IAEA-TECDOC-981

Assessment and management of ageing of major nuclear power plant components important to safety:

Steam generators

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FOREWORD

At present, there are over four hundred operational nuclear power plants (NPPs) in IAEA Member States. Operating experience has shown that ineffective control of the ageing degradation of the major NPP components (e.g. caused by unanticipated phenomena and by operating, maintenance, design or manufacturing errors) can jeopardize plant safety and also plant life. Ageing in NPPs must be therefore 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 wearout 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 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 and a widely accepted Methodology for the Management of Ageing of NPP Components Important to Safety which was issued by the IAEA in 1992. They have been compiled using contributions from technical experts in typically 10 to 12 countries for each report, a feedback from a September 1994 Technical Committee Meeting attended by 53 technical experts from 21 Member States (who reviewed first drafts in specialized working groups), and review comments from invited specialists.

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 CANDU, PWR and WWER nuclear power plants. The contributors to the drafting and review of this TECDOC are identified at the end of this publication. Their work is greatly appreciated. In particular, the contributions of P.E. MacDonald, C. Maruska and V.N. Shah are acknowledged. The officer who directed the preparation of the report was J. Pachner of the Division of Nuclear Installation Safety.

EDITORIAL NOTE

CONTENTS

1. INTRODUCTION

1.1. BACKGROUND

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 (maintenance, testing, examination and inspection of SSCs) is given in the IAEA Nuclear 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 in-service inspection (50-SG-O2), maintenance (50-SG-O7, Rev.1) and surveillance (50-SG-O8, Rev.1).

The Operation Code requires that NPP operating organizations prepare and carry out a programme of periodic maintenance, testing, examination and inspection of plant systems, structures and components important to safety to ensure that their level of reliability and effectiveness remains in accord with the design assumptions and intent and that the safety status of the plant has not been adversely affected since the commencement of operation. This programme is to take into account the operational limits and conditions, any other applicable regulatory requirements, and be re-evaluated in the light of operating experience. 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 In-Service Inspection (ISI) provides recommendations on methods, frequency and administrative measures for the ISI programme for critical systems and components of the primary reactor coolant system aimed at detecting possible deterioration due to the influences of stress, temperature, irradiation, etc. and at determining whether they are acceptable for continued safe operation of the plant or whether remedial measures are needed. 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 aim of the surveillance activities is to verify that the plant is operated within the prescribed operational limits and conditions, to detect in time any deterioration of SSCs as well as any adverse trend that could lead to an unsafe condition, and to supply data to be used for assessing the residual life of SSCs. The above Safety Guides provide general programmatic guidance, but do not give detailed technical advice for particular SSCs.

Ageing management specific programmatic guidance is given in Technical Reports Series No. 338 "Methodology for the Management of Ageing of Nuclear Power Plant Components Important to Safety" and in a Safety Practice No. 50-P-3 "Data Collection and Record Keeping for the Management of Nuclear Power Plant Ageing". Guidance provided in these reports served as a basis for the development of component specific technical documents

(TECDOCs) on the Assessment and Management of Ageing of Major NPP Components Important to Safety. This publication on Steam Generators is one of such 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. The design confines radioactivity from neutron activation or fission products to the primary coolant during normal operation. 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 50% 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 accidents, 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 year to about 5×10^{-4} per year. Steam generator tube rupture accidents are relatively small contributors to these values, but are risk significant due to containment bypass. 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. These risk significant accidents can be induced by operational transients and rare events with degraded steam generator tubes which could lead to core melt (Ellison et al. 1995).

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

The underlying objective of this 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 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/tubesheet boiling steam generators, commonly known as "recirculating vertical U-tube steam generators;" (b) vertical/tubesheet super heated 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 has a significant safety impact as discussed in Section 1.1; the steam generator tubes, tubesheets or collectors, plugs (tube and tubesheet), and sleeves (i.e. components whose failure impairs the primary to secondary pressure boundary). In addition, this 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. The TECDOC does not address life or life-cycle management of steam generators because it is written from the safety perspective and life management includes economic planning.

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, outside diameter, and transgranular stress corrosion cracking; 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 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 (France), Mitsubishi Heavy Industries (Japan), and Siemens-Kraftwerke Union (Germany), 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

In RSG, the primary system coolant flows through U-tubes with a tubesheet at the bottom of the generator and U-bends at the top of the tube bundle (Fig. 1). Primary coolant enters the steam generator at 315–330°C on the hot-leg side and leaves at about 288°C on the cold-leg side. 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

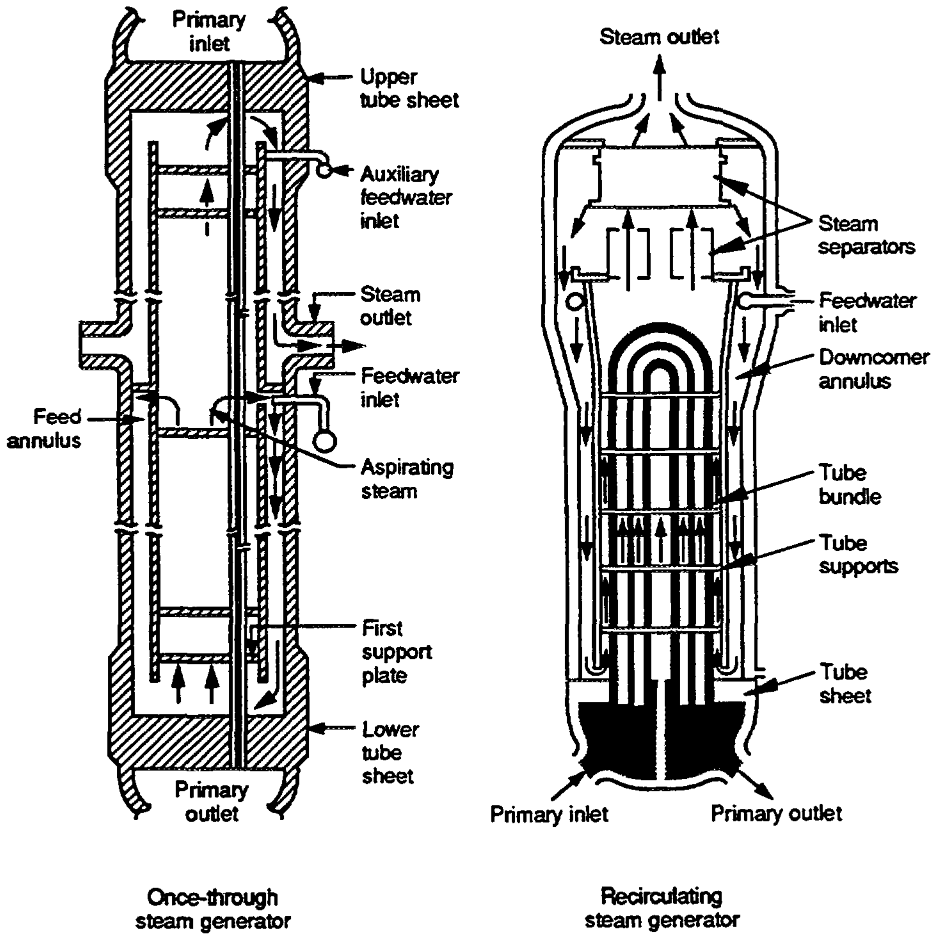


FIG. 1. PWR steam generator cross sections (EPRI 1985). Copyright Electric Power Research Institute; reprinted with permission (left).

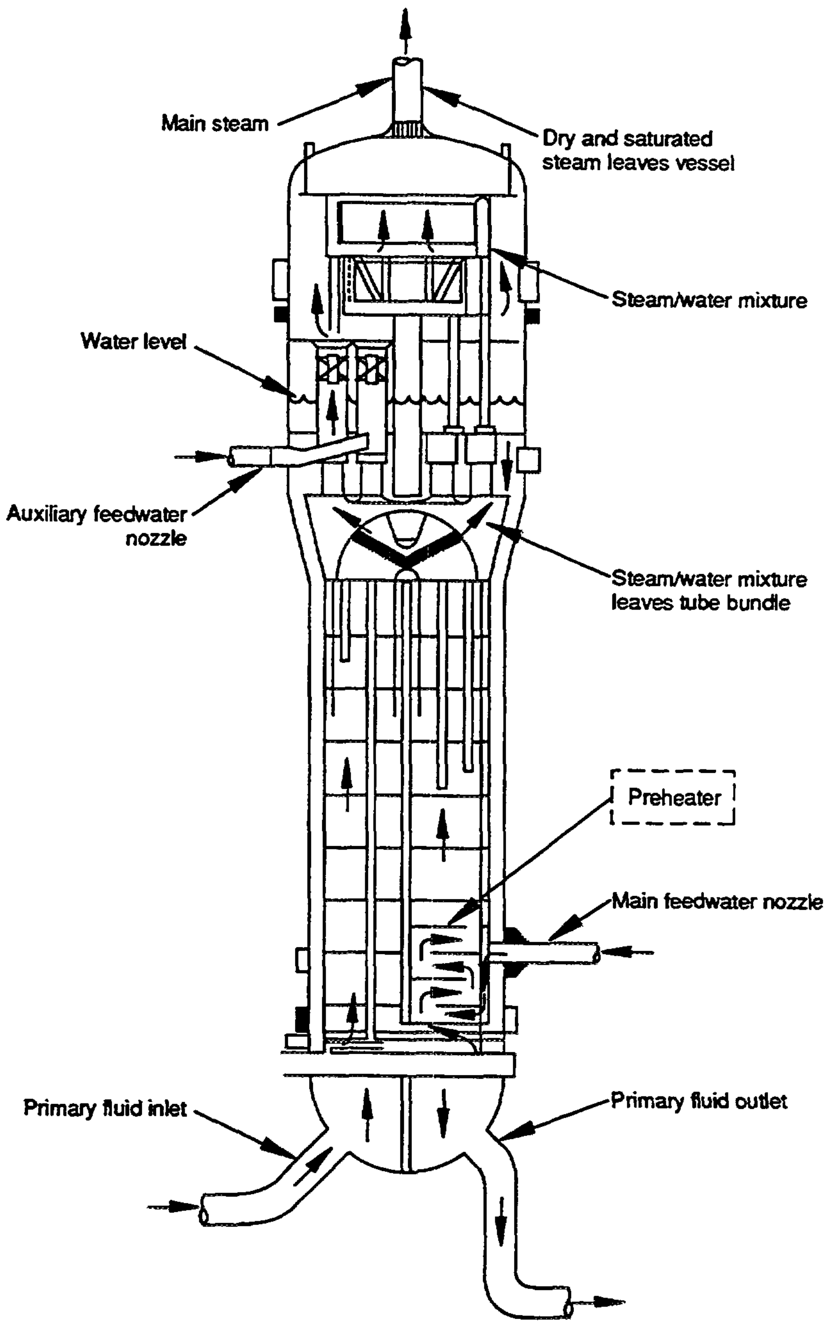


FIG. 2. Typical design of a steam generator with a preheater (CSGORG 1983).

the top of the tubesheet, and then up through the tube bundle where steam is generated. About 25% of the secondary coolant is converted to steam on each pass through the generator; the remainder is recirculated.

Some RSGs include economizer sections (preheaters), which are separate sections in the steam generator near the cold leg outlet, shown in Fig. 2. 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 secondary system coolant.

TABLE I. TYPICAL US STEAM GENERATOR MODELS AND THEIR PARAMETERS

Manufacturer type and model	Wesunghouse (recirculaung)						
	24	27	33	44[a]	51 A–M[a,e]	D2/D3[f]	D4[f]
Heat transfer area (ft2)[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)[b]	1 2187	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 matenal	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[c]	Full-depth rolled	Full-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	Dnlled hole	Dnlled hole	Dnlled hole	Dnlled hole	Dnlled hole	Dnlled hole	Dnlled hole
Tube support matenal	Carbon steel	Carbon steel	Carbon steel	Carbon steel	Carbon steelf	Carbon steel	Carbon steel
Preheater type	None	None	None	None	None	Split flow	Counterflow expanded preheater tubes
Flow distnbution 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 onginal 51s due to the slightly lower thermal heat transfer properties at the Alloy 690 matenal vis-à-vis the Alloy 600 matenal

[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 tubesheet thickness ranges from 525 to 610 mm

Table I lists the design features for eleven Westinghouse and two Combustion Engineering type steam generator models. Table II lists the design features of seven Mitsubishi Heavy Industries steam generator models and Table III lists the design features of the steam generators delivered by Siemens/KWU.

2.2. CANDU RECIRCULATING STEAM GENERATORS

Currently operating CANDU steam generators are vertical RSGs built by Babcock & Wilcox Canada Ltd. The only exception is the Wolsung 1 unit in the Republic of Korea which uses

TABLE I. (cont.)

Manufacturer type and model	Westinghouse (recirculating)				B&W once-through	Combustion Engineering (recirculating)	
	D5	E[g]	F	Δ75	177	67	80
Heat transfer area (ft^2)[b]	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	0.750 × 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 690	Alloy 600	Alloy 600	Alloy 600
Tubing heat treatment	Thermally treated	Mill-annealed or therm. 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	Eggcrate/ vertical	Eggcrate/ 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	Counterflow, expanded pre-heater tubes	Counterflow, expanded preheater 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 24 where they were 0.0135-0.0175 inches.

[f]Some later Model 51s 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 rotopeened for added resistance to PWSCC.

similar steam generators built by Foster Wheeler. Atomic Energy of Canada Limited, 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.

CANDU RSGs are very similar to the PWR RSG with some subtle differences in size, materials, operating temperatures and tube support structure. Figure 3 depicts the steam generator used in the Darlington Generating Station which has all the most current features of CANDU RSGs.

TABLE II. TYPICAL MITSUBISHI HEAVY INDUSTRIES RECIRCULATING STEAM GENERATOR MODELS 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 eggcrate	Drilled	Drilled, drilled chamfer	Broached eggcrate	Broached eggcrate	Broached eggcrate
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

TABLE III TYPICAL SIEMENS/KWU RECIRCULATING STEAM GENERATORS AND THEIR PARAMETERS

Manufacturer and model	MAN-GHH Obrigheim (Orig.)	MAN-GHH Obrigheim (Repl.)	Balcke Stade	Babcock Biblis A	[h] Standard with preheater	MAN-GHH Konvoi [j]	[k] Replacement SGs for 51C/51M/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 600	Alloy 800 M [p]	Alloy 800 M [p]	Alloy 800 M [p]	Alloy 800 M [p]	Alloy 800 M [p]	Alloy 690 [n] Alloy 800 M [p]
Tubing heat treatment	Mill annealed	[g]	[g]	[g]	[g]	[g]	Alloy 690 therm. treated Alloy 800 M [p] [g]
Tubesheet expansion method	Part-depth rolled (3 locations)	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	Eggcrate [b]	Eggcrate [c]	Eggcrate [d]	Eggcrate [e]	Eggcrate [e]	Eggcrate [e]	Eggcrate [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 690 Yes [o]
Peening of the roll-transition zone	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 strips, 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 ½ and Almaraz ½, Manuf ENSA), D3 (Ringhals 3, Manuf Framatome)

l) Replacement steam generator for Ringhals 2 5105 m^2, Doel 3, Asco ½ and Almaraz ½ 6103 m^2, Ringhals 3 7155 m^2

m) Replacement steam generator for Ringhals 2, Doel 3, Asco ½ and Almaraz ½ 5130 tubes, 57 row-1 tubes, Ringhals 3 5428 tubes, 59 row-1 tubes

n) Replacement generator for Ringhals 2 and Ringhals 3 Alloy 690, Doel 3, Asco ½ and Almaraz ½ Alloy 800 M

o) *Alloy 690 Tubes with Radius <300 mm*

p) Modified according to Siemens/KWU specification

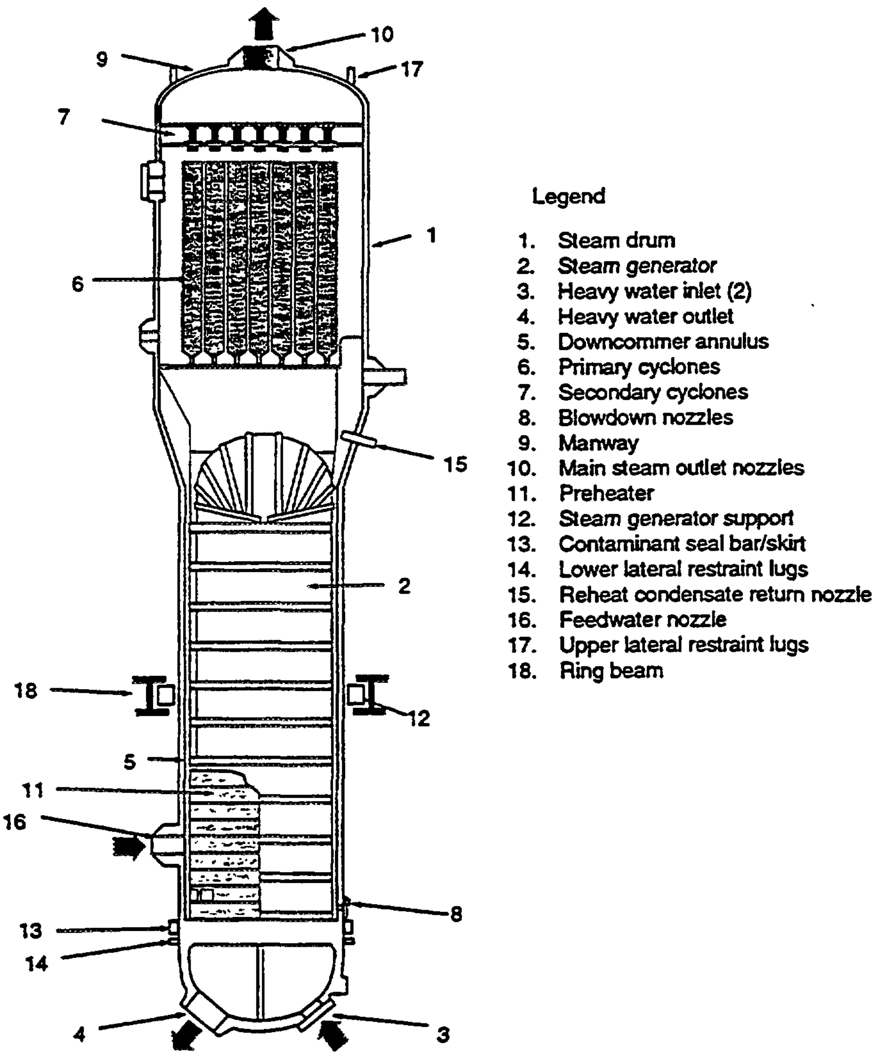
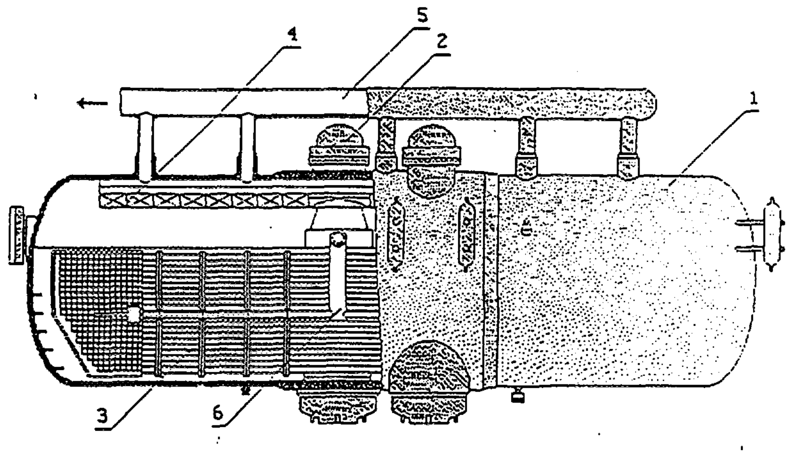


FIG. 3. CANDU Recirculating Steam Generator used at the Darlington station. This design is typical of the current CANDU models. (Courtesy of C. Maruska, Ontario Hydro.)

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_2O), 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, Monel 400 and titanium stabilized Alloy 800. These materials are susceptible to different types of degradation.



1. Steam generator pressure vessel
2. Primary collector
3. Heat exchange tubes
4. Moisture separator
5. Steam collector
6. Feedwater inlet

FIG. 4a. WWER-440 steam generator (side view). (Courtesy of Y. G. Dragunov, OKB Gidropress.)

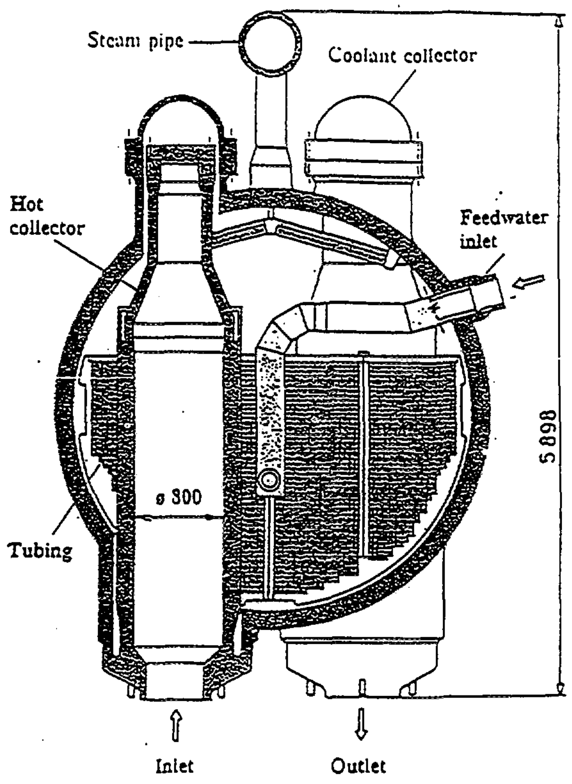


FIG. 4b. WWER-440 steam generator (end view). (Courtesy of Y. G. Dragunov, OKB Gidropress.)

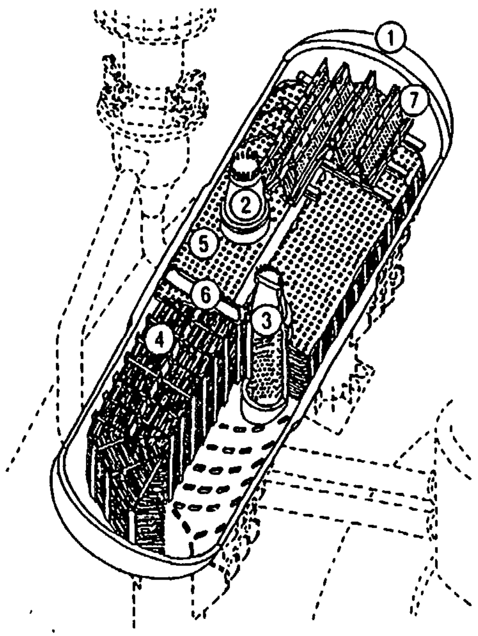


FIG. 5a. Cut-away drawing of a WWER-1000 steam generator (Koryakin 1993). Key: 1-Steam generator drum; 2-Cold header; 3-Hot header; 4-Heat exchanger tubes; 5-Submerged perforated separator; 6-Feedwater header; 7-Steam separators (Koryakin 1993). Copyright Nuclear Engineering International; used with permission.

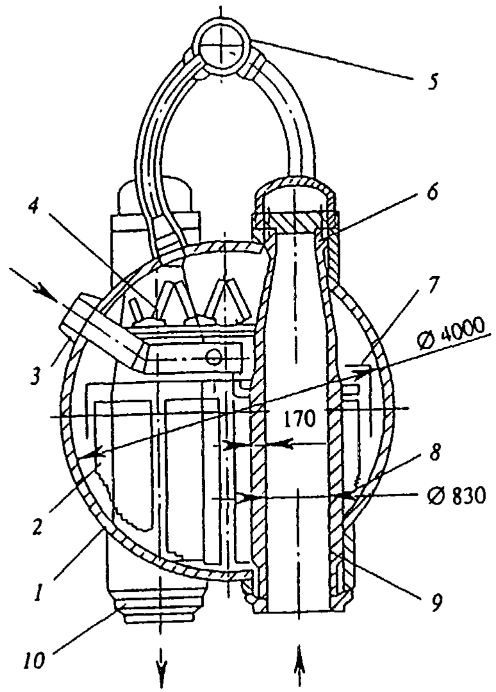


FIG. 5b. WWER-1000 steam generator (end view) (Titov 1991). Key: 1-SG shell; 2-Tube bundle; 3-Feedwater branch pipe; 4-Separation device; 5-Steam collecting heater; 6-Point of header jamming; 7-Immersed perforated sheet; 8-Unperforated section in perforated zone; 9-Inlet ("hot") header; 10-Outlet ("cold") header. Courtesy of Y. G. Dragunov, OKB Gidropress. Copyright Nuclear Engineering International; used with permission.

2.3. PWR ONCE-THROUGH STEAM GENERATORS

US once-through steam generators use straight heat exchanger tubes with tubesheets at both the top and bottom of the steam generator, as shown in Fig. 1. 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 tubesheet, 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.

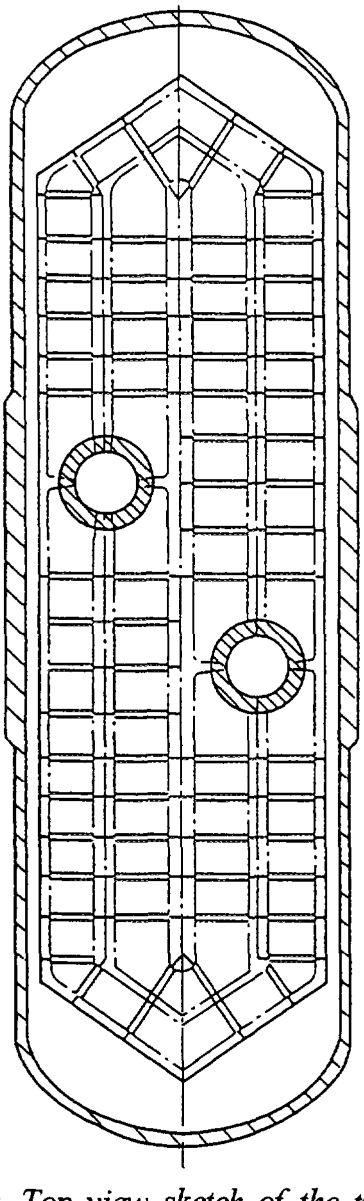


FIG. 6a. Top view sketch of the tube layout in WWER-440 and WWER-1000 steam generators. (Courtesy of Y. G. Dragunov, OKB Gidropress.)

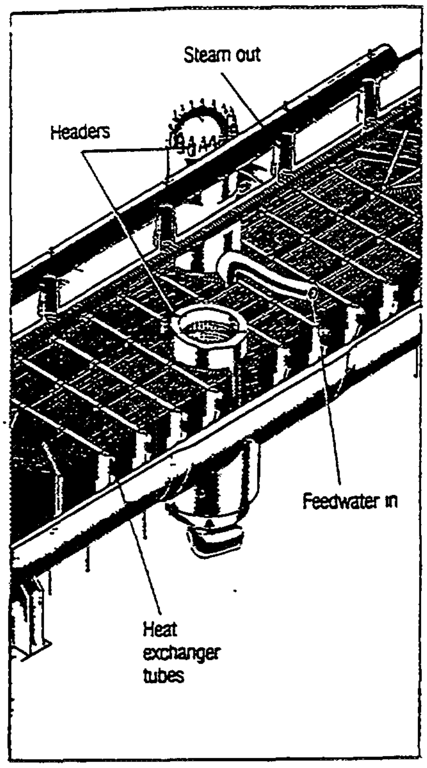


FIG. 6b. Basic arrangement of the heat exchanger tubes and headers used in the WWER-1000 steam generators (Titov 1991). Copyright Nuclear Engineering International, reprinted with permission.

TABLE IV. WWER STEAM GENERATOR PARAMETERS

Parameters	WWER-440	WWER-1000	WWER-1000U
Thermal power, MW	229.2	750	750
Steam capacity, kg/s	125	408.33	408.33
Pressure of steam, MPa	4.61	6.27	6.27
Steam temperature, °C	258.9	278.5	278.5
Feedwater temperature, °C	164-223	164-220	164-220
Coolant temperature, °C			
- at steam generator inlet	295	320	320
- at steam generator outlet	267	290	292
Coolant flow rate, m^3/hr	7100	21 200	21 200
Coolant pressure, MPa	12.26	15.7	15.7
Coolant flow rate in tubes, m/s	2.71	4.21	4.91
Average heat transfer factor, kW/m^2K	4.7	5.4	6.1
Mean logarithmic temperature head, °C	18.7	22.9	24
Specific heat flux (average), kW/m^2	89.23	123	141
Total heat exchanging surface, m^2	2576.6	6115	5126.6
Total number of tubes	5536	11 000	9157
Diameter and thickness of tube walls, mm	16x1.4	16x1.5	16x1.5
Tube mean length, m	9.26	11.10	11.14
Pressure loss along the coolant path, MPa	0.075	0.126	0.169
Reduced outlet steam rate from the evaporation surface, m/s	0.240	0.382	0.382
Steam humidity at steam generator outlet, %	0.25	0.2	0.2
Vessel material	22K	10GN2MFA	10GN2MFA
Collector material	08X18N10T[a]	10GN2MFA with inner cladding	08X18N10T perforated area
Heat exchanging tube material	08X18N10T	08X18N10T	08X18N10T
Collector dimensions in the perforated area			
- inner diameter, mm	800	834	780
- wall thickness, mm	136	171 with cladded layer	198
Hole array in the header perforated area			
- dimensions of minimum ligament, mm	11.34	6.93[b]	9.75
- number of horizontal rows along the height	77	110	94
- number of tubes in a horizontal row	89	120	112

TABLE IV. (Cont.)

