.30. Incorporation of zinc in oxides layer.

5.5.2 PHWR steam generators

The pH in the PHWR primary system is controlled by addition of lithium hydroxide or by using lithiated mixed bed ion columns. Boron and boric acid are not used in the PHWR primary system with exception of shutdown of the first fresh core (approx. 20 mg/kg B) and during cold shut down periods. The moderation is ensured by the use of D_2O. The applied Li concentration during the whole cycle is similar to that of PWRs end of cycle, i.e. approximately 0.7 mg/kg. PHWR have normally lower steam generator temperatures than those of PWRs. Therefore the observed corrosion effects are less than those in PWRs.

5.5.3 WWER steam generators

Fundamental principles of WWER primary water chemistry were developed in 1960s by the Kurchatov Institute of Atomic Energy. High temperature corrosion tests under irradiation were carried out in loop of experimental nuclear reactor. Ammonia injection was initially used as hydrogen source to avoid potential risk of hydrogen explosion. Since 1980, Kola and some other WWER plants have been using hydrazine injection instead of ammonia to create more favourable reductive conditions in primary coolant.

Potassium hydroxide was initially selected for primary coolant alkalization due to lower corrosion activity and lower solubility of its salts as compared to lithium compounds. In late 1960s the ammonia-potassium coordinated primary water chemistry was first implemented in WWER-365 unit at Novovoronezh NPP. From the very beginning the coordinated primary chemistry was based on optimum low alkaline pH_T value during fuel cycle.

WWER primary water chemistry specifications were periodically revised to address plant operational experience, fuel cycle and operational mode improvements. New data on coolant component behaviour at elevated temperatures are also taken into account. In 2001, the current WWER primary water chemistry standard was put in place at Russian WWER-1000 plants. In 2005 and 2007, the current primary water chemistry standards were also put in place at Russian WWER-440 plants. In 2007, the current primary water chemistry standards were put in place at Ukrainian WWER-440 and WWER-1000 plants (see Table 5.36). The present applied boron-alkaline mode is shown in Figure 5.31.

TABLE 5.36. PRIMARY WATER CHEMISTRY AT FIRST WWER PLANTS [139]

NPP, Unit	pH (25°C)	Coolant treatment	Dissolved hydrogen [N ml/kg]	Dissolved oxygen [mg/kg]
Novovoronezh Unit 1	6–7	N_2H_4 0.2–0.3 mg/kg in make-up water	0.5–1	0.02
Reinsberg	~ 10	$NH_3 \leq 35$ mg/kg	< 60	< 0.01
Novovoronezh Unit 2	9.5–10.5	KOH 2–20 mg/kg	20–40	< 0.01

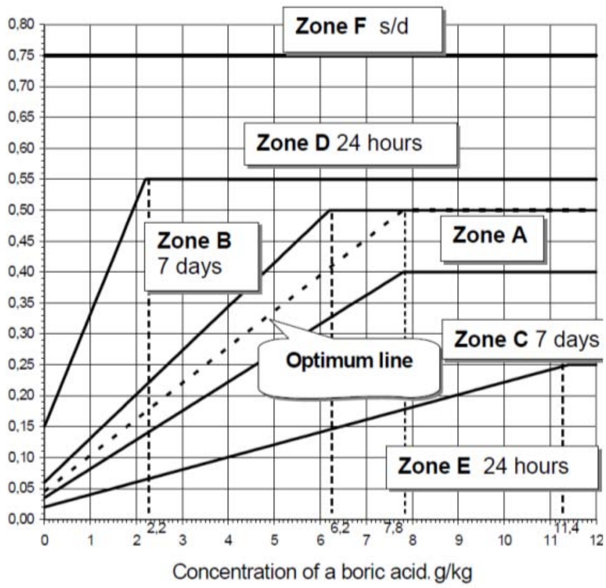


Figure 5.31. Present WWER-1000 boron-alkaline mode [139].

5.6 MEASURES TO CONTROL/IMPROVE SECONDARY-SIDE CHEMISTRY

5.6.1 Control of impurity ingress into the steam generators

Various ionic impurities may promote corrosive processes such as IGSCC/IGA, pitting, and denting, in steam generator tubing if concentrated up to aggressive levels in corrosion product accumulation areas (Section 4.1.8). This may be accelerated if sufficient reducing conditions cannot be maintained. The elimination of copper alloy parts in the secondary coolant system turns into a key issue to improve the steam generator safety against corrosion damage.

Impurities can be minimized by careful control of the plant chemistry during operation as well as shutdown conditions and startup transients.

Power operation:

- Preventing in-leakage of raw water from condenser tubes.
- Reducing the volume of make-up water.
- Quality control of chemical additives.
- Use of mechanical filtration of the condensate and feedwater if available.

Constant monitoring of the water chemistry and immediate corrective actions are important in maintaining the quality of the SG secondary water. Plant modifications that ensure the quality of the secondary water contribute to mitigating all the corrosion related degradation mechanisms on the secondary side.

5.6.2 Measures to control steam generator deposits

Deposits on the tube sheet (sludge), tube supports and on the tube surfaces create flow occluded areas, where impurities may concentrate. Concentration factors of greater than 10^5 over bulk water have been found in laboratory tests [140]. The source of secondary side deposits is corrosion of the secondary side components. Factors, which influence this corrosion are elevated oxygen levels due to air in-leakage or poor deaerator performance, pH, poor quality make-up water and, lay-up conditions. Another major source of deposits comes from condenser in-leakage (discussed in Section 5.3). A major effort should be in place during unit operation to try to prevent the generation, transport and subsequent accumulation of deposits in the steam generators. Corrective measures include sludge lancing and chemical cleaning.

Certain amount of oxygen in the condensate and feedwater systems is desired to control the feedwater corrosion product transport into SGs. This is because the small oxygen concentration counteracts the Flow accelerated corrosion (FAC) of the carbon steels and thus reduces the feedwater corrosion product transport rates. Oxygen concentration at final feedwater downstream HP feedwater heaters should be below detection limits in order to ensure absolute reducing conditions in the SGs to avoid SG tubing corrosion. However, presence of oxygen in condensate cannot be tolerated in PWR plants with copper bearing materials in condensers. The presence of oxygen would result in copper corrosion and increased feedwater copper transport into SGs and endangered SG tube corrosion performance.

The principal method of controlling corrosion product transport in the secondary systems of PWRs and the sludge build-up in their steam generators is through pH control. EPRI recommends a room temperature feedwater $pH_{25°C}$ between 8.8 and 9.2 for plants with copper alloys and above 9.3 for all ferrous plants [88]. VGB recommends to apply feedwater $pH_{25°C}$ of > 9.8 for copper free PWR plant to control feedwater corrosion product transfer into SGs. In addition, the plant make-up and auxiliary feedwater should be deaerated and a chemistry control programme should assure that the condensate/feedwater is clean, as discussed above.

5.6.3 Steam generator blowdown

The blowdown system should be able to accommodate a continuous blowdown rate of 1% of the main steaming rate and a periodic, transient rate of 3–7% of the main steaming rate. The blowdown water should be processed through filters and demineralizers and recycled to the condensate system to reduce the probability of oxygen transport into the system.

Normally continuous blowdown in WWER SGs used for dissolved impurities removal. Its location chosen in point of highest impurities concentration and this point is located in zone of lower heat flux. To arrange this, feedwater is distributed in a special manner along SG length thus stepwise evaporation principle is implemented. In operating WWER units continuous blowdown rate normally is 0.5% of main steam. For new build units continuous blowdown may be increased up to 1% in case of water chemistry problems or during hide-out return. Periodical blowdown used for short time to remove corrosion products from the bottom of the vessel with maximum flow rate.

6 STEAM GENERATOR INSPECTION, MONITORING REQUIREMENTS AND TECHNOLOGIES

Steam generators are routinely inspected during plant outages. This section identifies inspection and monitoring requirements and techniques for steam generators, with emphasis on examining the tubing, feedwater nozzle and shell welds.

6.1 TUBING NONDESTRUCTIVE INSPECTION REQUIREMENTS

The probability and consequences of steam generator tube failures can be reduced through appropriate and timely inspections. The steam generator tube inspection requirements in the USA are discussed first because a number of countries with PWR and CANDU units have used those requirements as a starting point for their own requirements. Tubing inspection practices in Canada, China, the Czech Republic, France, Germany, Japan, the Republic of Korea, Russia, Slovakia, Slovenia, Spain, Sweden, and Switzerland are summarized in Table 6.1 and also discussed in this section. Tubing inspection practices recommended by EPRI are also discussed.

Tubing inspection requirements differ somewhat in these and other countries because:

- Different steam generator designs, materials and site specific conditions are susceptible to different types of ageing degradation. Some types of degradation are easier to detect or give rise to less severe safety consequences than other types of degradation. As well as different tube wall thickness leads to different safety consequences and probability of leak or rupture.
- An appropriate level or steam generator and plant safety can only be maintained by a suitable combination of inspection and acceptance (fitness for service) requirements. Some countries have chosen to apply somewhat more conservative fitness for service criteria and less inspection. Other countries have chosen less conservative fitness for service criteria (thereby saving money on repairs) and more inspection.
- The frequency and scope of the inspections often increase as problems develop.

Complementary information concerning the fitness for service guidelines in various countries and methods for assessing the residual life of the tubing is presented in Section 7.

TABLE 6.1. STEAM GENERATOR TUBING INSPECTION GUIDELINES

Country	Baseline inspection	Number of tubes to be inspected	Inspection intervals
*USA	All tubes prior to service and after any major change in secondary water chemistry	First inspection, 3% of the total steam generator tubes at a unit. Subsequent inspections: see Table 6.2. Suggestion: All American plants follow the EPRI Guidelines for Examination of SG tubes maybe the document could be mentioned as a reference and used for definition of number of tubes.	First inspection, 6–24 months. Subsequent inspections, 12–24 months. If less than 5% of inspected tubes with indications and no defective tubes, 40 months. If more than 10% degraded and more than 1% defective, <20 months.
Canada	25% of the tubes prior to service	At least 10% of the tubes in one steam generator per unit.	First baseline inspection interval 4–6 years. Second inspection interval since first net power at 10–12 years, third inspection interval 16–18, fourth inspection interval 22–24 years, fifth inspection interval at 28–30 years.
Czech Republic	All tubes prior to service	100% of the tubes in each steam generator must be inspected full length. There are inspected all the tubes from the hot and cold collectors.	ISI intervals are gradually extended from 4 to 6 years/fuel cycles.
France	All tubes prior to service All tubes every ten years (1st after 30 months)	If susceptible tubing, all of the tubes are inspected in the hot leg roll transition, tube support plate and sludge pile regions, and the U bend region of the first row in service, with an appropriate probe. If less susceptible tubing: Sample of tubes inspected full length. All tubes in service with a previous defect indication.	Every outage for roll transition and small radius U bend regions. Every other outage for TSP and sludge pile regions. Sample every two years. Each outage.
Germany	All tubes prior to service	10% of the tubes per steam generator per inspection	Every five years all steam generators Every two years, one half of the steam generators
Japan	All tubes prior to service. Insertion depth of antivibration bars.	If no leakage and no defects: 30% If any leakage or defects: 100%	If no leakage and no defects, every other year. If leakage or defects, every year.
Republic of Korea	All tubes prior to service 20% of total number of tubes each SG	If a potential degradation area (expansion region, U bend, denting or inside the tube sheet) is not verified by the bobbin probe, an additional inspection by RPC is required. The periodical inspection depends on materials (Alloy 600MA/TT, Alloy 690TT), operating years, and degradation status.	Each refuelling outage
Slovakia	All tubes prior to service	100% of the tubes in each steam generator must be inspected full length. There are inspected all the tubes from the both hot and cold collectors.	ISI intervals are gradually extended from 4 to 6 years/fuel cycles.
Slovenia	All tubes prior to service	100% using bobbin coil and all reported indications, roll transitions and inner bends with pancake coil. (Probably, after SG replacement in 2000 the scope of inspection is changed).	Each refuelling outage
Spain	All tubes prior to service	If susceptible tubing: 100% using bobbin coil and all indications and roll transition regions with rotating pancake coil. If less susceptible tubing: 9 to 20%	Each refuelling outage
Sweden	All tubes prior to service	Random sample of 15–17% full length 100% hot leg tube sheet. 20–100% of other selected regions.	Each year
Switzerland	All tubes after one year of operation	If susceptible tubing: inspect the hot leg side up through the U bend region to the top tube support plate on the cold side-full inspection. If less susceptible tubing: random sample of 5.5% of all tubes.	Every outage Every three years

*): If more than 10% of inspected tubes show indications, additional 3% in that steam generator and 3% in remaining steam generators. If more 10% of second batch show indications, inspect additional 6% in area of indications.

6.1.1 Tubing inspection requirements in the USA

The requirements for the steam generator tubing inspections at US plants are included in the plant technical specifications, which are prepared by the plant operator and approved by the USNRC. Originally, those requirements generally followed the guidelines presented in the USNRC's Regulatory Guide 1.83 [141]. These guidelines are organized as follows: Access, equipment and procedures, baseline inspection, sample selection, supplementary sampling, inspection intervals, acceptance limits, and corrective measures. In summary, the steam generator should be designed with sufficient access to facilitate inspection and plugging, eddy current or equivalent equipment that is 'sensitive enough to detect imperfections 20% or more through the tube wall' should be used (unfortunately, reliable detection of certain defect types at such a shallow depth is not within the state of the art), and a baseline inspection of all tubes should be performed prior to service and after any major secondary side water chemistry change.

Regulatory Guide 1.83 recommends that at least 3% of the tubes in each steam generator be tested over their entire length during the first inspection, which should be performed after six effective full power months but before 24 calendar months. Subsequent inspections should not be less than 12 or more than 24 calendar months apart and may be limited to one steam generator encompassing 3% of the total tubes at the plant. All non-plugged tubes with previous indications (>20%) should be inspected. If any new indications are found (>20%) or if previous indications exhibit growth (>10%) the remaining steam generators should be inspected.

If more than 10% of the inspected tubes show indications (>20%) or one or more tubes must be plugged (>40%), an additional 3% of the tubes must be inspected. If the additional inspection indicates that more than 10% of the additionally inspected tubes have indications or one or more of those tubes must be plugged, 6% more tubes should be inspected in each steam generator. If two consecutive inspections result in less than 10% of the inspected tubes with indications (>20%) and no further penetration of previous indications (<10%), the inspection frequency should be extended to 40-month intervals. Unscheduled inspections should be conducted in the event of primary to secondary coolant system leaks exceeding the technical specifications or various design basis accidents (seismic, loss of coolant, main steam or feedwater line breaks).

Regulatory Guide 1.83 was used as the basis for the steam generator inspection requirements in the technical specifications for only a few years. By the early 1980s, the US utilities (e.g. Southern California Edison Co. 1982, Northern States Power Co. 1985, Georgia Power Co. 1987, Commonwealth Edison Co. 1987) were following the steam generator tube sample selection guidance in Table 6.2 [142]. The tubes selected for each in-service inspection include at least 3% of the total number of tubes in all the steam generators at a unit and are selected randomly except:

- Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas.
- The first sample of tubes selected for each in-service inspection of each steam generator generally includes all the tubes in service with previous indications greater than 20% of the wall thickness, tubes in areas where experience has indicated potential problems, and tubes adjacent to badly degraded tubes.

The results of each sample inspection are classified into one of the following three categories:

Category	Inspection Results:
C-l	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

TABLE 6.2. STEAM GENERATOR TUBE INSPECTION REQUIREMENTS IN THE USA

1st SAMPLE INSPECTION			2nd SAMPLE INSPECTION		3rd SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per steam generator	**C-1**	None	N/A	N/A	N/A	N/A
	C-2	Plug or sleeve defective tubes and inspect additional 2S tubes in this steam generator (SG).	**C-1**	None	N/A	N/A
			C-2	Plug or sleeve defective tubes and inspect additional 4S tubes in this SG.	**C-1**	None
					C-2	Plug or sleeve defective tubes
					C-3	Perform action for **C-3** result of first sample.
			C-3	Perform action for C-3 result of first sample.	N/A	N/A
	C-3	Inspect all tubes in this SG, plug or sleeve defective tubes and inspect 2S tubes in each other SG. Notification to NRC pursuant to 1.50.72(bX2) of 10 CFR Part 50.	All other SGs are **C-1**	None	N/A	N/A
			Some SGs **C-2** but no additional SGs are **C-3**	Perform action for C-2 result of second sample.	N/A	N/A
			Additional SG is **C-3**	Inspect all tubes in each SG and plug or sleeve defective tubes. Notification to NRC pursuant to 1] 50.72 (b) (2) of 10 CFR Part 50.	N/A	N/A

S = 3N/n% where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

Degraded tubes are tubes with indications greater than or equal to 20% of the nominal wall thickness, but less than a defective tube, and which exhibit a defect with a greater than 10% additional wall thickness penetration since the last inspection. Defective tubes are tubes with indications greater than the removal from service (plugging) or repair limit, which is often but not always 40% of the nominal wall thickness.

The first sample inspection defined in Table 6.2 requires a full end-to-end survey of each of the tubes. The tubes selected as the second and third samples (if required) during each in-service inspection may be subjected to a partial tube inspection provided:

- The tubes selected for these samples include the tubes from those areas of the tube sheet array where the tubes with imperfections were previously found.
- The inspections include those portions of the tubes where imperfections were previously found.

The in-service inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections, not including the pre-service inspection, result in all inspection results falling into the C-l category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months. If the results of the in-service inspection of a steam generator conducted in accordance with Table 6.2 at 40-month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. Additional, unscheduled in-service inspections shall be performed after the following conditions: primary to secondary tube leaks (not including leaks originating from tube to tube sheet welds) in excess of the limits of the technical specifications, or a seismic occurrence greater than the operating basis earthquake, or a condition IV loss of coolant accident requiring actuation of the engineered safety features, or a condition IV main steam line or feedwater line break.

Two steam generators are inspected during the first outage at units with four steam generators (4-loop Westinghouse type plants) and then one steam generator is inspected during the second and subsequent outages, unless additional inspections are required because of extensive degradation as indicated in Table 6.2. Only one steam generator is inspected during the first and subsequent outages at 2- and 3-loop Westinghouse type plants and at Combustion Engineering plants unless additional inspections are required because of extensive degradation as indicated in Table 6.2

If alternative fitness for service guidelines for ODSCC at tube support plates are used, more comprehensive inspections must be required by the plant technical specifications [143] These include bobbin coil probe inspections of all the hot leg tube support plate intersections, all the cold leg intersections down to the lowest cold leg tube support plate with known ODSCC, and 20% of the tubes full length. In addition, rotating pancake coil inspections are required for all bobbin coil indications greater than 1.0 volt (19 mm diameter tubes) or 2.0 volts (22 mm diameter tubes).

Also, rotating pancake coil inspections are required at all tube to tube support plate intersections with:

- Interfering signals from copper deposits.
- Dent signals greater than 5 volts.
- Large mixed residuals.

6.1.2 Tubing inspection requirements in Canada

The most recent Canadian Standard, CAN/CSA N285.4-05, requires a baseline inspection of 25% of the tubes in each steam generator after the steam generator is first installed, but prior to service. For periodic inspection, there are requirements as follows:

1. Periodic inspection sample size

The plant operator shall:

- Select tubes for inspection from a minimum of 25% of the steam generators in a specific unit.
- Perform at least one periodic inspection of all steam generators by the end of the fourth interval.
- Inspect a minimum of 10% of the tubes in the steam generator(s) selected for periodic inspection during that interval.
- For the random sample, inspect a minimum of 5% of the tubes in each steam generator of the periodic sample.
- For the specific sample, inspect a minimum sample of 25 tubes for each specific mechanism that is both postulated and plausible from the degradation assessment.

2. Inspection intervals

The plant operator shall perform periodic inspections in accordance with the time intervals defined:

Inspection interval*	Year since first net power date
Baseline	Pre-service
1	4–6
2	10–12
3	16–18
4	22–24
5	28–30
Note: * Interval 1 runs from the first day after 3 years of operation to the last day of the sixth year of operation, providing a 3-year window to perform the required inspections.	

The Canadian Standard requires that alternative NDE techniques be used to detect defects not readily detected by the standard bobbin coil eddy current inspection technique. Acceptable alternative NDE techniques include the use of specialized eddy current probes such as the transmit-receive Cecco probes and motorized rotating pancake coil probes. In addition, Ultrasonic, visual and profilometry inspection techniques should be used where appropriate. The choice of an alternate inspection method depends on the type of degradation encountered and its location.

The inspection discussed above describes the minimum requirements for Canadian reactors. In practice, the plant operators exceed these requirements and prepare specific programmes of inspection and assessment suited to the individual sites.

6.1.3 Tubing inspection requirements in China

The requirements for the steam generator tubing inspections at Chinese plants are included in the plant technical specifications, which are prepared by the plant operator and approved by NNSA (National Nuclear Safety Administration). Since different standards for design of steam generators are used, different standards for tubing inspection are adopted, and the frequency and scope of tubing inspections in some plants are different from those of other plants.

Plant technical specifications requires that alternative NDE techniques be used to detect defects not only detected by the standard bobbin coil eddy current inspection technique. Acceptable alternative NDE techniques include the use of specialized eddy current probes such as motorized rotating pancake coil probes.

6.1.4 Tubing inspection requirements in the Czech Republic

The Czech regulatory agency requires a baseline inspection before operation. Non-destructive examination of steam generators is carried out using ECT method with probes of bobbin type. ECT is performed in full scope (100% of SG tubing) utilizing sophisticated remote controlled equipment. The prescribed ECT practice is based on ASME procedure (probes, ISI intervals, testing method, signal analysis). Because of a very low amount of flaws in SG tubing, there are no requirements for using other types of probes (rotation probe and ×-probe) so far. Special rotating probe is used for ECT of tubing fixed in the collector region. Plugging criteria are depending on the depth of a defect/flaw, amplitude of a signal, and operational practice/experience. ISI intervals are gradually extended from 4 to 6 years/fuel cycles.

6.1.5 Tubing inspection requirements in France

The French regulatory agency requires a baseline inspection of all tubing full length before operation, periodic inspections at least every two years, and complete inspections (presumably 100% of the tubes full length) every ten years. The EDF guidelines for steam generators with susceptible tubing (Alloy 600MA) require a 100% inspection of the hot leg roll transition region and the U bends of the first row in service every outage and 100% inspections of the hot leg tube support plate and sludge pile regions every other outage, with follow-up inspections of indications during the next outage. The roll transition and small radius U bend inspections must be done with rotating pancake coil eddy current equipment. The tube support plate and sludge pile inspections can be done with bobbin coil eddy current equipment.

6.1.6 Tubing inspection requirements in Germany

The minimum scope and frequency of tubing inspections in the Federal Republic of Germany are specified in KTA 3201.4. Ten per cent of all tubes in the regions wetted by the secondary medium up to the first rolled-in joint in each steam generator must be fully inspected every five years. However, within 2 years one half of the steam generators shall be covered by inspections. During each in-service inspection those tube regions shall be examined, which are known from design and operational experience to be more susceptible to corrosive attacks. In spite of this, actual inspections have been more frequent and more extensive. Some Siemens/KWU (now AREVA NP GmbH) steam generators have been inspected every operating period over much of their life.

6.1.7 Tubing inspection requirements in Japan

The Japanese authority requires that 30% of tubes be inspected every other year when a steam generator has had no leakage and no tube degradation. If any primary to secondary SG leakage or any tube defects are detected, 100% of the tubes have to be inspected each year over their full length. Before each inspection, the steam generator tubes are subjected to a 13.8 MPa (2000 psi) differential pressure test to open tight cracks and make them more detectable. Bobbin coil eddy current equipment is used above the tube sheet region. Eight by one eddy current probes are used in the hot leg tube sheet region in most steam generators in order to detect circumferential degradation. Rotating pancake coil eddy current equipment is used in the tube sheet region of one Japanese plant in order to detect pitting.

6.1.8 Tubing inspection requirements in the Republic of Korea

Requirement and practices in the Republic of Korea: Inspection guidelines are described in Bulletin number 2009-23 of the Ministry of Education, Science and Technology in the Republic of Korea, the Official Regulations for an In Service Inspection of nuclear facilities. The regulations contain inspection tools, procedures, technical specification, sampling criteria, inspection interval, etc. A reference regulation of this is the USNRC R. G. 1.83 (In-service Inspection of pressurized water reactor Steam Generator Tubes).

Korean steam generator management programme (SGMP) has been implemented for the integrity of the steam generator since year 2005. The SGMP in the Republic of Korea was developed based on the following reference documents: NEI 97-06 rev.2, EPRI SG Integrity Assessment Guidelines revision 2, SG Examination Guidelines revision 7, SG In-Situ Pressure Test Guidelines revision 3.

20% of total number of tubes each SG is inspected on full length each cycle by using Bobbin Coil probe as a base line. If a ‘Potential Degradation’ area (expansion region, U bend, Dent/Ding or inside the tube sheet) is not verified by the Bobbin Coil probe, an additional inspection by RPC is required. The periodical inspection depends on materials (Alloy 600MA/TT, Alloy 690TT), operating years, and degradation status.

Defects with over 40% of a tube wall penetration should be repaired. Independent of the regulation, all crack like defects are recommended to be plugged except for two units.

6.1.9 Tubing inspection requirements in Russia

Russian steam generator tube inspections are performed when leakage of the primary coolant into the secondary coolant system is detected. All the tubes are inspected using ‘visual and hydro-luminescent’ methods. The secondary side is drained and pressurized with gas and video cameras are placed inside the collectors to look for bubbles. Or a fluorescent substance is added to the secondary water, which is pressurized, the primary side is drained, and the tube ends are inspected. Primary to secondary leak rates are monitored using a ^{24}Na injection into primary coolant and monitoring it in the SG secondary water.

Eddy current inspection also used at Russian nuclear power plants, but tubes are inspected only by bobbin coil probes so far. There are no regulatory requirements for scope of the inspection. Recommendation of main designer exists: In case of no active degradation conditions to inspect every SG per four years in order to reach 100% scope in 12 years. Scope and periodicity of inspection should be increased in case of finding degradation by results of sample inspection. All tubes should be inspected prior service.

6.1.10 Tubing inspection requirements in Slovakia

Non-destructive examination of steam generator tubing is carried out using ECT method with the bobbing type probe. The pre-operational inspections of new steam generators are performed in full scope (100% of SG tubing). Operational examination is performed in 100% range of SG tubing using of special remote controlled equipment. ISI intervals are gradually extended from 4 to 6 years/fuel cycles. Plugging criteria are depending on the depth of a defect/flaw, amplitude and phase of a signal. Because of a very low amount of flaws in steam generator tubing, there are no requirements for using other types of probes (rotation probe and ×-probe) so far. Special probes (rotation probe and ×-probe) are used in exceptional cases for specifying certain defects.