Parameters	WWER-440	WWER-1000	WWER-1000U
Tube array in tube bundle	square array	staggered	staggered
- array pitch along the vertical axis, mm	24	19	22.1
- array pitch along the horizontal axis, mm	29.5	23	25, 23[c]
Submerged perforated sheet	absent	installed	installed
Steam generator circulating factor (minimum)	4-6	1.5	1.9
Void fraction, %	0.32	0.493	0.485

[a]This material is also labelled 08Cr18Ni10Ti which is a titanium stabilized austenitic stainless steel with 0.08% carbon, 18% chrome, 10% nickel and less than 1% titanium

[b]Along medium surface

[c]25 mm for the central set and 23 mm for the lateral set

2.4. WWER STEAM GENERATORS

The steam generators used in the Russian designed WWER-440 and WWER-1000 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, a feedwater piping system, moisture separators and steam collector. A sketch of a WWER-440 steam generator is shown in Figs 4a and 4b (side and end views). A sketch of a WWER-1000 steam generator is shown in Figs 5a and 5b. The tube bundle arrangement in the WWER-440 and WWER-1000 steam generators, as seen from the top, is shown in Fig. 6.

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 tubesheet 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 (WWER-1000) horizontal cylinder consisting of forged shells, stamped elliptical ends and stamped branch pipes and hatches welded together as shown in Figs 4 and 5. 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 the (a) size (the WWER-1000 steam generator is about 4 meters longer), (b) tube arrangement (corridor versus staggered), (c) collector material, (d) feedwater supply location, (e) submerged perforated top plate (WWER-1000 only), (f) steam dryer arrangement, (g) emergency feedwater distribution system (WWER-1000 only), (h) steam header arrangement, (I) and vessel material. The WWER-1000U steam generator has been designed to replace the original WWER-1000 steam generators as needed. The WWER-1000U has the perforated region of the collectors fabricated from austenitic stainless steel. Table IV lists the WWER-440, WWER-1000, and WWER-1000U design features.

3. STEAM GENERATOR DESIGN BASIS, FABRICATION AND 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.

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 III of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code. The objective of designing and performing a stress analysis with the rules of Section III 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/tubesheet 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*. 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.

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 (76% Ni, 15.5% Cr, 8% Fe, < 0.15% C). The German steam generators designed by Siemens/KWU use Alloy-800M tubing. Now, most steam generators designed by Westinghouse, Framatome, Siemens/Framatome, Babcock & Wilcox and Mitsubishi-Heavy Industries are being fabricated with thermally treated Alloy 690 (61% Ni, 29.5% Cr, 9% Fe,

<0.025% C). Siemens/KWU and Babcock & Wilcox Canada are also supplying replacement steam generators with Alloy-800M tubing.

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 traveling belt at temperatures high enough to recrystallize the material and dissolve all the carbon (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 object 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. A higher carbon content requires a higher mill-annealing temperature to dissolve all the carbides. Undissolved intragranular 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 lower 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 outside diameter stress corrosion cracking (ODSCC). Alloy 600 tubing with insufficient carbides on the grain boundaries is susceptible to PWSCC.

Subsequent to the final mill-anneal, 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 [Shah et al. 1992]. 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 [Jones 1982]. 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 [Owens 1987a]. 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 [Hunt and Gorman 1986]. 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. 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.

Siemens/KWU Practice. The first two Siemens/KWU steam generators were supplied with Alloy 600 mill-annealed tubing and began leaking after two years of operation. Thereafter, all Siemens/KWU steam generators were fabricated with Alloy 800M tubing (33.5% Ni, 21.5% Cr, 44% Fe, < 0.03% C, < 0.6% Ti). Compared to the standard Alloy 800 ASTM specification, Siemens Alloy 800M has a reduced carbon content to minimize sensitization, an increased stabilization ratio (Ti/C > 12), and slightly increased chromium and nickel contents to achieve a higher resistance to pitting and transgranular stress corrosion cracking.

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 600. The practice for Babcock & Wilcox Canada Ltd. for manufacturing Alloy 600 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 tends to behave similarly, with respect to degradation mechanisms, to that used in once through steam generators built by Babcock & Wilcox in the USA.

The current practice for CANDU RSGs is to use titanium stabilized Alloy 800M 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 08X18N10T stainless steel which is a Ti-stabilized austenitic stainless steel with 0.08% carbon, 18% chrome, 10% nickel and less than 1% titanium.

3.2.2. Tube Installation in the Tubesheet

PWR and CANDU steam generator tubes have been installed in a thick tubesheet 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 tubesheet/collector inside surface cladding. For the early PWR plants, the mill-annealed tubing was connected to the tubesheet by hard rolling the tube into the bottom of the tubesheet for a length of about 60 to 100 mm. This left an approximately 0.2-mm wide, radial crevice (where chemical impurities could concentrate) between the tube and tubesheet along the top portion (about 460 mm) of the tubesheet. In later steam generators of Westinghouse design (early to mid-1970s), the tubing was expanded for the rest of the tubesheet 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/KWU steam generators were fabricated with either a three or two step mechanical hard roll until the late 1980s. 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 tubesheet thickness (stopping and starting within a few mm of each end) 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 tubesheet provides a larger holding force than can be obtained with a hydraulic expansion.

Kiss rolls have been used to install the tubes in the tubesheets 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 tubesheet faces parallel to within 0.38 mm so that the secondary side crevice depth is less than 2.5 mm.

Mechanical tubesheet crevices generally do not exist in the CANDU steam generators. Early units closed the tubesheet crevices by a second roll near the top (secondary side) of the tubesheet. Current CANDU models use a hydraulic method to close the tubesheet 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 tubesheet. As mentioned above, the WWER-440 collectors are made of the same Ti-stabilized stainless steel as the tubing. 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

Several types of tube support systems have been used in PWR steam generators, as shown in Fig. 7 [EPRI 1985a]. Most of the original steam generators of Westinghouse design have plate-type tube supports, where tubes pass through drilled holes in the plate. This construction leaves a narrow gap around the tube, between the tube and plate, which allows secondary coolant to flow through. Separate smaller holes are also provided for the secondary coolant flow. 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 Fig. 8). 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). Later Westinghouse 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.

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 Fig. 8. The antivibration bars in Westinghouse type RSGs are installed to provide support to at least row 11, though many were installed to deeper depths,

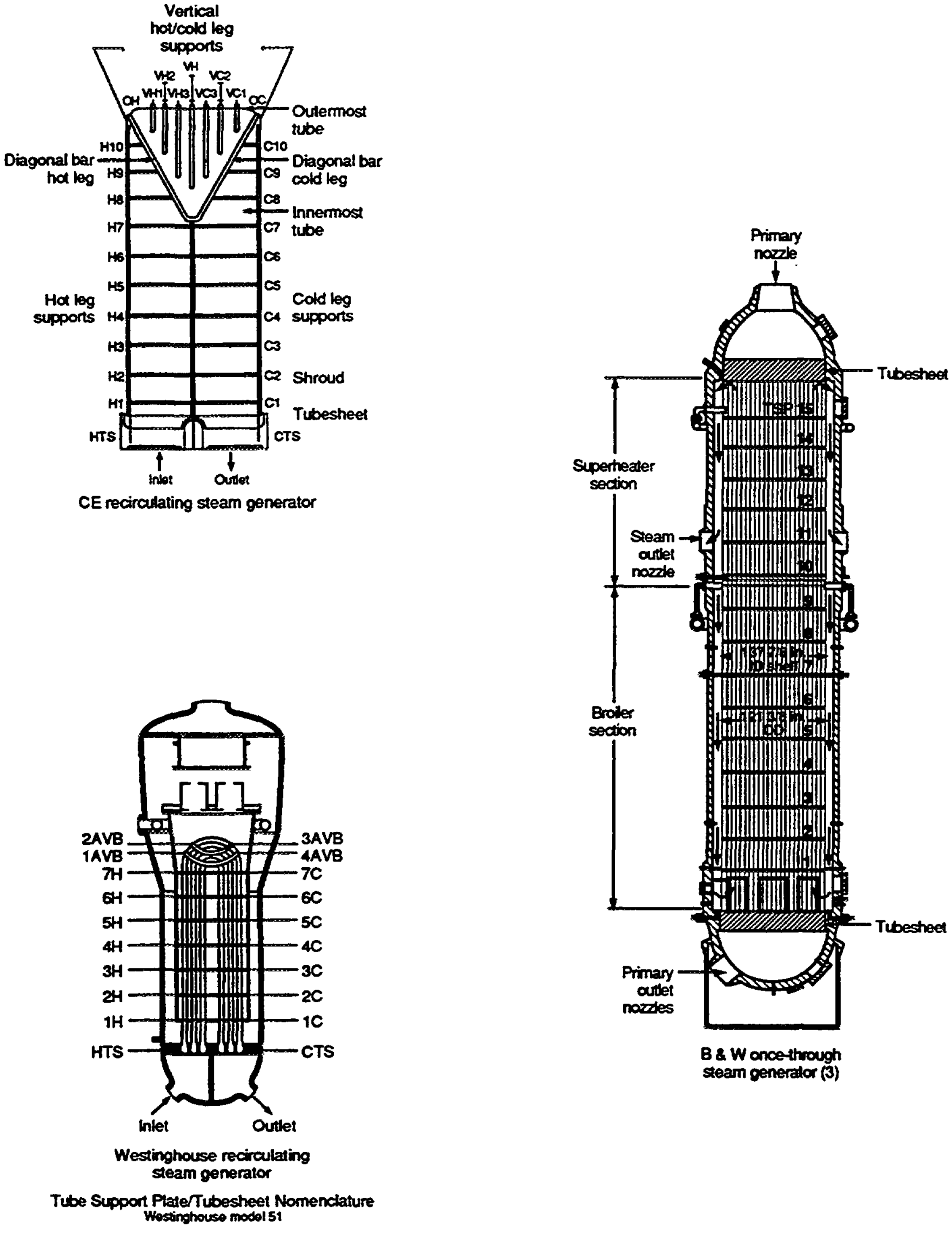


FIG. 7. Typical steam generator tube support layouts with tube support plate and tubesheet nomenclature.

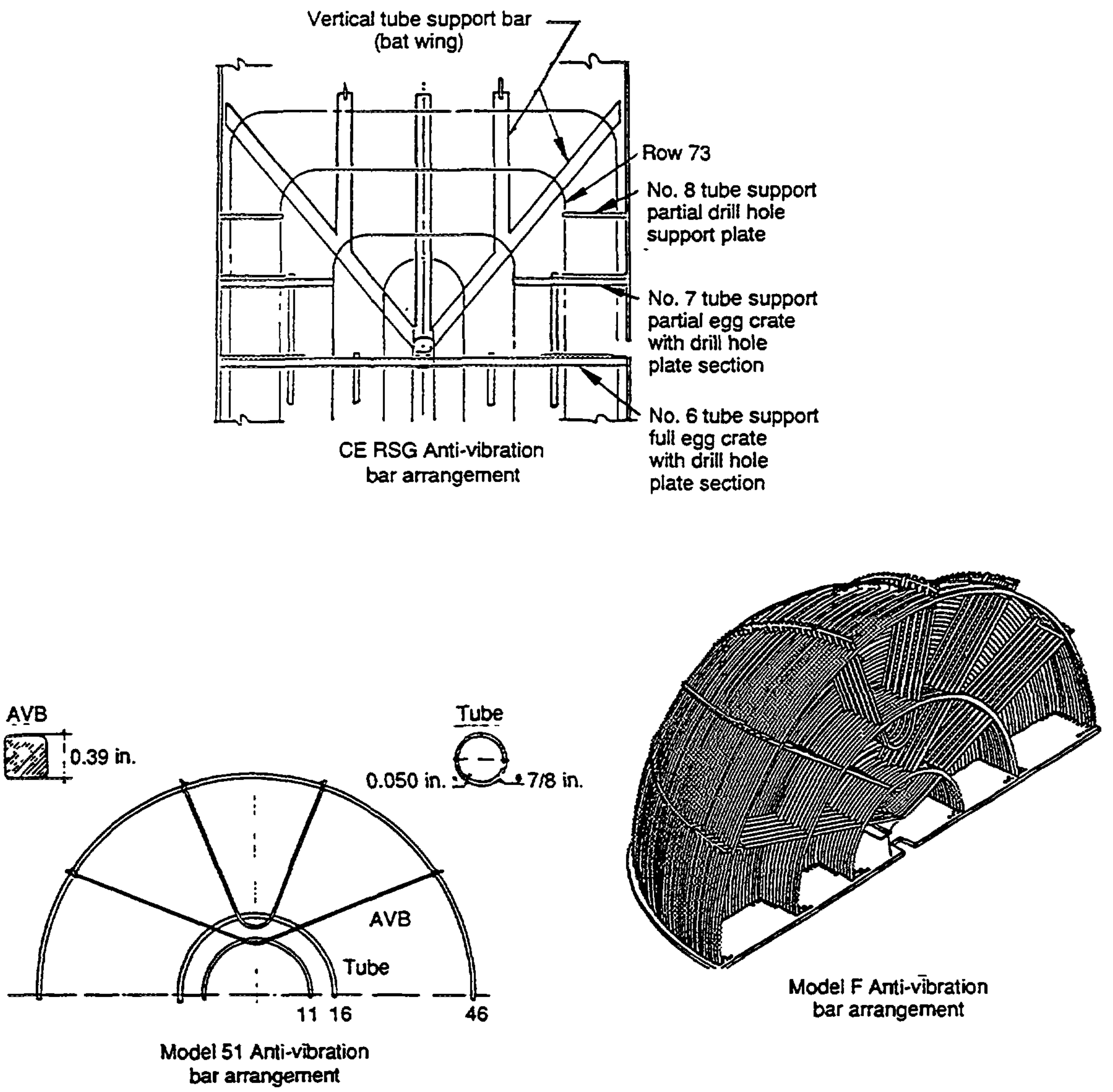


FIG. 8. Typical recirculating steam generator antivibration bar arrangement.

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 Fig. 8.

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 Fig. 9). 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.

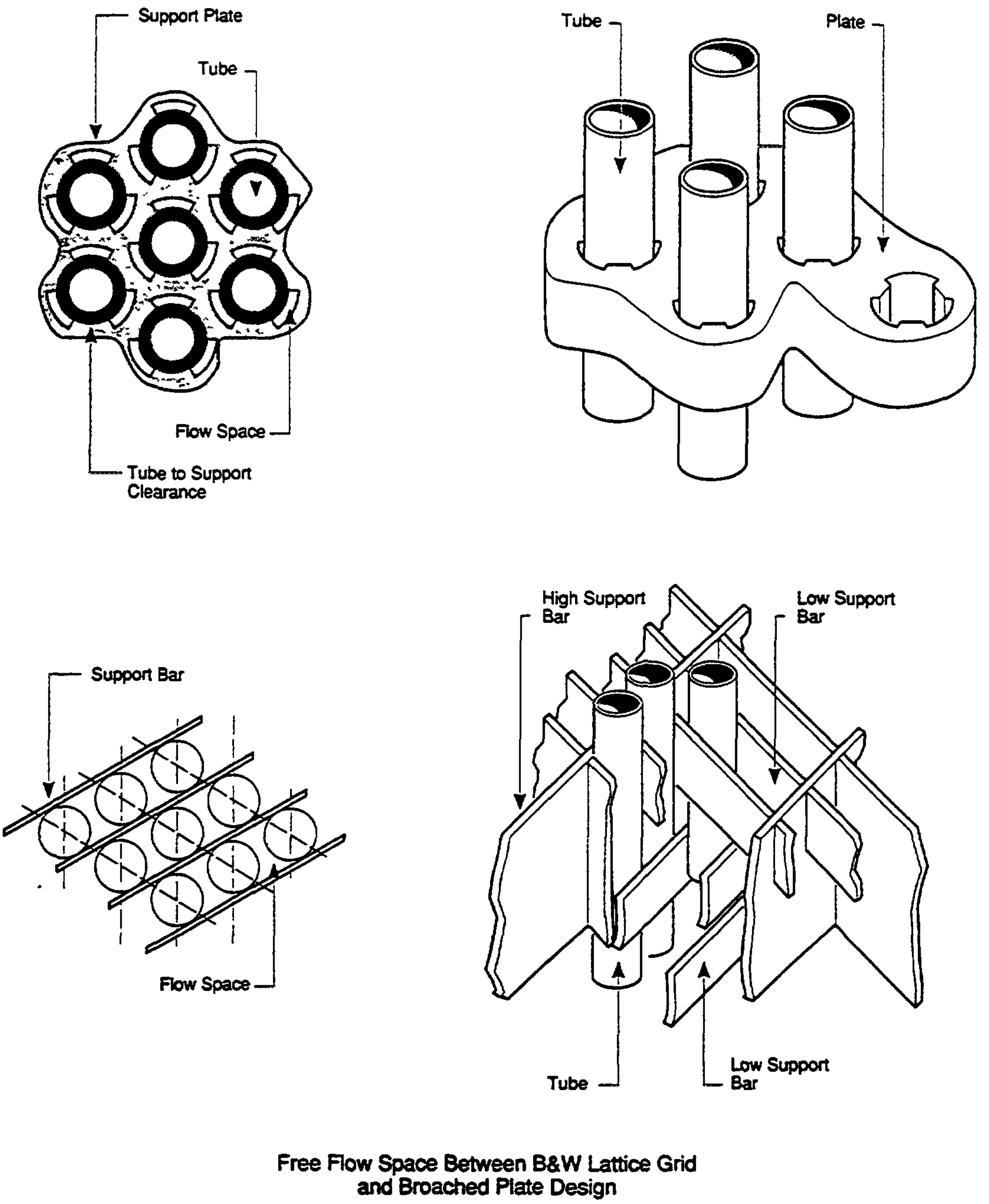


FIG. 9. Typical CANDU steam generator tube support structures. (Courtesy of C. Maruska, Ontario Hydro.)

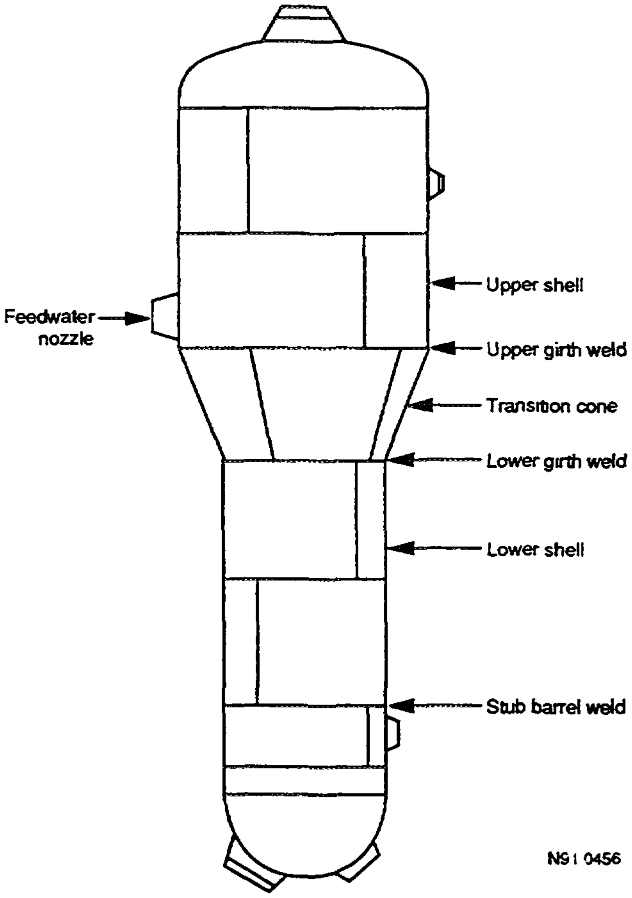


FIG. 10. PWR steam generator showing shell welds (Westinghouse 1990). Copyright Westinghouse Electric; reprinted with permission.

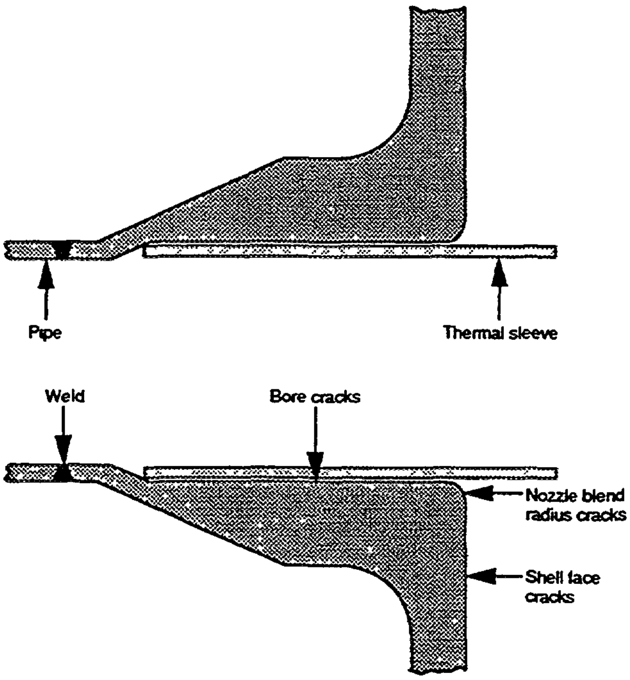


FIG. 11. Feedwater nozzle sites susceptible to high-cycle thermal fatigue damage caused by turbulent mixing of leaking feedwater and hot steam generator coolant (Westinghouse 1990). Copyright Westinghouse Electric; reprinted with permission.

3.2.4. Feedwater Nozzle and Shell

Figure 10 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 11 shows a typical Westinghouse feedwater nozzle and thermal sleeve. The Westinghouse thermal sleeve is welded to the feedring (not shown in figure). It fits snugly against the nozzle, but is not attached to the nozzle. Figure 12a 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 heat treat the entire steam generator.

The WWER steam generator pressure vessels and feedwater nozzles are shown in Figs 4, 5, and 6. 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 with the following chemical composition: 0.08% to 0.12% carbon, 0.17% to 0.37% silicon, 0.8% to 1.1% manganese, ≤ 0.30% chromium, 1.8% to 2.3% nickel, 0.4% to 0.7% molybdenum, 0.03% to 0.07% vanadium, and less than 0.02% sulphur and phosphorus.

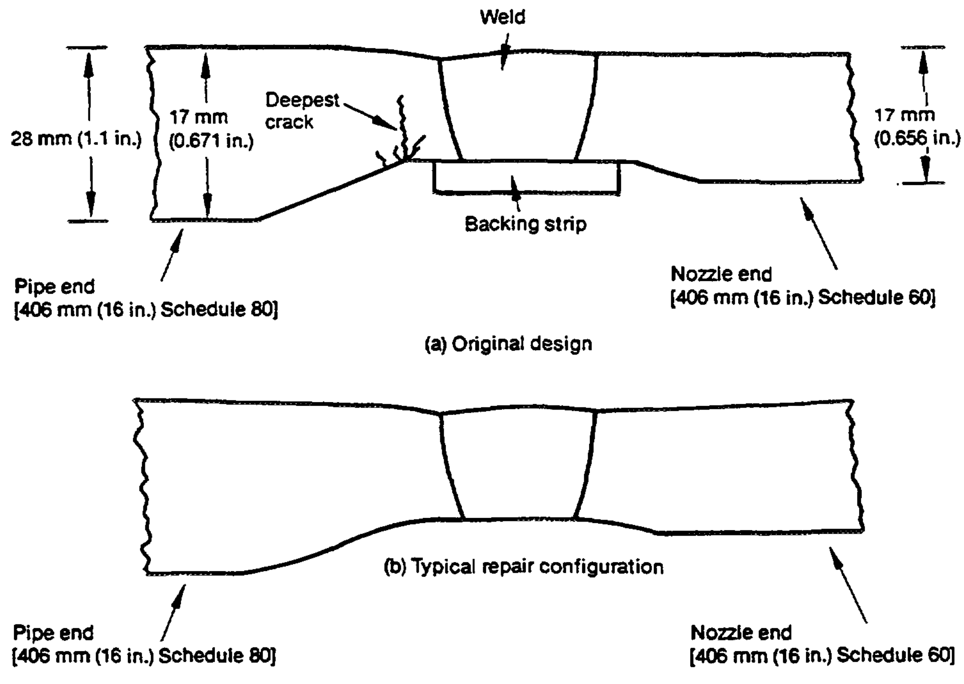


FIG. 12. Crack locations in the D.C. Cook nozzle (USNRC 1980).

4. STEAM GENERATOR DEGRADATION MECHANISMS

This section discusses the stressors, susceptible sites and failure modes associated with the various steam generator degradation mechanisms. PWR and CANDU recirculating steam generator tube degradation is discussed first, including primary water stress corrosion cracking, outside diameter stress corrosion cracking, fretting, pitting, denting, high-cycle fatigue, and wastage. This material is followed by similar information on PWR once-through steam generator 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. Steam generator plug and sleeve degradation is discussed in Section 8.

4.1. PWR AND CANDU RECIRCULATING STEAM GENERATOR TUBES

The relative impact of tube degradation mechanisms on overall PWR steam generator performance has dramatically changed over time. Figure 13 shows the percentage of the total number of tube failures[1] caused by each of the major degradation mechanisms for the years 1973 through 1994 (EPRI 1995a). Both PWR and CANDU recirculating steam generator and PWR once-through steam generator tube failures world wide are included. (Figure 13 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, a variety of corrosion mechanisms became important, including intergranular stress corrosion cracking/intergranular attack and pitting on the outside diameters of the tubes and primary water stress corrosion cracking on the inside surfaces. Fretting damage became more apparent after about 1983.

Table V lists the number of PWR and CANDU plants reporting various problems in 1977, 1982, and 1993 (EPRI 1994). There was a dramatic increase over the last 15 years in the number of plants reporting primary water stress corrosion cracking, outside diameter stress corrosion cracking, and fretting problems. Over 50% of the PWR units world wide have now reported some occurrence of tube fretting and wear. However, some plants report no problems, even after five years of operation (7-10% of the plants report no problems after five years of operation). Most of the PWR steam generator tubes which have failed over the years have been mill-annealed Alloy 600 tubes. However, some failures of thermally treated Alloy 600 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 thermally treated Alloy 600 tubing due to primary and secondary side stress corrosion cracking.

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[1] Failure is defined as a nondestructive 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.

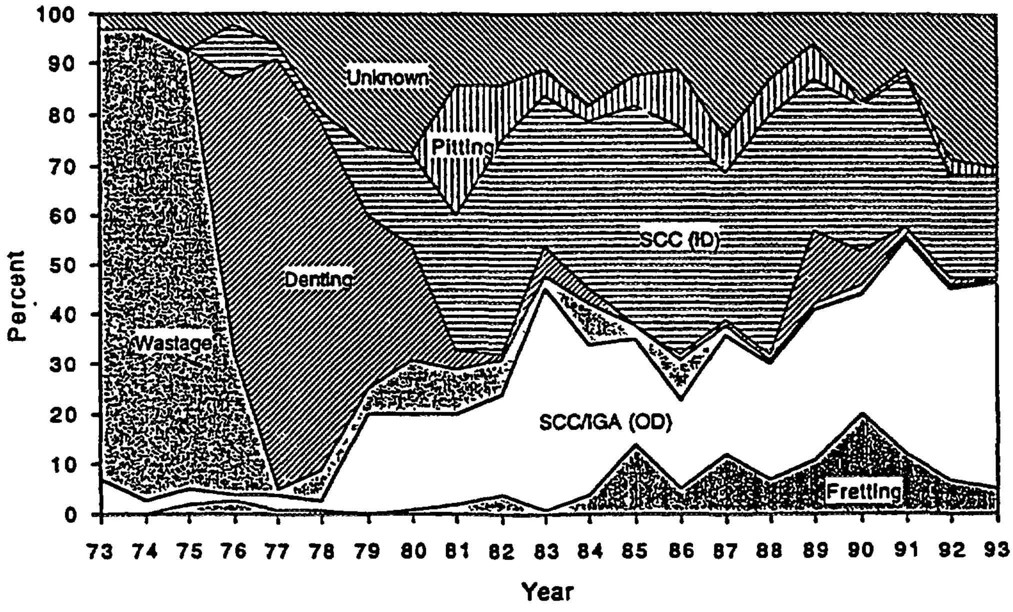


FIG. 13. Worldwide causes of steam generator plugging (EPRI 1995a). Copyright 1996 Electric Power Research Institute; reprinted with permission.

The Alloy 800M tubing used in the Siemens/KWU steam generators has performed relatively well. There were Alloy 800M tubing failures due to wastage in the Siemens/KWU steam generators which began operation in the 1970s with phosphate water chemistry, but there have been no wastage failures in the Siemens/KWU steam generators which began operation in the 1980s with an all volatile water treatment. There have also been some Alloy 800M tubing fretting failures in the Siemens/KWU steam generator which began operation before 1986. But, only one Alloy 800M pulled tube has exhibited a stress corrosion crack, pits have been found on only two Alloy 800M tubes, and no Alloy 800M tubes have exhibited detectable intergranular attack or primary water stress corrosion cracking. There have been no Alloy 690 tube defects of any kind reported to date.

Figures 14 and 15 identify degradation sites for PWR and CANDU steam generators, respectively. Table VI lists PWR steam generator degradation mechanisms, sites, stressors, failure mode and inspection methods for tubes and tubesheets. Table VII lists the degradation mechanisms and sites currently active in the CANDU steam generators and the corresponding countermeasures completed or in progress.

4.1.1. Primary Water Stress Corrosion Cracking (PWSCC)

Research has shown that stress corrosion cracking of austenitic stainless steels and nickel based alloys requires at least the following three conditions: susceptible tubing microstructure (alloy content or few intergranular carbides), high applied or residual tensile stress (near the yield strength), and a corrosive environment (high temperature water). The influence of the nickel content on the stress corrosion cracking processes in 18% chromium austenitic alloys when stressed slightly above the yield point of the material in demineralized water or water containing 1 g/L chloride ions is shown in Fig. 16 (Berge 1993). As indicated on the figure, Alloy 600 can be susceptible to pure (primary) water stress corrosion cracking, where as,

TABLE V. UNITS REPORTING STEAM GENERATOR PROBLEMS (EPRI 1994)

DATE	3/77	8/82	12/93
NO. UNITS:	52	99	235
REPORTED PROBLEMS:			
Denting			
- Tube Support Corrosion	15	30	36
- At and Above the Tubesheet	6	12	50
Tubing Corrosion			
- Wastage	19	28	39
- Pitting	0	3	16
- PWSCC	1	22	102
- ODSCC/IGA	6	22	85
Mechanical Damage			
- Fretting	9	15	128
- Fatigue Cracking	3	4	15
- Impingement	0	2	10
No Problems	26	32	48
No problems after 5 years ops (no. of units/no. >5yrs. ops).	1/14	4/57	20/205

Units reporting no problems after five years of operation

3/77	8/82	12/93	
Trillo	Kewaunee	Bruce-B 5	Obrigheim (Rpl)
	Mihama 3	Brokdorf	Philippsburg 2
	Neckarwestheim	Chinon B 3	Pickering-A 3
	Davis Besse	Cruas 3	Pickering-A 4
		Cruas 4	Pickering-B 7
		Genkai 2	Pickering-B 8
		Grafenrheinfeld	Robinson 2 (Rpl)
		Isar 2	Trillo 1
		Loviisa 1	Uljin 1
		Loviisa 2	Wolsung 1

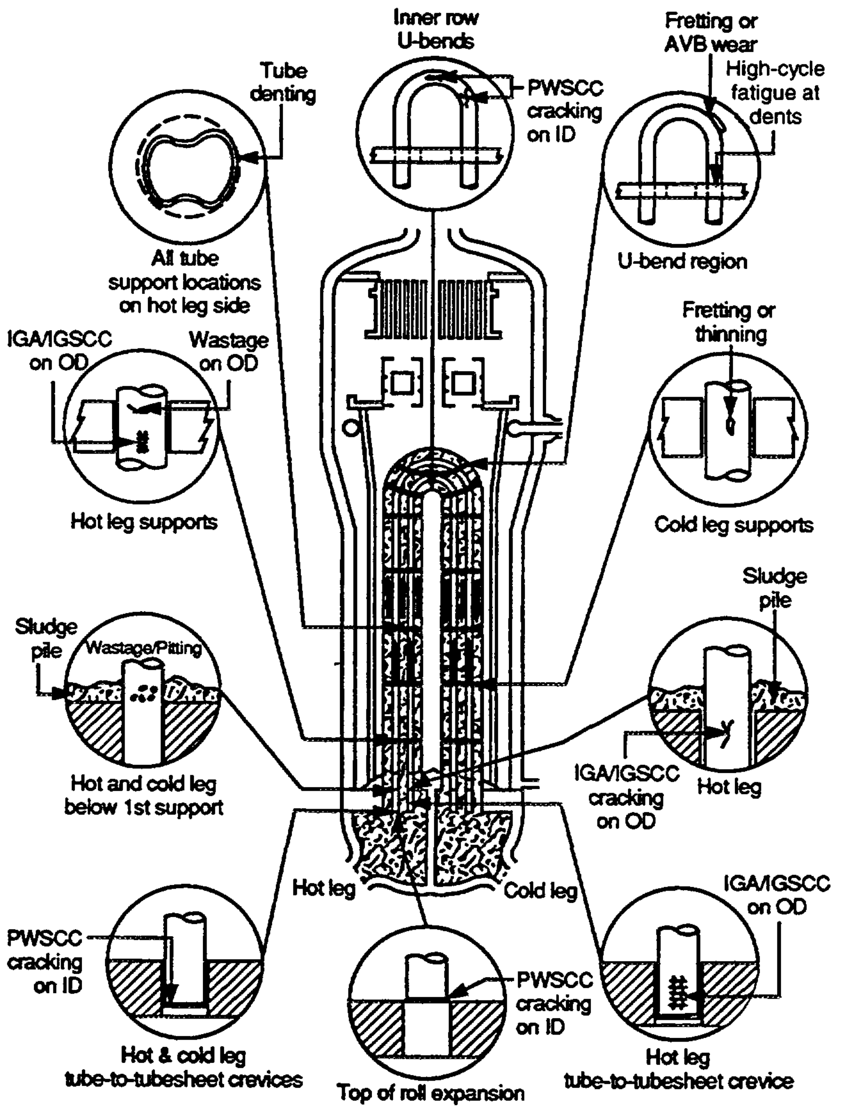


FIG. 14. Locations of known tube wall degradations in recirculating steam generators. (Courtesy of K. J. Krzywosz of the Electric Power Research Institute NDE Center; modified.)

Alloy 690 and Alloy 800M are generally not susceptible to PWSCC. Austenitic stainless steels with a nickel content below about 15% are susceptible to transgranular stress corrosion cracking when exposed to water containing significant amounts of chlorides (1 g/L). The occurrence of PWSCC of Alloy 600 strongly depends on the absence of intergranular carbides. High mill-annealing temperatures (1065°C) during final heat treatment produce intergranular carbides, which make Alloy 600 tubes resistant to PWSCC. In contrast, low mill-annealing temperatures produce intragranular 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.

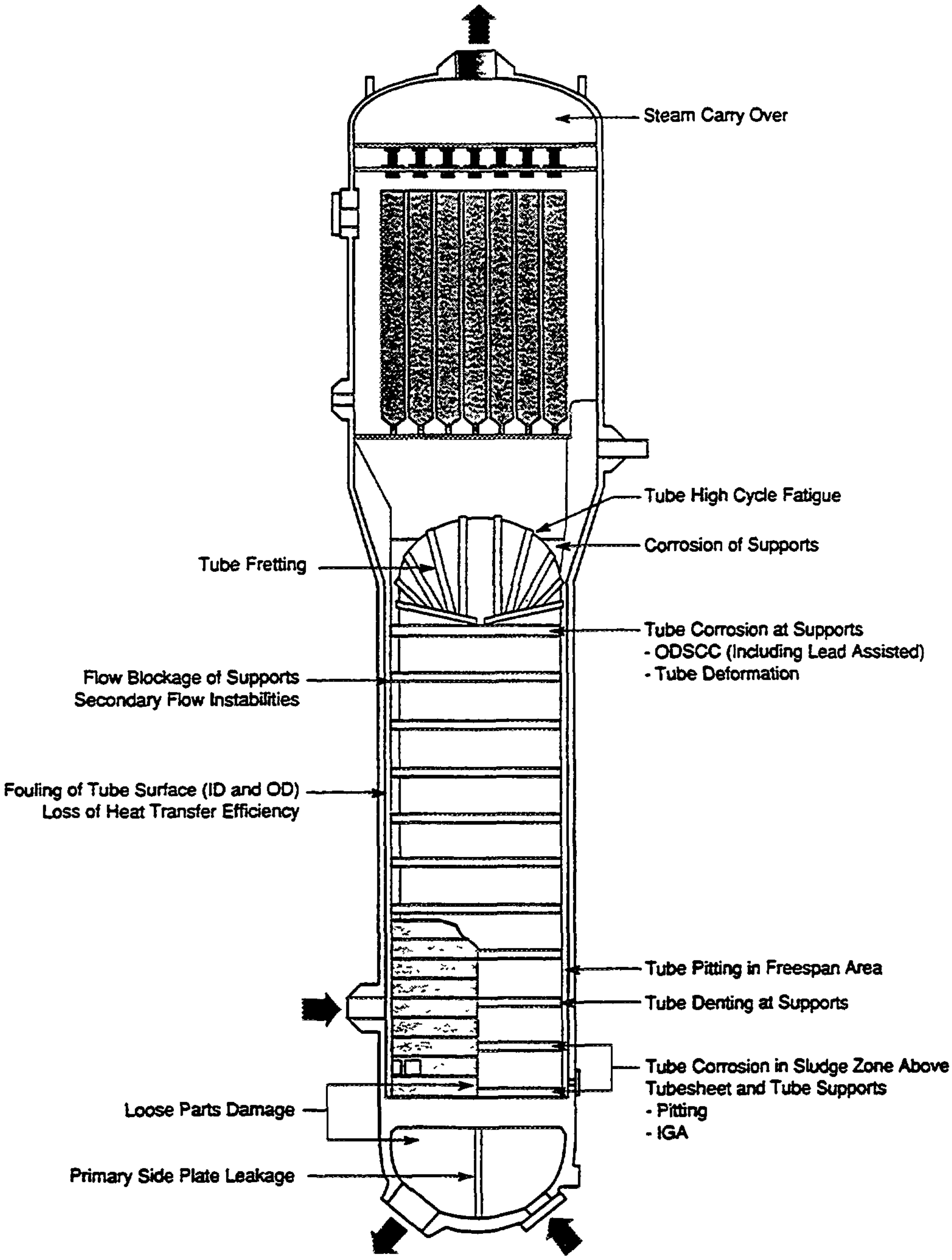


FIG. 15. Degradation mechanisms and locations in CANDU recirculating steam generators. (Courtesy of C. Maruska, Ontario Hydro.)

PWSCC occurs at locations on the inside surfaces of recirculating steam generator tubing with high residual stresses (introduced during fabrication and installation of the tubes, as discussed in Section 3.2). These locations are primarily the roll-transition regions in the tubesheets, 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, tubesheet, or sludge pile elevations. Section 4.1.5 discusses tube denting, e.g., deformation resulting in residual stresses due to buildup of corrosion products. PWSCC generally occurs on the hot-leg side of the recirculating steam generations; however, cold leg PWSCC has been observed.

TABLE VI SUMMARY OF PWR RECIRCULATING STEAM GENERATOR TUBE DEGRADATION PROCESSES

Rank[a]	Degradation Mechanism	Stressor	Degradation Sites	Potential Failure Mode	ISI Method
1	ODSCC	Tensile stresses, impurity concentrations, sensitive materials	• Tube-to-tubesheet crevices • Sludge pile • Tube support late • Free span	Axial or circumferential crack Circumferential crack Axial crack Axial crack	MRPC MRPC/Cecco 5 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 tubesheet 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, ultrasonics
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]Multifiequency rotating pancake coil probe

TABLE VII. SUMMARY OF MAJOR CANDU STEAM GENERATOR DEGRADATION

Rank	Degradation Mechanism	Stressor	Degradation Sites	Potential Failure Mode	ISI Method
1	ODSCC	High stress, corrosive environment due to deposit build-up	U-bend support intersections 7th support plate	Circumferential cracking Predominantly circumferential, some axial	Cecco 3 Cecco 3
2	Outside diameter pitting	Deposits which cause a corrosive environment	Tubesheet area under sludge pile and at lower tube support intersections and at freespan tubes	Local tube thinning leading to holes	E/C [carter] Ultrasonics
3	Fretting	Flow induced vibration, loose supports	U-bend support intersections	Metal loss which may lead to large hole	Bobbin coil
4	Corrosion of carbon steel supports	Corrosive environment, stress	U-bend supports	Support disintegration and metal loss/may lead to tube degradation from flow induced vibration due to lack of support	Visual (secondary access)
5	Erosion-corrosion, high or low cycle fatigue	Bolt failure	Primary head	Break up of bolted plates may lead to blockage of PHT inlet	Visual and metallography of bolts

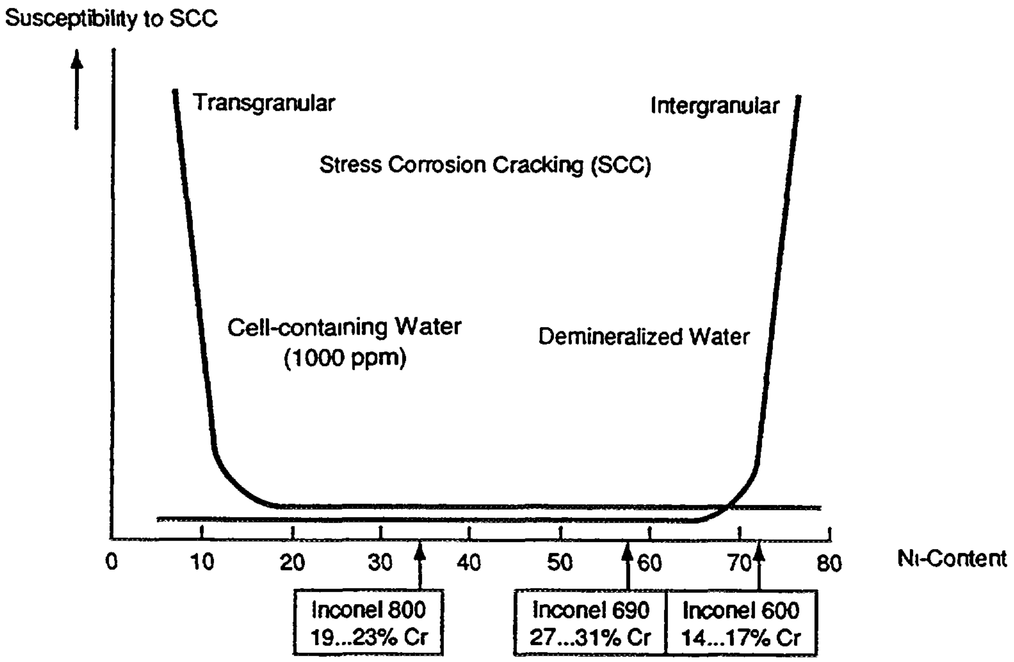


FIG. 16. Schematic diagram showing the influence of nickel content on the cracking processes occurring in three steam generator tubing materials stressed slightly above the yield point in 350°C water. (From Coriou 1971, as reported by Berge 1993. Copyright 1993 Electric Power Research Institute; reprinted with permission.)

Examination 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 (Dobbeni et al. 1985, Engstrom 1985):

1. Cracks in U-bends typically are axial in orientation, though occasional off-axial cracks have been detected.
2. 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.
3. 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.
4. Cracks at explosive transitions are typically circumferential in orientation, though occasionally axial PWSCC is noted by rotating pancake coil eddy-current testing.
5. Primary-side cracks at dented tube support plate intersections are typically axial, though some circumferential segments have been noted.
6. Cracks at dents associated with sludge pile deposits at the top of the tubesheet (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.

As of December 1993, at least 94 PWR plants worldwide (36 plants in the USA) with RSGs had experienced significant PWSCC at the roll transition (tubesheet), dent, and/or U-bend locations of the tubing (EPRI 1994). Approximately 14 180 recirculating steam generator tubes with PWSCC at or near the roll transitions have been plugged at 85 plants. Tubes with PWSCC have also been sleeved at 17 plants. Approximately 8430 recirculating steam generator tubes with PWSCC in the U-bend regions have also been plugged at 63 plants (however, several hundred tubes were preventatively plugged and may not have been defective). Fifty-three PWR plants have experienced both transition region and U-bend PWSCC and tubes with PWSCC at dents have been plugged at, at least, five plants.

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 600 mill-annealed 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 some plants. However, similar steam generators (same model number) at other PWR plants have experienced only a few tube failures due to PWSCC.

The Combustion Engineering plants with relatively high-temperature mill-annealed tubing initially reported significantly less PWSCC. However, both explosive-transition and U-bend PWSCC occurred at Maine Yankee after about 16 years of operation (model CE-67 steam generators) and a few cracks at the roll transition regions occurred at Palo Verde Units 1 and 3 after five to seven years of operation (model CE-80 steam generators). Recently, it was reported that after 22 years of operation 60% of the Maine Yankee steam generator tubes had indications of circumferential cracking at or near the expansion transition and the utility sleeved all 17 000 tubes in its three steam generators (USNRC 1995).

Nine 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 690 or Alloy 800M 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 600 tubing has over 11 effective full power years (EFPY) or approximately 18 calendar years 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 800, are not susceptible to PWSCC.

4.1.2. Outside Diameter Stress Corrosion Cracking (ODSCC)

Outside diameter stress corrosion cracking is a degradation mechanism which includes both intergranular stress corrosion cracking (IGSCC) and intergranular attack (IGA) on the outside surfaces of the tubing. Most of this degradation takes place in the tube to tubesheet and tube to tube support plate crevices, however, sludge pile and free-span ODSCC has been observed at some plants. IGSCC requires the same three conditions as PWSCC: tensile stress, material susceptibility, and a corrosive environment (in this case, high temperature water containing aggressive chemicals). 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.

ODSCC strongly depends on the concentration of corrosive impurities at dryout regions in the steam generator. The impurity levels in secondary-side systems are highly variable, and are likely influenced by at least the following: crevice geometry, cooling water type (fresh, brackish, sea), secondary plant materials (e.g., presence of copper), 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 tubesheet and the tube to tube support plate crevices, in the sludge pile region, and at free-span locations, especially free-span locations with significant crud build-up. Most outside 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 8th cycle. The axial cracks occur either singularly or in networks of multiple cracks, sometimes with limited patches of IGA. Shallow circumferential cracks may sometimes occur in the IGA affected regions producing a grid-like pattern of axial and circumferential cracks termed "cellur corrosion."

As of December 1993 at least 89 PWR plants (44 US plants) with RSGs and a few CANDU plants have experienced some degree of ODSCC in the tubesheet crevice, sludge pile, tube support plate intersection, or free-span locations (EPRI 1994). Approximately 14 140 recirculating steam generator tubes with ODSCC at the tube support plate locations have been plugged at 63 PWR plants. Approximately 13 860 recirculating steam generator tubes with ODSCC in the tubesheet crevice and sludge pile regions have also been plugged at 75 PWR plants (49 PWR plants have had both tube support plate and tubesheet 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 600 mill-annealed tubing. Only one tube with ODSCC has been found in the Siemens/KWU steam generators with Alloy 800M tubing and only one plant with thermally treated Alloy 600 tubing has reported ODSCC (Kori-2 has reported finding ODSCC in the tubesheet region and plugging 125 tubes). 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 (or in some cases, the plants have been shut down). However, similar steam generators (same model number) at other plants have experienced only a few per cent failures due to ODSCC.

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 [Pinard-Legry and Plante 1983]. 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.

The oldest running CANDU units tubed with Alloy 600 are currently experiencing widespread, but relatively shallow (5–10% of the wall thickness) ODSCC at the tube U-bend supports. This degradation has been due to a combination of heavy secondary side deposits which created an aggressive environment on the tube surface and corrosion of the carbon steel supports which caused high stresses in the area. The heavy deposits in the steam generators were due to early water treatment plant problems, condenser leakage, abnormal chemistry incidents, and feedtrain corrosion problems. Final failure of a few tubes occurred due to high cycle fatigue.

The degradation was severely aggravated in Bruce-A2 by contamination due to a lead blanket inadvertently left in one steam generator during maintenance activities. The lead was transported into the other steam generators at the unit through the water in the common steam drum. Cracking in the lead contaminated steam generators was typical of lead assisted cracking: mixed mode, transgranular and intergranular, ranging from 0–100% throughwall. Lead shielding was also inadvertently left behind in the Doel Unit 4 Steam Generator B in Belgium and is believed to have contributed to the severe ODSCC which subsequently occurred in that steam generator.

Because ODSCC can take several forms (short axial cracks, long axial cracks, circumferential cracking, cellur 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 tubesheet is much more difficult to detect with a standard eddy-current bobbin coil probe than PWSCC within the tubesheet or axial ODSCC at the tube support plates. However, it is possible to detect ODSCC within the tubesheet 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 tubesheet 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 tubesheet) can provide reinforcement in the event of a throughwall crack, provided the support does not move relative to the tube during the event and the crack is within the support. Freespan 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 freespan flaw before the flaw achieves a critical size. Tube ruptures have occurred due to freespan ODSCC.

4.1.3. 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/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/KWU steam generators (EPRI 1985a).

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 (EPRI 1994). 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 51F and Mitsubishi Heavy Industries model 51F) 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/KWU 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 Fig. 17, and the tubes are held in semicircular holes). This degradation is caused by flow

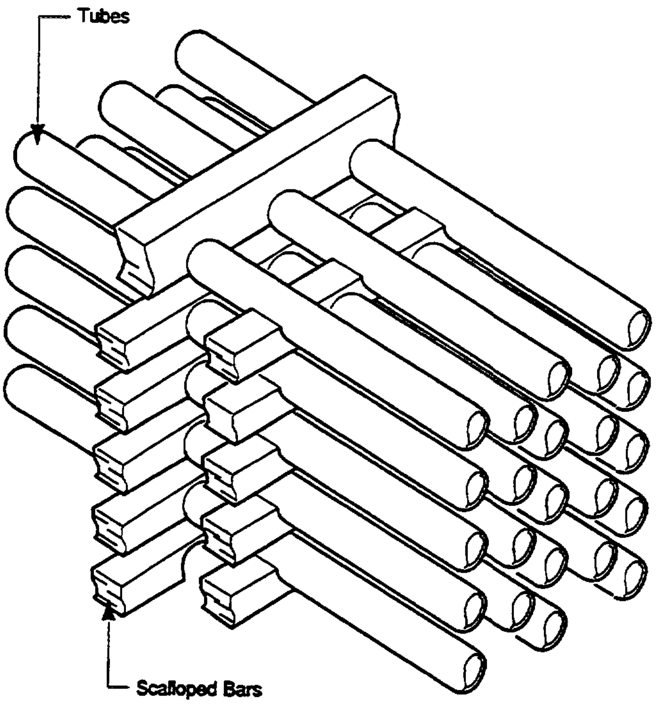


FIG. 17. CANDU recirculating steam generators staggered scallop bar arrangement. (Courtesy of C. Maruska, Ontario Hydro.)

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.

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 tubesheet 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 tubesheet. 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 impact, collapse, fatigue, fretting type wear, abrasion, and ductile overload and tearing.

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 tubesheet 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-tubesheet welds.

4.1.4. Pitting

Pitting is a steam generator degradation type appearing as groups of small-diameter wall penetrations resulting from local corrosion cells, probably promoted by the presence of chloride or sulphate acids. 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 and the presence of copper are probable accelerators. Any barriers to diffusion such as sludge accumulation on the tube wall will accelerate the pitting process by enhancing chemical concentration.

Pitting generally occurs at the top or within the cold leg sludge pile region. Pitting corrosion typically occurs in locally weak spots in the passivated surface of the Alloy 600 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% throughwall depth or less (EPRI 1994). 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 (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 (Laskowski and Hudson 1986, Angwin 1984, Theus and Daniel 1984). In addition, most of the pitting has been associated with Alloy 600 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 outside surface underdeposit corrosion and is caused by heavy secondary side deposits, both on top of the tubesheet 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 800M alloy has experienced a small number of tube failures due to pitting (underdeposit chloride pitting) at the first and second support plates. Early condenser tube leakage (seawater) and sludge deposits contributed to this degradation.

4.1.5. Denting

Denting describes the mechanical deformation or constriction of the tube at a carbon steel tube support plate intersection caused by the buildup of deposits and the growth of a voluminous support-plate corrosion product in the annulus between the tube and support plate.

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 tube supports. 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 [EPRI 1985a, Clark and Lewis 1985]. 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. 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 and attention to secondary-side water chemistry have reduced denting to a lesser concern, denting is still considered a degradation concern, 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 [EPRI 1985, Theus and Daniel 1984, Frank 1984, Nordmann et al. 1983].

Denting of Alloy 600 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 (Fig. 13). As of December 1993, 1471 RSG tubes at 41 plants (four Combustion Engineering and 37 Westinghouse-type plants) had been plugged because of tubesheet 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 (EPRI 1994). 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 600 and Monel 400 steam generators with carbon steel supports have also experienced tube deformation due to deposit buildup in the tube-support gaps and corrosion of the supports. However, tube cracking has not been detected in the deformed areas.

4.1.6. 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 55 000 kg (55 tonnes) of primary coolant to the secondary-coolant system. Approximately 1300 kg (1.3 tonnes) of steam, 0.6 curie of radioactive noble gases, and 0.01 curie 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 600 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.

4.1.7. 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.

4.2. PWR ONCE-THROUGH STEAM GENERATOR TUBES

Once-through steam generators in the USA use the same Alloy 600 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 [Turner 1988]. Table VIII 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.

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

Rank[a]	Degradation site(s)	Stressors	Degradation mechanism(s)	Potential failure mode	In-service inspection method(s)
1	Outside surfaces of the tubes on the 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 outside surfaces near the upper tubesheet 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	Inside surfaces of tubes near the upper tubesheet roll transitions and welds (primary side)	Sodium thiosulphate, air	Low-temperature primary-side stress corrosion cracking	Circumferential cracks	Eddy-current testing

[a] Based on operating experience and number of defects

4.2.1. Erosion-Corrosion

Erosion-corrosion results from entrained solid particles impinging on metal surfaces causing material removal, wear, and mechanical damage, especially if there is a protective surface film present. In a corrosive environment, the erosion process first removes the protective film from the tube, thus making the tube susceptible to more corrosion and then more erosion. Inspection of removed tubes indicates that erosion-corrosion has occurred in once-through steam generators on the outside of the heat exchanger 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 steam generators.

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 tubesheet 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 tubesheet (EPRI 1985, Theus and Daniel 1984). Sometimes these metal loss areas contained microcracks that acted as the site for fatigue crack initiation. Laboratory tests indicate that the corrosive metal loss, including the microcracks, can be achieved with concentrations of sodium sulphate, silicates, and chlorides (Monter and Theus 1982). 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 the open inspection lane to the upper tubesheet 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 inside 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 [Jones et al. 1982, Giacobbe et al. 1988]. 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 that aggressive concentrations of sodium thiosulphate and oxidizing conditions developed in the failure area from dryout and exposure to air. Most of the defects were circumferential in geometry and located in the upper part of the upper tubesheet 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. Outside Diameter Intergranular Stress Corrosion Cracking (IGSCC) and Intergranular Attack (IGA)

As discussed in Section 4.1.2 above, IGSCC requires tensile stress, material susceptibility and a corrosive environment. IGSCC cracks occur along the grain boundaries, normal to the maximum principle stress. IGA is characterized by local, corrosive loss of material along the grain boundaries. Both mechanisms require a concentration of corrosive impurities on the outside surface of the tubing.

Through December 1993, 543 tubes (about 0.25% of the once-through steam generator tubes in service) at four plants were removed from service or repaired due to IGSCC/IGA. The damage primarily occurred near the upper tubesheet (492 tubes).

4.3. WWER STEAM GENERATOR TUBES

The horizontal, U-shaped tubing used in the WWER-440 and WWER-1000 reactors has been relatively trouble free. The WWER tubing is made of titanium-stabilized austenitic stainless steel with about 0.08% carbon, 18% chrome, 10% nickel, $\leq$ 1% titanium and the rest mostly iron. Through the end of 1989, only about 2815 WWER-440 tubes and 655 WWER-1000 tubes had been plugged out of a total of 1 774 480 tubes in operation; e.g., only about 0.2% of the total number of tubes had been plugged (Titov et al. 1992).

The main cause of damage has been outside 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 ppb have been reported for relatively significant times (Rassokhin et al. 1992). 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 (Titov et al. 1992, Mamet and Martynova 1993). 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 VI) for up to 20% of the overall running time, and to the range of 5-6 for up to 2% of the running time. Also, up to 700 ppb of acetic acid (due to organic compound breakdown) has been found in the feedwater at several plants (Martynova and Mamet, 1991).

These secondary side chemistry excursions have also caused pitting corrosion, for example at the grid spacer locations at the Novovoronezh Units. There have also been a few collector weld defects which have resulted in plugged tubes. The repair criteria for the WWER steam generators is tube leakage and the method is plugging; e.g., leaking tubes are plugged, other indications (part throughwall defects) are usually ignored.

4.4. TUBE RUPTURE EVENTS

4.4.1. Tube Ruptures

The leak rate, degradation mechanism, rupture size, rupture location, and stressor and contributing factor information associated with ten steam generator tube rupture events is summarized in Table IX (MacDonald et al. 1996). These ruptures have occurred over the last 20 years at a rate of about one every 2–3 years and may continue to occur. The maximum leak rates have ranged from 470 L/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 ten ruptures: three ruptures were caused by ODSCC, two ruptures were caused by high-cycle fatigue, two ruptures were caused by loose parts wear, two ruptures were caused by PWSCC, and one rupture was caused by wastage.

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

	Plant,	Maximum Leak Rate	Degradation	Rupture	Rupture	Stressors and contributing factors
02/26/75	Point Beach-1 W-44	125	Wastage	2 adjacent ruptured bulges each about 20 mm long and wide	Slightly above the tubesheet, outer row on the hot leg side	Large sludge pile, ineffective cleaning
09/15/76	Surry-2 W-51	330[(1)]	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
06/25/79	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
10/02/79	Prairie Is -1 W-51	336[(1)]	Loose Parts Wear	38 mm long axial fishmouth opening	Tube bundle outer surface, 76 mm above the tubesheet on the hot leg side, Row 4, Column 1	Sludge lancing equipment left in the steam generator
01/25/82	Ginna W-44	760[(1)]	Loose Parts Wear, Fretting	100 mm long axial fishmouth opening	127 mm above the tubesheet 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
05/16/84	Fort Calhoun CE	112	ODSCC	32 mm long axial crack (small fishmouth 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
07/15/87	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
03/07/89	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 tubesheet at the lower tube support plate on the cold leg side, Row 18, Column 25	Long shallow groove, possibly a contaminant
02/09/91	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
03/14/93	Palo Verde-2 CE-80	240	ODSCC	65 mm long axial fishmouth opening in a 250 mm long axial crack	Freespan 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
[(1)]NRC estimates						

Additional ruptures caused by wastage are unlikely because only three reactors worldwide are now using phosphate water chemistry.

Additional 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 AVBs. 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 crack 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 outside diameter stress corrosion cracking has occurred in certain steam generators and more ruptures caused by those mechanisms are possible.

The rupture locations have generally been either just above the tubesheet (three 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 tubesheet 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.

The plant transient information is summarized in Table X (MacDonald et al., 1996). The operators were expected to (a) maintain the primary coolant subcooled, (b) minimize the leakage from the reactor coolant system to the defective steam generator secondary side, and (c) 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 letdown 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 X SUMMARY OF PLANT TRANSIENT INFORMATION

	Point Beach 1	Surry 2	Doel 2	Prairie Is 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 ejector rad	Air ejector 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 63 114 132 min		No	No		
atmospheric dump valves open	No	No	No	1 2 sec at scram			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	14 25 min 3 5 h	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[a]	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 minutes

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 IX, 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 letdown 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 effect 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

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

Plant	Date	Maximum Leak Rate	Defect Size	Defect Location	Degradation Mechanism
Braidwood Unit 1	23 October 1993	≈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	9 March 1992	57 L/h (15 gal/h)	Circumferential throughwall crack	Hot leg side of the tube in Row 67, Column 109, 4.8 mm above the tubesheet in the explosive transition region	ODSCC
McGuire Unit 1	16 January 1992	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	17 December 1990	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	6 March 1990	≈115 L/h (30 gal/h)	360° circumferential crack	Peripheral tube A77-1 next to the open inspection lane, bottom of upper tubesheet	High-cycle fatigue (environmentally assisted)
Beaver Valley Unit 2	21 June 1989	80 L/h (21 gal/h)	97% throughwall wear, small rupture	Hot leg side of the tube in Row 31, Column 16, 25 mm above the tubesheet	Loose parts damage
Indian Point Unit 3	19 October 1988	456 L/h (120 gal/h)	250° circumferential crack	Tube in Row 45, Column 51, just above upper support plate	High-cycle fatigue, denting

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

Seven incipient tube rupture events which occurred in the USA during the last seven years are summarized in Table XI (MacDonald et al. 1996).