After plugging of leaking tubes it is compulsory to apply a nitrogen bubble examination method. The secondary side of steam generator is drained and pressurized with nitrogen. The primary collectors are filled up with water and cameras are looking for bubbles.

6.1.11 Tubing inspection requirements in Slovenia

Initially, the sampling procedure outlined in USNRC RG.1.83 was followed. However, the condition of both steam generators triggered more extensive inspection. Current practice is full-length inspection of all tubes with bobbin coil probes. Additionally, all bends in Rows 1 and 2 and hot leg transition zones are inspected with multi-frequency rotating pancake coil probes. Bobbin coil indications at the tube support plates are also re-inspected with multi-frequency rotating pancake coil probes for confirmation. The expanded tubes in the preheater section (cold leg) are also inspected using rotating pancake coil probes. A complete inspection is performed during each refuelling outage.

All sleeves and the tube areas behind the sleeves are also inspected during each refuelling outage. Also, an ultrasonic baseline inspection was used to confirm the quality of the sleeve-to tube welds. I coil and Plus-point eddy current probes have been employed for subsequent examinations. They replaced their SG in 2000 by new ones with Alloy 690TT tubes so they don’t have sleeves anymore.

6.1.12 Tubing inspection requirements in Spain

All Spanish steam generators with susceptible material (Alloy 600MA) were inspected during each refuelling outage. All of the tubes were inspected over their full length using bobbin coil eddy current equipment. All the hot leg tube sheet areas and all the indications detected by the bobbin coil were also inspected with rotating pancake coil eddy current equipment. Fewer tubes were inspected in the Spanish steam generators with less susceptible material (Alloy 600TT). For example, only 20% of the thermally treated Alloy 600 tubes in the Westinghouse model F steam generators at one plant are inspected over their full length every outage with a bobbin coil, plus a random sample are inspected with rotating pancake coil eddy current equipment (the model F has stainless steel quatrefoil support plates). Now, in all other PWR plants with replacement steam generators (one with original SGs) that have Alloy 800NG tubing, 9% of the tubes are inspected over their full length every outage.

At the present, all Spanish PWRs have Siemens designed SGs with Alloy 800NG tubes except one that have Westinghouse model F SG with Alloy 600TT tubes.

6.1.13 Tubing inspection requirements in Sweden

In Sweden, a random sample of 15–17% of all tubes must be inspected full length using bobbin coil eddy current equipment each year. In addition, an augmented inspection of 20–100% of all tubes at specific regions (roll transition, tube support plate, etc.) is performed.

The augmented inspections include 100% of the hot leg tube sheet area. The Swedish regulatory authority must witness the inspections.

6.1.14 Tubing inspection requirements in Switzerland

The Swiss utility (Axpo) practice is to carry out a 100% inspection of their newer steam generators with Alloy 690TT tubing (which are not particularly susceptible to degradation) after one year of operation. A random sample of 5.5% of all tubes must be inspected every three years thereafter. In addition to a full inspection every three years, all the tubes in the older steam generators with Alloy 600MA tubing were inspected on the hot leg side, and up through the U bend region to the sixth support plate on the cold leg side, every outage. Multi-frequency bobbin coil eddy current equipment was used for these inspections, supplemented by rotating pancake coil inspections of the U bends in Rows 1 and 2 as well as indications within the tube sheet (including the roll transition region). The Swiss regulatory authority must witness the inspections.

At the one PWR plant with SGs using Alloy 800NG tubing the inspections are performed as follows:

100% inspection was performed at the beginning before putting all SGs into service. In subsequent cycles the x% tubes are inspected each year. During the subsequent operating cycles two SG out of three SGs are 100% ECT inspected every four years, whereas, the one SG is 100% ECT inspected every each two years. This steam generator is known to contain some foreign pieces at the top of tube sheet caused by fabrication.

6.1.15 EPRI tubing inspection recommendations

According to Pressurized Water Reactor Steam Generator Examination Guidelines, Revision 6 from EPRI, 2 types of steam generator examinations (i.e. prescriptive based examinations and performance based examinations) are respectively adopted by utilities, main sampling requirements for these 2 types of examinations are described as follows:

- The pre-service inspections (PSI) and first in-service inspection (ISI) of steam generator tubes shall be conducted on all tubing full length using a bobbin coil eddy current technique.
- Completion of the first ISI defines the periods of subsequent ISI that remain fixed throughout the SG lifetime. However, the frequency and scope of subsequent ISI of SG tubes are so different for utilities due to different materials and manufacturing process of tubes.

Since the bobbin coil is not qualified for all areas of the steam generator, a representative sample of abnormal conditions (for example, over/under expansion transitions, manufacturing burnish marks, unusual signals, dings, cold laps) observed during inspection shall be examined with other techniques (for example, rotating coil technology, array probes, or ultrasonic probes) to provide a basis for signal characterization and future historical comparisons.

6.2 TUBING INSPECTION TECHNIQUES

6.2.1 Eddy current testing

Primary reliance is placed on eddy current testing because that technology works well on thin walled tubes of the sort used in PWR and CANDU steam generators and because of the large number of tubes to be inspected. Two probes have been widely used: the standard bobbin coil and the more sensitive multi-frequency rotating pancake coil (MRPC). The great length of tubing to be inspected, as much as 738 500 m per inspection, favours the speed of the standard bobbin coil, more than 2770 m can be inspected per hour using a bobbin coil. Supplemental examinations of areas of concern can be performed using the slower, but more sensitive rotating pancake coil probes. However, the sizing capabilities for these inspection methods are limited. In some cases, the uncertainties in sizing of the defects are being determined by comparing the inspection results obtained using eddy current, and sometimes ultrasonic inspection, with metallographic examinations of pulled tubes. The advantages and disadvantages of eddy current methods (and in some cases ultrasonic) in detecting different degradation mechanisms in PWR steam generator tubing are briefly discussed here. The CANDU experience is discussed separately at the end of this section.

Primary water stress corrosion cracking

Axial PWSCC in the roll transition region can be detected with bobbin coil probes and circumferential PWSCC in the roll transition region can be detected with multi-frequency rotating pancake coils (3 coil probes). Other eddy current inspection methods such as array probes, and Cecco-3 and Cecco-5 probes, and ultrasonic inspection methods can also detect circumferential cracks. A rotating pancake coil can detect a circumferential crack greater than 50% through wall. However, any distortion in the expansion transition region may mask the PWSCC cracks. Therefore, tubes with such distortions should be examined with probes that can differentiate geometry variations from the inside diameter cracks. Generally, eddy current inspection is performed while pulling the probe through the tube. However, for the expansion transition region, it is recommended that rotating pancake coil inspections be performed during insertion to eliminate the drop through effect and improve the quality of the inspection results.

Cracks in the U bend region are difficult to detect because of the eccentricity of the probe while travelling in the bend. The bobbin coil probe appears to be able to detect axial cracks in the U bend regions only when the total number is beyond a certain threshold or the cracks are long. Flexible bobbin coil probes seem to work best.

Axial cracks can be sized with rotating pancake coil probes. One estimate of the accuracy of measuring the length of axial PWSCC using a rotating pancake coil probe is ± 1.5 mm. This estimate was obtained by comparing the MRPC length measurements with the actual maximum length of about 60 axial cracks in the roll transition regions of six pulled tubes from a Belgian PWR.

The eddy current (and ultrasonic inspection methods) capable of detecting circumferential cracks cannot reliably size the length of these cracks. Currently, industry is working on developing qualified sizing techniques. Eddy current inspection data using rotating pancake coil probes and metallographic data for circumferential crack samples are being used to develop these techniques. The samples were explosively expanded in a simulated tube sheet and cracks were produced in an accelerated acid environment. This configuration simulates a Combustion Engineering design steam generator. Worldwide pulled tube metallographic data are also being used to develop the sizing techniques. The pulled tube data show that eddy current inspections generally underestimate the actual arc length of a circumferential crack as shown in Figure 6.1. For example, an actual arc length of a circumferential crack was 360° whereas the corresponding eddy current result was about 100 degrees. Enhanced analysis of the rotating pancake coil inspection results can reduce this deficiency [144]. Some industry efforts are also directed towards developing improved eddy current techniques for sizing the maximum depths of circumferential cracks, which are needed for tube integrity assessments [145].

Eddy current techniques are not effective in detecting cracks with more complex morphologies than a pure axial or circumferential orientation. In one Belgian plant, large axial cracks in the roll transition region masked the response from a small circumferential crack that was also present in the roll transition region; the rotating pancake coil probe did not detect the circumferential crack.

In-service inspection results show that the crack propagation rate of axial cracks on the inside surface in the roll transition region can be estimated. However, crack propagation kinetics for circumferential PWSCC is not yet well characterized.

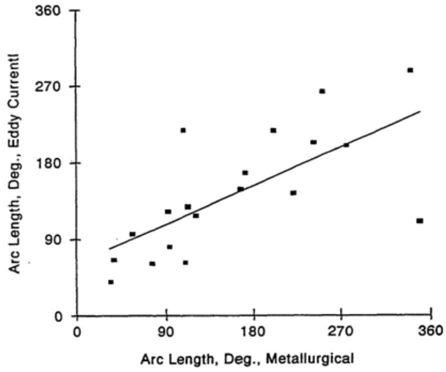


Figure 6.1. Comparison of actual arc length of circumferential crack in pulled tubes with the ones estimated using eddy current inspection. The data represents worldwide experience as of 1992 [145].

Intergranular attack

Intergranular attack is difficult to detect and characterize with eddy current testing. This is supported by the eddy current inspection experience at the Trojan plant, which indicated that the threshold at which intergranular attack can be detected reliably with MRPC and bobbin coil probes is not well understood [146]. Intergranular attack results in a slow and progressive change in the electrical conductivity and magnetic permeability of the material. Therefore, a bobbin coil probe in an absolute mode can provide detection and some information about the extent of the attack, but a bobbin coil probe configured in a differential mode is not sensitive to intergranular attack. Also the specialized pancake coil probes, such as the rotating pancake coil probe (or ultrasonic probes) which are sensitive to axial and circumferential cracks but insensitive to geometrical or magnetic discontinuities, are not likely to detect intergranular attack [147]. The Trojan plant staff took a conservative position that MRPC indications at the tube support plates may indicate intergranular attack greater than the 40 per cent plugging limit, even where a bobbin coil probe did not detect damage.

Eddy current probes cannot accurately assess the propagation of intergranular attack because these probes cannot characterize the damage.

Outer diameter stress corrosion cracking

The reliable detection and sizing of outer diameter stress corrosion cracking (ODSCC) using eddy current testing is difficult because of the low signal-to-noise ratios frequently exhibited by such cracks. ODSCC has been detected in the roll transition and explosively expanded zones, in tube to support plate crevices, especially in the steam generators with drilled hole support plates and in the free span regions in steam generators with heavy crud deposits. Intergranular attack, pitting, and denting are also sometimes observed in these locations. Intergranular attack is associated with ODSCC and ODSCC may also be initiated in pits. In some plants, circumferential ODSCC appears to be associated with significant denting at the support plates and was not detected by a rotating pancake coil probe. Axial ODSCC cracks have been detected at the tube support plate intersections and free span locations, circumferential cracks have been detected at both the expansion transition region and at the support plate intersections. Most of the ODSCC cracks are of short length [148].

An eddy current inspection with a bobbin coil probe may miss some axial ODSCC cracks at tube support plate intersections. In one case, metallographic examination of a pulled tube revealed axial cracks within two 30 degree wide bands on opposite sides of the tube, with the deepest one being 62 per cent through wall. However, the previous field inspection using a bobbin coil probe did not report these cracks using the plant voltage threshold criteria. A rotating pancake coil probe, using a 2.92 mm (0.115-in.) diameter unshielded pancake coil, may be used to detect axial ODSCC.

As discussed above, rotating pancake coil probes underestimate the length of circumferential stress corrosion cracks, including ODSCC cracks. This fact is illustrated in Figure 6.2, which presents a comparison of eddy current measurements of the arc length of a variety of circumferential cracks with the corresponding metallographic examination results [145]. For example, an actual arc length of a crack was about 270 degrees whereas the corresponding eddy current measured arc length was 90 degrees. As mentioned above, enhanced analysis of rotating pancake inspection results can provide better agreement between the inspection and actual arc lengths [144].

Use of multi-frequency/multi-parameter eddy current methods can help suppress the eddy current response of unwanted parameters including the support plates, tube sheet, and tube denting. As in the case of PWSCC, the eddy current techniques are not effective in detecting ODSCC with more complex morphologies than a pure axial or circumferential orientation. (Ultrasonic inspection methods are used at some plants to size the length and depth of the ODSCC cracks.).

Improved guidelines for detecting and sizing circumferential cracks using rotating pancake coil probes are being developed. The detection limit for a circumferential ODSCC crack in dents is about 50% of the wall thickness and a 50° arc length, or 100% of the wall thickness and 23° arc length. Based on the metallographic data for pulled tubes, the Wextex Owners Group has reported that the length of a circumferential crack in a Wextex expansion region can be estimated with an accuracy of ± 39°. (Wextex expansion is an explosive expansion of the tube over full depth of the tube sheet. This expansion method was used in the Westinghouse type steam generators during the early 1970s.) In January 1995, the EPRI In-service Inspection Guidelines Committee co-ordinated a series of circumferential arc length measurements using rotating pancake coil probes from several vendors plus Cecco-5 estimates from Westinghouse. All these measurements estimated the arc lengths within ± 37° to 45°, which is consistent with the Wextex Owners Group estimate [144].

Pitting

The accuracy of an eddy current pit depth measurement is severely limited because of the small size of the pits and because the pits are often filled with copper containing corrosion products which have a high electric conductivity. Ontario Hydro Technologies has developed a rotating ultrasonic inspection system for measurement of pit depths in Monel 400 steam generator tubes. High ultrasonic frequencies, on the order of 25 MHz, are used to obtain the required pit depth accuracy and water is used as a couplant. The inspection system is capable of accurately measuring pit depths to ± 2% of the tube wall thickness, which is equivalent to measuring a pit depth within µm. The depth measurement results on pulled tubes compared well with the metallographic results [149].

Denting

Bobbin coils are usually employed to detect and size most dents. (However, rotating ultrasonic inspection probes can provide more accurate radial profiles of a dented tube cross-section.) The denting growth can be considered as slow and its evolution as well controlled. However, very small dents can initiate stress corrosion cracking but cannot be detected with bobbin coil probes. French experts have calculated that dents as small as 20 to 30 microns are large enough to cause stresses capable of initiating stress corrosion cracking in susceptible Alloy 600MA tubing.

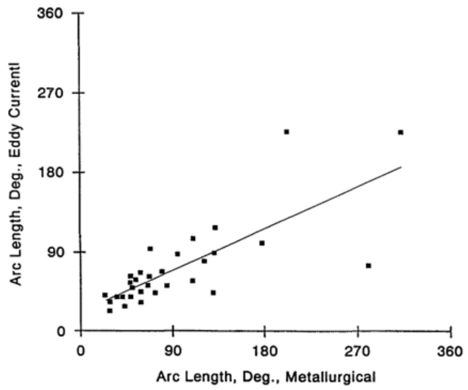


Figure 6.2. Comparison of actual arc length of circumferential ODSCC in pulled tubes with the ones estimated using eddy current inspection [144].

High cycle fatigue

It is difficult to detect a high cycle fatigue crack in a steam generator tube because the initiation time for such a crack is quite long and the crack growth is rapid. Mitsubishi Heavy Industries (MHI) have evaluated use of pancake coils for detection of circumferential fatigue cracks. Because the fatigue cracks are tight and rather straight, the evaluation focused on how the detectability is affected by the width of the crack and the type of the coil. The experimental results for the impedance of an artificial circumferential fatigue crack, 2×10^{-3} mm wide and 50% through wall, compared well with analytical results, and thus, validated the numerical analysis approach. The numerical solutions for different crack widths showed that for very narrow circumferential flaws such as fatigue cracks, the detectability of the crack is not affected by the crack width, and such cracks can be detected by pancake coil type probes [150].

Wear

Wear causes loss of material at the tube outside diameter. The shape of fretting induced wear is determined by the contact area with the supporting structure and its length is limited to the thickness of the supporting structure. Fretting induced wear is also limited to some critical tubes, which makes inspection much easier. This damage is relatively easy to detect and size with a bobbin coil probe. In addition, field experience shows that the wear rates tend to be low compared with the frequency of the in-service inspections.

Loose parts induced wear is generally limited to peripheral tubes and is also relatively easy to detect when it is suspected. However, the sizing of the affected area is less accurate than that for the fretting induced wear because the shape of the wear is unpredictable. The rate of the loose parts induced wear is also unpredictable and a long rapidly progressing wear scar may lead to tube rupture in less than a fuel cycle.

Erosion-corrosion

Erosion-corrosion is detected by conventional bobbin coil probes during normal in-service inspections of steam generators. In the majority of cases, indications are detected at least in one or two inspection intervals prior to the wall reductions reaching 40% of the initial wall thickness. Hence, it is concluded that there is some forewarning of damage by this degradation mechanism before it reaches a state where reliability is affected.

Corrosion fatigue

The metal loss associated with high cycle corrosion assisted fatigue can be detected by eddy current methods during the normal in-service inspection of a steam generator. However, some cracks are difficult to pick up due to their close proximity to the tube sheet and tube support plates. It is not clear from the limited data whether a gradual degradation can be detected before sufficient degradation has occurred to require removal of the tube from service.

Wastage

There is a general consensus that wastage can be accurately detected and sized using a bobbin coil probe when the wall loss is larger than 10% to 20%. Operating experience shows that the propagation rate of wastage is compatible with the frequency of in-service inspection.

Summary

Inspection of the steam generator tubes is critical to the safe and economical operation of nuclear power plants. Eddy current inspections using bobbin coil probes were fast and effective in detecting and sizing the degradation that took place in early steam generators. However, newer forms of degradation have appeared in recent years that require development of more sophisticated inspection tools. Often, different characteristics of the damage require different types of inspection tools.

The safety significance of the uncertainties in the eddy current technologies varies. For example, most PWSCC can be detected and then characterized well enough to make a repair decision with the available probes. Detection of IGA patches with standard multi-frequency bobbin coil probes is poor. However, this degradation is generally not deep enough to have any safety significance. Occasionally, there have been problems detecting ODSCC and three tube ruptures have occurred to date because of undetected ODSCC. Pitting is also very difficult to detect but is not expected to cause much leakage or contribute to a tube rupture. Most dents are detected relatively easily with conventional bobbin coil probes. However, very small dents can initiate cracking but cannot be detected with bobbin coil probes. In-service inspection is not an effective approach for preventing high cycle fatigue ruptures because of the rapid crack growth rates, two such ruptures have occurred to date. Wear and fretting damage is characterized by significant quantities of metal loss over an extensive area and as such is easily recognized by conventional eddy current methods. However, loose parts wear can sometimes occur very rapidly. Wastage and erosion-corrosion (and probably high cycle corrosion assisted fatigue) can be detected with eddy current technologies.

The primary method of tube inspection used in the CANDU units is also the standard multi-frequency bobbin coil eddy current method. Inspection probes and equipment have had to be adapted to the following CANDU steam generator characteristics: smaller tube diameters, reduced size of the primary head and the presence of a heavy magnetite layer on the inside surface of the tubes which abrades the probes. The circumferential stress corrosion cracking experienced at some units required the development of more sensitive and reliable eddy current probes. The special multichannel transmit-receive probes, developed by the Chalk River National Laboratory, are capable of detecting circumferential cracks > 60% through wall.

Inspection of Monel tubes with eddy current probes posed some difficulties due to the slightly ferromagnetic properties of the material. This makes it necessary to magnetically saturate the tube material in order to detect flaws. This is done by using an eddy current probe with a very strong permanent magnet built into the probe.

6.2.2 Ultrasonic and other inspection methods

Ultrasonic testing is a volumetric non-destructive method for in-service inspection of components. Ultrasonic methods, which can detect pits and circumferential cracks in the presence of axial cracks are being developed. This section discusses several ultrasonic techniques used in tube inspection.

Electromagnetic acoustic transducer

This method addresses ultrasonic inspection of steam generator tubing using an electromagnetic acoustic transducer [151]. It was developed to detect flaws in certain areas of tubes where the conventional single frequency, differential coil eddy current probe has not been entirely satisfactory, including in circumferential cracks, defects at dents or support plates, and defects in U bends.

The electromagnetic acoustic transducer (EMAT) system has a good detection capability for circumferential cracks and other defects that provide a fairly wide and sharp circumferential oriented cross section (e.g. dented areas), however, the system has difficulty detecting flaws with small cross sections, i.e. cracks that are tight. For example, the system can inspect U bends but does not always detect the axial cracks found in U bends. In addition, the system has limited defect depth-sizing capability.

Pulse-echo ultrasound for tube to support plate gap measurement

This equipment uses an ultrasonic technique for determining the condition of the gap between steam generator tubes and support plates, which allows monitoring of corrosion product build-up that might lead to denting. It also can determine the efficiency of chemical cleaning on removing this deposit build-up.

Optical profilometry

The optical profilometry has been tested successfully under laboratory conditions for tube dent measurement [152]. It can measure inside tubing profiles in the range of radii from 8.13 mm to 10.16 mm, with an average calibration error of 0.13–0.20 mm on the nominal inner diameter and ±0.15 mm on dents. Preliminary investigations suggest that the calibration error is most probably caused by variations in the interior surface finish.

Automated ultrasonic system

An automated ultrasonic system has been used at some CANDU units to detect shallow tube pits. This system uses high frequency ultrasonic (50–100 MHz) and is capable of detecting pit sizes ~5% through wall.

Nitrogen bubble method

This method is suitable for horizontal steam generators type WWER. The principle of the technique consists in filling up both primary collectors by water and then overpressure of the drained and dried secondary site of the steam generator by nitrogen. Bubbles that come out from a defective tube are searched by an underwater camera with a microphone and the leaking tube is identified. The method is used at nuclear power plants in the Czech Republic and Slovakia.

6.2.3 Pressure tests

Normally, a hydrostatic test of a pressure vessel is an operation by which this component is subjected to a suitable hydraulic pressure higher than the maximum permissible operating pressure, and the first hydrostatic test of a pressure vessel is performed by the manufacturer.

Hydraulic test of a pressure vessel involves subjecting the component to suitable hydraulic pressure in order to test its strength or leaktightness, that means hydraulic test is an important normal way to verify structural integrity of pressure components (including steam generator tubes). Hydraulic tests are beneficial to detection rate and quantification of defects.

In-service hydraulic test of a pressure component is performed by the utility under his own responsibility.

6.2.4 Destructive testing

Eddy current inspection (and ultrasonic examination) techniques and procedures can be qualified by removing previously inspected tubes from an operating steam generator and examining the defect indications in a laboratory. Appropriate destructive examinations of so-called ‘pulled tubes’ will not only quantify the defect indications but also provide considerable information about the degradation mechanisms. Specifically, pulled tubes can be used to determine if secondary side corrosion defects are acid or caustic induced and identify species associated with the chemical attack. Pulled tubes can also be used to determine leak rates (with mixed success to date) and burst pressures, information which is useful for assessing tube integrity. Furthermore, inspection of pulled tubes provides an opportunity to look for any incipient problems. The tubing selected for destructive examination should obviously have some defects, such as a roll transition indication, and must be accessible.

6.2.5 Deposit (sludge) mapping

Regarding WWER, it is a requirement that eddy current systems have to detect tube deposits. However, none of the inspection vendors has performed either qualification or provided any quantitative criteria to measure or fix deposits. Some inspection vendors provide information on electro conductive deposits as addendum to inspection results.

6.2.6 Visual inspection

In WWER visual inspection are required from secondary side not less frequent than every 4 years. In practice it is performed both by man and remote television devices. Tube bundle condition should be studied including cleanness of inter tube space and sludge on the bottom of the vessel. Cleanliness of collector pockets should be checked. For the new steam generator design special ports provided at the vessel bottom for visual inspection.

Siemens (now AREVA NP GmbH) recommends to perform frequently tube sheet visual inspections using endoscopy as an aid for the utilities decision, if in subsequent outage cleaning of SG tube sheet needs to be scheduled (e.g. by tube sheet-lancing). The recommended frequency of the visual inspections is (depending on the need) either each annual outage or every two outages.

6.3 MONITORING STEAM GENERATOR TUBE LEAKAGE

On-line monitoring of nitrogen-16 in the main steam lines can point to rapidly increasing primary to secondary leaks associated with, for example, high cycle fatigue cracking in the U bend region. Nitrogen-13 is produced in the primary water as it passes through the reactor core. It will be present as nitrogen-16 in the secondary system only if there is a primary to secondary leak. Nitrogen-16 does not accumulate in the secondary system because its half-life is only 7.35 seconds. Therefore, its presence provides a good measure of the current primary to secondary leak rate with a very rapid response time. (The threshold value is less than 1 litre per hour if the plant is at a nominal load.)

6.4 WWER STEAM GENERATOR COLLECTOR LIGAMENTS INSPECTION

During operation, cracks initiate in secondary side of WWER-1000 steam generator collectors due to high residual stress from explosive expansion during fabrication. These cracks expand gradually, and lead to cracking of collectors. Several steam generators were changed due to this type of corrosion cracking.

There are three types of collector ligament cracks as follows:

- Satellite cracks, with width up to 0.1 mm and length up to 1 mm.
- Planetary cracks, between 2 tube holes, with width of 0.2 mm to 0.5 mm and length through the ligament, and depth up to 30 mm.
- Arterial cracks, with width greater than 0.5 mm and length 1000 mm through the ligament among several tube holes, and depth through entire collector wall.

6.4.1 Collector ligament inspection requirements

Pre-service inspection

Sampling inspection of potential degradation zone of about 1200 tube holes ligaments shall be inspected, and baseline data should be established to be compared with further inspection data.

In-service inspection for explosive expanded steam generators

Same sampling zone should be inspected every two years for cold and every four years for hot collectors.

6.4.2 Eddy current testing of collector ligaments

Primary reliance is placed on eddy current testing for collector ligament inspection. There are 3 eddy current testing schemes for ligament inspection as follows:

- Using bobbin probes for routine inspection at first, and then using rotating probes for quantification analysis in case defect indications are detected by bobbin probes.
- Using rotating probes directly.
- Sometimes, to reduce inspection time at the request of nuclear power plants, using array probes (×-probe) for routine inspection at first, and then using rotating probes for precise qualitative and quantitative analysis.