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 steamline radiation monitors promptly detect increases in nitrogen-16 activity. When combined with appropriate alarm setpoints 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" (USNRC 1994).

4.5 PWR AND CANDU STEAM GENERATOR SHELL, FEEDWATER NOZZLE AND TUBESHEET

This section discusses degradation mechanisms in steam generator shells and feedwater 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 tubesheet or CANDU shell, nozzle, or tubesheet degradation reported. Thermal fatigue and erosion-corrosion are

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

Rank[a]	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

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

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 XII 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

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 feedtrain.) 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 (Bamford, Rao, and Houtman 1992). 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 [Kobayashi and Shockey 1991].

Feedwater Nozzles. Corrosion-fatigue cracks, caused by coolant thermal stratification and the stress concentrations at a counterbore (a joint between the feedwater nozzle and piping with a geometric discontinuity), have been observed in the vicinity of the feedwater nozzles. 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, [Cofie et al., 1994].

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 [USNRC 1979]. The resulting inspections revealed pipe cracks in the vicinity of the feedwater nozzles at 18 of the 54 facilities inspected [Cofie et al., 1994]. All cracks were corrosion-fatigue cracks caused by cyclic thermal stratification, except the cracks at one plant, which were identified as stress corrosion cracking [USNRC 1979b]. 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 [Bamford et al. 1987, Van der Sluys and Cullen 1987]. 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 [Van der Sluys 1982]. 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.

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 feedring design [USNRC 1990a]. This type of cracking was first observed in 1982 when a girth weld of a steam generator leaked at a US plant [USNRC 1982]. Linear indications have also been detected at least 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.

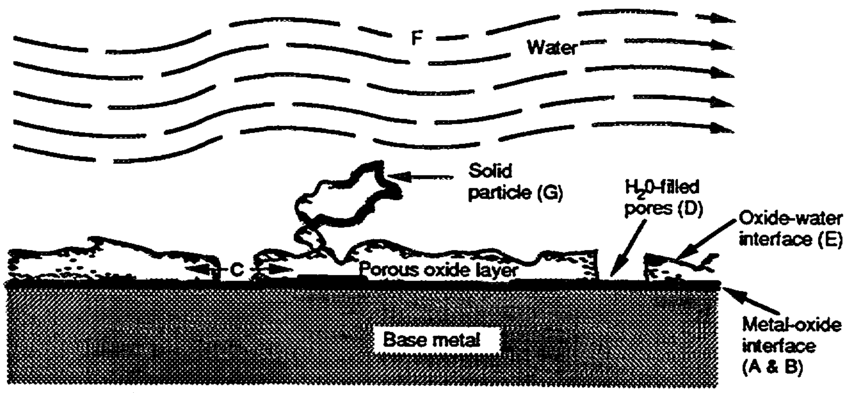
Leak-before-break analyses show that a stress corrosion crack will grow through the shell wall and produce a measurable leak before it exceeds the critical flaw size and the vessel ruptures [Westinghouse 1990]. Field experience to date supports this analysis. Inspection port holes in the steam generators have also experienced cracking, most likely stress corrosion cracking, on the inside surface. Grinding of the inspection port hole 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 Fig. 11), and feedring support bracket welds have all experienced cracking, probably due to both thermal fatigue and stress corrosion.

4.5.4. Erosion-Corrosion

Erosion-corrosion is a flow-assisted corrosion mechanism that affects carbon steel piping carrying single-phase, subcooled feedwater and steamlines 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



A. Iron hydroxides are generated: $Fe + 2H_2O \rightarrow Fe(OH)_2 + H_2$
B. Magnetite is formed according to the Schikorr reaction:
$3Fe(OH)_2 \rightarrow Fe_3O_4 + H_2 + 2H_2O$
C. A fraction of the hydroxides formed in step B and hydrogen generated in steps A and B diffuse along pores in the oxide
D. Magnetite can dissolve in the pores
E. Magnetite dissolves at the oxide-water interface
F. Water flow removes the dissolved species by a convection mass transfer mechanism
G. Solid particles break off porous oxide layer by a mechanical erosion mechanism

FIG. 18. Phenomena occurring during erosion-corrosion (Sanchez-Caldera 1984).

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. Figure 18 presents a simple model describing the phenomena occurring during erosion-corrosion (Sanchez-Caldera 1984).

The factors affecting the erosion-corrosion rate include the following:

- Piping configuration
- Feedwater temperature
- Bulk-flow velocity
- Turbulence
- pH level
- Oxygen content
- Impurities
- Piping material

Carbon steel components with less than 0.1 weight percent Cr are susceptible to erosion-corrosion damage. Although erosion-corrosion is a greater concern in PWR feedwater piping, steam generator components have also experienced damage from this mechanism. Erosion-corrosion of the thermal sleeve at Diablo Canyon Unit 1 was recently reported (USNRC 1993). 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 divider plate bolts (also carbon steel). (The primary side divider plate is located below the tubesheet 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 tubesheet.

4.6. WWER COLLECTOR, SHELL, AND FEEDWATER DISTRIBUTION SYSTEM

Although the WWER tubing has been relatively trouble free, stress corrosion cracking of the 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 tubesheets 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 (Titov 1991). 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 (Koryakin 1993, Titov 1991). These replacements occurred at only 3-25% of the design lifetime (240 000 h).

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 (IAEA 1994).

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" (Titov 1991). 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 (IAEA 1994). 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 (Titov 1991, Titov 1993):

(a) 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.

(b) 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.

(c) 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.

(d) 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.

(e) 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 ppb rather than the specified less than 150 ppb (Gorbatykh 1993, Martynova and Mamet 1991, Rassokhin et al. 1992). Excessive oxygen due to aerated auxiliary feedwater and copper from the condenser tubes may also have contributed to the problem (IAEA 1993).

(f) 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 steam generators fabricated but not in operation, a high temperature heat treatment at 650°C was conducted along with full depth hydraulic expansion of the tubes. The new WWER-1000U design will probably use titanium stabilized austenitic stainless steel in the perforated regions of the collectors rather then low alloy steel and the tubes will be expanded hydraulically.

The WWER-1000 steam generators fabricated in the Czech Republic by Vitkovice, J. S. C. for the Temelin plant incorporated several improvements to address these problems. All their Type 10GN2MFA low alloy steel was doubly vacuum treated to minimize the gas concentrations and secure a homogeneous chemical composition. The phosphorus and sulphur contents were reduced. The collectors were forged so as to suppress macrosegregations on their inner surfaces. The tubing was expanded to the collector wall by a hydraulic expansion process which minimized the residual stresses and crevices.

4.6.2. Erosion-Corrosion of the Feedwater Distribution System

As discussed in Section 4.5.4 above, erosion-corrosion is a flow-assisted 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, bulk-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 Fig. 4 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 center 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-assisted corrosion of the nozzles has occurred at a number of plans including Dukovany, Paks 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.

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 steam generators and will be installed in the Paks steam generators. Another retrofit design prepared by Vitkovice in the Czech Republic is characterized by a manifold above the water level and feedwater distribution through long downconers 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 generator. A slightly different upper feedwater system was installed in another Bohunice steam generator. 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 begun at Loviisa.

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.

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 Figs 4b and 5b). 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 off 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 curies of radioactive material (Solovyev, 1992).

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 ranging from 3–9 degrees BALL and carbide inclusions. The "character of the fracture surfaces was brittle" with numerous inter- and trans-granular microcracks. The breaks occurred in the transition region from the threaded to non-threaded material or in the first few threads. Some of the microcracks 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 (Solovyev 1992, IAEA 1995).

Corrective measures at Rovno 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 (IAEA 1995).

4.7. SUMMARY OF CURRENT WORLD EXPERIENCE

The status of the western (PWR and CANDU) steam generator tubing degradation is summarized first using information from EPRI (1994 and 1995a). That is followed by a short summary of the tube rupture experience and the risk impacts of tube ruptures. The status of the WWER steam generators is then discussed.

Figure 19 shows the percentage of the total number of PWR and CANDU plants that have plugged defective tubes in a given year. Data from 1975 to 1994 are plotted. In recent years, about one half of the PWR and CANDU nuclear power plants in the world were plugging steam generator tubes in any given year. This implies that about one half of the PWR and CANDU plants were operating with tubing defects near or beyond the national limits in any given year. Figure 20 shows the steam generator tubes plugged per year as a percentage of the total number of steam generator tubes in service. In recent years, the percentage of tubes plugged per year has been about 0.30–0.34 per cent (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 last few years 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.

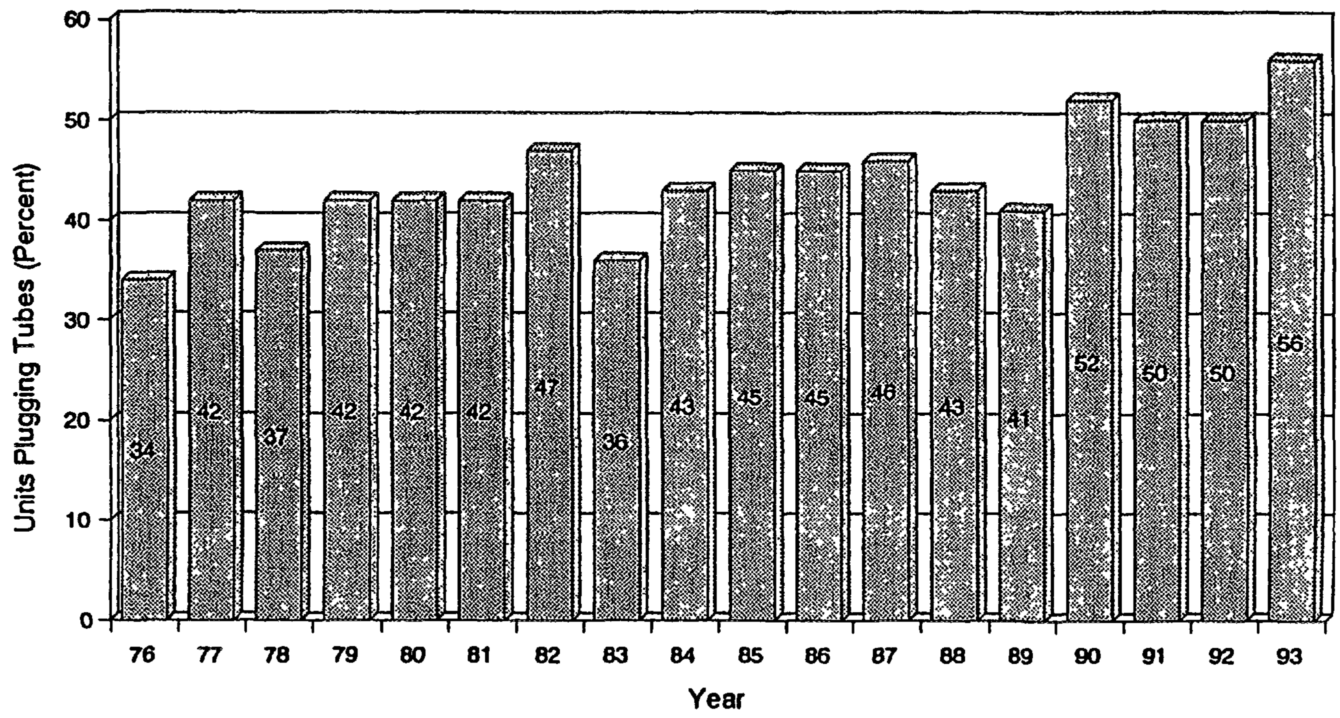


FIG. 19. Percentage of PWR and CANDU Nuclear Power Plants Plugging Steam Generator Tubes (EPRI 1995a). Copyright 1996 Electric Power Research Institute; reprinted with permission.

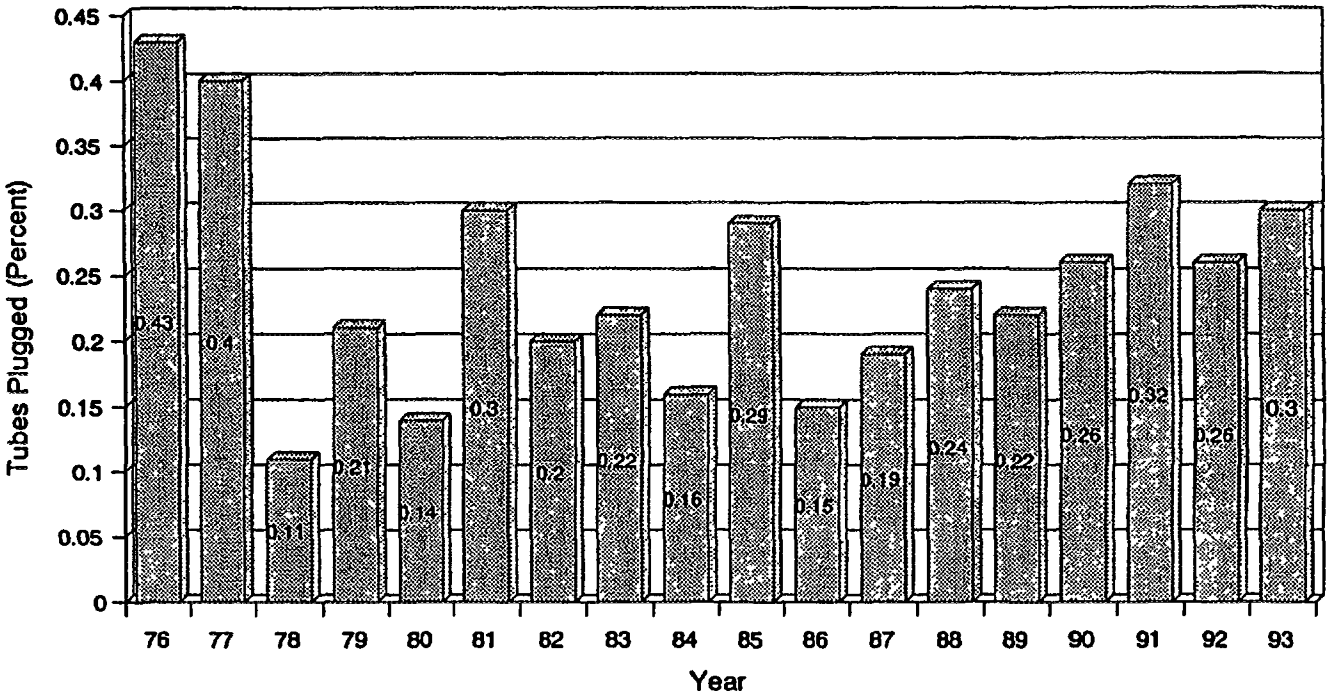


FIG. 20. Percentage of PWR and CANDU Steam Generator Tubes Plugged (EPRI 1995a.) Copyright 1996 Electric Power Research Institute; reprinted with permission.

Although an average plugging rate of 0.25–0.3 per cent per year may seem acceptable, over a 40 year steam generator life this amounts to about 10–12 per cent of the available tubes plugged. Also, not all steam generators are degrading equally. Table XIII lists some of the plants which have plugged significant numbers of tubes in the last few years. The causes of steam generator plugging on a world wide basis are shown in Fig. 13. 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 suggest that no one remedy will resolve all the problems and effective remedies are not easily found. However, it should be noted that there have been far fewer tubing failures in the replacement steam generators than in the original

TABLE XIII. PWR AND CANDU POWER PLANTS WITH SIGNIFICANT TUBING DEGRADATION IN RECENT YEARS

Plant	Year	# Tubes Plugged	Cause
Farley - 2	1990	548	PWSCC, IGA[a]
Palisades	1990	617	AVB Fretting
ASCO - 1	1990	624	PWSCC, IGA[a]
St. Lucie - 1	1991	468	ODSCC/IGA
Trojan	1991	1580	ODSCC/IGA
North Anna - 1	1991	600	PWSCC, IGA[a]
Beaver Valley - 1	1991	760	ODSCC/IGA
Bugey - 5	1991	331	PWSCC
Angra - 1	1991	400	ODSCC/IGA
ANO - 1	1992	306	ODSCC/IGA
D.C. Cook - 1	1992	354	ODSCC/IGA
North Anna - 2	1992	527	ODSCC/IGA
Oconee - 1	1992	612	Erosion/corrosion[a]
ASCO - 1	1992	353	ODSCC/IGA
V.C. Summer	1993	648	PWSCC, IGA[a]
North Anna - 2	1993	620	PWSCC, IGA[a]
Byron - 1	1993	608	PWSCC, IGA[a]
Catamba - 1	1993	740	PWSCC, IGA[a]
ASCO - 2	1993	431	ODSCC/IGA
Bruce - A	1993	440	ODSCC/IGA

[a] Secondary side.

equipment. Therefore, one would expect that the numbers of degraded and plugged steam generator tubes will, at some point, begin to decline as more replacement steam generators come on-line. As of December, 1993, a total of 50 steam generators at 18 nuclear plants in Belgium, France, Germany, Japan, Sweden, Switzerland, and the USA had been replaced.

As discussed in Section 4.4, 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 recent years. Steam generator tube ruptures due to loose parts damage, PWSCC and ODSCC are likely to continue to occur for a number of years.

During a tube rupture transient, the reactor operators are expected to (a) maintain the primary coolant subcooled, (b) minimize the leakage from the reactor coolant system to the defective steam generator secondary side, and (c) minimize the release of radioactive material from the damaged steam generator. The success of the reactor operators has been mixed; some were slow to understand what was occurring, slow to start reducing power, and slow to isolate the defective steam generator. Others reduced power and isolated the defective steam generator promptly. Some operators were slow to cool and depressurize the primary system, others took prompt action. The result was that the defective steam generators were overfilled in a number of cases and more radioactive material was released to the environment than necessary. Nevertheless, in all cases the plants were properly cooled down and the radioactive material releases were small and well below regulatory limits.

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 subcooling 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.

To summarize, there are a number of PWR and/or CANDU 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.

In contrast with some of the PWR and CANDU steam generator tubing, the WWER tubing has been relatively trouble free. 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.

5. STEAM GENERATOR AGEING MANAGEMENT: OPERATIONAL GUIDELINES

This section describes a set of operational guidelines which will 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 operational procedures are grouped into the following topic areas:

- Primary coolant system water chemistry control parameters
- Secondary coolant system water chemistry control parameters
- Measures to control secondary-side impurity incursions
- Measures to remove secondary-side impurities
- Measures to control steam generator deposits

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 and environmental conditions encountered in practice, the detailed operating procedures will vary somewhat 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.

5.1. PRIMARY COOLANT SYSTEM WATER CHEMISTRY CONTROL PARAMETERS

The purpose of the PWR primary coolant system water chemistry programme is to protect the fuel rod cladding from excessive oxidation and crud buildup and provide reactivity control for the reactor. PWR primary coolant system water chemistry which meets these objectives has no effect on steam generator degradation. Nevertheless, the PWR primary coolant water chemistry control parameters are discussed in this section for completeness.

PWR Steam Generators. The important parameters of the PWR primary reactor coolant chemistry are the boric acid, lithium hydroxide, and hydrogen concentrations, and the resulting pH level. A minimum high temperature (~300°C) pH of 6.9 ($pH_{300} = 6.9$) is required to avoid heavy crud deposits on fuel rods, which can cause accelerated corrosion of fuel rod cladding and increased radiation fields [Lott et al. 1992]. Some test results show that operation at a pH_{300} of 7.4 results in less crud deposits than that at 6.9. For current PWR operation, the typical range of pH_{300} is 6.9 to 7.4. The pH_{300} for most of the Electricité de France (EDF) plants is 6.9, and the pH is fixed at 7.2 if the cycle duration is 18 months.

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 ppm) at the beginning of the fuel cycle. Then, they are gradually reduced by 100 ppm/month. The concentration of lithium hydroxide (LiOH) is co-ordinated with the boric acid concentration to achieve the desired pH of approximately 6.9 or higher at operating temperature. At the beginning of the fuel cycle, the typical lithium level is about 4 ppm for a boron level of 2000 ppm, and then it is reduced as the boron level reduces [Lott et al. 1992].

Hydrogen is added to the primary coolant to suppress the buildup of oxygen from radiolysis. A hydrogen concentration of 25–50 cm^3/kg has typically been used. Recent EPRI sponsored studies indicate that increasing the hydrogen concentration in the primary coolant increases the rate of primary water stress corrosion cracking (PWSCC). Consequently, EPRI is encouraging utilities to maintain hydrogen concentrations near the low end of the specified range (i.e., 25– 35 cm^3/kg) [Gorman 1989].

The Revision 2 EPRI guidelines for PWR primary coolant system water chemistry are listed in Table XIV (EPRI 1990). EPRI is also about to issue a third revision of their

TABLE XIV. EPRI PRIMARY COOLANT SYSTEM WATER CHEMISTRY GUIDELINES FOR POWER OPERATION (REACTOR CRITICAL)

Control Parameter	Sample Frequency	Typical Value	Action Level		
			1	2	3
Chloride, ppb	3/wk[(a)]	<50	--	>150	>1500
Fluoride, ppb	3/wk[(a)]	<50	--	>150	>1500
Lithium, ppm	3/wk[(b)]	Consistent with Station Lithium Programme	--	--	--
Hydrogen, cc(STP)/kg H_2O	3/wk[(c)]	25-50[(d)]	<25 >50	≤ 15	≤ 5
Dissolved Oxygen, ppb	3/wk[(a)]	<5	--	>100	>1000

a These frequencies are a minimum based on Standard Technical Specifications. Typical industry frequencies are daily.

b An increased frequency of sampling is recommended during operations that may significantly impact the lithium concentration (i.e., feed and bleed).

c An increased frequency of sampling is recommended during operations that may significantly impact the hydrogen concentration (i.e., feed and bleed, purging of pressurizer vapor, etc.)

d Maintain near the low end of this range.

guidelines which will include the following changes: sulphate is added as a control parameter (50 ppb); the Action Level 1 for chlorides and fluorides will be 50 ppb, each; and the limitation on hydrogen control at 25–50 cc/kg will be removed for plants with steam generators susceptible to PWSCC. Also, there are some minor changes to the pH optimization principles, and the Level 1 definition. (The Level 1 value is now the value outside of which data or engineering judgement indicates that long-term system reliability may be affected, thereby warranting an improvement of operating practices.)

CANDU Steam Generators. The pH in the CANDU 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 CANDU primary system because the on-line refueling feature eliminates the requirement for a borated fuel shim.

WWER Steam Generators. The WWER primary reactor coolant chemistry is a reducing, weak alkaline chemistry treated with the addition of ammonia, potassium, and boric acid. The allowable at power pH and dissolved hydrogen, oxygen, ammonia, chloride, fluoride, iron, oil, copper, and boric acid concentrations are listed in Table XV for the WWER-440 plants with corrosion resistant stainless steel cladding on the inside surface of the reactor pressure vessel, the WWER-440 plants without reactor pressure vessel cladding, and the WWER-1000 plants. Valves for the Temelin plant in the Czech Republic are also listed in Table XV.

TABLE XV. WWER PRIMARY WATER CHEMISTRY

Control parameters	WWER-440 with stainless steel clad reactor vessel	WWER-440 without stainless steel cladding on the reactor vessel	Temelin	WWER-1000
pH at 25°C	≥6.0	6.0-10.2	5.7-10.2[a]	5.9-10.3
Ammonia, ppm	≥5.0	≥5.0	≥5.0[b]	≥5.0
Hydrogen (at 0°C, 0.1 MPa), ppm	2.7-5.4	2.7-5.4	3-6	2.7-5.4
Dissolved oxygen, ppm	≤0.01	≤0.005	≤0.01	≤0.005
Chloride and fluoride, ppm	≤0.1	≤0.1	≤0.1	≤0.1
Corrosion products in terms of iron at steady state operation, ppm	≤0.2	≤0.2	≤0.2	-
Oil, ppm	≤0.05	-	≤0.05	-
Copper, ppm	-	≤0.02	-	≤0.02
Boric acid, depending on core reactivity margin, g/kg	0-8	0-9.0	0 8	0-10.0
Total iodine isotopes radioactivity at the time of sampling, Bq/l	≤3.7X10[8]	≤3.7X10[8]	≤3.7x10[8]	-

[a]The lithium to boron ratio is co-ordinated to maintain a pH of 6.9. If the lithium decreases to 2.2 ppm, it is held at 2.2 ppm until a pH of 7.4 is reached.
[b]Normally at 10

5.2. SECONDARY COOLANT SYSTEM WATER CHEMISTRY CONTROL PARAMETERS

A secondary coolant system water chemistry programme should be established that limits the steam generator water impurity concentrations to certain specified values. The programme should identify all the required continuous and grab samples, specify the accuracy and frequency of the measurements, and specify the chemistry levels that initiate various corrective responses up to and including plant shutdown.

Recirculating Steam Generators. The PWR secondary water chemistry was based on co-ordinated phosphate additions to provide a buffering system until about 1974 in the USA, 1975 in Japan, and the mid 1980s in Germany. However, phosphate chemistry results in concentrations of chemicals in a sludge pile, which in turn causes general corrosion of the outside tubing surfaces. After several laboratory studies and field observations, almost all PWRs have now been switched from phosphate chemistry to an all-volatile treatment to mitigate the steam generator tube wastage problem. (However, one plant, Doel Unit 4, started operation with an all volatile treatment and switched to phosphate and one Spanish plant, Jose Cabrera, started with phosphate in 1968 and one Argentine plant, Atucha-1, started with phosphate in 1974; both remain on phosphate.)

The initial all-volatile treatments used a low molecular weight amine, ammonium hydroxide (NH_4OH) (ammonia) along with hydrazine (N_2H_4) as a scavenger of trace quantities of dissolved oxygen. Recently, 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. This results in even higher pHs in many parts of the secondary system and, therefore, further reduces erosion-corrosion in the feed train and wet steam piping. This, in turn, reduces sludge buildup 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.

A few US plants have converted to a combination of boric acid and morpholine. About 30% of the Japanese PWRs are converted to boric acid without morpholine. Some plants have also tried ethanolamine [$NH_2(CH_2)_2ON$]. Laboratory studies indicate that the addition of boric acid will prevent denting and IGSCC/IGA initiation in alkaline environments that would otherwise cause damage [Wood 1990]. Further findings indicate that adding boric acid after crack initiation in alkaline environments reduces the rate of crack propagation by a factor of 8 to 10. Boric acid can be added during normal plant operation and also during tubesheet crevice flushing operations performed during shutdown. The process has been fully qualified for compatibility with steam generator components by Westinghouse and ABB-Combustion Engineering. By the end of 1990, 32 power plants had accumulated a total of about 60 years of operating time with boric acid.

In addition, some plants in the USA are operating with elevated hydrazine concentrations (greater than 100 ppb) which increases the resistance of the steam generator tubing to IGA/IGSCC and pitting. Hydrazine is a reducing agent that decreases the electrochemical corrosion potential when oxidants are present and it is now recognized that high hydrazine concentrations provide better assurance that reducing conditions are being maintained.

TABLE XVI. WATER CHEMISTRY CONTROL PARAMETERS FOR RSGS AT >5% POWER (EPRI 1993C)

Parameter	Measurement frequency	Median value	Action level 1[b]	Sample location
pH @ 25°C (station with no copper alloys)	Continuous	9.3–9.8	(a) (a)	Blowdown Feedwater
pH @ 25°C (station with copper alloys)	Continuous	8.8–9.2	>9.2 (a) (a)	Condensate Blowdown Feedwater
pH agent	Daily	—	(a)	Feedwater
Dissolved O_2, ppb	Continuous	≤3	>5 >10	Feedwater Condensate
Hydrazine, ppb	Daily	(a)	<100	Feedwater
Total iron, ppb	Weekly	—	>5	Feedwater
Total copper, ppb	Weekly	—	>1	Feedwater
Cation conductivity μS/cm (ammonia AT)	Continuous	0.15 ≤0.2	>0.8	Blowdown Feedwater
Cation conductivity μS/cm (non-ammonia AT)	Continuous	0.5 ≤0.2	>0.8	Blowdown Feedwater
Sodium, ppb	Continuous	~2	>20	Blowdown
Chloride, ppb	Daily	~2	>20	Blowdown
Sulphide, ppb	Daily	~3	>20	Blowdown

[a]Per station pH programme.

[b]Corrective actions should be implemented as soon as possible. If the parameter is not below this value in one week, go to Action level 2.

TABLE XVII. SIEMENS/KWU GUIDELINES FOR SECONDARY WATER CHEMISTRY

		Control Parameter	Diagnostic Parameter
Feedwater			
pH		≥ 9.8	-
Cation Conductivity (25°C)	µS/cm	≤ 0.2	-
Oxygen	ppb	≤ 5	-
Hydrazine	ppb	-	≥ 20
Specific Conductivity (25°C)	µS/cm	-	≥ 15
Steam Generator Blowdown			
pH		-	≥ 9.5
Cation Conductivity (25°C)	µS/cm	≤ 1	-
Sodium	ppb	≤ 50	-
Main Condensate			
Cation Conductivity (25°C)	µS/cm	-	≤ 0.2
Oxygen	ppb	-	≤ 20
Hotwells			
Cation Conductivity (25°C)	µS/cm	-	≤ 0.2
Sodium	ppb	-	≤ 1
(Difference to Reheated Steam)			
Reheated Steam			
Cation Conductivity (25°C)	µS/cm	-	≤ 0.2
Make-up Water			
Specific Conductivity (25°C)	µS/cm	-	≤ 1
Chloride	ppb	-	≤ 50
Silica (in form of SiO2)	ppb	-	≤ 20

However, the thermal decomposition of some of the hydrazine to ammonia can cause problems in plants with copper alloy material in the secondary coolant system. The ammonia causes accelerated corrosion of the copper alloy and may adversely impact demineralizer operation. Nearly all of the Siemens/KWU plants are operating with high hydrazine concentrations (greater than 20 ppb specified and typical values of 80–200 ppb) and high pH values (greater than 9.8 specified and typical values of 10.0 to 10.2). The copper alloy condenser tubing in the older Siemens/KWU plants was replaced with either stainless steel or titanium tubing when the plants were converted to high hydrazine, high pH water chemistry.