6.5 FEEDWATER NOZZLE INSPECTION

The ASME Code, Section XI, provides the in-service inspection requirements for the steam generator shell, feedwater nozzle, and the adjacent feedwater piping. There are no inspection requirements for the feedring, J tubes, or thermal sleeves, although those components have experienced erosion-corrosion damage (wall thinning) in the field. In accordance with the Code, the ASME requirements include surface and volumetric examinations, which focus mainly on the feedwater piping welds and base metal immediately adjacent to the welds, feedwater nozzle blend radius, and steam generator shell girth welds. Radiographic and ultrasonic inspections have been used for this purpose. However, thermal fatigue cracks, particularly in the base metal away from the weld, are not always detected with an ASME examination. This section focuses on the inspection of the nozzle-to-pipe welds and adjacent piping welds because of some recent cracking incidents at these sites.

ASME Section XI In-service Inspection Requirements

The current pre-service and in-service inspection requirements include a volumetric examination of the inner 1/3 volume of the piping welds and adjacent base metal for a distance of 6 mm from the edge of the weld crown and a surface examination of the outside diameter surface of the weld and 13 mm of the adjacent base metal. The Code contains similar inspection requirements for the feedwater nozzle-to-vessel welds. The inspection requirements for the shell welds such as the girth weld include an examination of the entire volume. In addition to the welds, the Code also requires a volumetric examination of nozzle inside blend radii. For multiple vessels of similar design, such as the steam generators, the examinations may be limited to the nozzles of one vessel or the equivalent of one vessel distributed among the vessels.

Although pre-service and in-service inspections are currently required across the nuclear industry, they were not part of ASME Section XI Code prior to the winter 1972 Addenda of the 1971 edition. Thus, when cracking was discovered in the D. C. Cook nozzles in 1979, many plants had not performed pre-service or in-service examinations of the feedwater system. This lack of examination results was significant in that many plants did not have base line ultrasonic examination data for the examiners to compare in discriminating geometric reflectors, such as the counterbore and weld root, from service induced defects. This is especially important in the case of feedwater piping cracking, which has generally initiated at geometric discontinuities such as the counterbore comer. For plants that are performing examinations of welds in accordance with latter editions of ASME Section XI, the examination volume may not extend far enough to include the discontinuity at the counterbore comer. Some utilities are now including the examination of the counterbore comers in the in-service inspection of the feedwater system

Some recent events have illustrated the potential weaknesses in the ASME in-service inspection requirements. In March 1992, through wall cracking was discovered in a PWR feedwater nozzle-to transition piece weld at one US plant. Subsequent radiographic examinations revealed that several nozzle-to transition welds contained significant cracking. All of these welds had been previously examined ultrasonically. Further investigation revealed that the ultrasonic examinations were conducted using the minimal Code requirements and that the indications had been incorrectly identified as root geometry. No supplemental or enhanced techniques were used to verify that the indications were not cracks. As a result of these failures, the plant operator upgraded their ultrasonic procedures and expanded the examination volume for welds in piping and nozzle locations subjected to thermal stratification. The expanded volume includes the weld plus the adjacent base metal for a distance of two wall thicknesses. The plant operator also incorporated into their procedures a number of enhanced ultrasonic techniques to aid in the evaluation of detected indications. In addition, the in-service inspection personnel were provided enhanced training using the removed pieces of the damaged feedwater piping and nozzle.

Another incident involving misinterpretation of crack indications occurred at another US plant. These cracks were oversized by ultrasonic examination, which resulted in removal of the affected weld. These same cracks were not detectable with radiographic examination. Subsequent metallurgical evaluation results indicated that the ultrasonic examination had oversized a shallow crack by a factor of ten owing to inclusions in the weld area. The plant operator concluded that the ASME Code examinations were not adequate for small thermal fatigue cracks and that enhanced ultrasonic techniques, such as tip-diffraction and creeping wave techniques and automated scanning, were necessary to improve reliability, accuracy, and repeatability.

Improved in-service inspection methods for thermal fatigue cracks

Radiographic or ultrasonic testing may be used for detection of cracking at the inside surface of the piping. Each method has its own advantages and disadvantages, but is capable of providing complementary information on the condition of a weld and the adjacent base metal.

The inherent advantage of radiography is that testing can be performed through the insulation and a permanent record is obtained, which can be compared with the results of future examinations. The resulting image can also be used to characterize the weld geometry. Many of the disadvantages of radiography stem from convenience factors. These include radiological controls that may interfere with critical path activities, interference from contaminated and irradiated components, and access to the inside surface (which is available only at those plants with gamma plugs installed in the pipe wall adjacent to the feedwater nozzle). Otherwise, double wall techniques must be used, which have reduced sensitivity. The final consideration is that radiographic examination is arguably a less sensitive method for crack detection compared with ultrasonic examination. Although radiographic examination is sensitive to defects that are volumetric in nature (e.g. wall thinning, slag inclusions, etc.), the density difference caused by a crack may be insufficient for detection if the orientation of the crack is not parallel to the gamma or X ray.

Although ultrasonic examination can be sensitive and capable of detecting many types, sizes, and orientations of cracking, manual ultrasonic examinations have had two inherent disadvantages:

- Reliance on the inspectors' ability and judgement.
- The lack of a permanent record.

For the feedwater piping, these problems have resulted in inconsistent results, miscalls of both cracks and weld geometry (owing to the lack of baseline data), and a general lack of confidence in ultrasonic examination. These inconsistencies and miscalls have led to the development of enhanced inspection techniques.

Tip-diffraction techniques are widely used for crack depth sizing. The time of flight-diffraction technique is one of the tip-diffraction techniques that has been developed in recent years [153]. The time of flight diffraction signals associated with different crack configurations are illustrated in Figure ***6.3***. As shown in Figure 6.3 (a), two signals are present in the absence of a crack: a direct lateral wave signal and a signal reflected from the back wall. Diffraction occurs when the incoming sound beam impinges upon a finite planar reflector such as a crack. The diffracted sound energy from the crack tip acts as a point source and radiates a sound wave to the receiving transducer. The time of arrival of this signal can then be used to pinpoint the tip of the crack and determine the crack depth. Figure 6.3 (b) illustrates such a diffracted signal produced by the tip of a surface crack, note the presence of a back wall reflection signal and the absence of a lateral wave signal. The presence of a surface crack at the inside diameter will cause the loss of the back wall reflection signal, but a lateral wave and a diffracted signal from the crack tip are present, as shown in Figure 6.3 (c). All signals will be present for an embedded crack, as shown in Figure 6.3 (d). This approach provides a means of sizing, locating, and verifying the extent of the crack, but could be hindered by weld geometry on the outside and inside surfaces, which could cause a loss of surface contact and/or loss of back wall and lateral wave signals for reasons other than the presence of a crack.

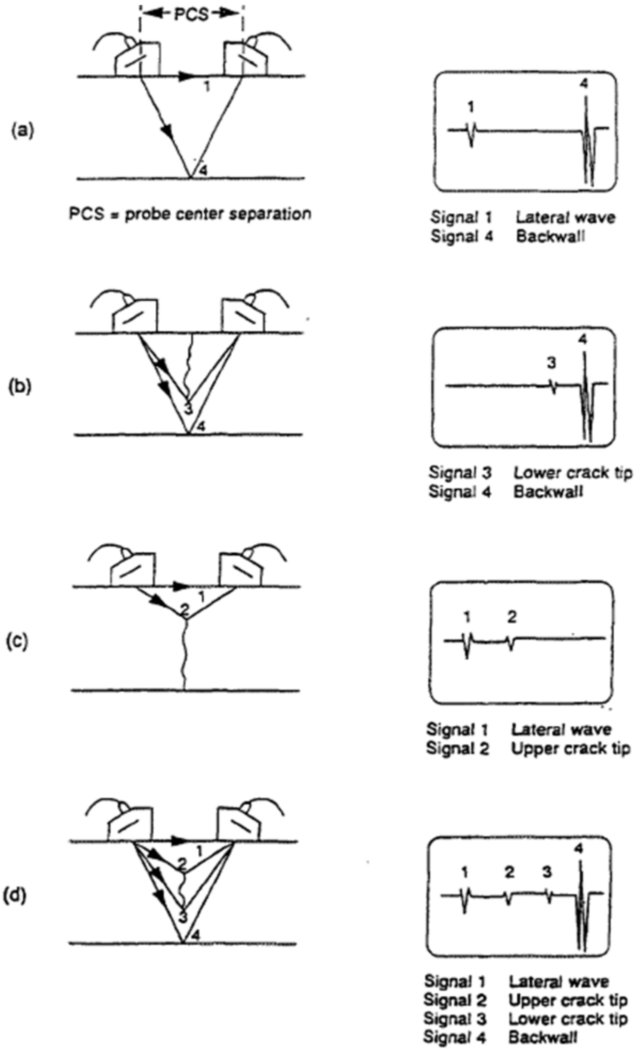


Figure 6.3. Examples of time of flight diffraction (TOFD) signals [153]. Copyright TRC; used with permission.

The improvement in sizing technology using the time of flight techniques is largely the result of the data published from the Programme for Inspection of Steel Components (PISQ Round Robin Tests (the PISCII Project), which showed that amplitude based methods were unreliable for determining the through wall extent of a crack [154]. Since that time, numerous transducer configurations (e.g. tandem, dual) have been developed to optimize the response from the crack tip and other portions of the crack to aid in crack sizing.

An approach developed for the detection of intergranular stress corrosion cracking in BWR recirculation piping that can be effective for the detection of thermal fatigue is the use of an inside diameter creeping wave and the related mode conversion techniques. This family of techniques has gained wide acceptance in the nuclear industry because of its high sensitivity to small connected surface flaws at the inside surface [155].

Another improvement is the use of automated inspection equipment to collect and store ultrasonic data. Automated scanning of feedwater nozzles was performed at San Onofre Unit 3 using the lntrospect/98 volumetric inspection system [156]. Using computer processing, 3-dimensional imaging of the data facilitated flaw characterization and discrimination of geometrical reflectors on the inside surface.

Such enhanced evaluations are becoming routine and are possible with many modem-scanning systems.

In the past, the primary constraint for automated ultrasonic inspection was collecting and manipulating large quantities of data. However, the continued evolution of computers has allowed for storage of gigabytes of data, and the speed to collect and manipulate the data. Modem computers have also provided a more efficient means of processing data and integrating processing with special search units. A good example of this is the TestPro/FATS system [157]. FATS (focused array transducer system) is an extension of the phased array techniques, which allow the beam to be focused electronically to the area of interest. This method reduces beam spread and allows the beam to focus on the crack opening to enhance detection, or focus on the crack tip to improve sizing accuracy.

One of the problems with performing ultrasonic examinations on piping welds is discriminating weld geometry from cracks. Therefore, an accurate representation of the weld geometry is important. Owing to the variation in weld geometry from weld to weld and to the inaccuracies of as-built drawings, weld profiles for each weld examined are a necessity. One method of obtaining this is by plotting thicknesses obtained by ultrasonic thickness measurements. An alternate method that has been used in Japan to visualize weld geometry is the use of computed tomography imaging of radiographic data [158]. The advantage of this approach is that an accurate cross section of any section of the weld, including the re-entrant comer of the counterbore, can be obtained. The disadvantage is, of course, the expense of performing such an examination.

6.6 MONITORING FATIGUE DAMAGE

This section briefly describes fatigue-monitoring programmes offered by vendors in Europe, Russia and the USA. It explains how some of the fatigue monitoring approaches have been implemented.

US approach

The nuclear steam supply vendors and EPRI have developed several systems for fatigue monitoring at critical sites in nuclear power plants. One such system is described below. In 1984, EPRI began developing this system through a contract with Structural Integrity Associates. The system includes a PC based on-line monitoring system called ‘FatiguePro’ that collects existing plant instrumentation data and then uses a Green's temperature-stress function and an ordered overall range counting method to process the data [159]. The plant instrumentation data such as pressure, temperature, and flow rate are used with the Green's influence function to determine stress versus time at the critical locations. The ordered overall range cycle-counting method is used to develop a stress/frequency spectrum from a measured stress history. The stress/frequency spectrum is combined with the ASME Code S-N curve to determine the fatigue usage. Via the effort of more than 20 year, a lot new function has been added to FatiguePro system. When carrying out exhausted damage evaluate, many factors can be considered, such as the change of the fluid temperature of transient state, thermal stratification, fatigue crack growth, environment fatigue. The human-computer interaction function of software is more and more strong.

French strategy

Electricité de France (EdF) was perhaps the first to implement fatigue monitoring in nuclear plants and has one of the most mature programmes in the world. The first EdF programme, the Transient Monitoring and Logging Procedure, was initiated with the commissioning of its earliest plants (in 1977) and consisted of a bookkeeping method. The actual transients were logged and checked, case-by-case, to ensure they were not more severe than the design basis.

Even though the monitoring and logging procedure worked for many of the plant components, EdF realized that advanced fatigue monitoring systems were required for more critical locations. Consequently, EdF developed a system called the Fatiguemeter, which uses plant instrumentation for measuring temperature, pressure, flow rate, and valve position (open or closed). An influence function approach for estimating thermal stresses, rain-flow counting, and Miner's linear damage rule were then used to calculate fatigue at various locations. Although the manual bookkeeping used as a part of the Transient Monitoring and Logging Procedure reduced the cumulative usage factor substantially, the use of the Fatiguemeter system resulted in an even further reduction in the usage factor [160]. One of the applications of the Fatiguemeter was monitoring of the steam generator feedwater nozzle at a 900 MW PWR plant.

After more than ten years of experience with the Transient Monitoring and Logging Procedure and six years with the Fatiguemeter, EdF, in collaboration with Framatome, has developed an integrated system called SYSFAC (SYsteme de Surveillance en FAtigue de la Chaudiere). This system incorporates the lessons learned from the previous two approaches, the logging system to review overall plant fatigue usage and a more detailed approach using the Fatiguemeter at key locations [160]. The EdF standardized plant design is helpful in developing this system because there are few plant-to-plant variations that have to be considered, and the lessons learned from one plant can be directly applied to others. The first SYSFAC is delivered to the pilot power plant by the beginning of 1996. The extension to all EdF’s nuclear 900 MW is planned after one more year of feedback experience [161].

AREVA NP GmbH (Siemens/KWU) strategy

A fatigue monitoring system (FAMOS) has been developed by Siemens/KWU (now AREVA NP GmbH) to quantify fatigue usage. The system uses both a global and local monitoring approach. Global plant process parameters have proven sufficient for most components such as the steam generator shell. However, AREVA NP GmbH determined that global monitoring was not sufficient for the feedwater nozzle, so additional thermocouples were mounted around the outside circumference of the feedwater nozzle. Data are obtained from these thermocouples and the corresponding heat conduction problem is solved to determine the stress and temperature fields. Once the stresses are known, a standard scheme for cycle counting (rain-flow cycle counting) and fatigue usage calculations is carried out. AREVA NP GmbH reported that thermocouple readings from the outside surface provided accurate temperature estimates for the inside surface for wall thicknesses up to about 50 mm. Most German nuclear power plants use some or all aspects of this fatigue monitoring strategy [159].

Russian strategy

To monitor the exhausted damage of important safe equipment (reactor pressure vessel/steam generator, etc.) in the WWER reactor, residual life automated control system (SACOR) had been developed in Russia.

SACOR supervises accumulation of fatigue damage to the most intense points of the constructive elements determined as a result of design calculations on durability. Calculation of fatigue damage of SACOR carries out under indications of the design transducers recording the current thermo mechanical condition of the equipment, with use of special approximating formulas for calculation of stress in each control point. In the stress calculation the loading factors due to the primary and secondary pressures, temperature compensation of pipelines, real moving of the equipment, and temperature fluctuations, thermo shocks and stratification of coolant under all operating conditions including the transient and accident conditions are taken into account.

So far, Generation I SACOR-M system, developed in 2001, has been introduced at 6 power units with WWER-1000. Generation II SACOR-320 developed and adapted for RP V-320 design is being introduced at Rostov Unit 2 to be further introduced at newly built NPPs with WWER. SACOR-320 is characterized by considering the actual steam generator displacements, usage of surface temperature resistance thermometers in a number of units for coolant supply into RP circulation system, additional usage of brittle and ductile strength mechanisms as the limiting states.

7 STEAM GENERATOR FITNESS FOR SERVICE ASSESSMENT

7.1 BACKGROUND

The steam generator (SG) tubes in pressurized water reactors as well as in PHWR reactors comprise a substantial portion of the reactor coolant pressure boundary and also play a role in fission product containment. These tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied upon to maintain the primary system's pressure and inventory. As part of the RCPB, the SG tubes are unique in that they are also relied upon as a heat transfer surface between the primary and secondary systems such that residual heat can be removed from the primary system; the SG tubes are also relied upon to isolate the radioactive fission products in the primary coolant from the secondary system. In addition, the SG tubes are relied upon to maintain their integrity; as necessary, to be consistent with the containment objectives of preventing uncontrolled fission product release under conditions resulting from core damage severe accidents. As a result, there are number of regulatory requirements to ensure that tube integrity is maintained. As a minimum, an effective steam generator life cycle management should ensure:

- Low probability of spontaneous tube rupture, in terms of occurrence per plant year, under normal operating conditions.
- Very low probability of tube rupture under accident conditions, in terms of the probability of occurrence of a design basis accident and consequential SG tube rupture.
- Limiting primary to secondary tube leakage during normal operation and during postulated accidents within regulatory dose limits.

7.2 TUBING REPAIR CRITERIA

Repair (sleeving) or removal from service (plugging) of excessively damaged steam generator tubing is necessary to prevent:

- Single or multiple tube ruptures.
- Excessive primary to secondary leakage.

However, a continuing issue has been exactly what constitutes excessive damage and which degraded tubes are or are not still fit for service. Some of the earliest guidance on this subject was published in the US Code of Federal Regulations and in the American Society of Mechanical Engineers (ASME) Pressure Vessel and Boiler Code [162, 163]. The ASME code states that for U tube steam generators, the allowable outside diameter flaw shall be less than 40% of the tube wall. This criterion was initially implemented in most countries with PWR or CANDU plants [164]. However, alternative criteria are allowed by the ASME code if accepted by the regulatory authority. Essentially, an alternative tube repair criteria must address the following four issues:

- Maximum (critical) size of a defect, which ensures stability of the damaged tube (analytical and experimental verification).
- Propagation rate of the defect until the next inspection.

- Ability of the inspection methods to detect defects of a critical size.
- Accuracy of the inspection methods to size defects of a critical size.

In recent years, a number of countries have found the original ASME criterion overly conservative and inflexible and have developed revised or new fitness for service criteria, often in conjunction with revised inspection requirements. Although the new fitness for service criteria used in most countries follow the general technical basis, there are substantial differences in implementation. However, the currently implemented repair criteria can be grouped into two families: generic and defect type and location specific criteria, as explained in the following sections.

7.2.1 Generic fitness for service criteria

No flaws

The simplest, most straightforward, and most conservative generic approach is to define a minimum detection threshold, inspect all the tubes on a regular basis, and remove from service or repair any tubes with indications above the noise level. This implies, of course, that there will be no leakage. (Should any leakage start, the plant will immediately be shut down and the tubes inspected.) However, this approach provides little or no incentive to improve the inspection and leak detection methods.

Wall thickness

Most widely implemented fitness for service criterion is a minimum wall thickness criterion (either the value specified in the ASME code or some other value). The minimum wall thickness value is determined by assuming uniform wall thinning around the circumference of the tube and calculating a wall thickness, which will sustain all postulated loads with appropriate margin. Generally, a plastic load limit analysis is performed with margins against tube burst of 3 and 1.43 for normal and accident conditions, respectively. Leak rate calculations are not required since through wall defects are not expected. A minimum wall thickness criterion works well for degradation mechanisms that remove considerable material such as loose parts wear, wastage, etc. However, a minimum wall thickness criterion can be overly conservative and costly for small defects such as pitting, axial ODSCC within the tube support plates, etc.

7.2.2 Defect type and location specific repair criteria

The occurrence of different types of tube degradation such as PWSCC within the tube sheet or axial ODSCC within the support plates initiated the development in some countries of defect type and location specific repair criteria. These criteria were developed to reduce the extent of the steam generator repair or plugging work without sacrificing plant safety by reducing the unnecessary conservatisms of the generic criteria. This was done by taking into account specific defect and location characteristics, which may reduce the chances of tube rupture or leakage. To date, four broad groups of defect specific repair criteria are in use:

P and F Criteria

Tubes with flaws in the region where the tube has been expanded against the tube sheet will not burst and probably will not leak. Therefore, criteria were developed specifically for full tube sheet depth expanded tubes, which allow tubes with flaws in the tube sheet region to remain in service without repair, regardless of defect size. However, the flaws must be some distance below the top of the tube sheet or bottom of the roll transition, whichever is lower, so as to prevent pull out of the damaged tube should it separate at the flaw. The F distance for full depth rolled steam generators is typically 38 to

51 mm. (The exact F distance is established by considering the length of roll expansion needed to resist the tube pull out forces.) The P distance is typically about 32 to 38 mm. It is established by considering the ability of other tubes to prevent tube pull out [165]. The tube sheet thickness is usually between 525 and 610 mm. Some countries developed variation of P and F criteria (recently, Korean regulatory body KINS developed so called H criteria).

Crack length criteria for axial PWSCC in residual stress dominated expansion transition zones

This type of repair limit was originally developed and implemented in some European countries (France, Belgium, Spain, Sweden, and Slovenia). Axial cracks located close to the top of the tube sheet and shorter than about 10 mm (for 19 mm [3/4"] tubes) or 13 mm (22.2 mm [7/8"] tubes) may remain in service, even if they are through wall. Implementation requires special inspection techniques, which are able to detect and size the length of the axial cracks and, depending upon the degree of the degradation, up to 100% yearly inspections.

Leak before of break criteria for axial PWSCC

This approach is of French origin and is very similar to the crack length criteria. In the early implementation stage, leak detection was considered to be as reliable as tube inspection. Only samples of tubes were therefore inspected while the non-inspected, and possibly nearly critical, defects were expected to be reliably detected by nitrogen-16 on-line leak monitoring. However, some of the long through wall cracks are rather leak tight, which can cause unreliable predictions of the leak rates. The current tendency is therefore to put increasing weight on the use of inspections and use leak detection as an additional safety feature.

Voltage criteria for ODSCC at the tube support plates

The very complex morphology of ODSCC forced the industry to a completely statistical approach. The signal amplitude of the bobbin coil eddy current testing inspection method was taken as the measure of defect severity. Based on degraded pulled-out tubes and specimens prepared in the laboratory, two correlations were developed:

- Bobbin coil signal amplitude versus tube burst pressure.
- Bobbin coil signal versus leak rate (individual defect in a tube).

The burst pressure correlation, together with allowances for defect progression and inspection uncertainties, is used to define the structural repair limit in the first step. The leak rate correlation, together with the recent population of defects in the steam generator under consideration and allowances for defect progression and inspection uncertainties, then gives an estimate of total leak rate during postulated accident conditions (e.g. steam line break).

Very early fitness for service guidance to the USA nuclear power plant owners was provided in Regulatory Guide 1.121 [166]. In late 1990’s the AECB issued a voluntary guidance on steam generator fitness for service [167] and US NRC followed with a draft regulatory guide DG-1074 [168]. However, it should be noted that the USNRC regulatory guides were not mandatory and the legal requirements applicable to a plant are those in its technical specifications, which are reviewed and approved by the USNRC. In parallel with the work at US NRC, Electric Power Research Institute (EPRI) commissioned a committee of US and foreign experts in steam generator tubing degradation issues to recommend an alternative fitness-for service guideline for outer diameter IGSCC/IGA defects. That work resulted in number of guidance documents which are used by nuclear industry from all over the world [18, 19, 137, 169–175]. Recently, number of countries adopted new, performance based regulatory approach to ensure steam generator (SG) tube integrity. The objective of these new requirements is to focus regulation directly on maintaining tube integrity rather than on the specific measures used to achieve this objective. Under these new requirements, PWR utilities must implement a programme that ensures the maintenance of tube integrity. Tube integrity is defined in terms of performance criteria for structural integrity and also for operational and accident leakage integrity. Utilities must periodically demonstrate that they have met these performance criteria. The scope, frequency, and methods of inspection must be such as to ensure the maintenance of tube integrity until the next scheduled inspection. In the requirements for the in-service inspection and repair of SG tubes are contained in the plant technical specifications (TS). Until recently, these TS requirements were entirely prescriptive in nature, consisting of specified sampling plans for tube inspection, specified inspection intervals, and flaw acceptance limits (termed tube repair limits) beyond which the tube must be removed from service by plugging or repaired. Although the old TS SG tube surveillance and fitness for service requirements were intended to ensure SG tube integrity in accordance with the design and licensing bases, operating experience has shown that these requirements, in and of themselves, did not necessarily ensure that facilities would meet this objective. For example, the required minimum tube inspection sample sizes and eddy current test flaw detection performance were sometimes insufficient to ensure the timely detection of flaws before the desired margins against burst and leak tightness were compromised. In addition, eddy current test measurement errors and flaw growth rates sometimes exceeded those allowed for by the tube repair criteria. Thus, the surveillance requirements alone did not necessarily ensure that the scope, frequency, and methods of inspection would be sufficient to confirm SG tube integrity.

7.3 TUBE PERFORMANCE CRITERIA

The tube performance criteria are the benchmarks against which the tubes should be monitored and maintained. The steam generator tube performance criteria address three areas of tube integrity performance:

- Structural integrity
- Operational leakage integrity
- Accident induced leakage integrity.

Steam generator tube integrity is maintained when all three of these criteria are met, and steam generators can only be operated when tube integrity is maintained. The structural and accident induced leakage performance criteria were based on the design and licensing basis of the plants. Satisfaction of these criteria ensures tube integrity; namely, that the SG tubes are capable of performing their safety functions consistent with the licensing basis.

The conditions for demonstrating tube structural integrity are defined by the structural integrity performance criterion. The structural integrity performance defines the margins to be applied in maintaining adequate tube integrity against gross failure by either burst or plastic collapse. The technical bases for the structural integrity performance criterion follow from the design margins implied in Section III of the ASME Boiler and Pressure Vessel Code [162, 163]. Leakage integrity performance criteria are defined separately for operational and accident induced conditions. It is required that condition monitoring and operational assessments be performed to demonstrate overall tube integrity. Tube integrity is demonstrated by satisfying the structural integrity and leakage performance criteria. Structural performance criteria can be established through deterministic or probabilistic calculations. Usually it is a good idea that both types of criteria be determined and used for operational assessments as well as for condition monitoring.

The deterministic structural integrity performance criterion can be defined as follows [167, 176]:

All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions including startup, operation in the power range, hot standby, and cool down and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor against burst under normal steady state full power operation primary to secondary pressure differential and a safety factor against burst applied to the limiting design basis accident in accordance with relevant regulations (for example national regulation or if it does not exist with international regulations (IAEA) or main designer recommendations). Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to ensure that there is reasonable assurance that a steam generator tube will not burst during normal or postulated accident conditions.