Because an all-volatile treatment does not buffer the system, the water chemistry needs to be constantly monitored and corrected. Water chemistry control guidelines developed by the EPRI Steam Generator Owners' Group require continuous (or daily) monitoring of cation conductivity, chloride, sodium, sulphate, pH, ammonia, dissolved oxygen, hydrazine, copper, and iron [Mundis 1983, EPRI 1982, EPRI 1993c]. The Steam Generator Owners' Group guidelines also establish 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. 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. The control parameters for greater than 5% power developed by the EPRI Steam Generator Owners' Group are listed in Table XVI. Note that the pH at 25°C in plants with no copper alloys in the secondary system should be higher (9.3 to 9.8) than the pH in plants with, for example, copper alloy condenser tubes. These control parameters are to be used as part of an approach where each plant develops a water chemistry optimization programme based on corrosion history, cooling water chemistry, secondary system design, and operating trends. The control parameters for the secondary water chemistry in Siemens/KWU plants are somewhat different from the EPRI guidelines and are listed in Table XVII. EDF also uses

TABLE XVIII. EDF GUIDELINES FOR FEEDWATER CHEMISTRY[a], POWER >25%, AMMONIA (AVT)

Parameter	Unit	Typical Value	Limiting Value	Frequency of Measurement	Remarks
pH @ 25°			9.0 - 9.2	Continuous	With Cu
			9.6 - 9.8	Continuous	Without Cu
Conductivity @ 25°	μS/cm	2.7 - 4.2		Occasional	With Cu
		10 - 17			Without Cu
Ammonia	mg/kg in NH_4	0.25 - 0.5	Required quantity	S	With Cu
		2 - 5			Without Cu
Oxygen	μg/kg		< 5	Continuous	
Hydrazine	μg/kg		> 5	Continuous	With Cu
		50	5 - 100		Without Cu
Suspended Iron	μg/kg	< 10		Quarterly Campaigns	
Suspended Copper	μg/kg	< 5		Quarterly Campaigns	
Soluble Copper	μg/kg	< 5		Quarterly Campaigns	

[a]Taken from EDF Instruction 83.032 Ind.1 - TE/M 1628 Ind E "Règles générales d'exploitation".

TABLE XIX. EDF GUIDELINES FOR FEEDWATER CHEMISTRY[a], POWER >25%, AVT: MORPHOLINE

Parameter	Unit	Typical Value	Limiting Value	Frequency of Measurement	Remarks
pH @ 25°			9.1 - 9.3	Continuous	With Cu
			9.1 - 9.7	Continuous	Without Cu
Conductivity @ 25°	μS/cm	3 - 5		Occasional	With Cu
		3 - 13			Without Cu
Morpholine	mg/kg	4 - 8	≥ 4	S	With Cu
		6 - 8	≥ 4		Without Cu
Ammonia	mg/kg in NH_4	< 0.3	< 0.5	S	With Cu
			< 3		Without Cu
Oxygen	μg/kg		< 5	Continuous	
Hydrazine	μg/kg		> 5	Continuous	With Cu
		50	5 - 100		Without Cu
Suspended Iron	μg/kg	< 10		Quarterly Campaigns	
Suspended Copper	μg/kg	< 5		Quarterly Campaigns	
Soluble Copper	μg/kg	< 5		Quarterly Campaigns	

[a] Taken from EDF Instruction 83.032 Ind.1 - TE/M 1528 Ind E "Règles générales d'exploitation".

somewhat different guidelines for the primary and secondary water chemistry than recommended by EPRI. The EDF values for the secondary side feedwater are listed in Tables XVIII and XIX; for plants at powers greater than 25% and ammonia or morpholine water chemistry, respectively.

Some plants are also trying to balance the ratio of cations and anions in the crevices, thereby preventing the formation of highly alkaline or acidic conditions. This technique is known as *molar ratio control*. 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 base cations in the steam generator bulk water. This, of course, requires an understanding of the relationship between the bulk water chemistry and the crevice chemistry and estimates of the hideout/hideout return fractions. The current version of the EPRI PWR secondary water chemistry guidelines (EPRI 1993c) suggests that plant operators consider implementing molar ratio control at plants where ODSCC is a serious concern. This recommendation is based on the fact that the available laboratory data indicate that IGA and IGSCC crack rates are lowest at or near a neutral pH (5 to 9). However, there can be problems associated with molar ratio

TABLE XX. CHEMISTRY CONTROL PARAMETERS FOR ONCE-THROUGH STEAM GENERATORS AT POWER

Parameter	Frequency	Normal value	Initiate action	Action response
pH		(a)		
Hydrazine, ppb	Daily	$\geq 3x[O_2]$[b] (20 ppb min)	$>3x[O_2]$ <20 ppb	Return to normal value within 24 hrs. or be in hot standby within an additional 24 hrs.
Dissolved oxygen, ppb	Continuous	≤3	>3	Return to normal value within 1 week or reduce power to ~30% until source is identified and isolated.
Sodium, ppb	Continuous	≤3	>3	Return to normal value within 100 hrs or be in hot standby within an additional 24 hrs.
			>6	Return to normal value within 24 hrs or be in hot standby within an additional 24 hrs.
			>10	Be in hot standby within 24 hrs.
Chloride, ppb	Daily	≤5	>5	Return to normal value within 100 hrs or be in hot standby within an additional 24 hrs.
			>10	Return to normal value within 24 hrs. or be in hot standby within 24 hrs.
			>20	Be in hot standby within 24 hrs.
"Corrected" cation conductivity, µS/cm	Continuous	≤0.2	>0.2	Return to normal value within 100 hrs or be in hot standby within an additional 24 hrs
			>0.5	Return to normal value within 24 hrs or be in hot standby within an additional 24 hrs.
			>1.0	Be in hot standby within 24 hrs.
			>2.0	Immediately go to hot standby.
Silica, ppb	Weekly	≤10	>10	Return to normal value within 100 hrs or be in hot standby within an additional 24 hrs.
			>20	Return to normal value within 24 hrs or be in hot standby within an additional 24 hrs.
			>50	Immediately go to hot standby.

TABLE XX. (cont.)

Parameter	Frequency	Normal value	Initiate action	Action response
Total iron, ppb	Weekly	≤5	>5	Should be returned to normal value within 24 hrs.
Copper[c], ppb	Weekly	≤1	>1	Should be returned to normal value within 24 hrs.
Sulphate, ppb	Daily	≤3	>3	Return to normal value within 100 hrs or be in hot standby within 24 hrs.

[a] Per station pH programme.
[b] Oxygen measured at condensate pump discharge.
[c] May be deleted for all-ferrous systems.

control. First, lead assisted transgranular stress corrosion cracking reaches a maximum at near neutral conditions. Second, if excessive amounts of chloride are added to the secondary coolant, denting and pitting can be a problem in certain steam generators. Therefore, an upper chloride limit of 5 ppb (10 ppb during transients) is recommended and molar ratio control should only be used in steam generators with low lead levels.

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 sludge buildup around the lower support plate flow holes that restrict the feedwater flow. Such flow restriction has forced some Babcock & Wilcox plants to derate by as much as 30% at times. The once-through steam generator water chemistry control guidelines developed by the Owners' Group are listed in Table XX.

CANDU Steam Generators. CANDU Steam Generator chemistry control is generally all volatile: morpholine/hydrazine (N_2H_4) for plants with copper alloys in the feedtrain, NH_3/N_2H_4 for all ferrous plants. One CANDU station uses only morpholine and no hydrazine, another station uses a combination of phosphate and morpholine/N_2H_4. 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 has started the use of 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.

TABLE XXI. WWER SECONDARY WATER CHEMISTRY

Russian Plants:

Control parameters	Feedwater below the high pressure preheater	Blowdown water
pH at 25°C	9 0 ± 0 2	8 0 - 9 2
Specific cation conductivity, µS/cm	≤0 3[6], ≤0 5[4,5]	≤5 0[4,6] ≤9 0[5]
Sodium, ppb	-	≤300[4,6] ≤500[5]
Chloride, ppb	-	≤150[7]
Iron, ppb	≤15	-
Copper[1], ppb	≤5 ≤3[3]	-
Dissolved oxygen[2] ppb	≤10	-
Oil, ppb	≤100	-
Hydrazine, ppb	≥5[4,5] ≥40[6]	-

Notes 1 Measured down the last low pressure preheater
2 Down the deaerator
3 If low pressure preheaters have stainless steel tubes
4 Novovoronezh Units 3 and 4
5 Kola Units 1, 2, 3, and 4
6 WWER-1000 plants
7 Prior to 1990 this was 500 to 1000 ppb

Czech Plants:

Control parameters	Feedwater	Blowdown water	Main condensate
pH at 25°C	9 7-10	-	-
Specific cation conductivity, µS/cm	<0 12	<0 12[a]	<0 1[c]
Sodium, ppb	-	2[b]	-
Chloride, ppb	-	2[b]	-
Dissolved oxygen, ppb	≤5	-	<10
Hydrazine, ppb	30-200	-	-
Diagnostic parameters			
pH at 25°C	-	9 4-9 7	10
Specific conductivity, µS/cm	12-25	-	25
Iron, ppb	<10	-	-
Copper, ppb	<2	-	-
Ammonia, ppm	3 5-12	-	-
Silicon, ppb	-	<<300	-
Fluorine, ppb	-	<10	-
NH_3, ppm	-	1 4-4 6	-
SO_4^{2-}, ppb	-	<4	-

Notes a. First action level >0 7, second action level >2, third action level >7
b First action level >20, second action level >100, third action level >500
c First action level >0 2, second action level >1 0

WWER Steam Generators. Ammonia and/or hydrazine water chemistry is used on the secondary side of the WWER steam generators. The WWER secondary water chemistry is designed to minimize (a) sludge buildup on the heat transfer surfaces, (b) corrosion and erosion damage, and (c) waste water. The WWER control parameters and allowable values for operation at any power level are listed in Table XXI. All parameters are measured at standard conditions of approximately 25°C and 0.1 MPa. Ingress of ion exchanger resin and products of the resin deterioration is not allowed. Deviation from the control parameters is addressed through the concept of action levels (three action levels are used).

5.3. MEASURES TO CONTROL SECONDARY-SIDE CHEMICAL IMPURITY INCURSIONS

Various organic acid and ionic impurities promote corrosive processes such as IGSCC/IGA, pitting, denting, and cold leg thinning in steam generator tubing. Impurities can be minimized by preventing in-leakage of raw water from condenser tubes, appropriate filtration of the condensate and feedwater, reducing the volume of make-up water, and elimination of copper alloy parts in the secondary coolant system.

Condenser Integrity. In-leakage of raw water through defects in the condenser tubes is an important cause of faulted chemistry conditions for RSGs which result in ODSCC, denting of tubes in generators with carbon steel support plates and pitting at the top or within the cold leg sludge pile region. To reduce condenser leakage, several plants have replaced their admiralty brass condenser tubing with either titanium (seawater and freshwater sites), or stainless steel tubing (freshwater sites only) with tube-to-tubesheet welds. Use of titanium condenser tubing is a standard feature in the more recent plants; however, a number of titanium tube leaks in condensers have occurred. The possible degradation mechanisms for titanium tubing are high-cycle mechanical fatigue caused by flow-induced vibrations, damage from loose parts such as broken turbine blade pieces, and hydriding. Additional design modifications may be needed to reduce the flow-induced vibrations. Also, the high temperature steam connections to the condenser should be bellows-type expansion joints to prevent air in-leakage. For existing installations without titanium or stainless steel tubing and welded joints, aggressive leak detection and correction methods should be used.

Condensate Polishing System. A condensate polishing system can potentially be an important part of an effective secondary side water chemistry programme. Condensate polishers are a cost effective means of achieving operating water chemistry specifications during startup. Use during operation can essentially eliminate the transport of corrosion products into the steam generator. And, full-flow condensate polishing protects against major chemistry excursions due to, for example, condenser tube leaks (Dooley et al. 1995).

However, condensate polishers "elute low concentrations of impurities that are known or suspected corrodents for secondary cycle materials. Those impurities include sulfate, sodium, chloride, soluble sulphonated and chlorinated organics, and resin fines that can degrade to sulphates and organic species in the steam generator" (Dooley et al. 1995). Also, accidental ingress of resins from these systems has caused aggressive chemical environments in some plants. If such an event occurs, immediate corrective action is needed to remove the aggressive chemicals from the secondary coolant. This may include shutting down the reactor, followed by flushing the system numerous times to prevent damaging concentrations of soluble products in the crevices. Therefore, there is disagreement over whether condensate polishers should be installed, and if they are installed, when they should be operated. Some plants are not equipped with condensate polishers, some plants polish only a small function of the feedwater flow, some plants only operate their condensate polishers during startup, shutdown or periods of condenser in leakage, and some plants polish all the feedwater all the time.

Recycle of Blowdown Water. Careful make-up water chemistry control is also needed to control the chloride content in the secondary 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 (decomposition products). More chlorides may be introduced into the steam generator 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. 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.

Control of Lead Contamination. Lead has been implicated in the accelerated stress corrosion cracking of Alloy 600 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 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 600, but also for Alloy 800 and Monel 400 (Takamatsu 1994, Rocher et al. 1994, Briceno et al. 1994, Miglin 1991 and Palumbo and King 1992). All the alloys tested corroded in aqueous lead contaminated environments, however, the Alloy 600 material was most susceptible. The most severe environment in the French studies (Rocher et al. 1994) 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 (Briceno et al. 1994).

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.

Removal of the Copper from the Secondary Coolant System. Copper oxide may act as an oxidizing agent in pitting corrosion of tubes and corrosion of tube support plates resulting in tube denting (by enhancing the formation of magnetite). Copper is transported to the steam generators due to the corrosion of components with copper-bearing alloys in the balance of the plant. Therefore, copper-bearing alloys should be removed from the secondary coolant system and replaced with carbon or stainless steel components. Also, copper oxide can be reduced to metallic copper by flushing in a highly concentrated hydrazine environment. Controlling the dissolved oxygen and eliminating the ingress of air are also important in mitigating the pitting and denting mechanisms.

Summary. Constant monitoring of the water chemistry and immediate corrective actions are important in maintaining the quality of the 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.

5.4. MEASURES TO REMOVE SECONDARY-SIDE IMPURITIES

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/tubesheet crevices as well as in the tube/tube support annuli. These procedures help prevent and mitigate IGSCC, IGA, and pitting.

Steam generator flushes. As discussed in Section 4, impurities can concentrate in the tubesheet and tube-to-tube support plate crevices, the sludge pile, and under freespan 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-laden 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. Electric heaters may be necessary to get enough heat into the crevices on the cold leg side. Steam generator flushing has been tried at a number of temperatures, the most common of which is 150°C. Sludge lancng 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 (Dooley et al. 1995).

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 powero 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 tubesheet crevices is hindered by sludge on the tubesheet. Therefore, hot soaking should be carried out after sludge cleaning (Dooley et al. 1995).

5.5. MEASURES TO CONTROL STEAM GENERATOR DEPOSITS

Deposits on the tubesheet (sludge), tube supports and on the tube surfaces create crevices where impurities may concentrate. Concentration factors of greater than 10^5 over bulk water have been found in laboratory tests (Gonzalez and Spekkens, 1986). 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. Preventive measures include: minimizing air in-leakage, operating at high pH, and removing corrosion products with a good blowdown system and by use of condensate polishers (see Section 5.3). Corrective measures include sludge lancing and chemical cleaning.

Reduce turbine/condenser/steam air in-leakage. Plant procedures should be in place to reduce the leakage of air into the secondary system, which require the use of state of the art detection and repair technologies. This will minimize ingress of oxygen and thereby minimize corrosion of the secondary side components. Oxygen is an oxidant itself and also increases the transport of other oxidants (ionic copper species and iron oxides such as hematite) which participate in corrosion reactions in RSGs.

Steam Generator Lay-up. At temperatures below about 200°F, the steam generators should be filled with de-oxygenated (<100 ppb 0_2), chemically treated water to minimize corrosion. An amine should be used to keep the pH above 9.8 and a hydrozine concentration above 75 ppm should be used to maintain a protective oxide film and a reducing environment. Hydrazine is an oxygen scavenger and inhibits general and localized corrosion of ferrous materials and reduces the pitting susceptibility of Alloy 600. The sodium, chloride and sulphate concentrations should be below 1000 ppb during wet lay-up and below 100 ppb prior to heatup. A positive nitrogen overpressure should be maintained during filling, draining, and cold shut down to minimize oxygen ingress. During periods when the steam generator must be drained for maintenance, nitrogen should be used to prevent contact between the steam generator water and oxygen. 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 (EPRI 1993c).

During heatup (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 ppb before exceeding 5% power. The hydrazine in the feedwater should be greater than three times the oxygen concentration and 100 ppb. 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 ppb each. In general, the heatup period should be used to reduce impurity levels in the steam generator and prepare the secondary coolant system for power operation. At least daily sampling of the feedwater and blowdown effluent are required to maintain the above values (EPRI 1993c).

If copper alloy condenser material is used on the secondary side, the excess hydrazine should be removed prior to heatup. Some of the hydrazine will thermally decompose to ammonia during heatup, 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 and an upper limit of 9.2 prior to heatup is recommended for systems with copper alloy material (EPRI 1993c).

Balance of Plant Corrosion. The principal method of controlling corrosion product transport in the secondary systems of PWRs and the sludge buildup in their steam generators is through pH control. EPRI recommends a room temperature feedwater pH between 8.8 and 9.2 for plants with copper alloys and above 9.3 for all ferrous plants (EPRI 1993c). 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.

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.

Lancing. Lancing uses high-pressure jets to mechanically remove sludge from the tubesheet face to alleviate IGSCC and IGA. By periodic sludge lancing, the depth of accumulated sludge can be kept below the height necessary to cause dryout and concentration of chemicals. Robotic inspection and lancing equipment, called CECIL (Consolidated Edison Combined Inspection and Lancing System), has recently been developed. CECIL is equipped with multidirectional pressurized water jets to remove sludge from around the tubes, grappling tools to remove foreign objects, and a video camera to inspect the tube bundle as the work progresses. This equipment allows close-up lancing of tenacious sludge deposits that cannot be effectively removed by water jets from nozzles in the tube lane or tube bundle periphery. Field tests at Indian Point Unit 2 in 1989 demonstrated that CECIL could remove about three times the amount of sludge removed during conventional lancing, and that it removed a significant amount of the hard sludge left after previous cleanings. CECIL has been used at a number of plants in the USA, France, and Japan. Sludge lancing is conducted either every or every other inspection period in France and Japan and every inspection period in Spain, Switzerland, and Belgium.

Pressure pulse and water slap. The other mechanical cleaning processes, pressure pulse and water slap, periodically release 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 tubesheet 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 has only resulted in short-term improvements.

6. STEAM GENERATOR INSPECTION AND MONITORING REQUIREMENTS AND TECHNOLOGIES

Steam generators are routinely inspected during plant outages, when their internal structures become accessible to inspection equipment. This section identifies inspection and monitoring requirements and techniques for steam generators, with emphasis on examining the tubing, tubesheet, feedwater nozzle and shell. Tables VI, VII and VIII list in-service inspection methods used to detect damage from the various degradation mechanisms.

6.1. TUBING 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, the Czech Republic, France, Germany, Japan, Slovenia, Spain, Sweden, and Switzerland are summarized in Table XXII and also discussed in this section. Tubing inspection practices used in Russia and those recommended by EPRI are also discussed.

Tubing inspection requirements differ somewhat in these and other countries because:

- Different steam generator designs and materials and specific sites 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.

- 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.

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 (USNRC 1975). 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

TABLE XXII. STEAM GENERATOR TUBING INSPECTION GUIDELINES

	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 23	• 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	• Every 5 years
Czech Republic	• All tubes prior to service	• At least 10% of the tubes in each steam generator must be inspected full length • Usually inspect all the tubes from the hot collector and 50% of the tubes from the cold collector	• Every four years • Every four years
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 four years all steam generators • Every two years, one half of the steam generators
Japan	• All tubes prior to service • Insertion depth of anti-vibration 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
Slovenia	• All tubes prior to service	• 100% using bobbin coil and all reported indications, roll transitions and inner bends with pancake coil	• Each refueling 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 refueling outage
Sweden	• All tubes prior to service	• Random sample of 15-17% full length • 100% hot leg tubesheet • 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 • 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 than 10% of second batch show indications, inspect additional 6% in area of indications.

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 were following the steam generator tube sample selection guidance in Table XXIII (USNRC 1981, Southern California Edison Co. 1982, Northern States Power Co. 1985, Georgia Power Co. 1987, Commonwealth Edison Co. 1987). The tubes selected for each inservice inspection include at least 3% of the total number of tubes in all the steam generators at a unit and are selected randomly except:

(a) 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; and
(b) 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.

TABLE XXIII. 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 S.G.	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 (S.G.)	C-1	None	N.A.	N.A.
			C-2	Plug or sleeve defective tubes and inspect additional 4S tubes in this S.G.	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 S.G., plug or sleeve defective tubes and inspect 2S tubes in each other S.G. Notification to NRC pursuant to ¶50.72(b)(2) of 10 CFR Part 50.	All other S.G.s are C-1	None	N.A.	N.A.
			Some S.G.s C-2 but no additional S.G.s are C-3	Perform action for C-2 result of second sample.	N.A.	N.A.
			Additional S.G. is C-3	Inspect all tubes in each S.G. and plug or sleeve defective tubes. Notification to NRC pursuant to ¶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.

The results of each sample inspection are classified into one of the following three categories:

Category	Inspection Results
C-1	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.

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 or equal to 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 XXIII 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:

(a) the tubes selected for these samples include the tubes from those areas of the tubesheet array where the tubes with imperfections were previously found; and
(b) 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-1 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 XXIII 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: reactor-to-secondary tube leaks (not including leaks originating from tube-to-tubesheet 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 XXIII. 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 XXIII.

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 (USNRC 1995b). 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 (a) interfering signals from copper deposits, (b) dent signals greater than 5 volts, or (c) large mixed residuals.

6.1.2. Tubing Inspection Requirements in Canada

The most recent Canadian Standard, CAN/CSA N 285.4-94, requires an inspection of 25% of the tubes in each steam generator after the steam generator is first installed, but prior to service. The initial in-service inspection sample and frequency is 10% of the tubes in one steam generator of each unit every 5 years. The inspection sample expands when significant degradation is detected as follows:

> "additional inspection includes tubes surrounding those with indications, which do not comply with the acceptance criteria, to bound the degradation. As a minimum the additional inspection includes all tubes whose centre lines are located within a radius of 2.5 times the tube spacing from centre line of affected tube. Consideration shall be given to additional inspection of similarly located tubes in other steam generators in the reactor unit (and in other units for a multi-unit station)."

The Canadian Standard is somewhat vague about the numbers of similarly located tubes in other steam generators that need to be inspected. Therefore, the Canadian regulatory authorities expect the owner to develop specific proposals and submit them for unit restart. The main reason for this is that the regulatory bodies consider the owner to bear the primary responsibility for the safety and good performance of the reactors, and it is up to the owner to define and defend a course of action for the 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 Canadian Standard also requires that a section of one tube be removed from one steam generator for metallurgical examination once every five years. This applies to the lead unit in a multi-unit station. The results of these periodic destructive examinations are to be used to calibrate the non-distructive examination techniques.

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. Even a new station such as Darlington exceeds these requirements in both extent and frequency. For example, Darlington is a four unit station but it requires a tube to be removed from one steam generator in each unit every two years. Also, the minimum inspection sample is 20% (instead of 10%) of one steam generator. Also, ultrasonic and specialized eddy current probes are always used, not just bobbin coil probes. This station has no active degradation mechanisms but is following an aggressive inspection (and preventive) programme.

6.1.3. Tubing Inspection Requirements in the Czech Republic

The Czech regulatory agency requires a baseline inspection before operation and then a minimum of 10% of the tubes in each steam generator inspected full length every four years. (Each of the six steam generators at each WWER-440 unit are inspected every four years.) However, recent practice has been to inspect all of the tubes from the hot collector side and 50% of the tubes from the cold collector side.

6.1.4. Tubing Inspection Requirements in France

The French regulatory agency requires a baseline inspection 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 600) 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.

6.1.5. Tubing Inspection Requirements in Germany

The scope and frequency of tubing inspections in the Federal Republic of Germany are specified in KTA 3201.4. Ten per cent of the tubes in each steam generator must be fully inspected every four years and half the steam generators must be inspected every two years. However, actual inspections have been more frequent and some Siemens/KWU steam generators have been inspected every operating period over much of their life.

6.1.6. 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 coolant system 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 tubesheet region. Eight by one eddy current probes are used in the hot-leg tubesheet region in most steam generators in order to detect circumferential degradation. Rotating pancake coil eddy current equipment is used in the tubesheet region of one Japanese plant in order to detect pitting.

6.1.7. 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. Eddy current inspection is being introduced at some Russian nuclear power plants. Primary-to-secondary leak rates are monitored using a ^{24}Na device.

6.1.8. Tubing Inspection Requirements in Slovenia

Initially, the sampling procedure outlined in USNRC R.G.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 multifrequency rotating pancake coil probes. Bobbin coil indications at the tube support plates are also re-inspected with multifrequency 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 refueling outage.

All sleeves and the tube areas behind the sleeves are also inspected during each refueling 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.

6.1.9. Tubing Inspection Requirements in Spain

All Spanish steam generators with susceptible material are inspected during each refueling outage. All of the tubes are inspected over their full length using bobbin coil eddy current equipment. All the hot-leg tubesheet areas and all the indications detected by the bobbin coil are also inspected with rotating pancake coil eddy current equipment. Fewer tubes are inspected in the Spanish steam generators with less susceptible material. 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). In another plant with Alloy 800M tubing, 9% of the tubes are inspected over their full length every outage.

6.1.10. 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 tubesheet area. The Swedish regulatory authority must witness the inspections.

6.1.11. Tubing Inspection Requirements in Switzerland

The Swiss utility (NOK) 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 600 tubing are 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. Multifrequency bobbin coil eddy current equipment is 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 tubesheet (including the roll transition region). The Swiss regulatory authority must witness the inspections.

6.1.12. EPRI Tubing Inspection Recommendations

When the EPRI alternative fitness-for-service guidelines for defects in the roll transition region are used, EPRI recommends a rotating pancake coil eddy current inspection of all in-service hot-leg tube expansion zones at each scheduled inspection outage. When the EPRI alternative fitness-for-service guidelines for defects in the tube support plate regions are used, EPRI recommends a bobbin coil eddy current inspection of all hot-leg tube support plate intersections, and all cold leg tube support plate intersections down to the lowest tube support plate with indications every outage. Supplemental rotating pancake coil inspections of a sample of tubes with bobbin coil voltages less than the tube repair limit is also recommended to characterize the defects.

It should be noted that the USNRC has not accepted the EPRI fitness-for-service guidelines for defects in the roll transition region, and, therefore, the EPRI tubing inspection recommendations for that defect type and location are currently not in the Technical Specifications at the US plants. The USNRC has accepted certain alternative fitness-for-service guidelines for ODSCC at tube support plates (see Section 7.2.2), but requires a somewhat more extensive examination than recommended by EPRI, as discussed in Sections 6.1.1 and 7.2.2.

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 multifrequency 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 ultrasonics) 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 multifrequency 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% throughwall. 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 traveling 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 (Van Vyve and Hernalsteen 1991).

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 tubesheet 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 Fig. 21. 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 (Malinowski 1995). 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 (Dembek 1995).

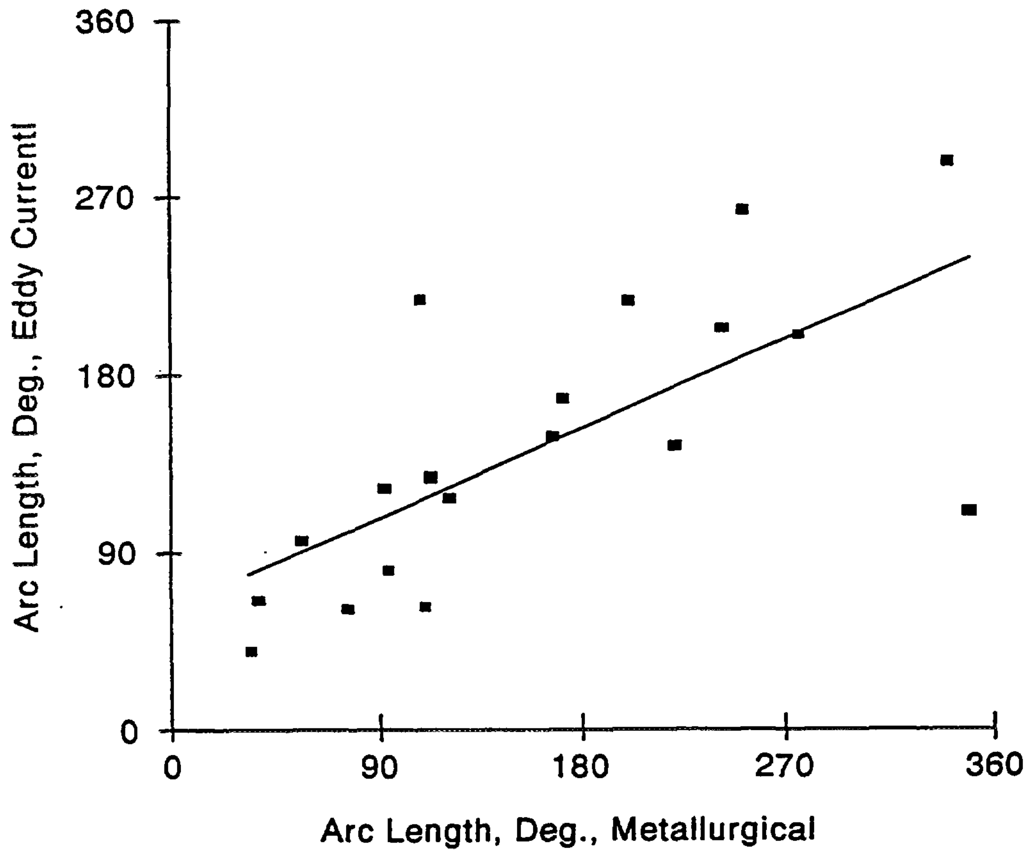


FIG. 21. Comparison of actual arc length of circumferential cracks in pulled tubes with the ones estimated using eddy current inspection. The data represents worldwide experience as of 1992 (Malinowski 1995).

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 are not yet well characterized.

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 (USNRC 1991a). 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 (Roussel and Mignot 1991). 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.

Outside Diameter Stress Corrosion Cracking. The reliable detection and sizing of 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 freespan 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 initiate 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 freespan 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 (USNRC 1990).

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 throughwall. 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 Fig. 22, which presents a comparison of eddy current measurements of the arc length of a variety of circumferential cracks with the corresponding metallographic examination results (Dembek 1995). 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 (Malinowski 1995).

Use of multifrequency/multiparameter 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.)

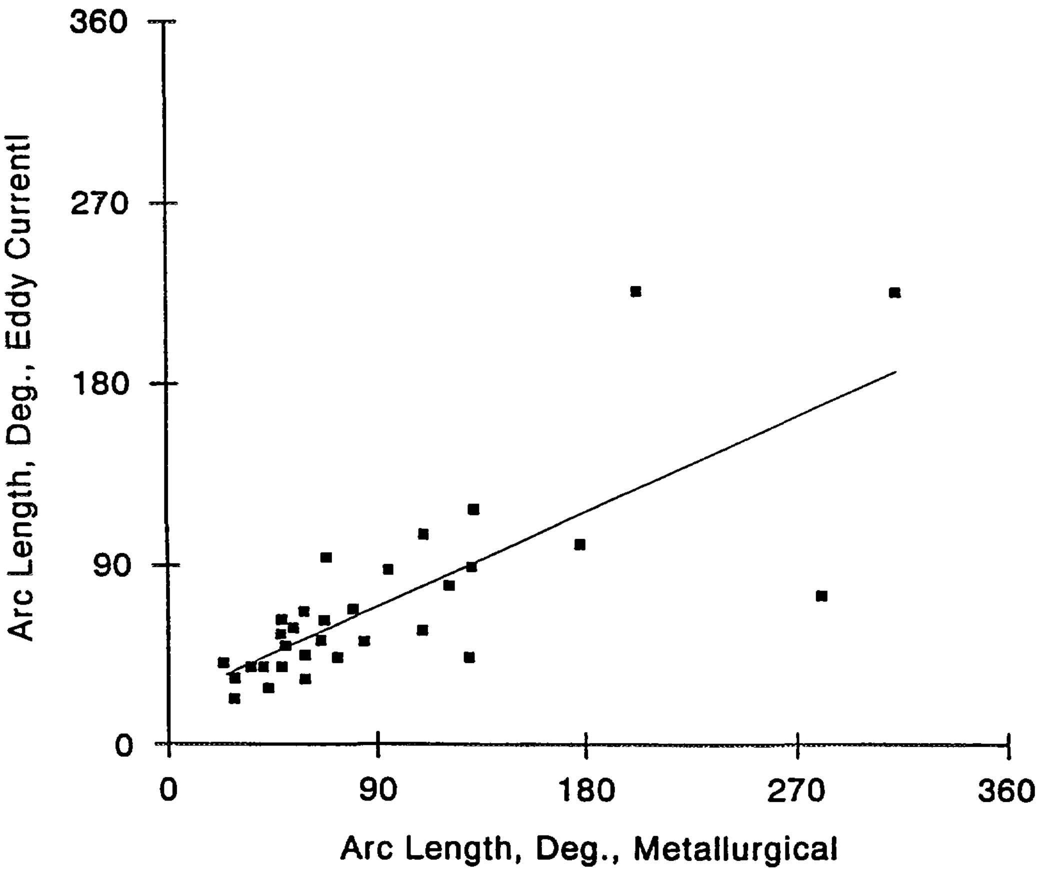


FIG. 22. Comparison of actual arc length of circumferential ODSCC cracks in pulled tubes with the ones estimated using eddy current inspection (Malinowski 1995).

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 tubesheet. 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 (Malinowski 1995).

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 m. The depth measurement results on pulled tubes compared well with the metallographic results (Moles et al. 1994).

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 600 tubing.

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% throughwall, 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 (Miyake et al. 1992).

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 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 tubesheet 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 multifrequency 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 multifrequency 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% throughwall.

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 nondestructive 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 (EMAT). This method addresses ultrasonic inspection of steam generator tubing using an electromagnetic acoustic transducer [Thompson and Elsley 1983]. 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 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 buildup that might lead to denting. It also can determine the efficiency of chemical cleaning in removing this buildup.

Optical Profilometry. The optical profilometer has been tested successfully under laboratory conditions for tube dent measurement [Oberg 1983]. 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.

Pitting. An automated ultrasonic system has been used at some CANDU units to detect shallow tube pits. This system uses high frequency ultrasonics (50-100 $_{MHZ}$) and is capable of detecting pit sizes ≈5% throughwall.

6.2.3. 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.

6.3. MONITORING LEAKAGE FROM TUBING

On-line monitoring of nitrogen-16 in the 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.)

Helium is used to search for air leaks after the unit reaches partial load. A load of at least 20% is necessary for efficient leak testing.

6.4. 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 examination 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 corner. 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 corner. Some utilities are now including the examination of the counterbore corners 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, and 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 (Pers-Anderson 1993). The time-of-flight diffraction signals associated with different crack configurations are illustrated in Fig. 23. As shown in Fig. 23(a), two signals are present in the absence of a crack: a direct lateral wave signal and a signal reflected from the backwall. 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 23(b) illustrates such a diffracted signal produced by the tip of a surface crack; note the presence of a backwall 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 backwall reflection signal, but a lateral wave and a diffracted signal from the crack tip are present, as shown in Fig. 23(c). All signals will be present for an embedded crack, as shown in Fig. 23(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 backwall and lateral wave signals for reasons other than the presence of a crack.

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 (PISC) Round Robin Tests (the PISC II Project), which showed that amplitude based methods were unreliable for determining the through-wall extent of a crack (Cowfer 1989). 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 (Brook 1986).

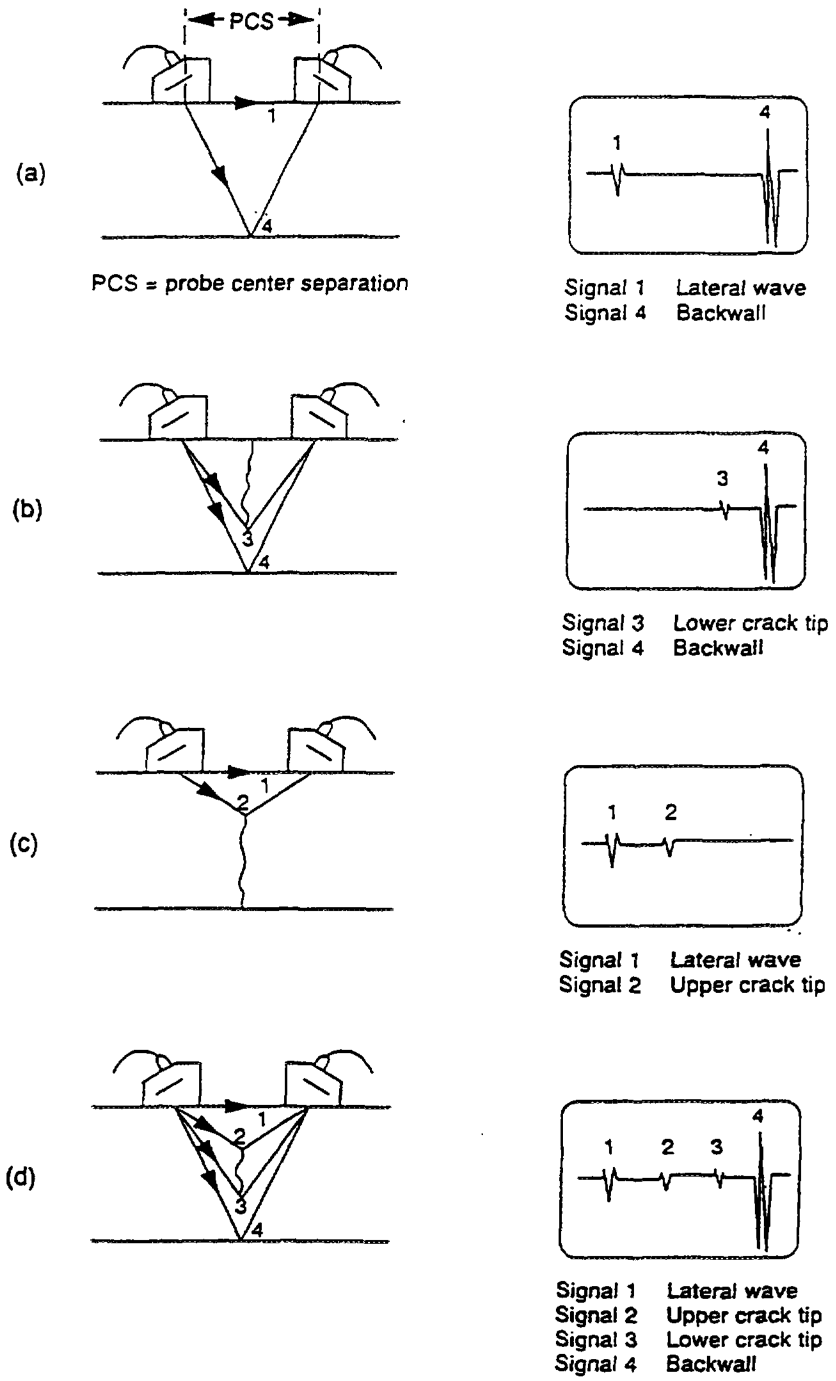


FIG. 23. Examples of time-of-flight diffraction (TOFD) signals (Pers-Anderson 1993). Copyright TRC; used with permission.

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 Introspect/98 volumetric inspection system (Mostafa and Ramsey 1994). 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 modern 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. Modern 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 (Bisbee 1994). 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 (Maeda and Yagawa 1991). The advantage of this approach is that an accurate cross section of any section of the weld, including the reentrant corner of the counterbore, can be obtained. The disadvantage is, of course, the expense of performing such an examination.

6.5. MONITORING FATIGUE DAMAGE TO FEEDWATER NOZZLES

This section briefly describes fatigue monitoring programmes offered by vendors in Europe, Japan and the USA. It explains how some of the fatigue monitoring approaches have been implemented, with emphasis on feedwater nozzles.

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 [Ware 1993]. 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. Improvements to the software, based on actual plant experience and fine tuning, include a correlation of thermal stratification interface level as a function of feedwater flow. FatiguePro has been installed in at least two Westinghouse four-loop plants.

Siemens-KWU Strategy. A Fatigue Monitoring System (FAMOS) has been developed by Siemens-KWU 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, KWU 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 (rainflow cycle counting) and fatigue usage calculations is carried out. KWU 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 [Ware 1993].

French Strategy. Electricité de France 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, rainflow 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 (Bimont and Cordier 1989). 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 (SYstème de Surveillance en FAtigue de la Chaudière). 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 (Bimont and Cordier 1989). 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. SYSFAC is undergoing the final phase of testing and will apparently be installed at a few French plants (Kergoat et al. 1994).

Japanese Strategy. Mitsubishi Heavy Industries Ltd has developed an on-line fatigue monitoring system for nuclear power plant components (Masamori et al. 1988). The project included development of surface temperature measurement instrumentation, of simplified stress analyses and a prototype system. Several locations, including the PWR feedwater nozzle, are being considered for local monitoring of transients causing fatigue damage.

Recently, Sakai et al. (1995) developed an advanced transient and fatigue usage monitoring system: the fatigue monitoring system of the Japanese PWR Group (FAMS). The system is based on the aforementioned Green's function approach but has an enhanced feature for monitoring fatigue usage caused by thermal stratification. The heat transfer coefficient at the piping inside surface is a function of temperature and flow velocity. To account for the changes in the heat transfer coefficient during thermal stratification, the system software has a Green's function database using the estimated heat transfer coefficient on the inside surface. The software has been verified using measured data obtained from a PWR plant and three-dimensional finite element analyses. Sakai et al. report that the first application of the FAMS system to a Japanese plant will be in the near future.

7. STEAM GENERATOR ASSESSMENT METHODS AND FITNESS FOR SERVICE GUIDELINES

7.1. TUBING REPAIR CRITERIA

Repair 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 U.S. Code of Federal Regulations and in the American Society of Mechanical Engineers (ASME) Pressure Vessel and Boiler Code and is discussed in Section 7.2.1 below. 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. However, alternative criteria are allowed by the ASME code if accepted by the regulatory authority and USNRC Regulatory Guide 1.121 provides guidance on how to develop alternative criteria. Essentially, four items must be addressed:

- the maximum (critical) size of a defect which ensures stability of the damaged tube (analytical and experimental verification);
- the propagation rate of the defect until the next inspection;
- the ability of the inspection methods to detect defects of a critical size;
- the 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 guidance contained in Regulatory Guide 1.121, 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. Both these types of fitness-for-service criteria are briefly introduced below and then discussed in more detail in Section 7.2.

7.1.1. 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. The 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 throughwall 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.

7.1.2. Defect Type and Location Specific Repair Criteria

The occurrence in recent years of new types of tube degradation such as PWSCC within the tubesheet 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 tubesheet will not burst and probably will not leak. Therefore, criteria were developed specifically for full tubesheet depth expanded tubes, which allow tubes with flaws in the tubesheet region to remain in service without repair, regardless of defect size. However, the flaws must be some distance below the top of the tubesheet 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 (Gorman et al. 1994). The tube sheet thickness is usually between 525 and 610 mm.

Crack length criteria for axial PWSCC in the residual stress dominated expansion transition zones. This type of repair limit was originally developed and implemented in some European countries (France, Belgium, Spain, Sweden, Slovenia). Axial cracks located close to the top of the tubesheet and shorter than about 10 mm (3/4" tubes) or 13 mm (7/8" tubes) may remain in service even if they are throughwall. 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.

The main underlying assumption is that Alloy 600 is very ductile. Therefore, reasonably short throughwall axial cracks exhibit slow propagation (typically about a mm/year) and do not tend to result in catastrophic tube failure. Rather simple analytical models (e.g., Erdogan 1976, for application see Flesch and Cochet, 1990) complement the experimental results well and enable reliable predictions of critical crack lengths. Crack growth predictions are estimated on the basis of statistical analyses of consecutive inspection results. The accuracy of the inspection methods is determined using the results of metallographic examinations of pulled-out tubes.

Leakage from tubes with various size cracks has been measured in the laboratory (Flesch and Cochet, 1990). It was shown that the leak rate through a single throughwall crack of about critical length is less than 70 L/h (0.3 gpm). Therefore, reduced operational leak rate limits (below 70 L/h per steam generator) and on-line leak rate monitoring (such as nitrogen-16) were carried out as an additional safety precaution.

The Swedish application of this criterion has an additional very interesting feature. The final value of the repair limit is chosen on the basis of probabilistic safety assessment analysis. The acceptable conditional tube rupture probability, given a steam line break, was set to 1%, which implies an acceptably low core melt frequency (Gorman, 1994, and references therein).

Leak before risk 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 throughwall cracks are rather leaktight, 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: (1) bobbin coil signal amplitude versus tube burst pressure and (2) 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). Should the total leak rate exceed the predefined acceptable value, the plant operator has the following options:

- repair or remove from service (plug) additional tubes,
- lower the reactor coolant system activity limits, or
- reduce the time between inspections.

Thus, the repair limit may depend on the condition of the steam generator, the growth rate of the defects, the coolant activity levels, and other factors, and may be updated at each inspection and repair campaign.

Note that the voltage criterion is not based on a mechanistic description or modelling of the defect in contrast to other criteria. Rather, a simple correlation between a selected

TABLE XXIV. GENERAL INFORMATION ON REPAIR CRITERIA CURRENTLY IMPLEMENTED

Parameter	Generic criteria: No leak, no flaw	Generic criteria: Wall thickness	Defect specific criteria: P*, F* (full depth rolled tubes)	Defect specific criteria: Crack Length (axial PWSCC)	Defect specific criteria: Leak before risk of break (axial PWSCC)	Defect specific criteria: Voltage criteria (ODSCC at TSP)
Repair limit						
Measure of defect severity	N/A	Remaining wall thickness [%]	Distance from the top of TS	Crack length	Crack length and leak rate	Signal amplitude [V]
Typical allowable value	Detection threshold	40-50%	>38-76 mm	<10 mm (3/4") <13 mm (7/8")	<13 mm (7/8")	1-15 V[1]
Inspection						
Method	Adequate to detect degradation	Bobbin	Bobbin	MRPC, UT	MRPC	Bobbin, confirmed by MRPC
Extent (min)	100%	3%	100% (TS)	100% (top of TS)	12% (top of TS)	100% bobbin[2]
Frequency (max.)	1 year	3 years	1 year	1-2 years	1 year	1 year
Leak through defects						
Required monitoring	Sampling, on-line	Sampling	Sampling	On-line	On-line	On-line
Impact on repair limit	None	None	None	None	None	Yes, increases number of plugged tubes

Parameter	Generic criteria		Defect specific criteria			
	No leak, no flaw	Wall thickness	P', F' (full depth rolled tubes)	Crack Length (axial PWSCC)	Leak before risk of break (axial PWSCC)	Voltage criteria (ODSCC at TSP)
Typical operational limit per steam generator (technical specifications)	0	3 8 l/min (1 gpm)	3 8 l/min (1 gpm)	<1 9 l/min (0 5 gpm)	<0 4 l/min (0 1 gpm)	<1 9 l/min (0 5 gpm)
Burst strength						
Structural model	As design	As design	Reinforcement by TS	Plastic limit load leak-before-break	With plastic limit load	No structural model[1]
Margin at normal operation	Design	>3	Margin against tube pull-out	>3	>3	3, 95% confidence
Margin at postulated accident (SLB)	Design	>1 4	Against pull-out	>1 4	>1 4	1 4, 95% confidence
Experimental background	Design	Design	Pull-out	Burst, leak	Burst, leak	Burst, leak

[1] Strongly depends on the inspection hardware and software, which differs in different countries (USA, France, Belgium)

[2] Hot-leg only

TABLE XXV. FITNESS-FOR-SERVICE GUIDELINES IN EIGHT COUNTRIES

Bases	How Implemented	Where Used
1 No detectable flaws or leakage	• No wall thinning > 20%, no defects over noise level	Japan
2 Flaws limited to a size which is calculated not to burst during normal operation and accident conditions	• Use safety factors of 3 for normal operation and 1 4 and 1 5 for accidents and conservative analysis methods • Often 40% of wall thickness	USA Canada
3 Flaws limited to a size which is calculated not to burst during normal operation and accident conditions	• Use safety factors of 2 7 for normal operation and 1 43 for accidents and margins for accuracy and growth • 50% of wall thickness	Germany
4 Flaw limited to a size which is not expected to burst during normal operation and accident conditions	• Use safety factor of 3 for normal operation and 1 4 - 1 5 for accidents with best estimate analysis, or conservative analysis methods with no safety factor; use most conservative result	Belgium Slovenia
5 Flaws limited to a size so that there is a low probability of tubing burst during accident conditions	• Use conservative analysis methods for each degradation mechanism (degradation specific management) - no explicit safety factors but aggressive inspections • Rely on a reliable nitrogen-16 leak detection system	France
6 Flaws limited to a size which is not expected to burst during normal operation and accident conditions	• Use conservative analysis methods supplemented by 100% inspections of affected areas and tight leak rate limits	Spain
7 Set defect size based on allowable risk of rupture during steam line break	• Estimate probability of rupture for each defect, and require sum for all defects to be < allowed limit (e g , 1%)	Sweden
8 No leakage, detectable flaws of any size which do not leak are allowed	• Plug any tube with detectable leakage	Russia
9 Ensure total leakage for all defects meets dose limits under normal operating and accident conditions	• Estimate leakage for all defects present at end of interval, make sure total leakage is significantly less than applicable site dose limits	Canada USA Belgium Slovenia Sweden

parameter, obtained from inspection, and experimental results (burst pressure and leak rate measurements) is derived.

A comparison of the important parameters for each group of repair criteria is given in Table XXIV.

7.2. TUBING FITNESS-FOR-SERVICE GUIDELINES IN VARIOUS COUNTRIES

The purpose of this section is to review and discuss the steam generator tubing fitness-for-service requirements in various countries and to describe in a general way how they are applied. The countries included in this review are Belgium, Canada, France, Germany, Japan, Russia, Slovenia, Spain, Sweden, Switzerland, and the USA. The US Fitness-For-Service guidelines are discussed first because a number of countries started with the US guidelines and then modified them. The basis and implementation approach of the Fitness-For-Service guidelines used in these countries are summarized in Table XXV. Much of the following material was taken from Gorman et. al., 1994.

7.2.1 Regulatory Practices and Fitness-For-Service Guidelines in the USA

Appendix A of Section 10 CFR 50 of the US Code of Federal Regulations requires that (a) US nuclear power plant owners assure that their reactor coolant pressure boundaries have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture and (b) the reactor coolant system and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during normal operation, including anticipated operational transients. 10 CFR 50 also invokes the ASME Code, including Section XI, which has specific inspection requirements for steam generator tubing and Section III, which has general design guidance appropriate for the analysis of steam generator tubing burst or rupture. Detailed requirements are contained in each nuclear power plant's Technical Specifications, which are part of the plant's license from the USNRC, and are often patterned on the USNRC Standard Technical Specifications.

Article IWB-3521.1 of Section XI of the ASME Code states that the allowable outside diameter flaws in the tubing in U-tube steam generators shall not exceed 40% of the tubing wall thickness. Many US nuclear power plants have this criterion in their Technical Specifications, however, Article IWB-3630 of Section XI does allow alternative criteria to be used, if approved by the USNRC, and a number of US plants use somewhat higher values in their Technical Specifications. For example, a 50% wall thickness criterion is used for most defects at Prairie Island Units 1 and 2, except general wall thinning (Northern States Power co. 1985). And, a 44% wall thickness criterion is used for all defects at San Onofre Units 2 and 3 (Southern California Edison Co. 1982).

Article F-1341.4 of Appendix F of Section III of the ASME code limits the applied load to 0.7 times the plastic instability load, which is determined from either an elastic-plastic analysis or testing. The plastic instability load is defined in Article NB-3213.26 of Section

III as the load at which unbounded plastic deformation occurs without an increase in load. This corresponds to a safety factor of 1.0/0.7 = 1.43 for design basis accident loads such as the loads that would be applied during a main steam line break. If the steam generator tubing

Detailed fitness-for-service guidance is provided to the US nuclear power plant owners in Regulatory Guide 1.121 (USNRC 1976). However, it should be noted that the USNRC regulatory guides are not mandatory and the legal requirements applicable to a plant are those in its Technical Specifications, which are reviewed and approved by the USNRC. Regulatory Guide 1.121 suggests that three factors be considered when developing a fitness-for-service limit: "(1) the minimum tube wall thickness needed in order for tubes with defects to sustain the imposed loadings under normal operating conditions and postulated accident conditions, (2) an operational allowance for degradation between inspections, and (3) the crack size permitted to meet the leakage limit allowed per steam generator by the technical specifications of the licenses" (USNRC 1976).

The minimum acceptable wall thickness is defined in such a way that:

- Tubes with part through-wall degradation should not be stressed beyond the elastic range during normal operation;
- There is at least a margin of safety of 3 against tube rupture or burst during normal operation;
- There is at least a margin of safety of 1.43 against tube rupture or burst during design basis accidents (ASME Code, Section III, Articles NB-3225 and F-1341.4)
- Any increase in the primary-to-secondary leak rate must be gradual enough to allow corrective actions to be taken prior to tube failure.

The method used to estimate the operational allowance (fraction of the total thickness to compensate for degradation during the next operating period) should be based on evaluation of the continuing degradation rate and a consideration of measurement error. A defect "that reduces the remaining tube wall thickness to less than the sum of the minimum acceptable tube wall thickness plus the operational degradation allowance is designated as an unacceptable defect" and a tube with that defect "should be plugged" (USNRC 1976).

Regulatory Guide 1.121 also suggests that conservative analytical models be used to establish the minimum acceptable tube wall thickness. The wall thickness must meet the design limits of the ASME Code as discussed above and the stress calculations for defective tubes must consider all stresses and deformations expected during several design basis accidents. A summary of the analysis performed must be provided to the USNRC when applying for alternate fitness-for-service guidelines.

Regulatory Guide 1.121 also suggests that the primary coolant system-to-secondary coolant system leak rate in the Technical Specifications be adjusted so that the allowable leakage rate during normal operation is less than "the leakage rate determined theoretically or experimentally from the largest single permissible longitudinal crack," so that remedial action can be taken if the cracks propagate suddenly. Also the leak rate should be less than the permissible leak rate based on the site boundary radiation dose. Although not included in Regulatory Guide 1.121, practice in the USA has been to ensure that the total of all primary system leaks will not exceed the site dose limits set by 10 CFR 100 during design base accidents, especially the main steam line break.

7.2.2. Alternative US Fitness-For-Service Guidelines for Outside Diameter IGSCC/IGA at Tube Support Plates

The tubes in the steam generators at the Trojan Nuclear Plant (now shut down) near Portland, Oregon, experienced considerable outside diameter IGSCC/IGA damage at the tube support plate locations. Because of the large number of tubes with suspect indications, the Trojan staff eventually decided to develop alternate fitness-for-service guidelines based on bobbin coil voltage, to limit the number of tubes requiring repair or plugging (Westinghouse 1991). This involved correlating bobbin coil eddy current voltage with burst pressures. The experimental work was performed by Westinghouse using pulled tubes from a number of PWRs as well as model boiler tubes tested at room temperature without tube support plate reinforcement. The results were then adjusted to the operating temperature of the steam generator using Alloy 600 temperature-dependent mechanical properties. A lower 95% curve was established and the voltages corresponding to (a) three times the normal operating pressure difference across the tubing walls and (b) 1.43 times the pressure drop during a main steam line break were determined. The expected growth rate in volts during the next operating cycle was computed based on limited prior experience and subtracted from the burst correlation results, along with an allowance for measurement uncertainty (analysis, probe wear, and calibration standards). Because of the uncertainty in the growth rate and the limited experience with this type of guideline, a limit for the bobbin coil voltage of 1.0 volt was chosen.

The Trojan alternate fitness-for-service guidelines required an extensive inspection programme. All the tubes were inspected during the next outage with bobbin coil eddy current equipment. All indications and all intersections up to the 5th tube support plate were then inspected with rotating pancake coil eddy current equipment. Care was taken to determine when a bobbin coil signal was a "possible indication" and a rotating pancake coil signal was something other than background noise. To provide additional assurance that the Trojan outside diameter IGSCC/IGA defects would be detected, the allowable primary-to-secondary coolant system leak rate was reduced to 492 litres (130 gallons) per day per steam generator and 1514 litres (400 gallons) per day for all four steam generators and nitrogen-16 monitors were installed on the main steam lines.

In parallel with the work at Trojan, EPRI commissioned a committee of US and foreign experts in steam generator tubing degradation issues to recommend an alternative fitness-for-service guideline for outside diameter IGSCC/IGA defects (EPRI 1993a, EPRI 1995b). Their approach is intended to be consistent with the NRC Regulatory Guide 1.121 and the ASME Section III philosophy, and is based on experimentally determined voltage limits, as follows:

$$V = V_{SL} - V_{NDE} - V_{CG}.$$

Where V is the voltage limit for repair, V_{SL} is a voltage structural limit from correlations of burst pressure versus bobbin coil measurement, V_{NDE} is the measurement error, and V_{CG} is the voltage growth associated with the expected crack growth during the next operating cycle. The values for V_{NDE} and V_{SL} were taken from an EPRI database, and V_{CG} is based on either plant specific data or conservative values developed by EPRI. All indications with a bobbin coil eddy current voltage greater than the calculated limit require repair. The development of these correlations is discussed in somewhat more detail in the next few paragraphs.

To develop the burst pressure versus bobbin coil eddy current correlation, EPRI compiled results from pulled tubes from a number of plants and model boiler tubes with diameters of 3/4-inches and 7/8-inches. The eddy current measurements were generally made before the tubes were removed from the steam generators. The burst tests were performed at room temperature without tube support plates. Tube support plate reinforcement was not used because eggcrate and quatrefoil tube supports do not provide coverage around the entire circumference and drilled hole tube support plates may move during a main steam line break accident, thereby uncovering the cracks. A curve fit at the lower 95% prediction interval was then determined and adjusted to 344°C (650°F) using lower bound temperature dependent mechanical properties. The lower value of the bobbin coil voltage at three times normal operating pressure or 1.43 times the main steam line break pressure drop was then determined. This was found to be 4.0V for the 3/4-inch tubing and 4.5V for the 7/8-inch tubing (for the data available at that time).

To calculate the expected voltage growth during the next operating cycle, data from consecutive operating cycles at six plants was evaluated. The per cent voltage growth for each indication and an average plant value was calculated for each plant, then a bounding average growth rate greater than all the plant average values was computed. This value was shown to be 35%/EFPY.

The measurement uncertainty associated with probe wear and analyst interpretation was also determined. Probe wear was varied from 0 to 0.5 mm on the centering buttons and numerous scans made of a four hole calibration standard. The calibration standard was prepared per ASME Code Section V, Article 8, Appendix II - 860.22. A standard deviation of 7% was determined. The largest 592 indications from a plant with confirmed outside diameter IGSCC/IGA at the tube support plates was evaluated by six analysts. The standard deviation of the voltage readings was found to be 10.3%. A combined root-mean squares deviation for measurement error of 20.5% was then calculated.

Using the EPRI values discussed above and an expected cycle length of 1.3 EFPYs, the repair limits are 2.4 volts for 3/4-inch tubing and 2.7 volts for 7/8-inch tubing. It should be noted that use of these limits requires 100% bobbin coil eddy current inspection, and supplemental rotating pancake coil eddy current inspections to characterize the indications as outside diameter IGSCC/IGA.

To use the EPRI voltage criteria, the primary-to-secondary coolant system leakage during various design basis accidents must also be estimated. Therefore, EPRI correlated leak rate and probability of leakage with bobbin coil voltage by testing pulled tubes and model boiler tubes at estimated main steam line break pressure differences of 16.1 and 18.3 MPa (2335 and

2650 psi). (However, not all the tubes were tested at both pressures, and analytical adjustments were used.) Using the best fit curves and standard deviations, along with the crack growth rate and measurement uncertainty distribution, a Monte Carlo analysis can be performed to calculate an accident leak rate at the end of the next operating cycle. (The leak rate for a given crack size is the probability of leakage multiplied by the leak rate.) The sum of the upper 95/95 probability/confidence level values is then used as the conservative upper bound leak rate and compared to the site boundary limits.

Also, to minimize the probability of rupture, the EPRI guidelines recommend that the allowable steam generator leak rate be reduced from 1893 to 568 litres per day (500 to 150 gpd).