In USA, the regulatory body (US NRC) and industry (NEI) agreed [176] on use of a safety factor of 3.0 against burst under normal steady state full power operation primary to secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary to secondary pressure differentials. The 'safety factor of three' criterion stems from Section III of the ASME Code [162], which, in part, limits primary membrane stress under design conditions to one-third of ultimate strength. The proposed structural integrity criterion would limit application of the 'safety factor of three' criterion to only those pressure loadings existing during normal full power, steady state operating conditions. Differential pressures under this condition are plant-specific, ranging from 8.3 MPa (1250 psi) to 10.3 MPa (1500 psi). However, differential pressure loadings can be considerably higher during normal operating transients, ranging between 11 MPa (1600 psi) to 14.8 MPa (2150 psi) during plant heat-ups and cool-downs. Given a factor of safety equal to 3 under normal full-power conditions, the factor of safety during heat-ups and cool-downs can be as low as about 2 for some plants. In addition, some countries may use slightly different values for the safety factors. However, these safety factors are consistent with the safety factors implicit in the specified tube repair limit of 40 per cent of the nominal tube wall thickness which has been in the TS since the 1970s and, thus, does not change the safety factors implicit in the licensing basis.

The proposed safety factor of 1.4 against burst applied to design-basis primary to secondary pressure differentials derives from the 0.7 times ultimate strength limit for primary membrane stress in the ASME Code, Appendix F, F-1331.1 (a). This criterion is also consistent with the stress limit criteria used to develop the standard 40% tube repair limit in the TS and, thus, does not change the plant-licensing basis.

Probabilistic structural performance criteria may be used as an alternative to the use of deterministic criteria. Proposed probabilistic criteria should not exceed the following:

- The frequency of steam generator tube bursts that occur as spontaneous, initiating events under normal operating conditions should not exceed 2.5×10^{-3}per reactor-year.
- The conditional probability of burst of one or more tubes under postulated accident conditions should not exceed 2.5×10^{-2}.

The accident induced leakage performance criterion requires limiting the amount of primary to secondary leakage that would occur during a design-basis accident, other than a tube rupture, to that which was evaluated as part of the unit's licensing basis. Demonstrating compliance with the accident induced leakage performance criterion, therefore, requires a calculation of the amount of leakage expected during various design-basis accidents. The calculated amount of leakage must be less than that assumed in the accident analyses. The accident induced leakage performance criterion is also intended to ensure that licensees maintain the amount of leakage caused by specific severe accident scenarios at a level that will not increase risk. Proposed accident induced leakage performance criterion should not exceed the following:

The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed maximum tolerable leak rate as approved by the national regulatory body.

The maximum tolerable leak rate (MTLR) shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all steam generators and leakage rate for an individual steam generator. In USA, the MTLR limit is 226.8 L/h [177, 178].

Operational leakage performance criteria are a matter of national regulation and may vary significantly from one country to another. The proposed operational leakage performance criterion is:

The reactor coolant system (RCS) operational primary to secondary leakage through any one steam generator shall be limited to the maximum allowable leak rate (MALR).

Although this criterion does not ensure tube integrity, it has been effective in limiting the frequency of tube ruptures and providing an indirect indicator of tube structural and accident induced leakage integrity. This criterion is important, since it can be monitored while the plant is operating. In USA, the maximum allowable leak rate is 23.65 L/h (150 gpd), while in Canada it ranges from 10–15 kg/h depending on specific NPP. In Russia, the RCS operational primary to secondary leakage through any one of WWER steam generators shall be limited to 4 L/h. The above numerical values are for information only. Member countries may have used different values for safety factors and the limiting amount of operational and/or accident induced leakage rates in accordance with national regulations.

7.4 STEAM GENERATOR TUBE FITNESS FOR SERVICE ASSESSMENT

Although there have been improvements in the requirements and practices pertaining to the design and operation of steam generators, tube integrity issues continue to arise. For the purpose of this guiding document, tube integrity means that the tubes are capable of performing their intended safety functions consistent with the licensing basis, including applicable regulatory requirements. Concerns relating to the integrity of the tubing stem from the fact that the SG tubing is subject to a variety of corrosion and mechanically induced degradation mechanisms that are widespread throughout the industry. These degradation mechanisms can impair tube integrity if they are not managed effectively.

The objectives of the steam generator fitness for service assessment include:

- Identification and characterization of material degradation within steam generators.
- Implementation of steam generator inspection programme to provide sufficient information concerning specific degradations present in the steam generators.
- Application of steam generator tube fitness for service assessment methods to evaluate condition of steam generators at the end of an inspection interval and to ensure integrity during the subsequent operation period.

Successful implementation of the above objectives should provide reasonable assurance that steam generator integrity is being maintained consistent with the licensing basis.

The steam generator integrity assessment consists of three key elements, as shown in Figure 7.1:

- Degradation assessment
- Condition monitoring
- Operational assessment.

The eye of steam generator integrity assessment represents the integration of critical elements of steam generator fitness for service assessment as seen through the eyes of the operational staff. The eye also represents clarity and vision of steam generator integrity assessment practices [2].

Figure 7.1.The eye of steam generator fitness for service assessment [2].

Degradation assessment is an initial stage of the fitness for service assessment that identifies the status of plant-specific steam generator material degradation. The objective of the degradation assessment is to prepare NPP operator for an upcoming inspection and maintenance outage to ensure that comprehensive steam generator inspection is performed, and that sufficient information concerning the degradation modes present, the tubes and internals with degradation, the size of these degradations, and other relevant information for fitness for service assessment is obtained.

Tube integrity performance is subject to two different types of assessments, as indicated in Figure 7.1: A condition monitoring assessment and an operational assessment. The *condition monitoring assessment* is a current and backward looking assessment to assess fitness-for service of the entire population of tubes, including validation and/or adjustment of predictive methods based on service experience to confirm that adequate steam generator integrity has been maintained during previous operation period (between previous and currently planned inspection outage). The current inspection results are compared against the acceptance criteria, as well as with the degradation predicted by the previous operational assessment. The condition monitoring assessment evaluates whether the acceptance criteria had been satisfied during the previous steam generator operation period. An integral element of the condition monitoring assessment is validation and/or adjustment of predictive fitness for service assessment methods during each inspection outage.

Operational assessment is forward rather than backward looking assessment to demonstrate that the steam generator integrity will be maintained through the next operating period.

7.5 DEGRADATION ASSESSMENT

Degradation assessment is the process of identifying and documenting existing and potential degradation in planning for an upcoming inspection and maintenance outage, including development of the inspection plans for the primary and secondary sides of the steam generator. The degradation assessment should be performed prior to each SG inspection and prior to pre-service inspection. In addition, a documented review of the previous outage degradation assessment shall be performed prior to each refueling outage when SG primary side inspections are not scheduled to validate the inspection interval. The degradation assessment should address the reactor coolant pressure boundary within the steam generator, e.g. plugs and tubes. The assessment should consider engineering analysis of the degradation mechanisms, as well as the operating experience from other similar steam generators. The purpose of the degradation assessment is to ensure that appropriate inspections are planned for the upcoming outage, by identifying all active degradation mechanisms and for each mechanism:

- Choose NDT method and technique or techniques to test for degradation based on the probability of detection and sizing capability.
- Establish the inspection sample population size (number of tubes to be inspected).
- Establish the extent of inspection (exact location of tubes, section, row, column, to be inspected).
- Establish the part(s) of the tube for confirmatory examination with advanced techniques.
- Establish the structural limits.
- Establish the flaw growth rate or a plan to establish the flaw growth rate.
- Establish inspection expansion criteria if new degradation is identified, or if the measured parameters change, such as degradation growth rate.

The identification of these parameters allows nuclear power plants to establish the examination and plugging criteria before an outage.

The assessment of potential degradation mechanisms affects both the inspection and structural assessment of the programme. The inspection component dictates the technique’s capability, including detection probability, sizing capability, and measurement uncertainty. The structural assessment applies the information gathered from the examination with degradation growth rate projections to establish the plugging criteria and/or inspection cycle length. To conduct an effective inspection, the plant management should integrate the structural and inspection components.

7.6 CONDITION MONITORING

Condition monitoring involves monitoring and assessing the ‘as found’ condition of the tubing relative to the tube integrity performance criteria. The ‘as found’ condition refers to the condition of the tubes during an SG inspection outage, prior to any plugging or repair of tubes. The condition monitoring assessment may utilize information from the tube inspections or from alternative examination methods to assess the condition of the tubing. Failure of one or more tubes to satisfy the performance criteria may be indicative of programmatic deficiencies in the plant programme for monitoring and maintaining steam generator tube integrity. The plant operators should assess the causal factors associated with this type of finding and implement appropriate corrective actions. For an unscheduled inspection that is due to primary to secondary leakage, the condition monitoring assessment need only to address the flaw type that caused the leak provided the interval between scheduled inspections is not lengthened. However, it will be necessary to estimate the contribution of accident leakage from the other active flaw types, as determined from the most recent operational assessment for these flaw types, to demonstrate that performance criteria for accident leak rate is met. The condition monitoring assessment and implementation of resulting corrective actions, if necessary, should be completed prior to plant restart.

Tube structural integrity may be monitored against the deterministic structural performance based on the results of in-service eddy current inspection for each flaw type. Tube structural integrity may be demonstrated by analysis for a given flaw type if the eddy current technique and eddy current personnel are validated for sizing with respect to that flaw type in accordance with referenced standards in the plant country. The analysis approach involves demonstrating that the most limiting flaws associated with each flaw type, as determined from in-service inspection, do not exceed the appropriate structural limit for each flaw type. Structural limit refers to the calculated maximum allowable flaw size consistent with the safety factor performance criteria.

Conservative bounding models and assumptions should be employed to account for uncertainties not directly treated in the assessment. Potential significant sources of uncertainty include error or variability of eddy current indication size measurement, material properties, and structural models. Structural models (i.e. models relating burst pressure to actual flaw size or to measured indication size) may be empirical or analytical (i.e. idealized models based on engineering mechanics). Empirical models quantify significant model uncertainties such as burst pressure data scatter and the parameter uncertainty of the empirical fit. Analytical models generally do not explicitly quantify uncertainties in the model estimates and, thus, should be developed to produce bounding estimates.

The conservatism of analytical models should be confirmed by test. For certain flaw types, analytical approaches to demonstrating tube integrity may be inappropriate or inefficient because of an inability to size certain flaw dimensions, large error or variability associated with indication size measurements, or large uncertainties of the structural models. These difficulties may necessitate bounding approaches to ensure a conservative analysis, but they may lead to unrealistic (overly conservative) results. Other approaches are also possible, which may provide a more realistic assessment and may be used as an alternative to, or as a supplement to, the above analytical approach for a given flaw type to demonstrate structural integrity in accordance with the performance criteria, but they have to be first justified.

Considerations for monitoring tube structural integrity against the probabilistic performance criteria should include the following for a given flaw type:

- Probabilistic approach should only be used when in-service inspection techniques and personnel are validated for detection and sizing in accordance with relevant regulations.
- The ‘as found’ frequency distribution of indications as a function of indication size should be established. The ‘as found’ distribution should be adjusted to consider the percentage of tube locations sampled to address the subject flaw type. The uncertainty of the as found frequency distribution is characterized by consideration of indication size measurement error or variability.
- Empirical models for burst pressure as a function of flaw size or indication size should be established. These models for burst pressure or failure load should account for data scatter and model parameter uncertainties.
- The probability of burst calculation should account for uncertainties in indication size measurement error or variability, material properties, and in the burst pressure model with rigorous statistical analyses. Statistical sampling methods such as Monte Carlo have to be used.
- The frequency of burst and conditional probability of burst estimates should be expected (mean) value estimates.

Primary to secondary operational leakage monitoring is an important defense-in depth measure that can assist plant operators in monitoring tube integrity during operation. Leakage monitoring also gives operators information needed to safely respond to situations in which tube integrity becomes impaired and significant tube leakage, rupture, or burst occurs. The objectives of leakage monitoring are to provide:

- Clear, accurate, and timely information on operational leakage to allow timely remedial actions to be taken to prevent tube rupture and burst.

- Clear, accurate, and timely information to facilitate the mitigation of any tube rupture or burst event.

Although leak-before-break cannot be totally relied upon for steam generator tubes, primary-to-secondary leakage monitoring can afford early detection and response to rapidly increasing leakage, thereby serving as an effective means for minimizing the incidence of SG tube rupture and burst. This can be achieved by having near real time leakage information available to control room operators. Use of such monitoring capability, along with appropriate alarm set points and corresponding action levels, can help operators respond appropriately to a developing situation in a timely manner. The monitoring programme should account for plant design, steam generator tube degradation, and previous leakage experience.

The potential primary to secondary leakage rate for the most limiting postulated design basis accident should be assessed, based on the 'as found' condition of the steam generator tubing, to confirm that the performance criteria for accident induced leakage were met immediately prior to the outage. The potential leak rate may be determined by analysis, based on the results of in-service eddy current inspection. The potential leak rate may be determined by analysis for a given flaw type provided the eddy current technique and eddy current personnel have been validated for sizing in accordance with referenced regulations.

Key elements of a condition monitoring accident leakage assessment by analysis should include the following for each flaw type:

- The 'as found' frequency distribution of indications for each active flaw type is established as a function of indication size. The distribution should be adjusted statistically to consider the percentage of tubes sampled to address the subject flaw type.
- Models relating the magnitude of leakage rate as a function of actual flaw size or eddy current indication size measurement for each flaw mechanism are established.
- The leakage calculation for each flaw and for total steam generator leakage rate is performed deterministically or probabilistically (e.g. with statistical sampling methods such as Monte Carlo), accounting for all significant uncertainties. Potential sources of uncertainty include eddy current indication size measurement error or variability, material properties, and leakage models. Leakage models may be empirical or analytical (i.e. idealized models based on engineering mechanics).

Empirical models should quantify significant model uncertainties such as data scatter and the parameter uncertainty of the empirical fit. Analytical models generally do not produce bounding estimates. The conservatism of analytical models should be confirmed by test.

In situ pressure testing may be used as part of, or as an alternative to, condition monitoring by analysis for a given defect type. Estimates of total leak rate from the results of the in situ tests should assume no functional relationship between leakage rate and the NDE indication size measurement, unless there are sufficient data and a rigorous statistical basis for doing so. These estimates should be adjusted to reflect indications involving the subject defect type that were not subjected to the pressure tests. In addition, these estimates should reflect the percentage of tube locations sampled by NDE to address the subject defect type.

7.7 OPERATIONAL ASSESSMENT

The operational assessment differs from the condition monitoring assessment in that it is 'forward looking' rather than 'backward looking.' An operational assessment should be performed to demonstrate that the performance criteria would continue to be met until the next scheduled steam generator in-service inspection. Operational assessment involves projecting the condition of the tubing at the time of the next scheduled inspection outage relative to the tube integrity performance criteria. This projection is based on the inspection results, the tube repair criteria to be implemented for each defect type, and the time interval prior to the next scheduled tube inspection. Corrective actions should be taken, as necessary, such that it can be demonstrated by operational assessment that the performance criteria will be met until the next scheduled in-service inspection. Corrective actions may include inspecting the steam generators at more frequent intervals or reducing the tube repair criteria. Generally it will be necessary to perform at least a preliminary assessment prior to performing tube plugging or repairs to ensure that the tube repair criteria being implemented are sufficient to support operation for the planned operating interval preceding to the next scheduled steam generator inspection.

A preliminary operational assessment and implementation of corrective actions, as necessary, should be completed prior to plant restart, demonstrating that the performance goals will continue to be met for at least 90 days following plant restart. The final operational assessment and additional corrective actions, as necessary, should be completed within 90 days of plant restart, demonstrating that the performance criteria will continue to be met prior to the next scheduled inspection. The proposed 90 day period may differ from one country to another. It is included here as an information (USA and Canadian regulations require a plant operators to complete preliminary inspection results and assessments within 90 days of the reactor restart from an outage) [164, 168].

Reasonable assurance that tube structural integrity will continue to be adequately maintained is established by demonstrating that the projected condition of the most limiting tubes immediately prior to the next scheduled inspection satisfies the deterministic criteria for each flaw type. Conceptually, this involves demonstrating that the projected limiting flaw sizes or indication sizes do not exceed the appropriate 'structural limit' for each degradation mechanism. Equivalently, this can involve demonstrating that the projected limiting flaws for each flaw type will exhibit burst-strength capacities.

The assessment methodology should account for all significant uncertainties so that, should the most limiting projected flaw or indication size be at the calculated structural limit immediately prior to the next scheduled inspection, the flaw or indication satisfies the performance criteria. The assessment methodology may be performed deterministically or probabilistically (e.g. with statistical sampling methods such as Monte Carlo). Conservative bounding models and assumptions should be employed to account for uncertainties not directly treated in the assessment. Potential sources of uncertainty include significant uncertainties associated with the projected limiting flaw or indication size, material properties, and structural model.

General considerations for projecting the most limiting flaw sizes associated with each defect type, including the uncertainty associated with these projections, include the following:

- Frequency distribution of indications left in service as a function of indication size.
- Frequency distribution of indications (as a function of indication size) found during the most recent past inspection of tubes that were not repaired or plugged at that time and that are not being inspected during the current inspection.
- Frequency distribution of flaw or indication growth rates as a function of indication size.
- Rate and size distribution function of new indications as a function of time between inspections.
- Probability distribution of eddy current sizing error or variability.

- Level of sampling performed during the current inspection and date of last inspection for un-inspected tubes.

Note that the above considerations for projecting the limiting flaw or indication size are based on the premise that eddy current technique and personnel are validated for sizing of the subject flaw type. If this is not the case, alternative or conservative bounding approaches must be taken. The evaluation of the performance of the predictive methodology in projecting the maximum flaw or indication size should be based on the results of future in-service inspections and appropriate adjustments made to the methodology as necessary to ensure this objective is met.

Structural models (i.e. models relating burst pressure to flaw or indication size) may be empirical or analytical (i.e. idealized models based on engineering mechanics). Empirical models should quantify significant model uncertainties such as burst pressure data scatter and the parameter uncertainty of the empirical fit. Analytical models generally do not explicitly quantify uncertainties in the model estimates and, thus, should be developed to produce bounding estimates. The conservatism of analytical models should be confirmed by test. For certain degradation mechanisms, operational assessment methodologies may be inefficient because of an inability to size certain flaw dimensions, large error or variability associated with flaw or indication size measurements, or large uncertainties of the structural models. These difficulties may necessitate bounding approaches to ensure a conservative analysis. However, the development of eddy current techniques with good probability of detection and sizing performance and more precise structural models is key to ensuring a realistic operational assessment and avoiding unnecessary corrective actions (including operational restrictions.

Considerations for performing the operational assessment against the probabilistic performance criteria structural integrity should include the following for a given flaw type:

- The probabilistic approach should only be used when in-service inspection techniques and personnel are validated for detection and sizing.
- The calculation of the frequency distribution of flaws or indications should be by the size projected to exist immediately prior to the next scheduled inspection. The specific details for projecting the distribution of flaw or indication sizes are to be developed by plant operators. The performance of the predictive methodology that projects a distribution that results in a conservative estimate of conditional probability of burst should be evaluated based on the results of future in-service inspections and appropriate adjustments made to the methodology as necessary to ensure this objective is met.
- The empirical burst pressure should be established as a function of flaw or indication size. These empirical models should account for data scatter and model parameter uncertainties.
- The projected distribution of flaw or indication sizes, the calculated frequency of burst, and the calculated conditional probability of burst during postulated accidents should include a rigorous statistical treatment of all significant sources of uncertainty affecting the calculation, including growth rate, indication size measurement, and burst pressure model. Statistical sampling methods such as Monte Carlo may be used.
- The frequency and conditional probability of burst should be evaluated at the one sided, upper 95% confidence level.

The potential steam generator primary to secondary leakage rate during the most limiting postulated accident (other than steam generator tube rupture) should be assessed relative to the performance criteria for accident leakage integrity, based on the frequency distribution of flaws or indications as a function of flaw or indication size projected to occur immediately prior to the next scheduled steam generator inspection outage. Conservative bounding models or assumptions should be employed to account for uncertainties not directly treated in the assessment. Considerations for establishing the magnitude of leakage for each flaw type as a function of flaw or indication size are the same as those identified for the condition monitoring. For certain flaw types, operational assessment methodologies may be inefficient because of an inability to size certain flaw dimensions, large error or variability in the eddy current flaw or indication sizing measurements, or large uncertainties of the leakage models. These difficulties may necessitate bounding approaches to ensure a conservative analysis. However, the development of eddy current techniques with good probability of detection (POD) and sizing performance and more precise structural models is a key to ensuring a realistic operational assessment and avoiding unnecessary corrective actions (including operational restrictions).

7.8 STATISTICAL METHODS FOR DEGRADATION GROWTH ASSESSMENT

This section summarizes the steps of an overall approach for estimating the probability of degradation of steam generator tubes. The approach employs a statistical technique and an empirical model, which is consistent with the known degradation processes. A statistical approach is useful because of the large number of tubes in each steam generator and because the occurrence of degradation of steam generator tubes is influenced by a number of materials and environmental variables. One approach used by some plant operators is to model the probability of occurrence of degradation at operating life ‘*t*’ by the Weibull probability distribution, which is easy to handle mathematically and has been successfully used to describe the statistics of material failure caused by fatigue and stress corrosion cracking. An alternate to the Weibull distribution is the ‘log-normal’ probability distribution. This method has proven particularly useful for the analysis of laboratory corrosion results (and is, in fact, suggested by the National Association of Corrosion Engineers for that purpose), and for long term projections of degradation in operating steam generators. However, in view of its broader use in recent analyses, the Weibull distribution will be emphasized here.

The equation for the two-parameter Weibull distribution is:

$$F(t) = 1 - \exp\left[-\left(\frac{t}{t_r}\right)^b\right]$$

Where:

F(t) is the cumulative probability (or fraction) of tubes ‘failed’ by a given degradation mechanism.
t is the time of operation using an appropriate time scale.
t_r is the scale parameter or characteristic time of the Weibull probability distribution (63.2% of a population has failed by the completion of a period of service equal to the characteristic time, the value of t_r, depends on the environment of the tube at the failure location).
b is the shape parameter or the slope of the distribution when plotted on a Weibull probability graph.

The fraction *F (t)* in the Weibull equation is the fraction of tubes that are ‘failed’ according to a particular criterion. Generally, a tube is considered to have failed when it is removed from service (plugged) or repaired by sleeving because of defects produced by the degradation mechanism being analysed. For some purposes, it is useful to use a criterion other than plugging or sleeving to define the failed condition for analysis purposes. Effective full power years (EFPY) is generally used as a convenient measure of time of operation (total energy generated divided by the reactor rated power). This measure of time provides an approximate means of accounting for the effects of changes in operating temperature of the tubes for different reactor operating conditions. If the reactor has operated for an extended period of time at substantially reduced power, *equivalent* full power years should be used. However, the determination of equivalent full power years requires a value of the activation energy for the degradation mechanism being analysed [6].

The parameters b and t_r in the Weibull equation are adjustable parameters generally determined by fitting the distribution function to the observed data. The exponent b defines the slope of the Weibull curve. Its value determines how much scatter there is in times to failure among a given population. This exponent accounts for the random variations of properties between different tubes in one steam generator. The characteristic time t_r in the Weibull equation is the basic rate constant of the degradation process. As several of the degradation mechanisms that affect steam generator tubes are considered to be stress assisted, thermally activated processes, the parameter t_r is primarily a function of temperature, stress, and chemical environment. For such mechanisms, an Arrhenius equation for the characteristic time t_r is used:

$$t_r \;=\; A\sigma^{-m} \exp\ [Q/R\,(1/T - 1/T_0]$$

Where:

t_r is the characteristic time appropriate to a specific location;
T is the temperature for the specific location;
σ is the appropriate stress component for the location;
m is the constant describing the stress dependence of the degradation mechanism;
Q is the activation energy of the degradation mechanism;
R is the gas constant;
T_0 is the temperature for a standard reference condition such as full power condition;
A is the constant determined from $t_{r0} = A\ \sigma_0^{-m}$, where t_{r0} is the characteristic time for reference condition T_0, σ_0.

Various estimates for the activation energy Q have been derived from laboratory studies and field experience. For example, the estimate for the activation energy for the PWSCC mechanism ranges from 39 to 65 kcal/mole, with a best estimate value of 50 kcal/mole [6, 179]. The stress exponent value (m) is approximately 4. The constant A is a scaling constant determined by the characteristic time for some standard stress level and reference temperature. The value of A will change whenever there is a systematic change in the material characteristics and chemical environment, the average stress level at the location of interest, or other conditions that may differ from plant to plant.

Figure 7.2 presents an example of the Weibull probability paper plot of the time of occurrence of degradation in SG tubing. In this plot, the logarithm of the lifetime is plotted on the horizontal axis and double logarithm of empirical cumulative probability of exceedance is plotted on the vertical axis. The slope of the regression line provides an estimate of the Weibull shape parameter (b), whereas the intercept is $b\times\log(t_r)$ from which the scale parameter or characteristic time can be back calculated.

Although a number of steam generator experts in the nuclear industry are quite comfortable with these approaches, some experts at the USNRC and the US national laboratories question its validity. An Arrhenius equation is an empirical correlation, which may be qualitatively useful, but may not, and in the case of Alloy 600MA tubing, has not always provided accurate life predictions. The failure of the calculated time to correlate with the field experience may arise from several uncertainties in the input variables. Frequently, the activation energy is given as 50 kcal/mole, however, the basis for this value is suspect. Some recent events have suggested that the value is temperature dependent and may be as low as 35 kcal/mole. Additionally, a single value of activation energy may not be valid for both incubation and crack growth, as is generally assumed when life prediction calculations are performed. Also, not all of the variables controlling stress corrosion cracking in steam generator tubes have necessarily been identified, and thus, their omission from the equation can only lead to erroneous results. This opinion is supported by the consistent failure of accelerated laboratory corrosion tests to correlate with the Alloy 600MA field experience.

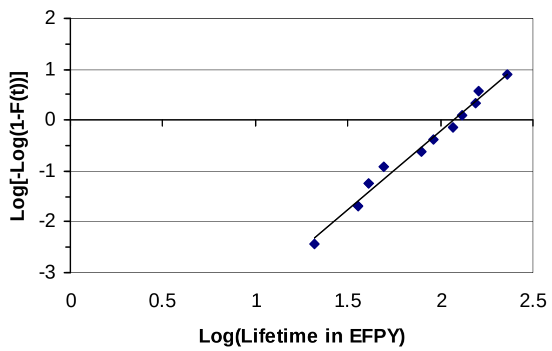


Figure 7.2. Weibull analysis of data for ODSCC in steam generator.