The USNRC provided guidance to US utilities who wished to implement the EPRI (or similar) alternative fitness-for-service guidelines for ODSCC at tube support plates in Generic Letter 95-05 (USNRC 1995a). Although the USNRC approved the basic approach discussed above, a number of key parameters were modified and made more restrictive (conservative). Also, the repair criteria discussed in Generic Letter 95-05 only applies to Westinghouse-designed steam generators with 19 mm (3/4 inch) and 22 mm (7/8 inch) diameter Alloy 600 tubes and drilled-hole tube support plates and axially oriented ODSCC confined within the tube-to-tube support plate intersections.

The USNRC voltage repair limits are:

- 22 mm (7/8 inch) diameter tubes with bobbin coil probe indications less than 2.0 volts may remain in service.
- 19 mm (3/4 inch) diameter tubes with bobbin coil probe indications less than 1.0 volt may remain in service.
- Tubes with bobbin coil indications greater than the above values but less than an upper voltage repair limit (calculated using the basic EPRI approach) may remain in service if a subsequent rotating pancake coil probe inspection does not confirm the indication.
- Tubes with other indications (above the upper limit, or between the lower and upper limit and confirmed by rotating pancake coil inspection) must be repaired.

As with the EPRI fitness-for-service guidelines, the upper voltage repair limit is determined by first determining the lower 95% prediction boundary for an appropriate set of room-temperature burst pressure versus bobbin coil voltage data, then reducing this lower limit to account for the lower 95/95% tolerance bound of the tubing material properties at 343°C (650°F). The structural limit voltage, V_{SL}, is then determined for a free span burst pressure of 1.4 times the differential pressure calculated for a main steam line break design basis accident. The structural limit voltage is then reduced to account for flaw growth during the next operating cycle and voltage measurement uncertainty. The flaw growth allowance should be based on the voltage growth rates observed at that plant during the last one or two inspection cycles or 30% per effective full power year, whichever is larger. The voltage measurement uncertainty should consider probe wear and the variability among data analysts and should be the 95% cumulative probability value (about 20%).

The total leak rate during a main steam line break accident must also be calculated by (a) determining the frequency distribution of the bobbin coil voltage indications, (b) determining an end of cycle distribution based on the expected crack growth and estimated measurement error and (c) use of empirical probability of leak and leak rate versus bobbin coil voltage indication models. The total leak rate must, of course, be within the licensing basis. The beginning of cycle bobbin indication frequency distribution must be scaled upward by a factor of 1/POD to account for non-detected cracks, where POD is the probability of detection of ODSCC flaws and can be assumed to be 0.6. Monte Carlo techniques can then be used to project the beginning of cycle voltage distribution to the end of the cycle, using the expected crack growth values and measurement uncertainties discussed above. Once the projected end of cycle voltage distribution is determined, the leakage is calculated by multiplying the voltage distribution by (a) an empirical probability of leakage as a function of voltage value and (b) an empirical leak rate as a function of voltage value. These empirical models should be developed from appropriate experimental data from either 22 mm or 19 mm tubing, as applicable.

Implementation of voltage-based repair criteria must include enhanced inspections. The bobbin coil inspection should include all the hot-leg tube support plate intersections and all the cold-leg intersections down to the lowest cold-leg tube support plate with known ODSCC. In addition, 20% of the tubes should be inspected over their full length with a bobbin coil probe. Rotating pancake coil inspections should be performed for all bobbin coil indications exceeding 2.0 volts from 22 mm (7/8 inch) diameter tubes or 1.0 volt from 19 mm (3/4 inch) diameter tubes. Also, rotating pancake coil inspections should be performed at all intersections with (a) interfering signals from copper deposits, (b) dent signals greater than 5 volts, or (c) large mixed residuals. Any indications found at such intersections with a rotating pancake coil should cause the tube to be repaired or plugged. The bobbin coil should be calibrated against the standard used to develop the voltage-based approach. Probe wear should be controlled. The data analyst's performance should be consistent with the measurement uncertainties used.

Implementation of a voltage-based repair criteria must also include a programme of steam generator tube removals and testing. Two tubes (at least four intersections) must be removed from each plant when the voltage-based repair criteria is first implemented. An additional tube (at least two intersections) must be removed during each outage following 34 effective full power months of operation, or after three refueling outages, whichever is shorter. The removed tubes must be subjected to leak and burst tests under simulated main steam line break conditions. The tube intersection areas must also be destructively examined to confirm that the degradation is axial ODSCC.

Implementation of voltage-based repair criteria must also include reduced leakage limits (568 L/d or 150 gal per day) and adequate leakage monitoring equipment. Also, tubes with known leaks must be repaired or plugged.

7.2.3. Alternative US Fitness-For-Service Guidelines for PWSCC in the Roll Transition Region Proposed by EPRI

Primary water stress corrosion cracking has been found in the roll transition region of full- and part-depth rolled PWR steam generators worldwide. One of the first alternative fitness-for-service guidelines was the F* criterion which is being used in a number of US plants. The F* criteria applies to steam generators with partial or full tubesheet depth hard rolled tubes and allows defects, regardless of size, detected below a certain distance from the bottom of the roll transition or top of tubesheet, whichever is lower, to remain in service. The F* distance is established by considering the length of roll expansion needed to resist tube pull out forces and is typically 38 mm to 50 mm (1.5–2.0 inches). In other words, the F* criteria has been applied at locations where there is a very low possibility of steam generator tube rupture or burst because the defect remains tightly enclosed within the tubesheet.

Recently, EPRI also commissioned a committee of US and foreign experts in steam generator repair issues to develop alternative fitness-for-service guidelines for tubes with axial PWSCC above the F* distance (EPRI 1993b). The following equation is used to find the largest allowable axial crack which can remain in service:

$$A = a + a_{TS} - a_{CG} - a_{NDE}$$

Where A is the allowable crack length, a is a reference crack length from a rupture correlation, a_{TS} is a correction for tubesheet constraint, a_{CG} is the allowance for crack growth during the next operating cycle, and a_{NDE} is a measurement uncertainty factor. To develop the rupture correlation (a versus burst pressure) EPRI compiled results from tests performed on 3/4-inch and 7/8-inch tubing by BELGATOM, Framatome and EDF, Westinghouse, and CEGB in Great Britain. The data were normalized and a bounding equation determined and then adjusted to the steam generator operating temperature.

The tubesheet correction factor was developed by BELGATOM as follows (for 3/4-inch tubing):

$0 < a < 4.5$ mm $a_{TS} = 4.5$ mm
$4.5 < a < 18$ mm $a_{TS} = 6.0 - a/3$ mm
18 mm $< a$ $a_{TS} = 0$

These values reflect the tubesheet reinforcement provided relatively short axial cracks at the roll transition.

The allowance for average crack growth during the next operating cycle (a_{CG}) was determined to be 0.76 mm/EFPY using data from Doel 2 for cracks with beginning-of-cycle lengths of 3 mm to 11 mm (Doel 2 has an inlet temperature of 330°C). However, use of plant specific data is recommended. To determine the measurement uncertainty (a_{NDE}), EPRI compiled results from comparisons of true crack length with crack length as measured by rotating pancake coil eddy current equipment in France, Belgium, Sweden, Spain, and the USA. The 201 data points provided the following relationship: True crack length equals the eddy current measured crack length less 0.39 mm with a two sigma distribution of 2.12 mm. Subtracting 0.39 from 2.12 mm provides an NDE error estimate of 1.73 mm [i.e., the average true length is 0.39 mm shorter than the measured length but at the 95% confidence level (2 sigma) the true length is 1.73 mm longer than the measured length.]

Using safety factors of 3 on the normal pressure drop and 1.43 on the design basis accident pressure drop, a critical crack length for a 7/8-inch tube of 10.7 mm is calculated. Use of this criterion required a 100% rotating pancake coil eddy current inspection of all in-service hot-leg tube expansion zones. It also required a primary-to-secondary coolant system leakage calculation, similar to the leakage calculation discussed in Section 6.2.2 above.

Also, to minimize the probability of rupture, EPRI recommends that the leak limit during normal operation be reduced to 568 litres per day (150 gpd) per steam generator.

The USNRC has not approved use of the EPRI proposed fitness-for-service guidelines for PWSCC in the roll transition region in the US. As discussed below, certain other countries are using variations of these guidelines.

7.2.4. Other Alternative Fitness-For-Service Guidelines in the USA

Extensive pitting in the Indian Point Unit 3 steam generator caused by a large Hudson River water excursion into the secondary coolant system in 1981, resulted in alternative fitness-for-service guidelines at Indian Point Unit 3 during the period 1981 to 1985. Limits of 65%, 50%, 55% and 63% of the tubing wall thickness were used at various times. These limits were based on burst testing of pulled tubes and various estimates of next cycle crack growth and measurement uncertainty. In 1985, Indian Point returned to the ASME 40% criterion and repaired or plugged all tubes with indications over 40% of the wall thickness.

Extensive circumferential IGSCC/IGA was found in 1991 on the outside surfaces of the tubes in the three North Anna Unit 1 steam generators. These defects were located in the tubesheet expansion region and directly above and below the hot-leg tube support plates. All tubes with significant indications were plugged. However, due to the rapid increase in the extent of the stress corrosion damage, the plant operator decided that a mid-cycle outage in 10 months was needed.

In an attempt to justify a normal 18 month fuel cycle, the plant operator burst tested pulled tubes and reevaluated their previous NDE data to develop a conservative crack growth correlation (over 50% of the 1991 indications were identifiable in 1989). Also, analysis and testing were performed to determine if fatigue at the defect locations could lead to tube rupture. Despite these efforts, it was decided that a mid-cycle inspection was necessary. The plant operator concluded that the results of that inspection showed that the models developed at the end of the previous operating cycle overestimated the number and size of the tubesheet expansion zone defects, but underestimated the number and size of the defects near the tube support plates. The mid-cycle and future inspections of North Anna Unit 1 consisted of 100% full length bobbin coil eddy current inspections, 100% 8 × 1 probe inspections of the hot-legs, 100% rotating pancake coil inspections near the top of the tubesheet, and follow-up of all bobbin and 8 × 1 probe indications with a rotating pancake coil eddy current inspection.

7.2.5. Regulatory Practices and Fitness-For-Service Guidelines in Belgium

The starting point for the Belgian fitness-for-service guidelines were the original US requirements discussed in Section 7.2.1 above. However, the Belgian regulators consider the

40% of tube wall thickness limit in Section XI of the ASME Code too conservative for some locations and some defect types, and too inflexible. For these reasons, they have revised their requirements for in-service inspection of steam generator tubes and have defined the objectives to be met, but assigned the responsibility to the plant operator to meet them. The revised technical specification

- states that the objectives of inspection are to: (1) determine whether tube degradation is occurring and identify the specific modes involved, (2) assess the rate of defect growth and compare it with values used in establishing plugging/repairing criteria, and (3) identify the tubes that require plugging/repairing.

- defines the content of the inspection programme, which must include: (1) definition of inspection techniques and procedures, (2) tubes and zones to be inspected and (3) the plugging/repairing criteria to be used for each type of degradation.

- gives general requirements: (1) requiring inspection methods to be selected such that they can reliably detect defects of concern, and (2) establishing the minimum sample size for inspection (3%) and requiring the sample size to be expanded and additional inspection to be used, if necessary, to achieve the objectives.

Based on the revised inspection requirements, alternate plugging/repairing criteria, i.e. defect specific fitness-for-service guidelines, have been developed by the plant operator aiming at (1) ensuring the structural integrity of the tubes, with adequate safety margin, under normal and during postulated accident conditions and (2) limiting the total primary-to-secondary leakage during and following an accident to a value consistent with the offsite dose limit. The controlling accident is considered to be a feedwater/steam line break. With regard to the safety factors, the Belgian regulators generally use the safety factors on loadings required by the USNRC Regulatory Guide 1.121 and the ASME Code.

The fitness-for-service guidelines are submitted to the safety authority for approval. They are reassessed after each inspection to take into account the latest degradation growth rates, the accuracy of the inspection technique, and any change in the acceptance criteria (e.g. additional burst test data).

The fitness-for-service guidelines in Belgium are both defect specific and location specific. For example, one type of fitness-for-service guidelines is for axial PWSCC at the roll transition at the top of the tubesheet of full depth rolled tubes. Other fitness-for-service guidelines have been developed for axial IGA/IGSCC at tube support plate intersections, for IGA/IGSCC in the sludge pile, and circumferential ODSCC at the roll transition at the top of the tubesheet. The fitness-for-service guidelines are of two general types, deterministic and statistical. Deterministic fitness-for-service guidelines are used when the morphology of the defect is such that reliable sizing is possible using available non-destructive examination methods, and the size of the defect can be reliably correlated with tube burst data. In these cases, the measured size is compared to an allowed defect size, which includes margins for sizing error and growth up to the next inspection, and required safety factors. Statistical fitness-for-service guidelines are used when accurate defect sizing by non-destructive examination technique is not possible. In this case, a statistical correlation is developed between a measured non-destructive examination parameter, such as bobbin coil voltage amplitude, and the burst strength of tubes with defects generally obtained from tubes removed from service. The lower confidence limit of this correlation, when combined with the required safety margin, is the maximum permissible value of the non-destructive examination parameter at the next inspection, i.e. after allowing for growth.

Predicted primary-to-secondary leakage during accidents is calculated on a combined deterministic-probabilistic basis, taking into account the measured crack size or measured non-destructive examination parameter at the start of the operating interval, probable crack sizes or non-destructive examination parameters at the end of the operating interval, and probable leakage behaviour based on tests of tubes removed from service.

7.2.6. Regulatory Practices and Fitness-For-Service Guidelines in Canada

The regulatory requirements for steam generator tubing fitness-for-service assessments in Canada are stated in Clause 14 of CAN/CA N285.4, "Periodic Inspection of Nuclear Power Plant Components" (Canadian Standards Association 1994). In general, the only flaw indications allowed in unrepaired tubes are where the predicted wall loss does not exceed 40% of the nominal wall thickness prior to the next inspection. However, the most recent version of this standard allows for indications exceeding the basic 40% criteria, when a satisfactory fitness-for-service assessment is performed. The fitness-for-service methodology discussed below is based on recent assessments carried out at Ontario Hydro for Bruce-A Unit 2 and Bruce-B (Gorman et al. 1995).

The fitness-for-service assessment requires demonstration that the incremental risk associated with continued operation of a steam generator with a known degradation mechanism is justified, understood and controlled. This has led to the following acceptance criteria;

1 Demonstrate that the predicted probability of steam generator tube rupture remains unchanged, thus ensuring that the frequency of the event is unchanged from that considered in support of the operating license.

2(a) Demonstrate, for all design basis events with possible induced tube failures, that there are justifiable margins between estimated doses due to consequential tube leakage and the applicable dose limits.

2(b) Demonstrate that post-accident operating conditions are manageable and procedures adequate in such a way that overall consequences remain acceptable.

It has been the experience to date that the response to design basis events (criterion 2(a)), has defined the permissible degree of tube degradation in affected CANDU plants (Grant 1994). Criterion 1 has been demonstrated for the degradation mechanisms experienced by CANDU units to date, but it may not always be possible to do that for all degradation mechanisms which might affect the tubes in the future.

CANDU plants routinely monitor steam generator leakage with methods capable of detecting leaks below 10^{-3} kg/s. Plant operating procedures require shutdown when the leak rate exceeds 15 kg/h. However, the correlation of leak rate with degradation is usually poor, because of the dependence of the leak rate on other variables such as applied loads, crack morphology, crud, etc. Leak monitoring is a useful precaution, but it does not in itself preclude the existence of large flaws or tube ruptures, it needs to be supplemented by other actions such as in-service examinations (Grant 1994).

Criterion 2(a) leads to the development of a Maximum Allowable Leak Rate per unit against which a Total Estimated Consequential Leak Rate due to an event is compared.

The general fitness-for-service assessment methodology consists of the following steps:

Determination of Degradation Mechanism and Root Cause. The first step in the assessment process determines the degradation mechanism and the root cause of the problem (more than one degradation mechanism may be affecting the tubes). This leads to two possible paths of action depending on how widespread the problem is. If the population of affected tubes is known to be small, i.e. the degradation is not generic, then the affected tubes are either taken out of service or are allowed to remain in service if the tube flaw indications are less than the 40% plugging criterion. Actions may also take place to remove the cause of the problem. For example, if the degradation was caused by debris, there is an effort to remove it from the steam generator. If the tube degradation is found to affect a large population of tubes in the steam generators, i.e. the degradation is generic in nature, then the fitness-for-service assessment continues.

Failure of the Tube(s) under Normal Operating Conditions. For normal operating conditions, it is necessary to determine the specific degradation mechanism(s); characterize the tube flaw characteristics and material properties, the loadings and the tube behaviour under such loadings; and, determine the mode(s) of failure of the degraded tube and the resulting leak rate. Sources of information for this step include non-destructive and destructive (tube pulls) examinations and structural testing of tubes containing characterized defects. This information is required to demonstrate that degradation induced failure of the tube will occur in a stable controlled manner. This leads to an evaluation of the increase in probability of boiler tube rupture under normal operating conditions and an evaluation of the adequacy of the basic Shutdown Leak Rate. Criterion 1 is satisfied if it can be shown that the maximum predicted probability of boiler tube rupture remains unchanged. This criterion must be satisfied for the fitness-for-service assessment to continue.

Failure of the Tubes as a Consequence of Design Basis Events. In order to estimate a total leak rate for a particular tube degradation mechanism as a consequence of a specific event, it is necessary to answer the following questions:

(i) How are the tubes likely to fail?

(ii) How many tubes are at risk of failing at the end of the operating cycle, i.e. just prior to the next inspection?

(iii) What remedial measures could be put in place to correct or mitigate the degradation and what is the impact of these measures on the safety assessment?

(i) Determine Failure Mode of Tubes

Again, it is necessary to determine the specific degradation mechanism(s); characterize the tube flaw characteristics and material properties, the loadings and the tube behaviour under such loading; and, determine the mode(s) of failure of the degraded tube and the resulting leak rate. This is required to determine the level of degradation beyond which credit can not be taken for pressure boundary integrity for a particular event (i.e. the tube is at risk of leaking). This is referred to as the Accident Specific Degradation Threshold Value (ASDTV). To determine the ASDTV, event specific loadings are considered. These loadings are obtained from thermal hydraulic analyses of each design basis event and include the appropriate factors of safety. ASDTV is analytically calculated using flaw models which have been validated by suitable structural tests.

(ii) Determine Number of Tubes at Risk of Failing by the End of the Operating Cycle

To predict how many tubes are likely to fail by the end of the operating cycle, the future condition of the tubes must be predicted by determining the present condition, the rate of change of the degradation and the duration of the operating period to the next inspection. In-service examination results and probability models provide an estimate of the future condition of the tubes. In the Bruce-A Unit 2 case the ODSCC was extremely difficult to detect and required the development of a new eddy current inspection probe, called Cecco-3. This sensitive probe was a key factor in the success of the overall assessment. The impact of any remedial action on both the present condition and the rate of change is also included in the assessment.

In the fitness-for-service assessment, a Maximum Tolerable Flaw Size (MTFS) is also calculated (based on ductile collapse of flawed tubes) and is used to establish the plugging criterion which considers the inspection interval, expected growth rate, and inspection uncertainty. The loadings considered for determining the MTFS are the loadings which represent bounding loading conditions for the ASME Service Levels A, B, C and D. The assessment then considers the future condition of the tubes and the calculated threshold value ASDTV to predict the total number of tubes at risk of leaking by the end of the operating cycle.

(iii) Remedial Actions

To determine appropriate remedial actions, which could be corrective or preventive in nature, the degradation mechanism, the root cause and contributing factors must be thoroughly understood. Further, the impact of all remedial actions must be taken into account in the safety assessment.

Total Estimated Consequential Leak Rate. The total Estimated Consequential Leak Rate is determined by evaluating the product of the total number of tubes at risk at the end of the operating cycle and the total leak rate per tube. Criterion 2 is satisfied if it can be shown, for all design basis events, that there are justifiable margins between the estimated consequential doses due to tube leaks and the applicable dose limits and that the overall post accident consequences remain acceptable.

Fitness-for-Service Assessment. The steam generators in the unit are judged to be fit for continued service if Criteria 1 and 2 are satisfied. If these relationships are not shown to be true, then additional measures must be implemented to either further correct the situation (new plugging limits, internal modifications, cleaning, etc.) or shortening the operating interval and/or reducing the power levels. The assessment is then repeated.

7.2.7. Regulatory Practices and Fitness-For-Service Guidelines in the Czech Republic

Defective steam generator tubes with 80% or greater wall thickness reduction have been plugged. This value was recommended by the manufacturer, Vitkovice, and has not been approved by the Czech regulatory body. Additional work to determine the final criterion is under way (burst testing). Leakage limits were developed and approved by the Czech regulatory body in 1993.

7.2.8. Regulatory Practices and Fitness-For-Service Guidelines in France

The measures taken by EDF and the French regulatory authority, DSIN, to prevent tube rupture or burst during normal, off-normal, or accident conditions are based on aggressive inspection and leak detection programmes supported by defect type and location specific fitness-for-service criteria (Cochet 1989, Saudan 1992, Lemaire 1993). To find PWSCC in the roll transition region of steam generators susceptible to PWSCC, the hot leg side roll transition region of every tube is inspected during each outage using rotating pancake coil eddy current equipment. To find PWSCC in the small radius U-bends, the U-bend region of all the tubes in the first row still in service and a sample of the tubes in the second row are inspected during each outage, using a flexible rotating coil (susceptible steam generators). To find outside diameter IGSCC/IGA at the tube support plates, the hot leg tube support plate locations are inspected during every other outage, using bobbin coil eddy current equipment (susceptible steam generators). Follow-up inspections of affected tubes still in service are performed during the next outage. Also, 100% of the hot leg tube length in the sludge pile is inspected using bobbin coil eddy current equipment every other outage. The accuracy of the examination techniques is assessed by comparing the measurements to the results of pulled tube destructive examinations (more than 350 to date).

The primary-to-secondary coolant system leak rates in French steam generators at plants that have experienced tube degradation are measured by γ and β spectrometry and nitrogen-16 monitors, in addition to grab sample measurements.

- When a nitrogen-16 monitor detects a leak greater than a threshold of 20 L/h (lowered from 72 L/h in 1995), the plant must be shut down immediately.

- When lower leak rates are detected by the nitrogen-16 monitors and are confirmed by grab sample measurements, plant shut down is required when the following limits are exceeded.

- leak rate increase ≥3 L/h per day, or continuously increasing during 3 days at a leak rate increase ≥1 L/h per day;

- difference between steam generator leak rates ≥3 L/h;

- leak rate ≥3 L/h (steam generators least susceptible to PWSCC) or ≥10 L/h (steam generators susceptible to PWSCC).

These stringent total leak rate thresholds and allowable leak rate increases, together with the maximum allowable background level, are considered important in France as a general means to improve the surveillance of the tube bundle integrity. Improving the sensitivity of the monitors so that the occurrence of a potentially new type of growing defect can be detected earlier, and developing procedures to prevent tube rupture, enhance the safety margins of the French plants whether or not the flaws which contribute most to the leakage or the leakage increases are relevant to the leak before risk of break approach, since the nature and the origin of the flaws cannot be identified during operation. Leak rates models are presently being developed to better account for the experimentally observed leak rates from the various kinds of flaws. These models will eventually be used to predict the expected primary-to-secondary coolant leak rates from the tubing inspection data.

The defect type and location specific fitness-for-service guidelines used in France are summarized as follows:

Axial PWSCC in the roll transition zone. The axial crack length limit is based on an analysis of crack growth and tube burst during a main steam line break, which is considered to be the design basis accident that imposes the highest loads. Correlations of critical crack length versus burst pressure have been developed from experiment. The analysis uses these correlations and the maximum tube diameter and minimum wall thickness, adverse mechanical properties, upper-bound temperatures and pressures, a conservative allowance for crack growth during the next operating cycle, and margin for NDE error. Safety factors are not applied. In developing these correlations, the French specialists concluded that a crack with an end within the tubesheet where the tube is in contact with the tubesheet can propagate in an unstable manner in only one direction. The maximum allowable free crack length, which takes into account accident conditions, is 13 mm for the 900 MWe plants. A temporary criterion of 13 mm has also been adopted for the 1300 MWe plants. A definitive plugging criterion will be established after completion of certain probabilistic risk studies.

Circumferential PWSCC. Tubes with circumferential PWSCC must be plugged because (a) the leak before risk of break approach does not apply since the cracks are often not throughwall until the tube is close to rupture (i.e., the cracks tend to propagate around the tube first), and (b) the rotating pancake coil eddy current detection limit is only about 50% of the wall thickness. In other words, the French experts do not believe that there is much margin between initial detection of circumferential PWSCC and possible rupture under extreme accident conditions.

PWSCC in the inner row U-bends. All tubes with indications measured with bobbin coil and flexible rotating coil eddy current equipment must be plugged. This is because it is almost impossible to pull tubes and develop correlations of actual crack length versus NDE results and prove that leak before risk of break applies. Preventive plugging of tight U-bend tubes susceptible to PWSCC was carried out at several French units to improve the availability of the plants.

Outside diameter IGSCC/IGA at tube support plates. The repair or plugging criteria is a bobbin coil voltage of 2 volts, which corresponds to approximately 17 volts in the USA. This rather large limit (as compared with a typical US repair criteria of 1 to 2 volts) is due to the assumption that the tubing will be supported in those regions by the tube support plates during various design basis accidents. The 17 volt value was apparently obtained from an experimental correlation between bobbin coil eddy current voltage and tubing burst strengths with support plates present, plus a voltage value for the expected crack growth during the next operating period, plus an allowance for measurement error. A more conservative value (1 volt) is used for defects at the higher tube support plate elevations of some steam generators (e.g. the model 51A).

Outside diameter IGSCC/IGA in the sludge pile. A bobbin coil eddy current voltage of 500 mV without an axial crack, or 200 mV with an axial crack of 10 mm or greater (detected by rotating pancake coil), or any ODSCC indication from both bobbin coil and rotating pancake coil equipment, are the repair or plugging limits for IGSCC/IGA in the sludge pile.

Other indications. All other indications beyond those discussed above, including wear caused by foreign objects, AVBs, etc., and free-span defects, are judged against the ASME 40% of wall criterion.

7.2.9. Regulatory Practices and Fitness-For-Service Guidelines in Germany

The repair or plugging criteria in the Federal Republic of Germany are designed to prevent rupture during normal operation or design basis accident loadings (Azodi et al. 1987). Defective steam generator tubes are evaluated on a case by case basis. However, wall degradation of 50% or greater generally results in plugging. This value was obtained from burst test results and:

- a measurement uncertainty of $\pm$10% for eddy current testing and about $\pm$5% for ultrasonic examinations

- a factor of safety of 2.7 against rupture during normal operation and 1.43 against rupture during design basis accident loadings

- an operational allowance for crack growth or additional wastage during the next operating period of about 3% of the wall thickness (steam generators with phosphate water chemistry).

7.2.10. Regulatory Practices and Fitness-For-Service Guidelines in Japan

The fitness-for-service guideline issued by the Japanese Ministry of International Trade and Industry is simply steam generator tubing "flaws are not allowed" (Shizuma 1992). The term "flaw" is interpreted to mean any indication (crack, pit or general wall thinning) greater than 20% of the nominal wall thickness. Obviously, primary-to-secondary coolant system leakage is not allowed and a plant with a leak must be immediately shut down upon detection of the leak. Indications of degradation with a depth less than 20% are considered acceptable if the eddy current signal shows no change from the previous inspection. Preventive plugging of tight U-bend tubes susceptible to PWSCC has been performed at two units.

7.2.11. Regulatory Practices and Fitness-For-Service Guidelines in Russia

The fitness-for-service guideline currently used in Russia (and presumably in the rest of the former Soviet Union) is no steam generator tubing leakage. All tubing with throughwall cracks which cause detectable primary-to-secondary coolant system leakage are plugged. All other defect indications are ignored. There has been no sleeving in the WWER steam generators.

7.2.12. Regulatory Practices and Fitness-For-Service Guidelines in Slovenia

The fitness-for-service guidelines in Slovenia were traditionally based on the 40% tube wall loss repair criterion. For the power plant located in Krško, a plant specific value of 45% was derived and implemented. However, this approach was considered overly conservative which lead to the implementation of the degradation specific guidelines outlined below. The defect type and location specific approach is mainly based on extensive inspection (see section 6.1.7.) and additionally supported by on-line leak detection monitoring (nitrogen-16) and allowable leak rates of 40 L/h per steam generator.

Axial stress corrosion cracking in the roll transition area. The P^* and crack length repair criteria are currently implemented. The P^* criterion allows for any defects located at least 38 to 76 mm (depending on the position of the tube) below the top of tubesheet and for axial defects anywhere inside the tubesheet. The crack length repair criterion is actually based on the Belgian approach described above and allows for axial cracks in the expansion transitions, and for both PWSCC and ODSCC in the sludge regions, if the axial cracks are shorter than 6 mm. An additional restraint is that tubes with cracks located more than 7 mm above the tubesheet have to be repaired if the 45% criterion is violated.

Circumferential stress corrosion cracking in the roll transition area. Any tube with detected defects of this kind is to be repaired or plugged.

PWSCC in the inner row U-bends. Any detected defect triggers repair or plugging of the tube.

ODSCC at tube support plates. Recently, a conservative version of the EPRI based voltage methodology has been implemented for ODSCC at the tube support plates. Initially, 100% of the tubes are inspected using a bobbin coil probe. All bobbin coil indications with a signal amplitude exceeding 1 volt and depth reading exceeding 45% are inspected again using a multifrequency rotating pancake coil probe. Tubes with defects confirmed by multifrequency rotating pancake coil probes are then repaired. Probabilistic analyses addressing events of tube burst and excessive leakage during a steam line break were performed and are currently being refined to support the implementation of this approach.

Other. Tubes with defects exceeding the traditional 45% loss of tube wall thickness are repaired.

Sleeved tubes. All sleeved tubes and all sleeves are inspected during each outage. A 45% loss of tube wall thickness criterion is applied for both the intact part of the tube and the load carrying portion of the sleeve. In practical terms this means repair of all tubes with detected indications, as no wall depth readings can be obtained from the I-coil and Plus-point eddy current probes.