Empirical models may be used to establish the relationship between a tube integrity parameter (e.g. burst pressure or accident leakage rate) and defect size or NDE indication size. Development of empirical models should conform to principles of good statistical practice for purposes of establishing mean correlations and for quantifying the uncertainties associated with the mean correlation. Empirical correlations should reflect a statistically significant set of data such that uncertainties associated with the correlation can be quantified. Ideally, the data should be relatively uniform over the range of flaw sizes of interest. If the data set is relatively sparse over a portion of the flaw size range compared to another portion, standard statistical tests should be performed to ensure that the model parameters are not being unduly influenced by individual data in the sparsely populated portion of the flaw size range.

Empirical correlations should be a reasonable fit of the data as evidenced by 'goodness of fit' and residual analysis. Empirical models for burst pressure and leakage rate should explicitly account for data scatter and for model parameter (e.g. slope and intercept) uncertainties. Such models should involve a statistically significant correlation with defect or indication size (e.g. a linear regression fit of the data can be shown valid at the $P = 0.05$ level). If such 'significance of correlation' cannot be rigorously demonstrated for leakage rate models, the regression fit of the leak rate data, as a function of defect or indication size should be assumed to be a constant value. Empirical models for probability of leakage (POL), if used, should explicitly account for parameter uncertainty. For POL models, a number of functional forms may exhibit similar goodness-of-fit attributes; however, they may lead to significantly different results for a given flaw size. Thus, the functional form of the fit should be selected with care to ensure a conservative leakage assessment.

7.9 USE OF PROBABILISTIC FRACTURE MECHANICS ANALYSIS TO ASSESS STEAM GENERATOR AGEING

The development of probabilistic fracture mechanics technologies started in the late 1970s. The first applications in the field of nuclear engineering were concerned with the reliability of the reactor pressure vessels and primary coolant piping. In early 1990s a probabilistic fracture mechanics approach has been applied to the problem of steam generator reliability, and then only to the question of tubing rupture due to axial PWSCC at the expansion transition regions [180–182].

The basic advantage of a probabilistic fracture mechanics analysis, as compared with a classical fracture mechanics assessment of design margin, is an ability to address the uncertainties inherent in the detection and sizing of cracks and in estimating crack initiation and propagation rates. In other words, all available information (both certain and uncertain) can be used. The main product of a probabilistic fracture mechanics analysis is a probability of tubing rupture value. The objectives of the steam generator tubing probabilistic fracture mechanics analyses are to:

- Quantify the influence of ageing management activities such as tubing inspection and plugging on the probability of steam generator tube rupture.
- Compare various ageing management options.
- Limit the number of shutdowns caused by out-of-specification primary to secondary leakage [180–182].

The key items required for a probabilistic fracture mechanics analysis are:

- Measured crack length distribution from the most recent tube bundle non-destructive examination.
- Non-detection probability as a function of flaw size and the flaw sizing accuracy, both from comparisons of pulled tube destructive and non-destructive examination data.
- Crack initiation rates from comparison of the data from the last two or three sequential bundle examinations.
- Crack propagation rates from laboratory experiments or again from comparison of the data from the last two or three sequential bundle examinations.
- Probability of detecting a leak before the tube ruptures from laboratory experiments and the leak detection system sensitivity.
- Probability of tube rupture as a function of loading (i.e. the critical crack length).
- Uncertainties in various dimensions and material properties.

EdF has developed a probabilistic fracture mechanics computer code called COMPROMIS, which uses this type of information to keep the probability of a tube rupture in the French steam generators below 10^{-2} to 10^{-4} per reactor-year. The COMPROMIS code calculates three key items:

- Initial crack size distribution.
- Change in the crack size distribution with time.
- Probability of tube failure based on an evaluation of leak before break.

The initial crack size distribution is calculated using a Bayesian approach, which calculates the ‘a priori’ distribution of true sizes from the measured ‘a posteriori’ distribution and knowledge of the ‘likelihood function’ (inspection reliability). Probability distributions of the detection and measurement errors (both systematic and random), which are crack size dependent, are used to adjust the measured crack size distribution. These probability distributions are based on comparisons of measured eddy current indications and destructive metallurgical examination results from about 150 pulled tubes. Also, the initial crack size distribution is adjusted based on the plugging or repair limits, and the probabilities of detecting flaws larger than the limit.

The evolution of the initial crack size distribution with time is calculated by considering the probabilities of new cracks being initiated during the operating period and the expected propagation of existing cracks. The crack initiation model is based on Weibull statistics similar to those discussed in Section 7.8 above. The crack propagation model is based on a correlation between the crack propagation rate and the stress intensity factor, which depends, in part, on the crack size and was developed from laboratory work.

The third key item calculated in the COMPROMIS code is the probability of tube failure, considering the probability of a detectable leak before break. To obtain the probability of a detectable leak, a stochastic method is used, which considers random factors, uncertainties, and variabilities in an empirical crack size versus leakage model. A Monte Carlo simulation then calculates the probability of rupture versus crack size, considering variations in tube thickness, tube diameter, yield strength, ultimate strength, and tube to tube support plate contact. Finally, cumulative failure probabilities are calculated as a function of time.

The COMPROMIS code has been successfully used to evaluate the influence of the inspection strategy (frequency and number of tubes inspected), helium leak testing, the plugging criterion, and other controllable parameters on the probability of a steam generator tube rupture. Other probabilistic fracture mechanics analyses have shown that implementation of nitrogen-16 monitors leads to about two orders of magnitude lower tube rupture probabilities and the non-detection probability associated with the existing eddy current inspections has the largest influence on the tube rupture probability [180]. The methodology is quite general and can be easily transferred to other combinations of ageing mechanisms, sites, and inspection technologies and work has recently been directed towards circumferential cracking at roll transitions and ODSCC at tube support plates.

Under contract from the Atomic Energy Control Board of Canada (now the Canadian Nuclear Safety Commission), Dominion Engineering Inc. developed an initial version of a Monte Carlo based code called CANTIA (CANdu Tube Inspection Assessment) to simulate the effects of tube inspection and maintenance strategies on the safe operation of CANDU design nuclear steam generators. The integrity and leak rate models in CANTIA were specifically intended for the CANDU steam generators in Canada [183]. The CANTIA, recently updated by CNSC and Argonne National Laboratory staff, uses a probabilistic steam generator tube failure model [184, 185]. It calculates a time dependent flaw size and number of distribution so that the probability of failure or the rate of leakage can be estimated. It uses a Monte Carlo approach; each important parameter is treated as a random variable with known or predictable median behavior and a known or predictable distribution of behavior (i.e. variation) around the median. Both the median and variance of each random variable are specified by the user, or, if desired, a fixed (deterministic) value can be used. For each Monte Carlo trial, the value of each variable is chosen randomly in accordance with the selected distribution function, or the fixed value is used, so that the trials reflect the variability of the actual situation. A large enough number of trials (chosen by the user) are then run for each analysis to provide a stable statistical distribution of the results. For each Monte Carlo trial, CANTIA determines flaw sizes, growth rates, inspection results, material properties, etc. for each tube, and tracks the progression of the flaws in each tube throughout the model time period.

If the user has entered a ‘measured’ initial flaw distribution as opposed to an ‘actual’ one, the ‘actual’ flaw distribution is estimated from the measured flaw distribution density f(×) by dividing f(×) by the probability of detection function POD (×) and then renormalizing. Thus the number of flaws initially present is increased to account for the undetected flaws. CANTIA randomly selects a flaw size from the ‘actual’ flaw size distribution (whether entered by the user or calculated from the measured flaw size distribution and POD) for each tube with a flaw at the initial time. Initiation times for flaws in tubes without initial flaws are also randomly selected, the size of the flaw at the time of initiation is selected by the user. Flaw growth rates are then randomly selected for each tube in the modeled population, and the size of the flaw on each tube at each future time of interest is calculated. CANTIA then determines the conditions in the steam generator at each time of interest. It begins by calculating the primary to secondary leak rate through each flaw under normal and accident conditions and assessing whether or not each flaw would cause its tube to fail under accident conditions at the first chronological time of interest (as input by the user). Next, inspections are performed if either the time of interest is a scheduled inspection time (as entered by the user), or the primary to secondary leak rate under normal conditions is larger than the allowed maximum (as entered by the user). Inspections are modeled with an initial sample size and expansion rule parameters and POD and measurement error distributions selected by the user, and are performed until either all of the tubes are inspected or no additional expansions of the tube sample size are required by the inspection expansion rules. Detected flaws that are larger than the plugging limit are then 'repaired' by removing the tube from the sample population. This process is repeated for each additional time of interest.

Given the information about POD and measurement error, the prediction of detected and measured flaw size distribution is easy. A more complex inverse problem is to predict the distribution of actual flaw sizes from the measured flaw sizes. A more refined statistical model has been developed by Pandey et al [186, 187] to analyse measured flaw size data, which are contaminated by NDE sizing random error. This study shows that ignoring the sizing error can lead to erroneous estimates of the degradation growth rate, which affects the operational assessment of SG tubing.

7.10 PROBABILISTIC PREDICTION OF LIFETIME OF SG TUBING

Alloy 800 is a low carbon version of the austenitic nickel (33%)-iron (42%)-chromium (22%) alloy, which is widely used for steam generator tubing in nuclear stations (PWR and CANDU[7]) due to its high resistance to intergranular corrosion and stress corrosion cracking (SCC). The operating experience with CANDU and KWU fleets of steam generators confirms excellent resistance of Alloy 800NG tubing to various modes of in-service degradation seen in other alloys, such as Monel 400 or Alloy 600MA. As many CANDU plants are approaching the end of life, degradation free performance of Alloy 800NG SG tubing in the remaining and extended plant life is of critical concern to the nuclear utility industry. If it can be demonstrated with high confidence that the lifetime of SG tubing would exceed 60 years, the replacement of SGs would not be required during refurbishment of the plant and considerable monetary benefits can be realized.

SG tubing is exposed to a varying environment in terms of electro-chemical potential (ECP) and local chemistry conditions. The most probable locations where the tubing materials may be susceptible to environmental degradation are SG crevices or beneath deposits. This is because non-volatile impurities such as chlorides and sulphates can hide out and concentrate in crevices, or beneath deposits, under heat transfer conditions. Because of the hideout of SG impurities an electrochemical corrosion cell will be formed between the surfaces of tube free span and tube inside the crevice that would result in corrosion degradation in crevices. Mechanisms of SG tubing degradation are well summarized in many references, such as [188–190].

Probabilistic approaches have quite useful in predicting the remaining lifetime of SG tubing and reliability impacts of degradation, as they can incorporate various sources of uncertainty and limitations of data [191, 192]. Degradation free lifetime (DFL) is defined as the duration of the service life of SG tubing in which no degradation takes place. The onset of degradation is considered to have taken place when 0.05% to 0.1% of the tubes in a SG have experienced an active SCC

[7] CANadian Deuterium Uranium, a trademark of Atomic Energy Canada Ltd.

degradation mode, which requires significant maintenance attention, such as tube plugging. The prediction of degradation free lifetime is important from the point of view of maintenance planning [193]. In case of Alloy 600MA tubing, rich in-service experience and degradation data are available to estimate the Weibull lifetime distribution. For example, median lifetime of Alloy 600MA is estimated as 14 EFPY and the Weibull slope of b = 3.34.

However, other tubing materials, such as Alloy 800NG used in CANDU steam generators, Siemens designed steam generators and Alloy 690TT used in modern PWRs SGs have shown excellent resistance to stress corrosion cracking (SCC), and occurrence of in-service degradation of these alloys have rather rare. When adequate in-service data are not available, the prediction of the lifetime distribution becomes a challenging problem [189, 194]. The problem of prediction the lifetime distribution can be analyzed using two approaches:

- Material improvement factor (IF).
- Probabilistic Bayesian approach.

Improvement factor method

The concept of improvement factor (IF) is currently used by the industry to quantify the benefit of improved design and materials with reference to the performance of Alloy 600MA tubing. The IF in case of Alloy 800NG can be defined as the ratio of the median DFL of the Alloy 800NG tubing to the median DFL of Alloy 600MA tubing. The estimation of the IF is based on the data obtained from experimental programme or in-service experiences regarding the occurrence of degradation. For example, outer diameter SCC of tubing is a serious form of degradation mechanism. The median degradation free lifetime of Alloy 600MA tubing is estimated as 13.96 EFPY from in-service data. Considering the experience of Alloy 800NG tubing in CANDU plants in Canada, the median life time is estimated as 34.77 EFPY, which mean that improvement factor for Alloy 800NG is approximately 2.50. The DFL distribution of Alloy 600MA and Alloy 800NG are compared in Figure 7.3 below.

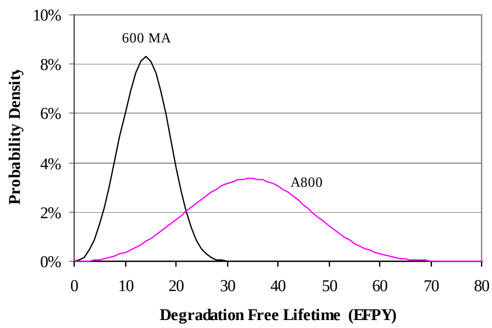


Figure 7.3. Comparison of degradation free lifetime distributions for 600 MA and A800 (800NG) alloys.

Based on laboratory test results, Slade et al. [193] compiled DMIFs under a variety of chemical environments (i.e. pH values). They reported an aggregated DMIF of 4.5, which was computed by weighting the DMIF with the relative frequency of occurrence of pH values. Given a DMIF of 4.5, the median lifetime of Alloy 800NG is estimated as 63 EFPY.

For several years the CANDU industry has carried out a variety of SG tubing corrosion tests, coupled with crevice chemistry testing and modeling, in order to provide a basis for understanding existing SG degradation, for predicting and anticipating future degradation, and for ensuring appropriate materials selection for new SGs. Although a number of short- and long term autoclave tests with CERT, U bends, C rings, capsules, etc. have been carried out, a key factor in being able to compare and contrast the results of these tests has been that they were carried out in a consistent set of chemistries, based on hideout return data from CANDU steam generators. The corrosion susceptibility of Alloy 800NG, Alloy 600MA, Alloy 690TT and Alloy 400 has been evaluated by performing a series of electrochemical measurements under the plausible SG secondary side crevice conditions [195].

Based on these electrochemical data, recommended safe ECP/pH zones for minimizing the corrosion degradation of the SG alloys were defined for SG alloys under CANDU operating conditions, as shown in Figure 7.4 [196].

Since the area of the safe ECP-pH zone for an alloy characterizes its aggregate resistance to degradation under diverse chemical environments, the ratio of the safe zone areas of Alloy 800NG to Alloy 600MA can serve as a more comprehensive estimate of the material improvement factor (DMIF), and results are presented in Table 7.1. A general assumption is here that the variation of ECP and pH in their entire range is equally likely. Under lead free conditions, the DMIF of Alloy 800NG with reference to non-sensitized Alloy 600MA is 1.46, which increases to 3.4 in comparison with sensitized Alloy 600. It is believed that Alloy 600MA tubing in the SGs of Bruce CANDU Station is generally sensitized and some lead contamination is present in the steam generator. In such case, the improvement factor can be inferred quite high (over 20 as shown by case 2.2 in Table 7.1). In summary, safe ECP-pH zone can be utilized to estimate improvement factor.

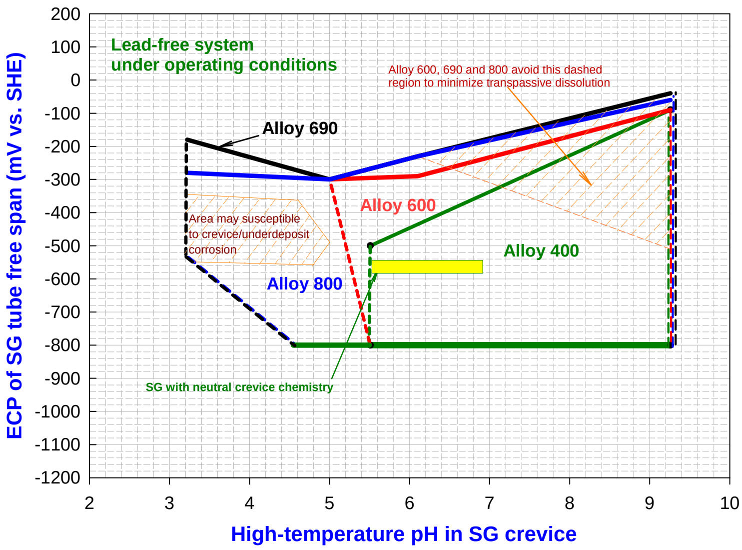


Figure 7.4. Recommended ECP/pH zone with minimized corrosion for steam generator alloys at CANDU SG operating temperature.

TABLE 7.1. IMPROVEMENT FACTORS DERIVED FROM SAFE ECP-pH ZONE FOR ALLOYS 800NG AND 600MA

No	**Case**	**Improvement Factor (Alloy 800NG)**
1	*Lead free conditions*	
1.1	Not sensitized Alloy 600MA	1.46
1.2	Sensitized Alloy 600MA	3.40
2	*Lead contamination*	
2.1	Not sensitized Alloy 600MA	2.66
2.2	Sensitized Alloy 600MA	20.14

Bayesian approach

In the improvement factor method, a linear scaling is applied to the median lifetime of Alloy 600MA without changing the Weibull shape parameter (*b*), which means the coefficient of variation of Alloy 800NG is the same as that of the Alloy 600MA (33%). The constancy of the Weibull shape parameter is a significant assumption in the current approach, since the composition and microstructure of Alloy 800NG and its response to chemically aggressive environments is mechanistically different than that of Alloy 600MA.

It can be concluded that in order to derive lifetime distribution of Alloy 800NG, some uncertain pieces of information should be combined with some expert judgment about the median lifetime of Alloy 800NG tubing. Therefore a systematic approach is needed where different assumptions can be integrated and their sensitivity to final distribution can be methodically assessed. A comprehensive probabilistic Bayesian approach was used to build such a model [190]. In this model, the Weibull shape parameter (*b*) and the median lifetime of Alloy 800NG tubing are considered as uncertain variables. Prior information about these variables is presented in form of probability distributions, which are updated through the information available from the in-service performance of Alloy 800NG tubing in the CANDU fleet. This method yields the lifetime distribution, which allows computing the reliability of Alloy 800NG tubing at any age and the associated confidence interval. This approach is generic, and it can be applied to evaluate the effect of other degradation mechanisms different types of materials.

8 STEAM GENERATOR MAINTENANCE: MITIGATION, REPAIR, REPLACEMENT

This section discusses mitigation and repair techniques for degradation mechanisms in tubes, tube sheets, feedwater nozzles and shells. Sections 8.1, 8.2 and 8.3 cover mitigation and repair techniques for tubes. Table 8.1 summarizes countermeasures for tube failures in PWR steam generators. Most of the measures reduce corrosion by controlling water chemistry, or by reducing temperature or tensile stresses. Section 8.4 addresses vibration problems. Sections 8.5 and 8.6 cover mitigation and repair techniques for feedwater nozzles and shells. Sections 8.7 and 8.8 deal with WWER collector repair and replacement. Section 8.9 covers replacement measures, such as use of improved tube materials and modification of the tube supports, which cannot be used in existing steam generators, but can be incorporated into new designs. The effectiveness of the methods presented in this section has been mixed. In general, corrective measures are not as effective as preventive measures, such as those discussed in Section 5.

8.1 PRIMARY-SIDE MITIGATION TECHNIQUES FOR TUBES

PWSCC may be mitigated by reducing tensile stresses through measures such as roto-peening or shot peering, stress relieving of the U bends and controlling the denting problem. In addition, lowering the operating temperature, protecting susceptible sites (e.g. plugging or sleeving, Section 8.3), and reducing (< 25 cm^3/kg) or increasing (> 50 cm^3/kg) the hydrogen concentration in the PWR coolant to outside of the current water chemistry specification range may also help to mitigate PWSCC.

8.1.1 Roto-peening and shot peening

Both the shot and roto-peening processes use the impact of a high velocity small-diameter mass on the inside surface to produce a layer of cold worked material a few tens of microns deep. Shot peening uses high velocity metallic, ceramic, or glass particles. Roto-peening uses the impact of shots bonded to fabric in a flapper wheel and requires remote tooling in a radioactive plant. Because there is no post-process non-destructive field inspection technique to quantify the benefit, the effectiveness of the peening depends entirely on the process controls. This is a preventive technique, not a repair method for an already cracked tube. These processes have been used at some units in Europe, Japan, and the USA. However they are not generally used because they are not effective in preventing the growth of existing cracks, although, they do slow the propagation of old cracks. Also, both roto-peening and shot peening create outer diameter tensile stresses, which could possibly increase the susceptibility of the tubing to ODSCC. This is considered in the field process specifications, which limit the outside diameter stress increases to about 4-6 ksi. Also, both processes require remote tooling. There is very little to differentiate the two methods, although only shot peening is currently being used.

8.1.2 Stress relieving

Stress relieving at 705°C for at least 5 minutes also reduces the susceptibility of Alloy 600MA to PWSCC, particularly at the U bends. Laboratory studies indicate that the use of in-situ stress relief techniques results in an increase of PWSCC initiation time at least by factor 10. Stress relieving of Alloy 600MA tubes in the 650–760°C range may cause sensitization (formation of chromium depleted regions near grain boundaries) and susceptibility to secondary side IGSCC/IGA; however, this may not be a concern for Alloy 600MA material with intergranular carbides and low solid-solution carbon content. Thermally treated Alloy 600 and 690 may also be stress-relieved without causing sensitization.

8.1.3 Reducing the hot leg side temperature

Corrosion is a thermally activated process and is, therefore, strongly affected by the tubing temperatures. The primary coolant entering the hot leg sides of the recirculating steam generators (RSG), or the top of the once through steam generators (OTSG), is about 25°C to 40°C (45–72°F) hotter than the coolant leaving the cold leg side of the RSG or the bottom of the OTSGs. Therefore, the hot leg side of the tubes in the RSG have usually experienced corrosion degradation much earlier than the cold leg sides. Similarly, the upper regions of the tubes in the OTSGs have experienced corrosion degradation, while the lower regions have been relatively immune from these problems. The primary coolant hot leg temperatures at full power vary from about 315°C to 327°C (599–621°F) at most PWR plants, initiation of stress corrosion cracking has usually been later at plants with lower hot leg temperatures. A few plants with Alloy 600MA SG tubes have operated with hot leg temperatures at the steam generator inlet as high as 330°C (626°F) and have experienced relatively early and extensive primary and secondary side corrosion. (However, the outside diameter stress corrosion cracking may have been influenced by factors other than temperature.) Conversely, the CANDU plants have operated with a hot leg temperature of about 308°C (586°F) and have not experienced PWSCC to date.

Reducing the temperature of the tubing on the hot leg side by about 10°C or more is believed to slow down, though not preclude, various thermally-activated damage mechanisms on both the primary and the secondary side. This is a temporary mitigation technique that can increase the time between the steam generator outage required for inspection. Plant availability is increased, but this benefit may be offset by reduced power during operation.

However, it is possible to reduce the hot leg temperature by up to 10°C without lowering the power at some plants because of the turbine designs.

8.1.4 Zinc injection

Zinc addition creates thin and adherent stable oxide layers on stainless steel and Alloy 600MA, Alloy 600TT or Alloy 690TT SG tube surfaces. According to this, an inhibiting effect of zinc on PWSCC can be expected.

The first laboratory studies with respect to effect of zinc addition on PWSCC was published by Westinghouse [197–199]. Based on their results they confirmed that considerably higher quantities of zinc are necessary for mitigation of PWSCC than for radiation field control (40–50 µg/kg instead of 5 µg/kg). In their work highly stressed reverse U bend specimens of Alloy 600MA, Alloy 600TT and Alloy 690TT were exposed under simulated primary coolant conditions with and without zinc addition. Three heats of Alloy 600MA tubing were selected. Two heats with high susceptibility (1019 with high strain and 96834L with low strain) were tested. The thermally treated Alloy 600 and Alloy 690 RUBs (reverse U bend) were tested both in the high stress configuration.

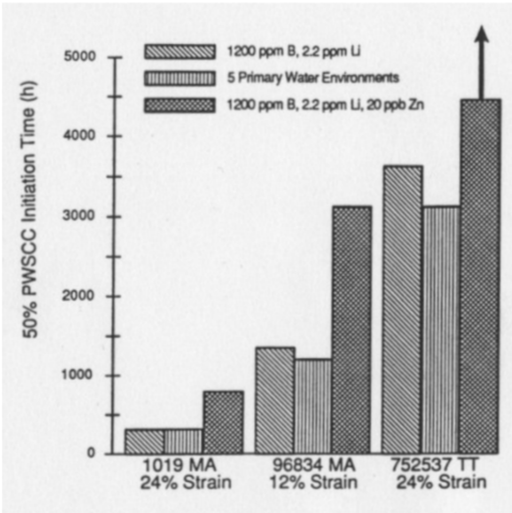


Figure 8.1. Average PWSCC initiation times for different conditions of Alloy 600MA RUB specimens [198].

As a result, statistically, significant reduction of initiation time and extent of PWSCC were observed as a function of zinc addition versus in the absence of zinc additives (Figure 8.1):

- The lower strained heat 9834L Alloy 600MA RUBs lasted 4 times longer than the higher strained heat 1019 RUBs.
- The thermally treated heat 752537 tested at higher strain level lasted 8–10 times longer than the heat 1019 RUBs.
- For each material, PWSCC initiation was delayed in the test environment containing 20 µg/kg of zinc. For the heats 1019 MA and 96834 MA, the RUBs tested in the environment containing 20 µg/kg of zinc took 2.5 times longer to initiate PWSCC.
- For Alloy 600TT heat 752537 RUBs, no PWSCC initiation was observed after 4500 hours of exposure with the addition of zinc borate. In contrast, PWSCC had initiated in over 50% of the RUBs of this heat, in a shorter time period of 3200 hours, without presence of zinc.
- Due to significant Alloy 600TT PWSCC resistance, no initiation was expected and none was observed in the Alloy 690TT RUBs, either with or without zinc.

- Based on detailed examination of the cracks (depth and lengths), zinc addition reduces the extent of the cracks also. For the sensitive heat 1019 the average value of the crack length and depth was by factor two smaller by zinc addition.

All other primary system materials of interest showed a reduction of both overall corrosion and metal release rates in presence of zinc additives.

Field experience

Laboratory and field data. Both confirm that zinc addition has definitely beneficial effect on the PWSCC initiation. However, with respect to PWSCC crack growth rate the beneficial effect of zinc is not so clear and the field experience is sometimes ambiguous, at least for thick walled components like reactor pressure vessel head (RPV) penetrations. For SG tubes a reduction by a factor of 1.5 was estimated by EPRI, based on field experience [138].

8.1.5 Control of hydrogen concentration

PWSCC of alloy 600MA and its welding alloys (Alloy 82, 182) seems to be most susceptible at Ni/NiO transition potential as shown in Figure 8.2. Maximum growth rate was under the range of $E_{Ni/NiO}$+-80 mV. US approach is to increase the hydrogen content, and Japanese one is to decrease the hydrogen content, respectively. EPRI has been issuing a revised version of the primary water chemistry guidelines.

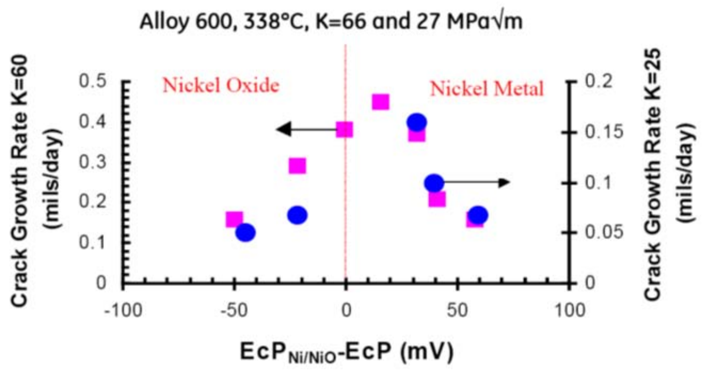


Figure 8.2. Crack growth rate for Alloy 600MA in simulated PWR environment at 338°C [200].

8.2 SECONDARY-SIDE MITIGATION TECHNIQUES FOR TUBES

The actions which will slow down or prevent outer diameter stress corrosion cracking (ODSCC), intergranular attack (IGA), pitting, and denting of the steam generator tubing are primarily those discussed in Section 5 above, associated with the control of secondary side water chemistry (chemical additives, actions to limit impurity ingress, and steam generator cleaning). Reducing the hot leg temperatures to values at or below about 300°C (575°F) will significantly slow down thermal-activated damage mechanisms such as IGSCC and IGA, but not to the same extent as PWSCC [4, 201]. Another secondary side mitigation technique used on many of the older Westinghouse type steam generators with tube to tube sheet crevices was full depth or almost full depth expansion (usually hydraulic expansion) of the tubes.

8.3 SUMMARY OF MITIGATION TECHNIQUES FOR TUBES

The possible techniques used to mitigate the SG tube degradation are summarized in Table 8.1.

TABLE 8.1. COUNTERMEASURES FOR TUBE FAILURES IN PWR STEAM GENERATORS

Mechanism	**Mitigation of damage in existing tubes**	**Improvements in new/replaced steam generators**
PWSCC	Roto-peening or shot peening to residual stresses, stress relieving of the U bends and control of the denting problem.	Alloy 690TT tubes with an optimum strength of about 380 MPa, little or no residual stresses.
Intergranular stress corrosion cracking, intergranular attack	Control of the alkaline impurities, chlorides, sulphates; flush tube sheet crevices; use of hot soak, sludge lancing, and chemical cleaning; neutralization of crevice alkalinity; addition of boric acid; and full depth roll expansion of tubes to eliminate crevices.	Alloy 690TT tubes with an optimum microstructure, no tube sheet crevices, improved access for lancing and cleaning, increased blowdown capacity, and flow patterns that minimize sludge accumulation.
ODSCC	Control of the alkaline impurities, chlorides, and sulphates; elimination of condenser leakages and ingress of salt impurities	
Pitting	Elimination of condenser leakages and ingress of air/oxygen, chlorides, and sulphates; removal of copper from the feedwater train, condensers and MSR.	Titanium or stainless steel condenser tubes, no copper alloys in the feedwater train, and corrosion resistant tube materials (Alloy 690TT or Alloy 800NG)
Combination of pitting and SCC from the secondary side	Control of the alkaline impurities, chlorides, and sulphates; elimination of condenser leakages and ingress of chlorides, and sulphates	
Denting	Elimination of condenser leakages and ingress of air/oxygen and chlorides; use of hot soaks; removal of copper from the Condensers, MSR and feedwater train.	Strict water chemistry control, stainless steel support structures, support plates that preclude stagnant water in the annuli, and titanium condenser tubes
Wastage	Use of all-volatile treatment water chemistry; elimination of hideout chemical concentrations; use of sludge lancing, chemical cleaning, hot soaks and flushing; preclusion of resin ingress.	Flow patterns that minimize hide-out and chemical concentrations and sludge accumulation; improved access for cleaning; increased blowdown capacity.
High cycle fatigue and fretting in RSGs		Additional antivibration bars (AVBs) and insertion of the AVBs deeper into the bundle; minimum tube to AVB clearances and wear matching of the AVBs to the tubes.
Erosion-corrosion; corrosion fatigue in OTSG	Control of the chemistry and entrained solid particle content of the secondary side coolant	

8.4 TUBE REPAIR

Damage and failure of steam generator tubes occurs with greater frequency than with other components, partly because the tubes are exposed to both the primary and secondary coolant and more than 50% of the pressure boundary is associated with the tubing. For this reason much of the research and actual repairing in steam generators is associated with the tubing.

8.4.1 Plugging

Plugging was the only countermeasure available for PWR steam generator tubes with unacceptable flaws until the early 1980s. Denting has caused several thousand tubes to be plugged in some plants. Even now, plugging is often done for unacceptable degradation above the tube sheet region because the current sleeving techniques are difficult or expensive to implement high up in a steam generator. As of 1994, more than 103 000 plugs are installed worldwide in PWR and CANDU plants [43]. Plugs have typically been made from bar stock of Alloy 600MA material; however, most currently installed plugs are made of Alloy 690TT material. Commonly used techniques to plug a tube include welding, explosive forming, and mechanical or rolled installation. A typical mechanical plug in its unexpanded and expanded forms is shown in Figure 8.3.

A plugged tube may continue to be susceptible to stress corrosion cracking, fatigue, and fretting damage, and finally sever. However, the temperature of the coolant in a plugged tube is about 40°C (70°F) less than an unplugged tube on the hot leg side. This will greatly reduce the PWSCC rates. A severed tube may experience large amplitude vibrations because of fluid-elastic instability and then damage neighbouring tubes. To prevent this, plugged tubes can be stiffened by inserting stabilizers, for example, solid rod segments that can be threaded to each other and to the plug.

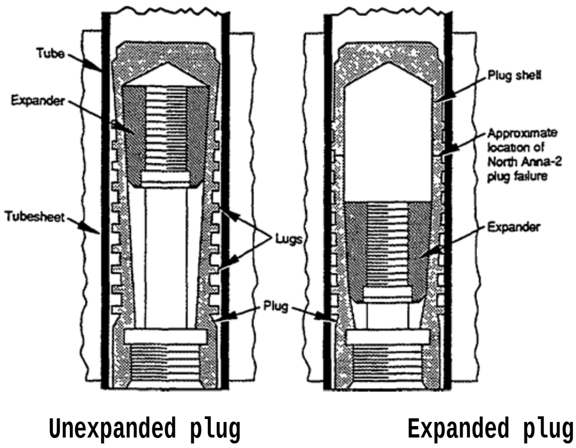


Figure 8.3. Sketches of unexpanded and expanded mechanical plugs [202]. Reprinted with permission.

Certain types of plugs are also susceptible to PWSCC type degradation, as described below:

1. Explosive plugs of Westinghouse design installed in the 1970s have experienced PWSCC, as evidenced by several reports of leaking plugs. These plugs were made of mill annealed Alloy 600. Explosive plugs have leaked in at least three plants because of large plastic strains and unfavourable residual stresses at plug comers. The cracking seen in at least one plant was circumferential in orientation and occurred at the top transition of the explosive expansion, i.e. in a pressure boundary region.

2. PWSCC has recently been reported as occurring in Babcock & Wilcox mechanically rolled plugs installed in recirculating and once through steam generators, and has been identified in different thermally treated Alloy 600 tube plug heats [203]. This PWSCC has occurred in the form of circumferential cracks located in the transition below the roll expansion, i.e. at the ‘heel’ location, which is not part of the pressure boundary, so that plug integrity is not affected (see Figure 8.4). To a lesser extent, degradation in the form of axial cracks in the transition above the roll expansion, i.e. in the ‘toe’ location, which is part of the pressure boundary, has also been identified. The degradation has been detected by rotating pancake coil inspection. Cracked plugs have only been seen on the hot leg sides to date.

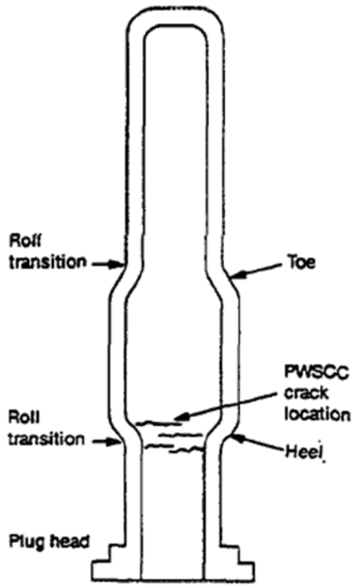


Figure 8.4. PWSCC cracks in rolled plug supplied by Babcock & Wilcox [203].

3. Mechanical plugs of Westinghouse design have experienced PWSCC in the expanded area. These plugs have been installed in large numbers since about 1980. The most significant occurrence of PWSCC in this type of tube plug occurred in February 1989 at North Anna Unit 1 [204, 205]. The plug involved was made with thermally treated Alloy 600 material. In this incident, circumferential PWSCC occurred nearly through wall all around the circumference of a plug, as shown in Figure 8.3 [202]. The remaining ligament broke during a plant transient and allowed the top part of the plug to be propelled up the tube until it hit the U bend, which it penetrated, causing a significant primary to secondary side leak. The adjacent tube was deformed, but not penetrated, by the impact of the plug top.

   It was originally estimated that mechanical plugs potentially susceptible to PWSCC had been installed in about 7000 tubes in Westinghouse steam generators in approximately 20 US PWR plants. However, plugs made with what were thought to be relatively non-susceptible heats have recently experienced significant circumferential cracking at only about 20% of the estimated lifetime. The USNRC now requires US utilities to implement a programme of plug removals, inspections, and repairs for all Westinghouse mechanical plugs fabricated from thermally treated Alloy 600. Also, installation of Westinghouse mechanical plugs fabricated from Alloy 600 material should be discontinued [206].

   More than 3000 steam generator tubes in France have also been plugged with Alloy 600MA mechanical plugs. Some of the plugged tubes have experienced a ‘boiler effect’ due to through wall cracks in the plugs. Removal of these plugs from the hot leg tube ends is now scheduled.

4. Welded plugs manufactured by Combustion Engineering have also degraded and resulted in leakage in service. Cracking in these Alloy 600MA plugs has occurred in the welded region and is believed to be caused by PWSCC degradation. Plug defects are repaired by rewelding or replacement with a new welded plug. Improvements in weld materials and procedures are expected to preclude future degradation in the new welded plugs. Similar problems have also occurred in Europe.

   Despite the plugging of a relatively large number of tubes, a steam generator may still generate the rated capacity of electricity because it normally starts operation with a significant margin of available capacity. However, continued plugging after the margin is exhausted can significantly reduce plant capacity [201]. Also, the plugging of a very large number of tubes can impact the thermo-hydraulics of a steam generator and result in safety problems. Before this occurs, the potential economic consequences (cost of anticipated repairs and cost of lost capacity from plugged tubes) should necessitate extensive sleeving or steam generator replacement. Steam generators lose their capacity margin when about 5% to 20% of their tubes are plugged.

Sleeves can be installed into previously plugged steam generator tubes to restore plant capacity if the plugs are successfully removed. Welded plugs are typically removed by electric discharge machining (EDM) or drilling or milling techniques. Mechanical plugs can generally be removed (pulled) with a hydraulic device.

5. Plugging of WWER steam generator tubes is performed by welded plugs. The plugs are made of austenitic steel type 08CH18N10T. The plugs are inserted into the mechanically bored holes in both collectors and welded.

8.4.2 Sleeving

Sleeves placed inside PWR steam generator tubes bridge over the damaged tube regions. They are designed to take the full loads that the original tubing was designed to take, i.e. the sleeve replaces the tube as a structural element from its top joint to its lower joint. Most of the currently available sleeving techniques are designed to cover the inside surfaces of PWR steam generator tubes in the region from the bottom of the tube sheet to slightly above the sludge piles. Another location for sleeving is at tube support plate intersections, where sleeves are used to repair IGA/IGSCC occurring at the tube support plate-to tube crevice. Sleeves at tube support plates have only been used on a very limited basis in the USA (originally at Palisades in the mid-1970s and recently at one or two other plants on a trial basis), but they are now being extensively used in some Japanese and other plants. Sleeves can be installed into previously plugged steam generator tubes to restore plant capacity if the plugs are successfully removed. The sleeve is normally made of a material having better corrosion resistance than the original tube material, such as thermally treated Alloy 600 or Alloy 690.

Sleeve designs vary primarily in the joint between the sleeve and the tube. The sleeve top joints can be either the leak limiting type or the leak-tight type. The leak limiting type such as a hydraulically expanded joint and a hybrid expanded joint have been widely used, and are continuing to be used in relatively low temperature plants (typical hot leg temperature less than 315°C). However, recently hybrid expanded joint sleeves have been installed in a high temperature plant (typical hot leg temperature in the range of 325°C to 330°C). The sleeves are generally 760 mm to 914 mm (30–36 in.) long. The hybrid expansion is constructed by first making an approximately 100 mm- (4 in.) long hydraulically expanded section, and then making a shorter 50 mm (2 in.) long mechanical-roll (hard roll) expanded section centred within the hydraulically expanded section as shown in Figure 8.5, making a leak-tight or nearly leak-tight mechanical joint. Residual and operating stresses in the lower hard roll transition, shown in Figure 8.6, are likely to be the highest in the entire hybrid expanded joint. The upper joint of the sleeve is provided with an over-length of 50–112 mm (2–4.5 in.), which represents a length of unexpanded sleeve above the upper expanded section that should limit lateral displacement of the tube in the event of a circumferential break of the parent tube in the upper joint region. Note also that the upper hydraulic transition of the upper joint of the parent tube represents the primary pressure boundary. Also, the inside surface of the parent tube along the sleeve over-length is deeply creviced and is in contact with the primary coolant. Also, the gap between the section of the parent tube which is no longer the primary pressure boundary and the sleeve is a deeply creviced geometry, and if a defect in the parent tube grows through the wall, the crevice will be filled with stagnant secondary water that may promote IGSCC or IGA of both the parent tube and sleeve. The reasons for using a hybrid expansion are to:

- Make the main transition between the unexpanded and expanded areas by a hydraulic method, which results in lower residual stresses with less potential for stress corrosion cracking.
- Include a mechanically rolled area, which results in a tighter joint with lower leakage than achievable using hydraulic expansion alone.

Sleeves currently being installed in higher temperature plants with PWSCC use leak tight joints, which are made by brazing or welding after the sleeve is expanded to be in intimate contact with the tube as shown in Figure 8.7. Explosively welded joints are expanded and welded in one operation. Laser welding of the sleeving is being used in the USA, Europe and Japan, in part, to reduce radiation exposure. The sleeves are typically 900 mm (36 in.) long or longer to ensure that the top joint is well above the tube sheet and sludge pile areas and there is sufficient over-length above the top joint. The weld regions must be prepared before sleeving to remove any oxidation or corrosion layers, thereby ensuring a proper metallurgical bond.

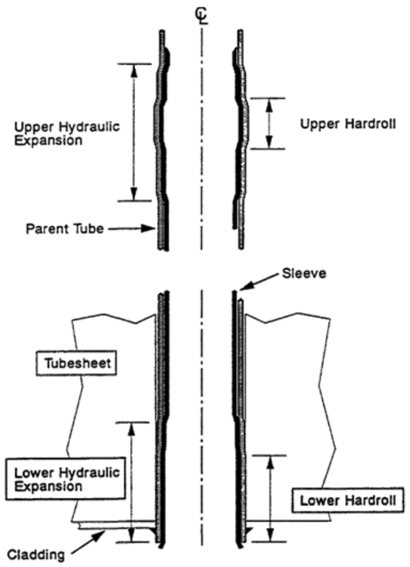


Figure 8.5. Typical sleeve installation with a hybrid expanded joint [207]. Copyright Westinghouse Electric Corporation; reprinted with permission.

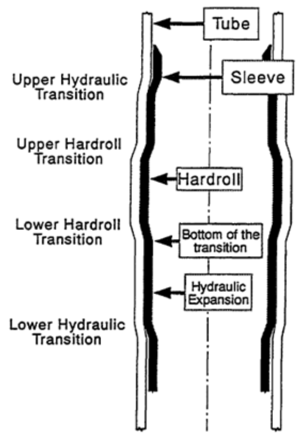


Figure 8.6. Hybrid expansion joint configuration [207]. Copyright Westinghouse Electric Corporation; reprinted with permission.

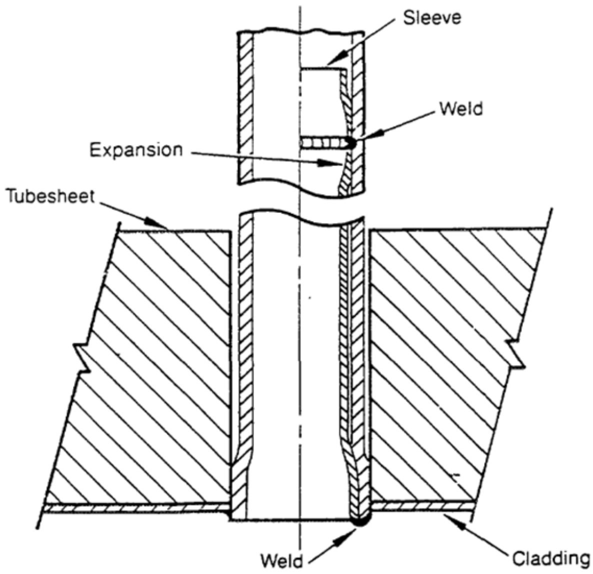


Figure 8.7. Welded sleeve design (Combustion Engineering) [4]. Copyright Electric Power Research Institute; reprinted with permission (modified).

Welded joints in free span areas of high temperature plants (typical hot leg temperature of about 327°C) with PWSCC susceptible Alloy 600MA tubing are generally stress relieved with a short time high temperature heat treatment, in order to minimize the likelihood of PWSCC. Westinghouse installed approximately 30 000 laser welded sleeves in the Doel Unit 4 and Maine Yankee steam generators during 1994 and 1995.

Explosively expanded sleeve joints have also been used to affect a leak-tight repair for degradation both at the top of the tube sheet and at tube support plate elevations; these were referred to as 'Tdnetic’ sleeves. In the period from 1991 through 1992, more than 2500 such sleeve repairs were made by Babcock & Wilcox in steam generators at Duke Power's McGuire Unit 1 and Unit 2 plants, and at Trojan. After three separate forced outages due to primary to secondary leakage, all of the kinetically sleeved tubes were removed from service by plugging. The cracking that occurred was circumferentially oriented PWSCC of the parent tube just above the upper explosive joint. Failures occurred both in joints that were not stress relieved (due to high local as-fabricated residual stresses) and joints that received a high temperature post-installation stress relief. The latter failures are probably due to the high stresses that can develop during thermal stress relief of a tube that is not free to expand axially due to ‘lock-up’ at the tube support plates (e.g. restraint due to localized denting or corrosion product build-up).

Another approach to the repair of roll transition region stress corrosion defects in part depth rolled tubes is the design used on an experimental basis at Doel Unit 2. This approach uses the thin Alloy 600 mini sleeve shown in Figure 8.8; this sleeve is about 40 mm (1.5 in.) long, explosively expanded and welded over the cracked tube. A portion of the tube that was not previously expanded is now expanded against the tube sheet, thereby providing the load carrying capability. In other words, the transition region between the deformed and undeformed portions of the tube is now in a new defect free location, with probably less residual stresses than the original hard rolled joint. The sleeve is so thin that the inside dimension of the tube is practically not altered, allowing full flow of reactor coolant. This design does not preclude the future use of a longer sleeve with other designs and processes if new defects are found later.

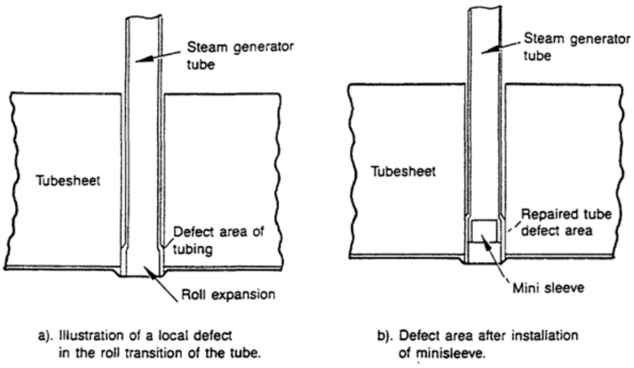


Figure 8.8. The minisleeve design (Babcock & Wilcox) using explosive welding [208]. Copyright Electric Power Research Institute; reprinted with permission.

Service experience with the almost 100 000 sleeves installed worldwide has generally been good. However, some parent tubes at least eight plants have experienced degradation and were subsequently plugged and removed from service. The cracking is mainly caused by stress corrosion in which the residual stresses introduced by the sleeving process play a major role. The experience with the kinetic sleeves was mentioned above, examples of other problems are discussed below.

Use of mini-sleeves at Doel Unit 2 was discontinued because shortly after their installation, PWSCC occurred in five expanded tubes at the tops and bottoms of the sleeves. All tubes with this type of sleeve were plugged. At two other plants, four parent tubes experienced through wall cracking at the welded sleeve joints and the sleeves collapsed. At another plant, the defective weld in two welded sleeve joints has resulted in leakage of primary coolant.

In 1993, over 1700 tubes in three steam generators at the Doel 4 plant were repaired with hybrid joint sleeves. During the next refuelling cycle, two of the sleeved tubes leaked. One of the leaking tubes was pulled and examined in the laboratory. The examinations showed that the leakage occurred at the upper hydraulic transition of the upper joint. The leak resulted from a 180 degree, through wall circumferential crack, which initiated at the inside diameter (PWSCC). Removal and examination of another sleeved tube also showed a 90% to 100% through wall circumferential crack extending 30 degrees around the parent tube. The utility has plugged or laser-weld repaired all the tubes in which hybrid joint sleeves were installed in 1993.

Out of 75 indications detected in the upper region of the sleeves with hybrid expanded joints at the Kewaunee plant, 74 were circumferential and one axial. Most of the circumferential indications were detected at the lower hard-roll transition of the joint. These indications were most likely initiated by ODSCC. Several indications were detected at the lower hydraulic transition. One circumferential indication was detected at the upper hydraulic transition, which, as mentioned before, constitutes a primary pressure boundary. The axial indication was located in the hard-roll region and most likely initiated by ODSCC. No sleeved tube from the Kewaunee plant has been pulled and examined in the laboratory. So the degradation mechanisms responsible for detected indications have not been identified with certainty.

Inspection of the parent tube through the intervening sleeve is difficult. This is particularly true for detection of circumferential cracks at upper transition regions. Special eddy current probes are being developed for this inspection.

Estimates of the service performance for sleeve repairs of degraded tubes are usually based on accelerated corrosion tests of mock-ups prepared to replicate as nearly as possible the conditions that exist in the field. Recently, this has included testing under conditions of axial restraint, to stimulate far field stresses that develop due to lock-up at support plates. Environments that have been used for these tests include high temperature (400°C) dense steam and mild caustic (NaOH) solutions. In order to benchmark the results of these tests (i.e. to provide some basis for interpreting the results in terms of performance in the steam generator) components whose corrosion resistance in service is known are included in the test autoclaves. These latter mock-ups are typically mechanical roll expansions.

The anticipated performance of a sleeve (lifetime) depends on the nature of the sleeve repair (mechanical without stress relief versus a fusion with or without thermal stress relief, etc.), the location of the degradation, whether the degradation is PWSCC or ODSCC, the resistance of the parent tube to stress corrosion, the extent of the restraint at nearby tube support plates, operating temperature, and possibly other factors. Therefore, the lifetime of a sleeved tube could be as little as two cycles when the parent tube has a low resistance to stress corrosion cracking, the joints are mechanical and not stress relieved, and the steam generator is operating at high inlet temperatures (e.g. 330°C). Or, the lifetime of a sleeved tube could be as long as 20 years for thermally stress relieved laser welded sleeves in a low temperature steam generator (e.g. 315°C).

8.4.3 Nickel plating

A nickel plating technique has been developed by Framatome and Belgatom to repair PWSCC cracks in PWR steam generator tubes. The nickel plating consists of electrolytically cleaning the damaged surface and then depositing up to about 200 microns of pure nickel on the damaged surface. The nickel deposit on the damaged tube wall bridges the through wall cracks and stops leakage of primary coolant into the secondary system. In addition, the nickel deposit prevents contact between the primary coolant and the damaged tube wall, arresting crack propagation and stopping the initiation of new cracks. Nickel plating has been qualified for steam generator tubes and has been applied to about 1100 tubes in Belgium and Sweden. All these tubes, except the first few, are still in service, whereas unplated tubes are degrading.

Nickel plating has several advantages over sleeving. It generates very low residual stresses and does not require a subsequent heat treatment, and it can be applied anywhere in the straight part of the tube. It also allows later access to areas above the plated section for repair of any damage, whereas sleeving does not. Nickel plating is also a reversible process because, if needed, the plating can be stripped off chemically without damaging the tube.

Nickel plating has one major drawback; the thin plating does not provide a structurally acceptable pressure boundary. Therefore, the parent tube has to continue to carry most of the pressure loadings and parent tubes with large through wall cracks may not have adequate strength. With respect to in-service inspection of the plated region, nickel is magnetic and the nickel layer creates a barrier to the small magnetic field introduced by conventional eddy current coils. Therefore, these methods cannot be used to inspect a nickel plated region. However, a new ultrasonic inspection method capable of detecting axial and circumferential cracks has been developed to overcome this problem. Pulsed magnetic saturation eddy current techniques may also be used for inspecting nickel plated tubes [209].

8.5 VIBRATION CONTROL

8.5.1 Preheater repairs

The wear/fretting problem in the Westinghouse type D2/D3 RSGs was addressed by redistributing feedwater flow between the primary and auxiliary feedwater inlets to reduce the flow into the preheater through the primary inlet, and by incorporating a preheater manifold to reduce cross flow vibration. Turbulence and peak flow velocities were reduced. Westinghouse model D4/D5/E RSGs were modified by performing an expansion of the tubes within the tube baffle plates at certain preheater locations, in effect changing the tube natural frequency. In addition, a split of the feedwater flow between primary and auxiliary inlets was also implemented on the D4/D5 RSGs. The inspection results to date indicate that these modifications have been effective at reducing preheater wear/fretting to a level of minor concern [210, 211]. The Krsko plant has operated for about 10 years without any problems in the preheater sections of their Westinghouse model D-4 steam generators, after expansion of some of the tubes and split feedwater was introduced.

8.5.2 Antivibration bar replacement

Fretting problems occurred in a number of the earlier RSGs and resulted in additional or longer antivibration bar installations. For example, additional antivibration bars were installed in the Beznau Unit 1 steam generators in Switzerland. Antivibration bars have been replaced in Japan, Spain, the USA, and elsewhere.

8.6 MITIGATION OF THE THERMAL FATIGUE OF THE FEEDWATER NOZZLES AND PIPING

Several modifications in the operation of the auxiliary feedwater systems have been made to minimize or prevent thermal fatigue of the feedwater piping and nozzles. The modifications include:

- Use of auxiliary feedwater with a steady flow instead of fluctuating or intermittent flow.
- Shorter hot standby and low power operating periods during which auxiliary feedwater has to be used.
- Use of a nitrogen blanket on the condensate storage tank, which feeds the auxiliary feedwater system. This prevents ingress of oxygen to the auxiliary feedwater, and thus reduces corrosion fatigue.
- Use of heated auxiliary feedwater to reduce corrosion fatigue.
- Use of temperature monitoring to control the auxiliary feedwater injection and thermal loadings.

Several modifications in the design of the feedwater system have also been made in the existing or new steam generators minimize or prevent thermal fatigue damage to the feedwater piping and nozzles. Some of these modifications have been also employed for repairing the thermal fatigue damage as discussed in the next section. The modifications include:

- Replacing the sharp counterbore with a blend radius to reduce stress concentrations.
- Installing a separate nozzle for injecting the auxiliary feedwater directly into the steam generator.
- Use of a spraying device located in the feedwater piping upstream of the nozzle to mix the cold auxiliary feedwater with the hot water in the pipe.
- Installing a long thermal sleeve to protect the feedwater piping from thermal stresses and fatigue damage induced by thermal stratification.
- Welding the thermal sleeve to the feedwater nozzle to reduce stratification in the annulus region between nozzle and thermal sleeve.
- Use of a destratification loop in the feedwater piping (either just inside or just outside the steam generator shell).

8.7 REPAIR OF FEEDWATER NOZZLES AND PIPING

At one PWR plant in the USA, the feedwater nozzle bore region, blend radius, steam generator shell inside surface beneath the nozzle, and feedring support bracket welds experienced thermal fatigue cracking. All cracks and indications were removed by grinding and were repaired by welding to the design configuration. Cracks were also found on the inside surface of the bore of the inspection ports, which were ground and weld repaired with the Westinghouse half-bead technique [212].

The feedwater piping-to-steam generator nozzle connections have been particularly susceptible to thermal fatigue damage. In the case of D.C. Cook, piping was repaired as shown in Figure 8.9. The backing strip was removed in the redesign, and the sharp discontinuity, where the crack initiated was replaced with a blend radius. Also, a long thermal sleeve was installed to protect the counterbore region and a gamma plug was installed for in-service inspection of the thermal sleeve.

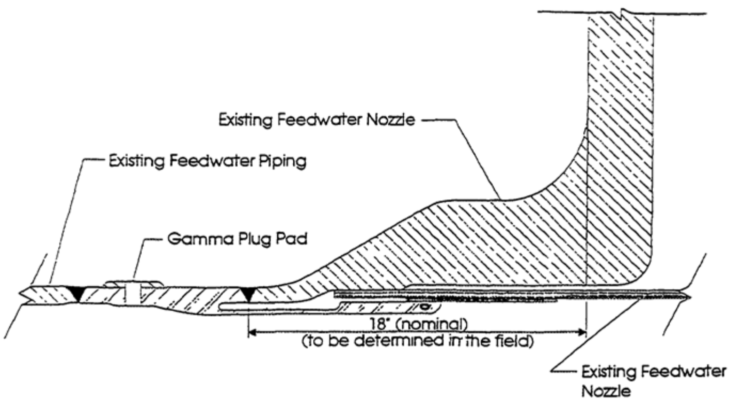


Figure 8.9. Schematic diagram of tuning fork repair used in feedwater nozzles [64]. Copyright American Society of Mechanical Engineers; reprinted with permission.

At Diablo Canyon Unit 1, erosion-corrosion of the outside surface of the carbon steel thermal sleeve caused thinning of the sleeve. This damage was due to feedwater leakage through the feedwater nozzle-thermal sleeve joint and the fact that the chromium content of the thermal sleeve material was less than 0.1 weight per cent. Thermal sleeves are being repaired with a new tuning fork design, shown schematically in Figure 8.9. The tuning fork is an integrated single piece, welded to the existing piping. It fits over the old thermal sleeve, preventing bypass leakage between the existing nozzle and thermal sleeve. There is a region of stagnated water in the gap between sleeve and nozzle, but no flow [64]. Several plants have also replaced the affected portion of the piping adjacent to the feedwater nozzle.

8.8 WWER COLLECTOR REPAIR

Technology of the repair of collectors with cracks in ligaments between holes has been developed, tested on the specimens and introduced at NPPs (SUNPP, Balakovo NPP). After localization of cracked ligaments tubes were drilled out from holes. Then plugs of the same material as collector were installed by welding (45 pieces). After that last plug of stainless steel is installed and two layer cladding was restored (see Figure 8.10).

Technology of replacing of the upper part of the steam generator collector with cracks in the cylindrical part or in the threaded holes has been developed and successfully applied in Bohunice and Dukovany NPPs. The damaged upper part of the collector was replaced by the new original part and welded.

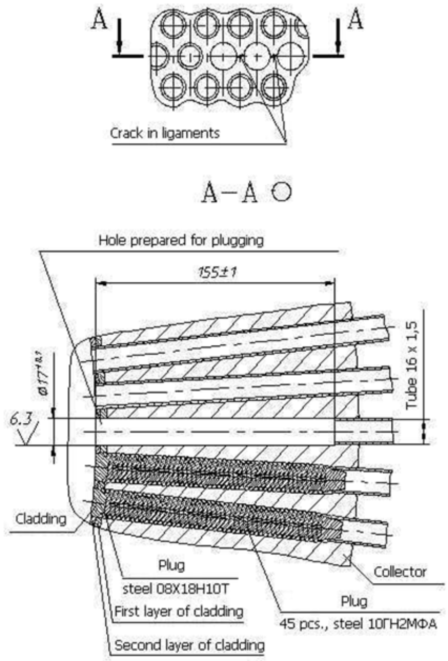


Figure 8.10. WWER-1000 collector repair.

8.9 WWER FEEDWATER COLLECTOR REPLACEMENT

After erosion-corrosion of carbon steel distribution collectors at some WWER-440 units replacement programmes were undertaken. Original design of collector inside of tube bundle was impossible to reproduce it, so new design above tube bundle was developed. In Rovno and Paks design short simple nozzles used. In case of Loviisa anti stratification tubes implemented in order to avoid possible water hammer, because at Loviisa same collector is used for emergency feedwater supply (20°C). In case of Dukovany design is maximum close to original but more complicated.

In Bohunice and Mochovce there were changed the feed water distribution systems in all steam generators. The new distribution pipes are made of stainless steel and the new distribution system is placed above the tube bundle.

At WWER-1000 same design of distribution collector used for replacement but made of stainless steel. The only difference is modified distribution of feedwater along the SG length. Due to this redistribution stepwise evaporation principle was implemented, so distribution of impurities in SG was optimized in order to avoid uncontrolled zones of impurity concentration. In new design, maximum impurities concentration is localized in ‘cold’ edge of vessel with minimum heat flux. Continuous blowdown line located in this region called ‘salt compartment’ to provide effective impurities removal. To stabilize zone of ‘salt compartment’ a plate was installed above tube bundle.

At some WWER-1000 and all new build units design of distribution pipes changed, so part of the feedwater supplied to corridor between tubing packages in order to suppress steam and improve circulation (see Figure 8.11 and Figure 8.12).

8.10 STEAM GENERATOR REPLACEMENT

The loss of power attributed to plugging of the steam generator tubes or the effort involved in sleeving a large number of tubes may not be acceptable. In such a situation, the following three alternatives are available: replacing the entire steam generator, replacing the lower assembly of the steam generator, or retubing the steam generator using the existing tube sheet and shell structures.

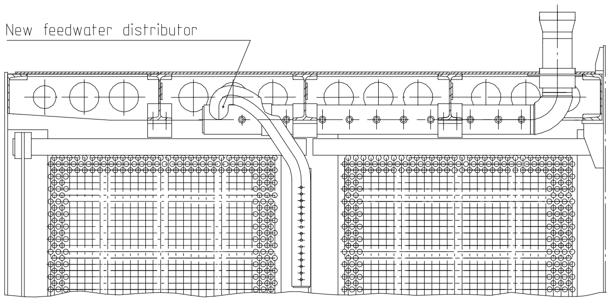


Figure 8.11. Feedwater distribution modification at WWER-1000.

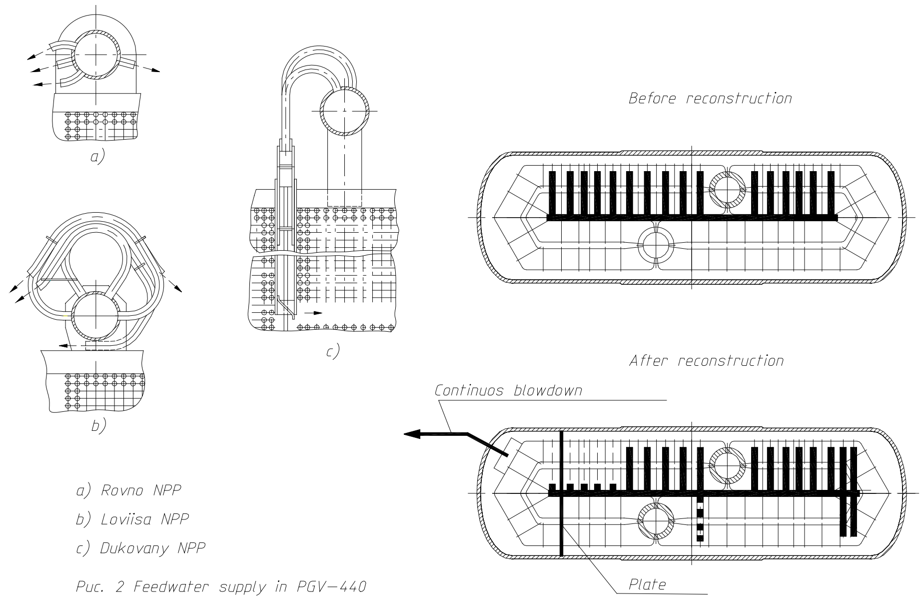


Figure 8.12. Feedwater distribution reconstruction at WWER-1000.

Replacing the entire steam generator involves cutting the piping (primary and secondary), forcing the generators from their supports, and removing them through existing equipment hatches in the containments. Where existing equipment hatches cannot be used, considerable work may be involved in cutting temporary transfer openings in pre-stressed concrete containments. The replacement of PWR steam generators also introduces difficulties in fit-up and welding not encountered in previous nuclear plant maintenance or repair projects and requires considerable decontamination work. On the positive side, because utilities are now exchanging steam generator replacement experience, the outage times caused by replacement have been significantly reduced. For example, the Gravelines 1 steam generator replacement was completed in 40 days.

Replacement of the lower assembly of a recirculating steam generator involves cutting the steam generator at the transition cone and removing the lower assembly, including the tube sheet forging, tubes, etc., and then replacing it with a new lower assembly. This procedure has been chosen for Turkey Point and North Anna Unit 1 because it was difficult to cut the reactor coolant piping because of access problems. Instead, a channel head cut was used; however, cladding the inside surface of this weld proved to be more difficult than anticipated.

In-place steam generator retubing involves cutting and removing the tubes and tube support structures and replacing the steam drying and separation equipment. Retubing has not been used at any utility because it requires a two- to three-year outage period, the cost of the lost power during the outage is significantly higher than the cost of the other repair/replacement options, the site work involves as much fabrication as in manufacturing a new steam generator, and the process controls may not be as effective in the field as in the shop. This option also involves a significantly large radiation exposure to the personnel.

8.10.1 PWR replacement steam generator designs

Steam generator replacement is expected to result in a longer steam generator life than repair because design and materials improvements (some of which are listed in Table 2.1 through Table 2.5) can be implemented, and the impact of prior operating history is removed. Some of the improvements that are being incorporated into new PWR steam generators are discussed m this section.

Design and manufacturing modifications to reduce residual and vibrational stresses and corrosion sites are being used. The residual stresses at the expansion transition region and at Flow Lines the U bends in the new steam generators have been first reduced by the use of better manufacturing processes and then by using peening and stress relieving techniques, respectively. The new steam generators generally contain a minimum of three sets of antivibration bars rather than two, which are inserted deeper into the tube bundle to improve bundle stability and reduce flow induced vibration. The bar material has been selected to provide a better wear match to the tubing, and tube to antivibration bar clearances are minimized. Also, the antivibration bars are field replaceable in some designs. The tube support structures in new steam generators (such as the quatrefoil, trefoil broach holes and eggcrate designs) prevent fluid and impurity stagnation in the tube/tube sheet annuli. Finally, new tube/tube sheet joints in the replacement steam generators, consisting of a full-length hydraulic expansion and (for some vendors) either a one or two step hard mechanical roll, have eliminated crevices where impurities can concentrate.

More corrosion resistant materials are being used. The US industry's consensus on the best steam generator tube material is thermally treated Alloy 690, which is also being used in France, Japan, and elsewhere. Alloy 800NG tubing is being used in Germany, Belgium, Netherlands, Switzerland, Spain, Canada, Argentina, Brazil and Republic of Korea. The tube support structures in new steam generators are now being fabricated with 12% chromium ferritic stainless steels such as types 409, 410 or 405 to preclude denting.

Other improvements include: increased blowdown capacity to help remove impurities and reduce accumulation of sludge; a flow redistribution baffle plate to direct the recirculation water across the tube sheet at a velocity sufficient to minimize sludge deposition on the tube sheet (Figure 8.13); a slightly reduced pitch between tubes so that the number of tubes can be increased to allow for additional tube plugging margin or provide more power; slightly redesigned steam generator shells to reduce the number of welds that must be inspected and eliminate the longitudinal welds; forged heads with integrated nozzles, man-ways and support pads; redesigned feedwater piping to prevent water hammer events and minimize stratification in the nozzle (Figure 8.14); and, a shell design modified to mitigate the girth weld cracking problem (the girth weld is not located at the upper shell and transition cone joint but at some distance above the joint).

Ease of future mitigation, repairs and replacements is now being considered in the design of the replacement steam generators. Improved access for secondary side lancing and chemical cleaning of the tube sheet top surface has been incorporated with larger man ways and hand holes in appropriate locations. Access for sleeving and other repairs has also been improved. The original (older) designs of the PWR steam generators and containments did not anticipate the need for steam generator replacement during the plant life; however, this need is addressed in the newer designs.

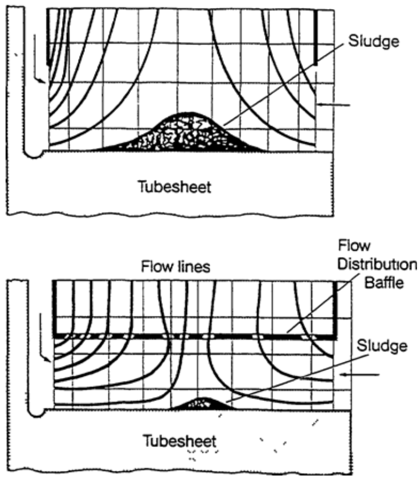
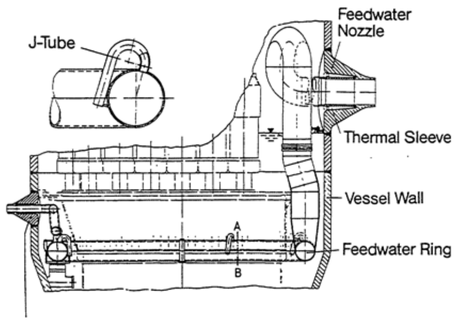


Figure 8.13. Flow distribution baffle to increase the velocity above tube sheet, minimize the flow stagnation zones, and minimize deposits on tube sheet (Courtesy of P. J. Meyer; Siemens AG).



Emergency Feedwater Nozzle

Figure 8.14. Siemens/KWU feedwater distribution system with an anti-stratification loop. (Courtesy of P. J. Meyer, Siemens AG).

8.10.2 CANDU replacement designs

The current design of steam generators for CANDU units has stabilized Alloy 800NG tubing, stainless steel lattice grid tube supports, flat U bend restraints (AVBs), and high capacity separators in an integral drum. Most CANDU steam generators are of the integral preheater type as well.

8.10.3 WWER replacement designs

For replacement of WWER-1000 steam generators generally same design is used, but with hydraulic expansion of tubes and some modification, including feedwater redistribution (see Figure 8.11 and Figure 8.12). New design of PGV-1000MKP is also suitable for replacement at the existing units.

9 STEAM GENERATOR AGEING MANAGEMENT PROGRAMME

The information presented in this IAEA-TECDOC suggests that steam generator tubing degradation caused by stress corrosion cracking, fretting, vibration induced fatigue and other age related mechanisms continues to be a significant safety and cost concern for many steam generators, even for some of the replacement steam generators with improved materials and designs. Also, stress corrosion cracking, corrosion fatigue and thermal fatigue have caused and will probably continue to cause cracking in some PWR steam generator shells and feedwater nozzles. And, stress corrosion cracking of the WWER collector material, and possibly the cover bolts, may also continue to occur. Therefore, systematic steam generator ageing management programmes are needed at all nuclear power plants.

The preceding sections of this IAEA-TECDOC dealt with the key elements of a steam generator ageing management programme (AMP), whose objective should be to maintain the fitness for service of the steam generators at a nuclear power plant throughout their service life. Section 9 and Figure ***9.1*** show how these elements are integrated within a plant specific steam generator AMP. Such an AMP should be implemented in accordance with guidance prepared by an interdisciplinary steam generator ageing management team organized at a corporate or owners' group level. For guidance on the organizational aspects of a plant AMP and interdisciplinary ageing management teams refer to IAEA Safety Guide No. NS-G-2-12 'Ageing Management for Nuclear Power Plants' [213].

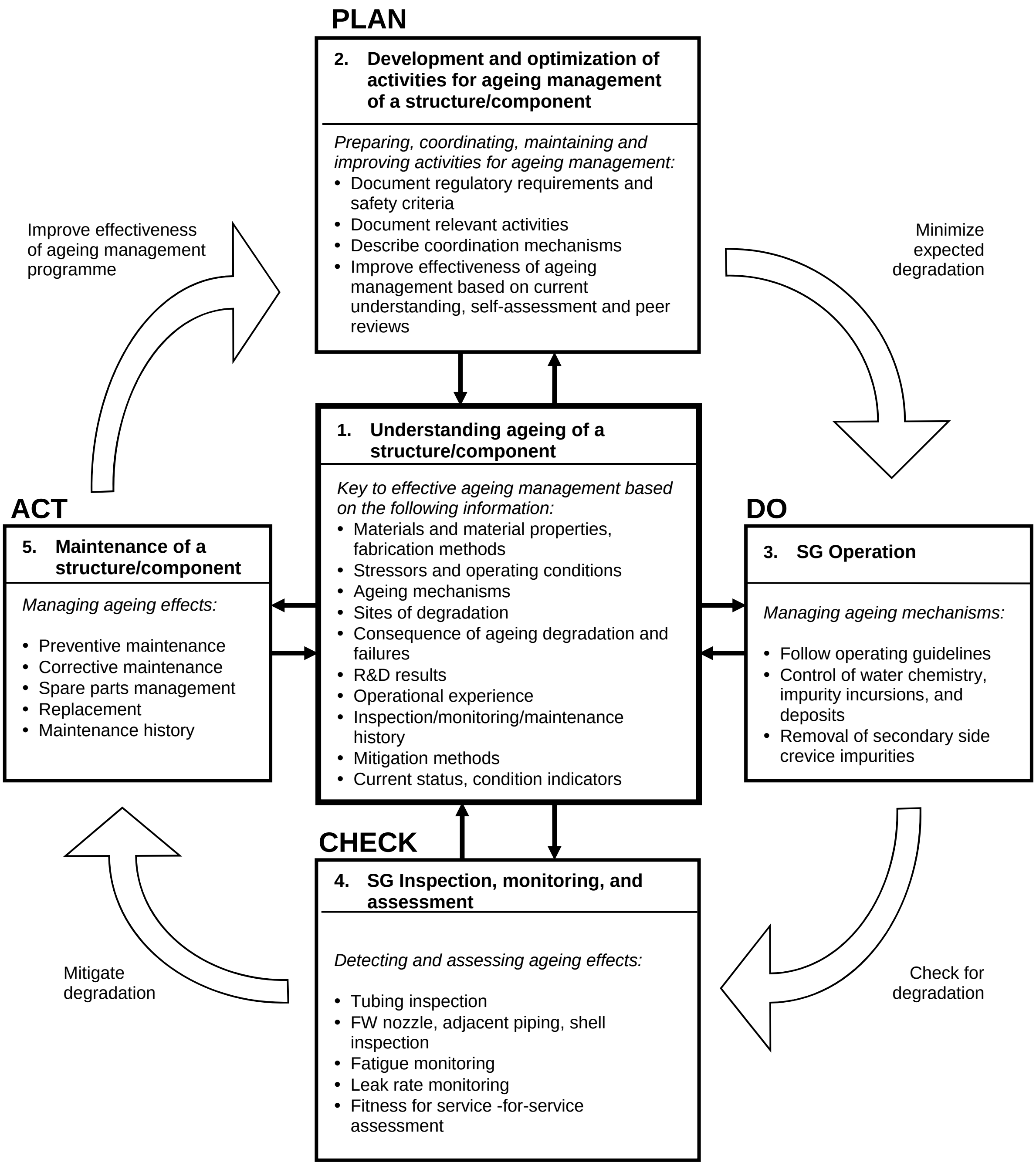


Figure 9.1. Key elements of steam generator ageing management programme (AMP) and their interfaces. Based on plan-do-check-act elements.

A comprehensive understanding of a steam generator, its ageing degradation, and the effects of the degradation on the steam generators ability to perform its design functions is the fundamental element of an AMP. This understanding is derived from a knowledge of the design basis (including applicable codes, and regulatory requirements); the design and fabrication (including the materials properties and specified service conditions); the operation and maintenance history (including commissioning and surveillance); the inspection results; and generic operating experience and research results. Sections 1.1, 2, 3 and 4 contain information on important aspects of the understanding of steam generators and their ageing.

Section 4.4 of this IAEA-TECDOC also contains a detailed summary of the steam generator tube ruptures that have occurred to date around the world (nine tube ruptures and seven incipient tube ruptures). The summary includes details of rupture size and location, contributing factors, maximum leak rates and a description of the resulting consequences. In all cases, the plants were properly cooled and radioactive releases were small and well below regulatory limits. On the other hand, these ruptures as well as the widespread tube degradation reported in Section 4 have been a significant concern to the safety authorities in various countries.

In order to maintain the fitness for service of a steam generator it is necessary to control within defined acceptable limits the age related degradation of the steam generator. Ageing degradation control consists of the following elements, based on an understanding of steam generator ageing:

- Prudent operation consistent with operational guidelines aimed at minimizing degradation (Section 5).
- Inspection and monitoring consistent with requirements aimed at timely detection and characterization of any degradation (Section 6).
- Assessment of the observed degradation in accordance with appropriate guidelines to determine fitness for service (Section 7).
- Mitigation, repair or replacement to correct unacceptable degradation (Section 8).

A steam generator AMP is a mixture of the above elements and specific ageing management actions designed to minimize, detect and mitigate ageing degradation before the steam generator safety margins are compromised. This mixture reflects the level of understanding of the steam generator ageing, the available technology, the regulatory/licensing requirements, and plant life management considerations/objective. Timely feedback of experience is essential in order to provide for on-going improvement in the understanding of the steam generator ageing degradation and in the effectiveness of the AMP. The following subsections address the main features and interfaces of key elements of a steam generator AMP as shown in Figure 9.1.

9.1 DEFINITION OF AGEING EFFECTS

In general, an ageing effect may be defined as a change in performance of a system, structure or component (SSC), or change in physical or chemical properties resulting in whole or part from one or more active degradation mechanisms. Examples of ageing effects include:

- **Change in material properties**

  Any change in a material, which is detrimental to that material’s ability to meet design requirements. Mechanisms that may result in a change in material properties include galvanic corrosion, photolysis, thermal degradation, and thermal oxidative degradation.

- **Cracking**

  Service induced cracking of materials includes both flaw initiation and growth within base metals and associated weld materials. Ageing mechanisms that may result in crack initiation and growth include fatigue, intergranular attack, stress corrosion cracking, and thermal degradation.

- **Flow blockage**

  A reduction in tube bundle or tube to tube support plate cross-sectional area such that a significant reduction or redistribution in flow occurs, when the steam generator is called upon to perform its intended function. Flow blockage may be caused by corrosion product build-up, bio-fouling, particulate fouling, and precipitation fouling.

- **Loss of fracture toughness**

  A change in material properties of a metal such that design requirements are potentially compromised. Ageing mechanisms that contribute to loss of fracture toughness include irradiation embrittlement and thermal ageing embrittlement (TAE).

- **Loss of heat exchanger performance (reduction of heat transfer)**

  A loss of heat exchanger performance due to a build-up of materials (fouling) on the steam generator tubing surfaces, both outside and inside. Loss of heat exchanger performance may occur by any of the mechanisms determined to cause flow blockage.

- **Loss of material**

  A reduction in the material content of a component or structure and may occur evenly over the entire component surface or be confined to localized areas. Ageing mechanisms, which may result in loss of material include: crevice corrosion, erosion corrosion, flow accelerated corrosion (FAC), erosion-cavitation, galvanic corrosion, general corrosion, selective leaching, microbiologically influenced corrosion (MIC), pitting, and wear.

- **Loss of preload**

  A general reduction in the tensile load for a bolted connection (for example, bolted divider plates). Ageing mechanisms contributing to loss of preload in bolted connections include:

  - Each of the listed ageing effects has some degree of detrimental effect on steam generator operability and reliability, including passive (e.g. pressure boundary integrity) and active functions. The degradation mechanism (DM) initiation and propagation times depend on pressure, temperature, water chemistry, residual stresses, flow conditions, operating practices, etc.
  - Physical/material ageing of SGs reduces safety margins provided in the design, and as a result NPP safety could be impaired if reductions in safety margins are not detected, and corrective action is not taken before loss of functional capability occurs. It may increase the probability of common cause failures, e.g. simultaneous degradation of physical barriers and redundant components which could result in the impairment of one or more levels of protection provided by the defence in depth concept. Ageing in NPPs should therefore be managed effectively to ensure the availability of required safety functions throughout the plant service life, taking into account changes, which occur with time and use.

- Common ageing terminology facilitates communication and mutual understanding among nuclear professionals, when dealing with ageing management issues. Nuclear industry developed number of documents with recommended ageing terminology to be used within the nuclear professional community [214, 215].

9.2 KEY ELEMENTS OF STEAM GENERATOR AGEING MANAGEMENT PROGRAMME

A systematic evaluation of the ageing management requirements for steam generators should be performed in order to acquire information and knowledge about the following four elements:

- Understanding ageing
- Prevention of ageing
- Detection and monitoring of ageing
- Mitigation of ageing effects.

9.2.1 Understanding steam generator ageing and feedback of operating experience

Understanding steam generator ageing is the key to effective management of steam generator ageing, i.e. it is the key to:

- Integrating ageing management activities within a systematic NPP AMP, managing ageing mechanisms through prudent operating procedures and practices.
- Detecting and assessing ageing effects through effective and practical inspection, monitoring and assessment methods.
- Managing ageing affects using proven maintenance methods.

This understanding consists of a knowledge of steam generator design, technical specifications and performance requirements, materials and material properties, stressors and operating conditions, likely degradation sites and ageing mechanisms, condition monitoring indicators/data needed for the assessment and management of steam generator ageing, and of the consequences of age related degradation and failures both under normal operating conditions and design basis event (DBE) conditions. In addition, the following aspects contribute to understanding of steam generator ageing:

- Acceptance criteria including applicable regulatory or code requirements, and safety analysis limits and conditions.
- Available analytical models (i.e. based on theory) or empirical models (i.e. based on observation or experiment) for predicting future degradation.
- Data requirements for the assessment of ageing (including any deficiencies in the availability and quality of existing records materials and material properties).
- Relevant R&D results.

The understanding of steam generator ageing is derived from the steam generator baseline data, the operating and maintenance histories, and external experience. This understanding should be updated on an ongoing basis to provide a sound basis for the improvement of the AMP and operating, inspection, monitoring assessment and maintenance methods and practices.

The steam generator baseline data consists of the performance requirements, the design basis (including codes, standards, regulatory requirements), the original design, the manufacturer's data (including materials data), and the commissioning data (including inaugural inspection data). The steam generator operating history includes the pressure-temperature (P-T) records, system chemistry records, and significant event reports. The steam generator maintenance history includes the inspection records and assessment reports, design modifications, and type and timing of maintenance performed. Retrievable, up to date records of this information are needed for comparisons with applicable external experience.

External experience consists of the operating and maintenance experience of:

- Steam generators of similar design, materials of construction and fabrication.
- Steam generators operated under similar water chemistry or with similar tube alloy material, even if the steam generator designs are different.
- Relevant research results.

It should be noted that effective comparisons or correlations with external experience require a detailed knowledge of the steam generator design and operation. The present IAEA-TECDOC is a source of such information. However, this information has to be kept current using feedback mechanisms provided, for example, by owners' groups or industry associations like EPRI or INPO. External experience can also be used when considering the most appropriate inspection method, maintenance procedure and tooling.

9.2.2 Definition of steam generator ageing management programme

Existing programmes relating to the management of SG ageing include operations, surveillance and maintenance programmes as well as operating experience feedback, research and development (R&D) and technical support programmes. Experience shows that ageing management effectiveness can be improved by integrating and co-ordinating relevant programmes and activities within a systematic ageing management programme. Safety authorities increasingly require licensees to define such AMPs for selected systems, structures and components (SSCs) by documenting relevant programmes and activities and their respective roles in managing SSC ageing. A definition of a steam generator AMP includes also a description of mechanisms used for programme co-ordination and continuous improvement. The continuous AMP improvement or optimization is based on current understanding of steam generator ageing and on results of self-assessments and peer reviews.

9.2.3 Prevention of steam generator ageing

Operating conditions and practices significantly influence steam generator degradation, and therefore, are the primary means for the staff of a nuclear power plant to minimize degradation caused by potential ageing mechanisms. These practices include primary and secondary water chemistry control, control of secondary side impurity incursions (condenser integrity, use of condensate polishers, recycle of the blowdown water, control of lead contamination, and removal of copper from the secondary coolant system), removal of secondary side crevice impurities (flushes and soaks), and control of steam generator deposits and crud (air in-leakage, steam generator lay-up practice, pH, steam generator blowdown system performance, and crud lancing). These activities are, of course, closely related and were discussed in detail in Section 5. They are summarized below.

The secondary side water chemistry is extremely important and a secondary side chemistry programme must be developed for the specific conditions of the plant and maintained to minimize the corrosion of the steam generator tube and shell and the balance of plant materials. In general, an all-volatile treatment programme is used with:

- One or more amines to maintain cycle pH.
- Moderate to high concentrations of hydrazine to maintain a reducing environment and scavenge small amounts of dissolved oxygen in the final feedwater.
- Other additives (e.g. boric acid) to modify the crevice chemistry.

The exact combination of additives to be used will vary somewhat from plant to plant depending on such things as the tube degradation experiences, steam generator design, make-up water chemistry, type and use of condensate polishers, balance of plant materials and corrosion experience, hideout return experience, etc. In addition, the water chemistry programme should limit the steam generator secondary side water impurity concentrations to certain specified values. The programme must include adequate sampling and specific action levels up to and including plant shutdown.

A second closely related area of plant operation is the control of secondary side impurity incursions. This includes policies and practices associated with condenser integrity, use or not use of the condensate polishing system, recycling of the blowdown water, lead contamination and removal of copper from the secondary side systems. The condenser must be essentially leak-tight over the life of the plant. Although condensate polishers are an effective means of achieving water purity during startup and can protect against major chemistry excursions, they can also release low concentrations of impurities that are known to cause corrosive conditions in steam generators. They need to be used with care, if any. A blowdown recovery system is used to reduce the quantity of make-up water and the chlorides and other impurities carried by the make-up water and introduced into the steam generator. Effective operating procedures should be used to control both acute and chronic sources of lead contamination. And, copper-bearing alloys should be removed from the secondary systems and replaced with stainless steel components.

A third related area of plant operation is removal of impurities from the secondary side crevices. As discussed in Section 4, impurities concentrate in the tube sheet and tube to tube support plate crevices, the sludge pile, and under free span crud (bridging) deposits. Steam generator hot soaks and flushes or chemical cleanings are used, as necessary, to remove impurities from these locations (after sludge lancing).

The fourth important and related area of plant operation is control of the steam generator deposits (crud). Plant procedures should be in place to minimize the leakage of air into the secondary coolant system through the aggressive use of state-of-the-art detection and repair technologies. Wet lay-up with chemically treated, de-oxygenated water (and a positive pressure nitrogen blanket if allowed due to safety issues) can be used whenever possible when the steam generator is in a shutdown condition. The feedwater $pH_{25°C}$ should be above 9.1 for plants with copper alloys and above at least 9.6 (targeted above 9.8) for all ferrous plants using ammonia (for details see Section 4). The SG blowdown system should continuously remove and clean about 0.5% (typically in the range from 0.3–0.7%) of the main steaming rate, and up to 1.5% of the main steaming rate during short transients. And, maybe most importantly, sludge lancing should be performed periodically to remove hard crud.

9.2.4 Detection and monitoring of ageing

The steam generator inspection, monitoring and assessment activities are designed to detect and characterize significant component degradation before the steam generator safety margins are compromised. Together with an understanding of the steam generator ageing degradation, the results of the steam generator inspections provide a basis for decisions regarding the type and timing of maintenance actions and decisions regarding changes in operating conditions and practices to manage detected ageing effects.

Current inspection and monitoring requirements and techniques for steam generator tubes as well as feedwater nozzles, adjacent piping and the steam generator shells are described in Section 6. In general, the rigor and extent of the inspection increases dramatically as the steam generator develops problems. Normally, an inspection of a significant fraction of the tubes (and collectors or other components) with non-destructive techniques is required, supplemented by destructive examinations such as metallography on pulled tubes.

It is extremely important to know the accuracy, sensitivity, reliability and adequacy of the non-destructive methods used for the particular type of suspected degradation. The performance of the inspection methods must be demonstrated in order to rely on the results, particularly in cases where the results are used in fitness for service assessments. Inspection methods capable of detecting and sizing expected degradation are therefore selected from those proven by relevant operating experience. Current methods used for the inspection of steam generator tubes and their respective detection and sizing capabilities are described in detail in Section 6.2.

The main safety function of steam generator tubes is to act as a barrier between the radioactive primary side and the non-radioactive secondary side. Safety margins are part of the design and licensing requirements of a nuclear power plant to ensure the integrity of the tubes under both normal and accident conditions. A fitness for service assessment is used to assess the capability of the tubes to perform the required safety function, within the specified margins of safety, during the entire operating interval until the next scheduled inspection.

Fitness for service assessments have used a variety of methods in response to the particular conditions and circumstances present at the time of the assessment. Section 7.2 of this IAEA-TECDOC describes the fitness for service guidelines used in 12 different countries. Generally, a graduated approach with three levels of assessment is used to demonstrate fitness for service:

- The simplest and most conservative assessment method uses generic criteria (e.g. 'No flaws allowed' or '40% of wall limit') for all types of defects and degradation mechanisms. This method is discussed in Section 7.2.
- When the generic criterion is exceeded, a degradation specific assessment can be applied. This method reduces the conservatism of the generic criteria by using a deterministic analysis of the specific types of degradation detected, (e.g. per ASME rules and safety margins). It is used by plant operators to reduce steam generator repair work (e.g. plugging) that would be required by the generic criteria. The degradation specific assessment is described in Section 7.2.
- A probabilistic assessment may be used to demonstrate fitness for service, when a degradation specific assessment fails to meet the criteria. This method requires probabilistic calculations to assess the conditional probability of tube failures, leak rates, and ultimately risk of core damage or of exceeding site dose limits. Risk calculations should take into account the probability that some degraded tubes may be inadvertently left in service and that non-steam generator design basis events may increase with time due to other age related degradation. Although probabilistic assessments of steam generators have not been widely used, this method provides a useful way for handling uncertainty while avoiding excessive conservatism. For more details see Sections 7.8 through Section 7.10.

9.2.5 Mitigation of ageing effects

A variety of maintenance actions are available to manage ageing effects detected by inspection and monitoring methods in different parts of a steam generator (see Section 8). Decisions on the type and timing of the maintenance actions are based on an assessment of the observed ageing effects, available decision criteria (e.g. for tube plugging), an understanding of the applicable ageing mechanism(s), and the effectiveness of available maintenance technologies.

Maintenance actions for managing/repair of steam generator tube degradation include preventive/mitigation methods such as roto-peening, shot-peening and stress relieving; and corrective/repair methods such as plugging, sleeving and nickel plating. Tube wear/fretting problems have been treated by preheater design modifications that reduce turbulence and peak feedwater flow velocities and by installing additional or longer antivibration bars. Design modifications have been used to mitigate the thermal fatigue of the feedwater nozzles and adjacent piping. Maintenance actions for steam generators with highly susceptible material or exposed to very poor water chemistry may have to include certain additional measures such as chemical cleaning, and ultimately steam generator replacement.

9.3 APPLICATION GUIDANCE ON DEVELOPMENT OF A STEAM GENERATOR AGEING MANAGEMENT PROGRAMME

Existing programmes relating to the management of SG ageing include operations, surveillance and maintenance programmes as well as operating experience feedback, research and development (R&D) and technical support programmes. Experience shows that ageing management effectiveness can be improved by integrating and co-ordinating relevant programmes and activities within a systematic ageing management programme. Safety authorities increasingly require licensees to define such AMPs for selected systems, structures and components by documenting relevant programmes and activities and their respective roles in managing SSC ageing. A definition of a steam generator AMP includes also a description of mechanisms used for programme co-ordination and continuous improvement. The continuous AMP improvement or optimization is based on current understanding of steam generator ageing and on results of self-assessments and peer reviews.

A recommended methodology, which consists of the evaluation of relevant information and documentation of the findings, is illustrated in a flowchart shown in Figure 9.2. The results of operating experience, research and development, and available previous ageing evaluations (both generic and plant-specific) should be used in the evaluations. Relevant applicable ageing management reviews (e.g. prepared by the vendor/owners' group, suppliers or technical support organizations) should be used to minimize duplication of effort, if available.

Evaluation of actions to prevent ageing

Potential actions to prevent and control ageing degradation should be evaluated. The evaluation should address the following aspects:

- Identification of potential preventive actions that can be taken in design, materials, fabrication and construction, commissioning, operation and maintenance practices.
- Service conditions (i.e. environmental conditions and operating conditions) to be maintained and operating practices aimed at preventing or slowing down potential degradation of steam generators.

Evaluation of methods to detect and monitor ageing

Existing monitoring methods should be evaluated, with account taken of relevant operating experience and research results; to determine whether they are effective for timely detection of ageing degradation before failure of the steam generator occurs. Sampling checks of equipment should be applied to detect precursors of ageing degradation when applicable.

Steam generator

↓

Understanding of ageing

- Design and specifications
- Materials and material properties
- Service conditions
- Performance requirements
- Operation and maintenance histories
- Generic operating experience
- R&D results

Documentation of the information, including:

- Current understanding of steam generator ageing (e.g. ageing mechanisms and effects, sites of degradation, any analytical/empirical models for predicting SG degradation, any gaps in the understanding of ageing).
- Acceptance criteria including applicable regulatory or code requirements, safety analysis, and operational limits and conditions.
- List of data requirements for the assessment of SG ageing (including any deficiencies in the availability and quality of existing records).

↓

Prevention of ageing

Evaluation of the effectiveness of methods and practices for prevention of SG ageing degradation.
Documentation of the information, including:

- Design, materials, fabrication and construction, operations and maintenance methods and practices to prevent ageing degradation.
- Operating conditions and practices that prevent or minimize the rate of ageing degradation.

↓

Monitoring of ageing

Evaluation of monitoring methods, taking into account relevant operating experience and research results.
Documentation of the information, including:

- Functional parameters and condition monitoring indicators for detecting, monitoring, and trending ageing degradation.
- An assessment of the capability and practicability of existing monitoring techniques to measure these parameters and indicators with sufficient sensitivity, reliability, and accuracy.
- Data evaluation techniques for recognizing significant degradation and for predicting SG future performance.

↓

Mitigation of ageing

Evaluation of the effectiveness of existing methods and practices for mitigating SG ageing degradation.
Documentation of the information, including:

- Maintenance methods and practices, condition monitoring (including refurbishment and periodic replacement of parts and consumables) to control ageing degradation.
- Operating conditions and practices that minimize the rate of SG ageing degradation.
- Possible modifications to design and materials of the SG to control ageing degradation.

↓

Report on ageing management review

- Steam generators-specific information on understanding, monitoring, and mitigating ageing.
- Recommendations for the application of results of the ageing management review in plant design, operation and maintenance, and for R&D to address gaps in knowledge and technology.

Figure 9.2. A sample methodology for ageing evaluation, including review and evaluation of relevant information and documentation of the findings. (Adapted from IAEA NS-G-2.12 [213]).

In the evaluation of existing monitoring methods to identify effective and practical monitoring methods and technology, the following should be addressed:

- Functional parameters and condition monitoring indicators for detecting, monitoring and trending ageing degradation.
- An assessment of the capability and practicability of existing monitoring techniques to measure the functional parameters and condition monitoring indicators with sufficient sensitivity, reliability and accuracy.
- Data evaluation techniques for recognizing instances of significant degradation, failure rates and their tendencies, for predicting future integrity and steam generator functional capability.
- Data tracking techniques for detecting, monitoring, and measuring trends regarding:
  - Fitness for service and structural integrity,
  - Functionality,
  - Confirmation that safety analysis assumptions continue to be met,
  - Confirmation that safety analysis and operational limits and conditions continue to provide suitable information, and are expanded or revised as necessary.

Evaluation of methods to mitigate ageing

The effectiveness of existing methods and practices for mitigating steam generators ageing degradation should be assessed, with account taken of relevant operating experience and research results. When the AMP is established, the programme should include a method of identifying and evaluating effective and practical mitigation methods and technology. The information obtained should include:

- Maintenance methods and practices (including refurbishment and periodic replacement of parts and consumables) to control ageing degradation.
- Operating conditions and practices that minimize the rate of steam generator ageing degradation.
- Possible modifications in design and materials of the SG to control ageing degradation.

Report on evaluation of ageing management requirements

The results of the evaluation of ageing management requirements should be documented. The results of the evaluation should provide steam generators-specific recommendations for the ageing management for plant design, fabrication and construction, operation and maintenance, and for R&D to address gaps in knowledge and technology.

Condition monitoring assessment

At the initiation of the AMP, and at defined intervals, the utilities should perform an assessment of the actual condition of steam generators to:

- Determine the current performance and condition of the steam generators, including the assessment of any age related failures or indications of significant material degradation.
- Compare the current performance and condition against predictions for the identified ageing mechanisms and acceptance criteria.
- Based on current performance and conditions, predict the future performance, ageing degradation, and, if possible, the residual service life of the steam generator (i.e. the length of time the SG is likely to meet its function and performance requirements).

- Determine whether the ageing degradation assumptions made regarding the design of the SG remain valid, and recommend appropriate follow-up corrective actions and preventive measures for input to the AMP.

The condition of an SG should be assessed from:

- The relevant ageing management review report.
- Operation, maintenance, and engineering data, including acceptance criteria specific to that SG.
- Inspection and assessment results, including those of updated inspections and assessments, if available.

The ageing management programme should identify:

- Effective and appropriate actions and practices for managing ageing that provide for timely detection and mitigation of ageing effects in the steam generators.
- Indicators of the effectiveness of the programme.

9.3.1 Ageing management programme effectiveness performance indicators

To evaluate the effectiveness of the ageing management programme (taking into account the results of the condition monitoring assessments), indicators should be developed and used by the operating organization. Examples of indicators include:

- Material condition with respect to acceptance criteria.
- Trends of data relating to degradation, failure, repair and plugging.
- Comparison of preventive and corrective maintenance efforts (e.g. in terms of person-years or cost).
- Number of recurrent failures and instances of degradation.
- Status of compliance with inspection programmes. Any existing nuclear power plant programmes that are considered for use for ageing management should also be evaluated against the attributes listed in Table 9.1. Programmes that do not have these attributes should be modified, as appropriate.

The ageing management programme should be documented. The AMP document should provide a summary of the ageing management programme that highlights information useful for understanding and managing ageing, including materials, degradation sites, ageing stressors and environment, ageing mechanisms and effects, inspection and monitoring requirements and methods, mitigation methods, regulatory requirements and acceptance criteria.

9.3.2 Attribute of an ageing management programme

Each ageing management programme should cover the nine generic attributes of an effective programme in accordance with IAEA Safety Guide No. NS-G-2-12 ‘Ageing Management for Nuclear Power Plants’:

- Scope of the ageing management programme based on understanding ageing.
- Preventive actions to minimize and control ageing degradation.
- Detection of ageing effects.
- Monitoring and trending of ageing effects.
- Mitigating ageing effects.
- Acceptance criteria.
- Corrective actions.
- Operating experience feedback and feedback of R&D results.
- Quality management.

TABLE 9.1. COMPARISON OF GENERIC ATTRIBUTES OF AN EFFECTIVE AGEING MANAGEMENT PROGRAMME ON IAEA SAFETY GUIDE NO. NS-G-2.12 AND CONTENT OF THIS REPORT

IAEA-NS-G-2.12 Ageing Management for Nuclear Power Plants		**Sections of this report**
Attribute	**Description**	
1. Scope of the ageing management programme based on understanding ageing	• Structures (including structural elements) and components subject to ageing management. • Understanding of ageing phenomena (significant ageing mechanisms, susceptible sites): Structure/component materials, service conditions, stressors, degradation sites, ageing mechanisms and effects.	Introduction of this report
2. Preventive actions to minimize and control ageing mechanism	• Identification of preventive actions • Identification of parameters to be monitored or inspected. • Service conditions (i.e. environmental conditions and operating conditions) to be maintained and operating practices aimed at slowing down potential degradation of the structure or component.	Operational guidelines/ Preventive maintenance
3. Detection of ageing effects	• Effective technology (inspection, testing and monitoring methods) for detecting ageing effects before failure of the structure or component.	Inspection/monitoring/qualification
4. Monitoring and trending of ageing effects	• Condition monitoring indicators and parameters monitored. • Data to be collected to facilitate assessment of structure or component ageing. • Assessment methods (including data analysis and trending).	Inspection/monitoring/qualification
5. Mitigating ageing effects	• Operations, maintenance, repair and replacement actions to mitigate detected ageing effects and/or degradation of the structure or component.	Preventive maintenance/mitigation
6. Acceptance criteria	• Acceptance criteria against which the need for corrective action is evaluated.	Fitness for service assessment
7. Corrective actions	• Corrective actions if a component fails to meet the acceptance criteria.	Repair/replacement
8. Operating experience feedback and feedback of research and development results	• Mechanism that ensures timely feedback of operating experience and research and development results (if applicable), and provides objective evidence that they are taken into account in the ageing management programme.	Operational guidelines
9. Quality management	• Administrative controls that document the implementation of the ageing management programme and actions taken. • Indicators to facilitate evaluation and improvement of the ageing management programme.	Ageing management programme

The relationship between the nine generic attributes of the IAEA Safety Guide [213] and the content of this report are shown in Table 9.1. The general aim of this publication is to reflect basic international technical information for AMPs and to provide a state-of-the-art description of degradation mechanisms treated and the main factors influencing their occurrence, the locations affected, as well as the strategies available for mitigation and repair. This information is useful for both regulators and utilities to establish and review ageing management programmes.

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ABBREVIATIONS

AECL	Atomic Energy of Canada Limited
AFT	auxiliary feedwater tank
ALARA	as low as reasonable achievable
AMP	ageing management programme
APWR	advanced PWR
ASCA	advanced scale conditioning agent
ASME	American Society of Mechanical Engineers
AVB	antivibration bar
AVT	all-volatile-treatment
BAT	boric acid treatment
BCH	bulk cleaning head
BOC	beginning of cycle
BOP	balance of plant
CANDU	Canada Deuterium-Uranium
CANTIA	CANdu tube inspection assessment
CCWS	component cooling water system
CC	cation conductivity
CFR	Code of Federal regulations
CPP	condensate polishing plant
CPS	condensate polishing system
CSA	Canadian Standards Association
CST	condensate storage tank
DART	deposit accumulation reduction technology
DBE	design basis event
DFL	degradation free lifetime
DH	dissolved hydrogen
DM	degradation mechanism
DMA	di-methyl-amine
DMT	deposit minimization treatment
ECCS	emergency core cooling system
ECP	electro chemical potential
ECT	eddy current test
EdF	Electricité de France
EDI	electro deionization
EDM	electric discharge machining
EDTA	ethyle-diamine tetra-acetic acid
EFPY	effective full power years
EMAT	electromagnetic acoustic transducer
EPRI	Electric Power Research Institute
ETA	ethanol amine
FAC	flow accelerated (assisted) corrosion
FAMOS	fatigue monitoring system
FATS	focused array transducer system
FSAR	final safety analysis report
GPD	gallon per day

GPH	gallon per hour
HOR	hide-out return
HTCC	high temperature chemical cleaning
HTMA	high temperature mill annealed
I&C	instrumentation and control
IDSCC	inner diameter stress corrosion cracking
IER	ion exchange resin
IGA	inter-granular attack
IGSCC	inter-granular stress corrosion cracking
IPE	individual plant examinations
ISI	in-service inspection
JAPC	Japan Atomic Power Company
KTA	Kern Technischer Ausschuss (German Nuclear Technology Expert Group)
KWU	Kraftwerk Union (former nuclear section of Siemens)
LIMS	laboratory information management system
LWR	light water reactor
MA	mill annealed
MALR	maximum allowable leak rate
MHI	Mitsubishi Heavy Industries
MIC	microbiologically influenced corrosion
MPA	methoxy-propyl-amine
MRC	molar ratio control
MRP	materials reliability programme
MRPC	multi-frequency rotating pancake coil
MSD	moisture separator drain
MSR	moisture separator reheater
MTLR	maximum tolerable leak rate
NDE	non-destructive examination
NEA	Nuclear Energy Agency
NG	nuclear grade
NISA	Nuclear and Industrial Safety Agency
NNSA	National Nuclear Safety Administration
NSSS	nuclear steam supply system
NUSS	Nuclear Safety Standards
ODSCC	outer diameter stress corrosion cracking
OECD	Organization for Economic Co-operation and Development
OEM	original equipment manufacturer
OTSG	once through steam generator
OWC	oxygenated water chemistry
PbSCC	lead (Pb) induced stress corrosion cracking
PHWR	pressurized heavy water reactor
PLiM	plant life management
POD	probability of detection
POL	probability of leakage
PPB	particles per billion
PPM	particles per million

PSA	probabilistic safety assessment
PSAR	preliminary safety analysis report
PSI	pre-service inspection
PT	phosphate treatment
PTS	pressurized thermal shock
RCS	reactor coolant system
RCPB	reactor coolant pressure boundary
RPV	reactor pressure vessel
RSG	recirculating steam generator
RUB	reverse U bend
PWSCC	primary water stress corrosion cracking
PWR	pressurized water reactor
SAR	safety analysis report
SC	specific conductivity
SG	steam generator
SGLC	steam generator Level Control
SGMP	steam generator Management Programme
SGR	steam generator replacement
SGTP	steam generator tube plugging
SRP	standard review plan
SS	stainless steel
SSC	(plant) system structures and components
SYSFAC	SYsteme de Surveillance en FAtigue de la Chaudiere
TAE	thermal ageing embrittlement
TG	turbine and generator
TGSCC	trans-granular stress corrosion cracking
TOFD	time of flight diffraction
TS	tubesheet
TSL	tubesheet Lancing
TSP	tube support plate
TT	thermal treated
TTS	top of tubesheet
UBHC	upper bundle hycraulic cleaning
USNRC	United States Nuclear Regulatory Commission
UT	ultrasonic testing
VDS	vertical deployment system
VGB	German large power station owners group
WWER	Water moderated, water cooled energy reactor

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