7.2.13. Regulatory Practices and Fitness-For-Service Guidelines in Spain

A research programme was launched in Spain to manage steam generator degradation. Participants included the utilities, manufacturers (ENSA), inspection agency (Tecnatom) and research centers (Ciemat) [Bollini 1993]. The fundamental objective of the Spanish fitness-for-service criteria is the same as that of the French criteria, namely, to assure that the critical crack length under accident conditions is not exceeded during normal operation so that tube rupture will not occur during a design basis accident. Defect type and location specific fitness-for-service criteria, along with aggressive inspections of defected steam generators, are used.

The Spanish defect type and location specific fitness-for-service guidelines are discussed below.

Axial PWSCC in the roll transition area. Two guidelines are used, the first is the P* criterion, which allows a tube with axial PWSCC to remain in service if the indication is below the top of the tubesheet and motion in the vertical direction is controlled by an essentially nondefective tube. The second guideline is based on the French leak before risk of break approach which assumes that accurate leak rate measurement during normal operation will detect crack growth before the crack reaches the critical length. Primary-to-secondary coolant system leak rate correlations as a function of crack size are, of course, needed for this approach and were based on the French work, modified with Spanish data. The largest allowable crack length is 8 mm, which is based on a critical crack length of 13 mm (12.6 mm when the rolling is non-standard) less an upper bound crack growth of 4 mm per fuel cycle and a measurement uncertainty of 1 mm. All tubes with indications equal to or longer than 8 mm (7.6 mm in the case of non-standard rolling) must be repaired or plugged. The maximum number of parallel axial cracks in a tube is 20. Tubes with axial PWSCC in excess of 18 mm above the tubesheet must be repaired or plugged when the defect is deeper than 40% of the wall thickness.

Circumferential PWSCC in the roll transition area. Tubes with circumferential PWSCC in the roll transition area or above the P* criterion limit must be repaired or plugged. The P* criterion allows tubes to remain in service if the circumferential indication is located 38 mm or more (for most of the non-peripheral tubes) below the top of the tubesheet and motion in the vertical direction is controlled by an essentially non-defective tube.

Outside diameter IGSCC/IGA at the tube support plates. The Spanish utilities have proposed a fitness-for-service guideline of 78% of the wall thickness for these defects. The Spanish regulatory agency Consejo de Seguridad Nuclear has not yet approved that criteria and the Spanish utilities are considering the EPRI bobbin coil voltage criteria discussed above.

Other indications. The plugging criterion for fretting damage at the antivibration bar intersections is 55% of the wall thickness. All indications other than the defect type and location specific defects discussed above are judged against the ASME 40% of wall thickness criteria.

The maximum primary to secondary leak rate for steam generators with susceptible tubing is limited to 5 L/h above a steady leak rate at the beginning of the cycle of 5 L/h or less. The maximum primary to secondary leak rate for steam generators with Alloy 800M or thermally treated Alloy 600 tubing is 72 L/h (1728 L/d) during normal operation.

7.2.14. Regulatory Practices and Fitness-For-Service Guidelines in Sweden

The starting point for the Swedish fitness-for-service guidelines are the US requirements, except that the tubes must be repaired or plugged when the defect indication is greater than 50% of the wall thickness, rather than the 40% specified in the ASME code. However, defect type and location specific requirements have been developed for axial PWSCC in the tubesheet region and outside diameter IGSCC/IGA at the tube support plates.

The Swedish approach for judging axial PWSCC in the tubesheet region is probabilistic or risk based in nature (Hedner 1990). The objective is to limit the probability of steam generator tube burst during a main steam line break to less than 1%, i.e., the sum of all tubes with an indicated crack length, times the probability of burst for that crack length, must be less than 0.01.

In equation form:

$$\Sigma \mu_x P_x < 0.01$$

where μ_x is the number of cracks of length x and P_x is the probability of burst or rupture of a tube with a crack of length x. The probability of burst includes the expected crack growth during the next fuel cycle and measurement error and varies as a function of crack length and distance above the tubesheet. For example, a 12.4 mm crack is calculated to have a probability of burst of 1%, a 9 mm crack is calculated to have a probability of burst of 0.34%, and a 6 mm crack is calculated to have a probability of burst of 0.0001%. Only the lengths of cracks above the tubesheet are considered. Tubes with axial cracks below the top of the tubesheet can remain in service without repair. Tubes with circumferential PWSCC can remain in service when the cracks are below the P* distance (38 mm below the top of the tubesheet). Tubes with circumferential PWSCC above the P* distance must be repaired or plugged.

Outside diameter IGSCC/IGA indications at tube support plates with depths up to 70% of the wall thickness can remain in service provided that the indication is within the length of the tube support plate and is in the lower five tube support plates. These limits are based on tube burst testing with a tube support plate present and analysis to determine tube support plate deflection during design basis accidents. Defects at the upper tube support plates are allowed when the bobbin coil voltage is less than 1.5V.

7.2.15. Fitness-For-Service Guidelines in Switzerland

The repair criteria used by the Swiss utility (NOK) is that all tubes with clear indications within the tubesheet, independent of their depth, will be sleeved and all tubes with indications outside the tubesheet and greater than 50% of the wall thickness will be plugged. Multifrequency bobbin coil eddy current equipment is used outside the tubesheet region and rotating pancake coil eddy current equipment is used for supplemental examination of indications within the tubesheet.

7.3. STATISTICAL METHODS FOR DEGRADATION GROWTH ASSESSMENT

This section summarizes the steps of an overall approach for estimating the rate 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 rate of degradation of steam generator tubes is influenced by a number of materials and environmental variables. One statistical technique used by some plant operators is 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 (Lipson and Sheth 1973) is

$$F(t) = 1 - \exp[-(t/t_r)^b]$$

where

$F(t)$ = cumulative fraction of tubes "failed" by a given degradation mechanism

t = time of operation using an appropriate time scale

t_r = 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 = 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 analyzed. 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 analyzed (Shah et al. 1992).

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

$$t_r = A\,\sigma^{m} \exp\left[Q/R\,(1/T - 1/T_o)\right]$$

where

t_r = characteristic time appropriate to a specific location
T = temperature for the specific location
σ = appropriate stress component for the location
m = constant describing the stress dependence of the degradation mechanism
Q = activation energy of the degradation mechanism
R = gas constant
T_o = temperature for a standard reference condition such as full power condition
A = constant determined from $t_{ro} = A\,\sigma_o^{-m}$, where t_{ro} is the characteristic time for reference condition T_o, σ_o.

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 (Gorman et al. 1991, Stein and McIlree 1986). The stress exponent value (m) is approximately 4 and is briefly discussed in Section 4.1.1. 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 24 represents the application of the Weibull model for an assessment of PWSCC damage to the hot-leg transition region of recirculating steam generator tubes. Tube inspection data from several plants for PWSCC failure in the hot-leg transition and rolled portion of the

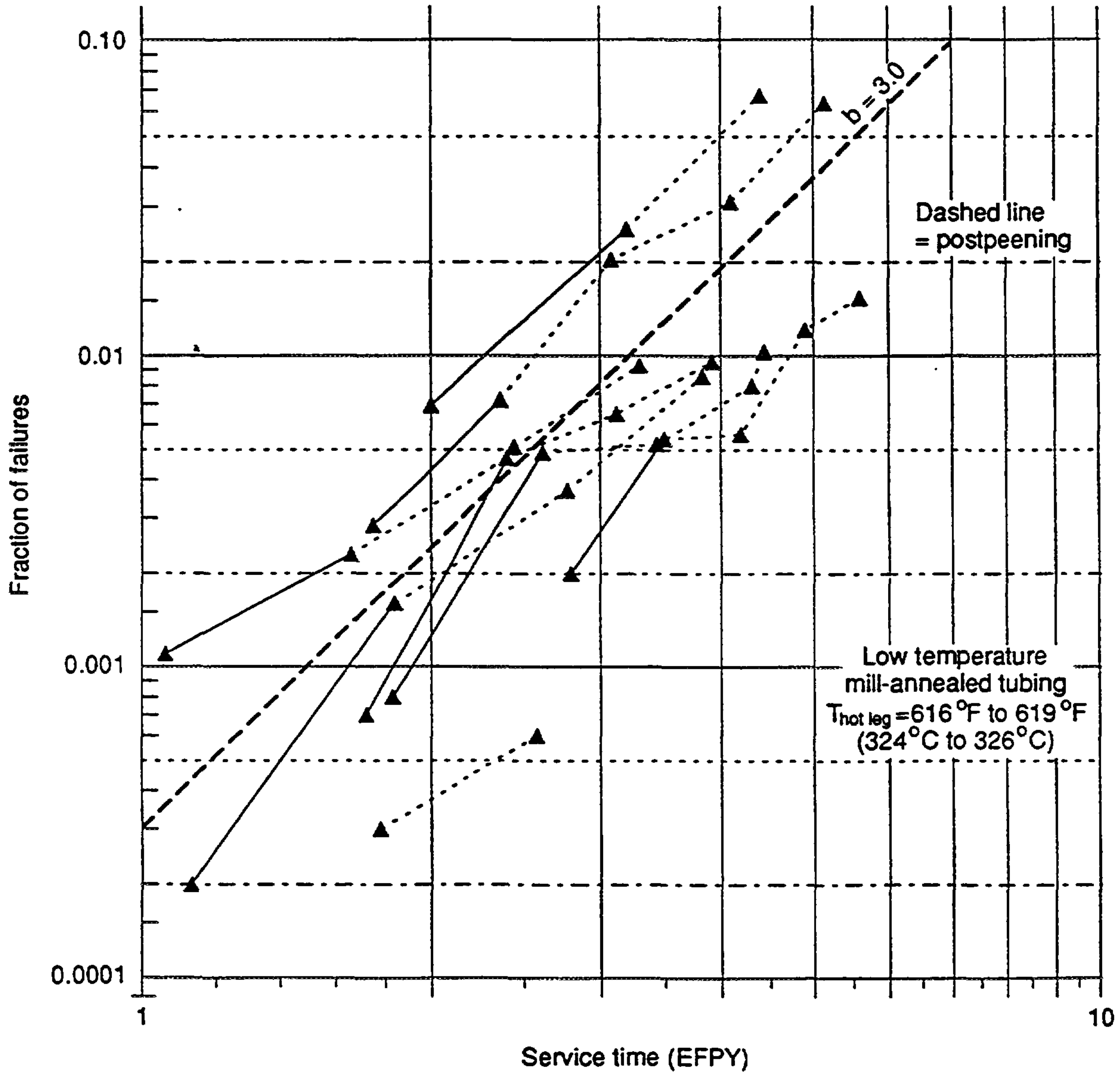


FIG. 24. Weibull analysis of data for PWSCC at hot-leg roll transitions and rolled area below the top of the tubesheet for plants with full depth rolls. (Courtesy of A. P. L. Turner, Dominion Engineering.)

tube near the top of the tubesheet have been compiled and plotted using a Weibull distribution. These plants use similar detection technologies and have similar low-temperature mill-annealed tubing material and primary water chemistry. Therefore all the tubes in all the plants are within the same PWSCC population. All the tubes are included in the analysis. The plots illustrate the scatter expected in plant inspection data for PWSCC degradation. The data for each plant lie approximately on a straight line, except where perturbed by application of peening as a remedial measure. Even though the intercepts and the slopes (Weibull exponents *b*) for each plot vary, the slopes scatter around the bold dashed line drawn for a Weibull exponent of 3.0. Therefore an exponent of 3.0 can be used to make short extrapolations to predict the future rate of degradation at a plant where insufficient data are available to establish a plant-specific slope. However, when looking at a Weibull plot of steam generator tubing failure data (or eddy current indications of defects) over a longer period of time, the slope tends to taper off and the rate of cracking is overpredicted when a slope of 3 is used. This has led some plant operators to use log-normal statistics for projections.

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 600 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 600 field experience.

7.4. 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. It has only been in the last few years that 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 (Marko and Cizelj 1992, Pitner et al. 1993).

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 (1) to quantify the influence of ageing management activities such as tubing inspection and plugging on the probability of steam generator tube rupture, (2) to compare various ageing management options, and (3) to limit the number of shutdowns caused by out-of-specification primary-to-secondary leakage (Pitner et al. 1993, Cizelj et al. 1996).

The key items required for a probabilistic fracture mechanics analysis are:

- a measured crack length distribution from the most recent tube bundle non-destructive examination,

- the 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,

- the probability of detecting a leak before the tube ruptures from laboratory experiments and the leak detection system sensitivity,

- the probability of tube rupture as a function of loading (i.e. the critical crack length) and,

- the uncertainties in various dimensions and material properties.

Examples of this type of information can be found in Pitner et al. 1993, Cizelj et al. 1995, and Cizelj et al. 1996.

Electricité de France 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:

1) the initial crack size distribution,
2) the change in the crack size distribution with time,
3) the 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 a 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 7.3 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 (Cizelj et al. 1996). 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.

8. STEAM GENERATOR MAINTENANCE: MITIGATION, REPAIR AND REPLACEMENT

This section discusses mitigation and repair techniques for degradation mechanisms in tubes, tubesheets, feedwater nozzles and shells. Sections 8.1, 8.2 and 8.3 cover mitigation and repair techniques for tubes. Table XXVI 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. Section 8.7 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 rotopeening or shot peening, 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 the hydrogen concentration in the PWR coolant helps mitigate PWSCC.

8.1.1 Rotopeening and Shot Peening

Both the shot and rotopeening 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. Rotopeening 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 nondestructive 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, but 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 rotopeening and shot peening create outside diameter tensile stresses which could possibly increase the susceptibility of the tubing to ODSCC. This is recognized 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 600 to PWSCC, particularly at the U-bends. Laboratory studies indicate that the use of in-situ stress relief techniques results in at least a factor of 10 increase in the time of PWSCC initiation. Stress relieving of Alloy 600 tubes in the 650–760°C range may cause sensitization

TABLE XXVI. COUNTERMEASURES FOR TUBE FAILURES IN PWR STEAM GENERATORS

Mechanism	Mitigation of damage in existing tubes	Improvements in new/replaced steam generators
Primary side stress corrosion cracking	Rotopeening or shot peening to residual stresses, stress relieving of the U-bends and control of the denting problem.	Alloy 690 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, and carbonates; flush tubesheet 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 690 tubes with an optimum microstructure, no tubesheet crevices, improved access for lancing and cleaning, increased blowdown capacity, and flow patterns that minimize sludge accumulation.
Pitting	Elimination of condenser leakages and ingress of air/oxygen, chlorides, and sulphates; removal of copper from the feedwater train.	Titanium or stainless steel condenser tubes, no copper alloys in the feed train, and corrosion resistant tube materials (Alloy 690).
Denting	Elimination of condenser leakages and ingress of air/oxygen and chlorides; use of hot soaks; removal of copper from the 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 hot blowdowns and flushing; preclusion of resin ingress.	Flow patterns that minimize hide-out and chemical concentrations and sludge formation; improved access for cleaning; increased blow-down 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 and corrosion fatigue in once-through steam generators	Control of the chemistry and entrained solid particle content of the secondary side coolant	

(formation of chromium depleted regions near grain boundaries) and susceptibility to secondary-side IGSCC/IGA; however, this may not be a concern for Alloy 600 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 RSG, or the top of the once-through steam generators, 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 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 outages 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.

8.2. SECONDARY-SIDE MITIGATION TECHNIQUES FOR TUBES

The actions which will slow down or prevent outside diameter stress corrosion cracking (IGSCC and IGA), pitting, and denting of the steam generator tubing are primarily those discussed in Section 5 above associated with control of the secondary coolant system 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 (Richards 1985, EPRI 1985). Another secondary side mitigation technique used on many of the older Westinghouse-type steam generators with tube-to-tubesheet crevices was full-depth or almost full-depth expansion (usually hydraulic expansion) of the tubes.

8.3. 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.

8.3.1. 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 tubesheet region because the current sleeving techniques are difficult or expensive to implement high up in a steam generator. More than 103 000 plugs are currently installed worldwide in PWR and CANDU plants (EPRI 1994). Plugs have typically been made from bar stock of Alloy 600 material; however, most currently installed plugs are made of Alloy 690 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 Fig. 25.

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.

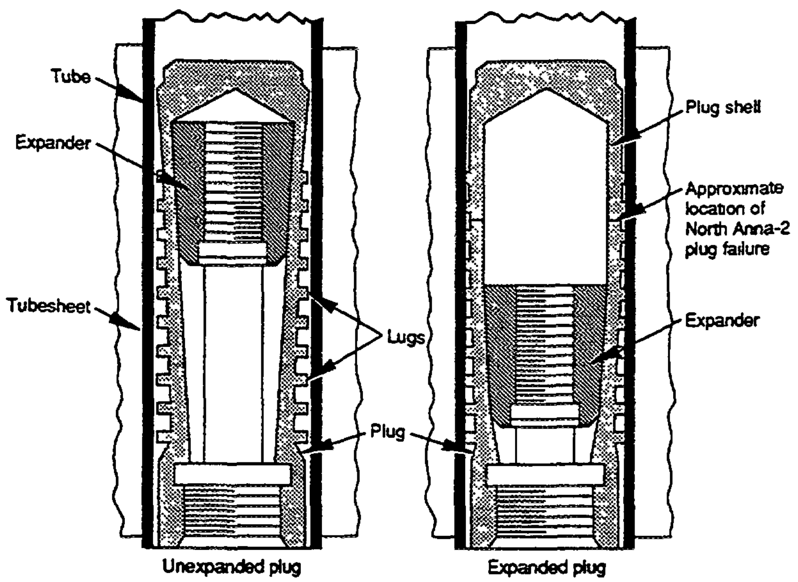


FIG. 25. Sketches of unexpanded and expanded mechanical plugs (Westinghouse 1989). Reprinted with permission.

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 corners. 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 (USNRC 1989b). 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 Fig. 26). 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.

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 (USNRC 1989a, USNRC 1990b). The plug involved was made with thermally treated Alloy 600 material. In this incident, circumferential PWSCC occurred nearly throughwall all around the circumference

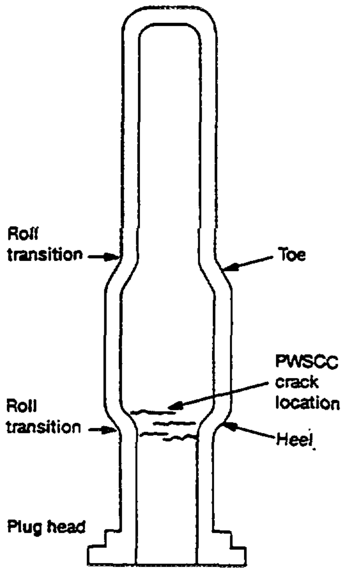


FIG. 26. PWSCC cracks in rolled plug supplied by Babcock & Wilcox (USNRC 1989b).

of a plug, as shown in Fig. 25 (Westinghouse 1989). 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 (USNRC 1991).

More than 3000 steam generator tubes in France have also been plugged with Alloy 600 mechanical plugs. Some of the plugged tubes have experienced a "boiler effect" due to throughwall 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 600 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 (Richards 1985). Also, the plugging of a very large number of tubes can impact the thermohydraulics 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.

8.3.2. 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 tubesheet 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 leaktight 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 (hardroll) expanded section centered within the hydraulically expanded section as shown in Fig. 27, making a leaktight or nearly leaktight mechanical joint. Residual and operating stresses in the lower hardroll transition, shown in Fig. 28, are likely to be the highest in the entire hybrid expanded joint. The upper joint of the sleeve is provided with an overlength 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 overlength 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 (a) 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, and (b) 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 Fig. 29. 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 tubesheet and sludge pile areas and there is sufficient overlength 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.

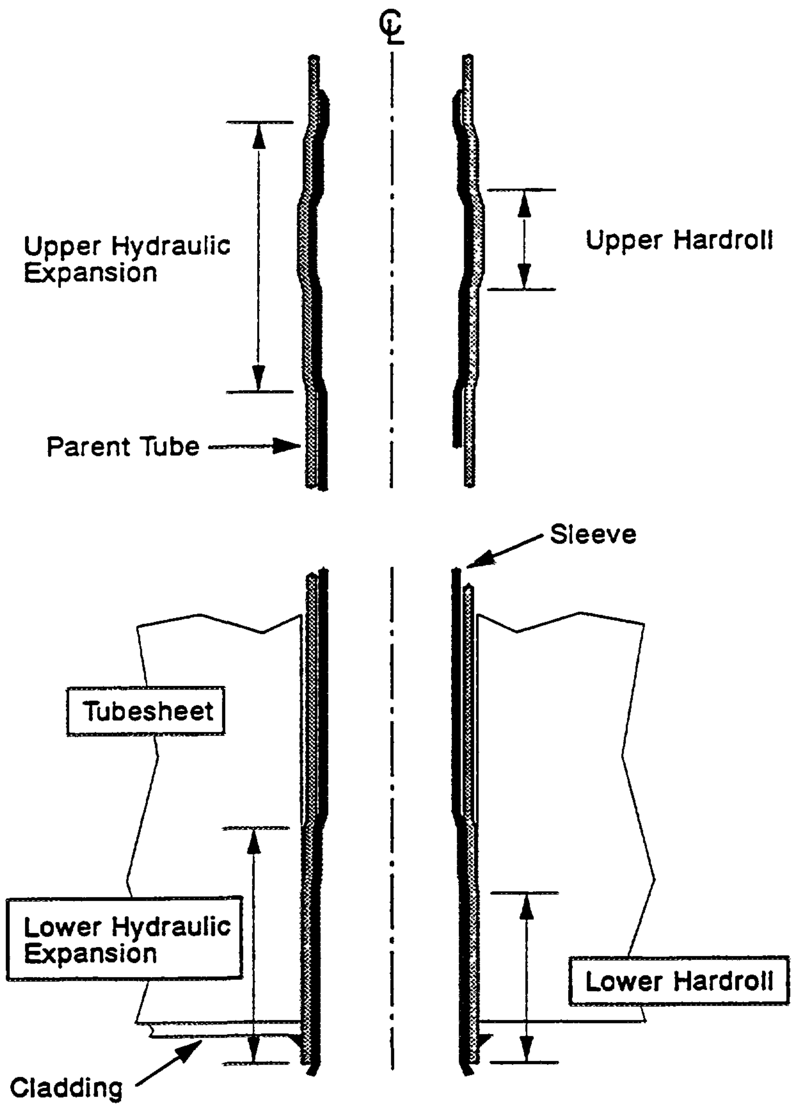


FIG. 27. Typical sleeve installation with a hybrid expanded joint (Westinghouse 1994). Copyright Westinghouse Electric Corporation; reprinted with permission.

Welded joints in free span areas of high-temperature plants (typical hot-leg temperature of about 327°C) with PWSCC susceptible 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 leaktight repair for degradation both at the top of the tubesheet and at tube support plate elevations; these were referred to as "kinetic" 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

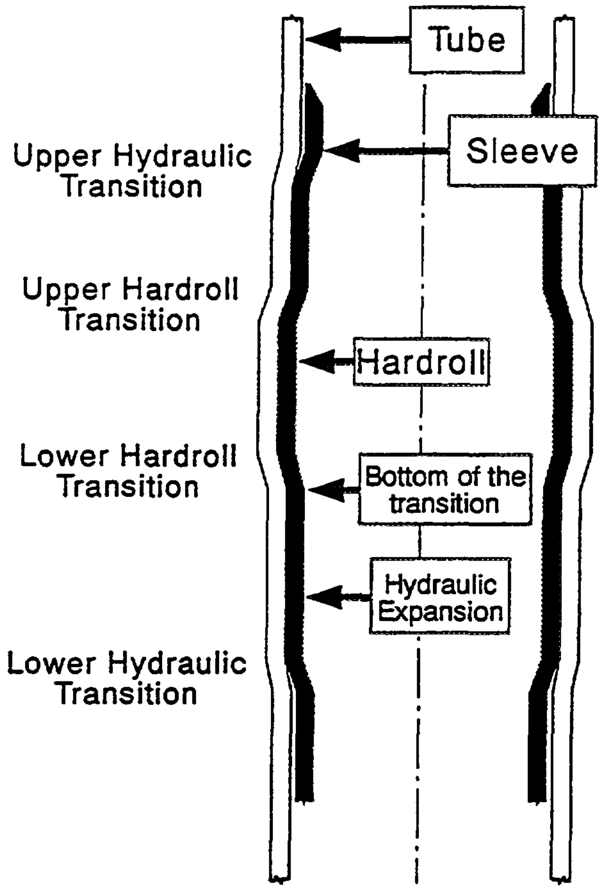


FIG. 28. Hybrid expansion joint configuration (Westinghouse 1994). Copyright Westinghouse Electric Corporation; reprinted with permission.

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 buildup).

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 minisleeve shown in Fig. 30; 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 tubesheet, 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.

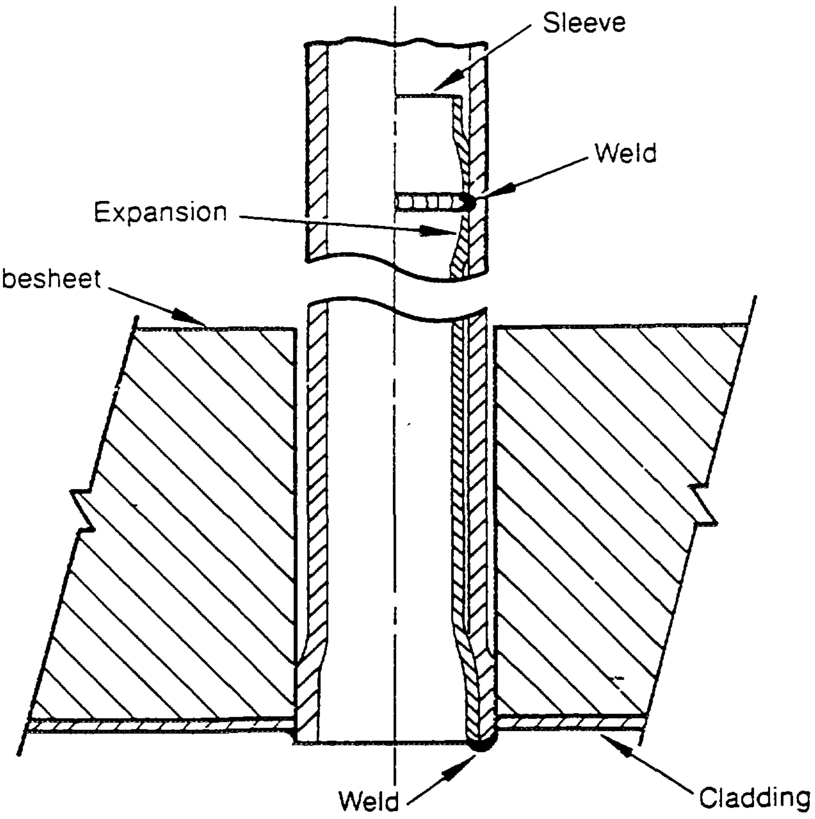


FIG. 29. Welded sleeve design (Combustion Engineering) (EPRI 1985). Copyright Electric Power Research Institute; reprinted with permission (modified).

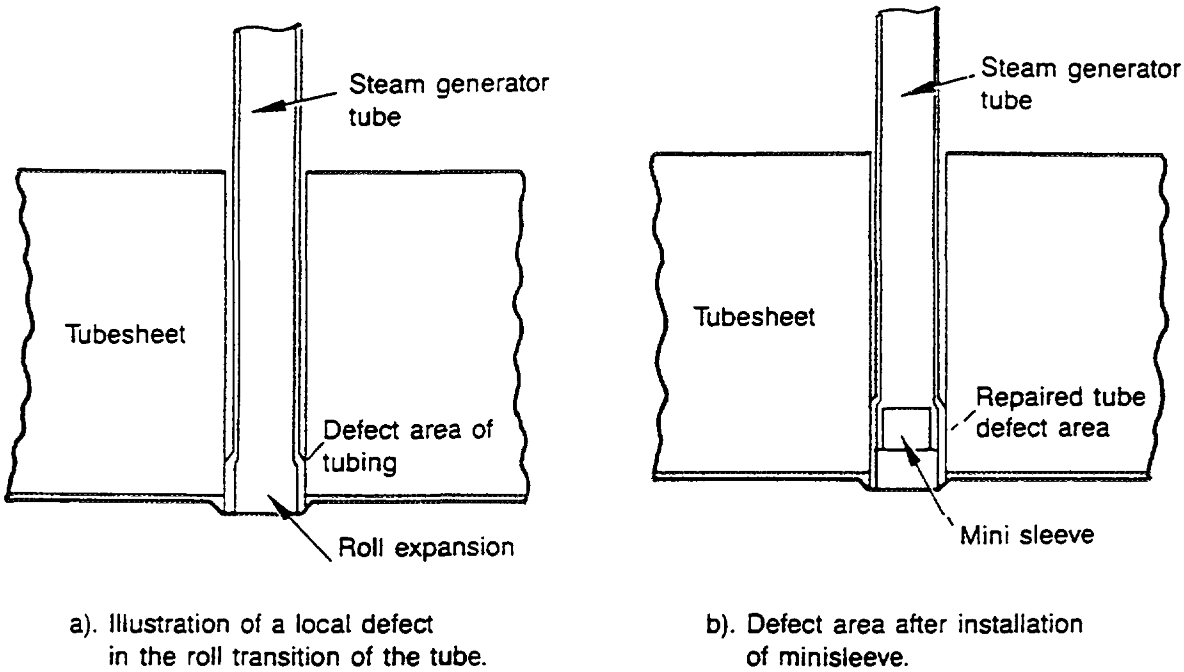


FIG. 30. The minisleeve design (Babcock & Wilcox) using explosive welding (Gorman and Mundis 1983). Copyright Electric Power Research Institute; reprinted with permission.

Service experience with the almost 100 000 sleeves installed worldwide has generally been good. However, some parent tubes at 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 minisleeves 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 throughwall cracking at the welded sleeve joints and the sleeves collapsed. At another plant, the defective welds 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 refueling 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, throughwall circumferential crack which initiated at the inside diameter (PWSCC). Removal and examination of another sleeved tube also showed a 90% to 100% throughwall 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 hardroll 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 hardroll 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 mockups 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 mockups 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).

8.3.3. 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 in the last eight years. All these tubes, except the first few, are still in service, whereas unplatted 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 [Dodd 1988].

8.4. VIBRATION CONTROL

8.4.1. 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 crossflow 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 [Hofmann et al. 1986, Sudduth 1986]. The Krško 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.

8.4.2. 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.

8.5. 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).

8.6. 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

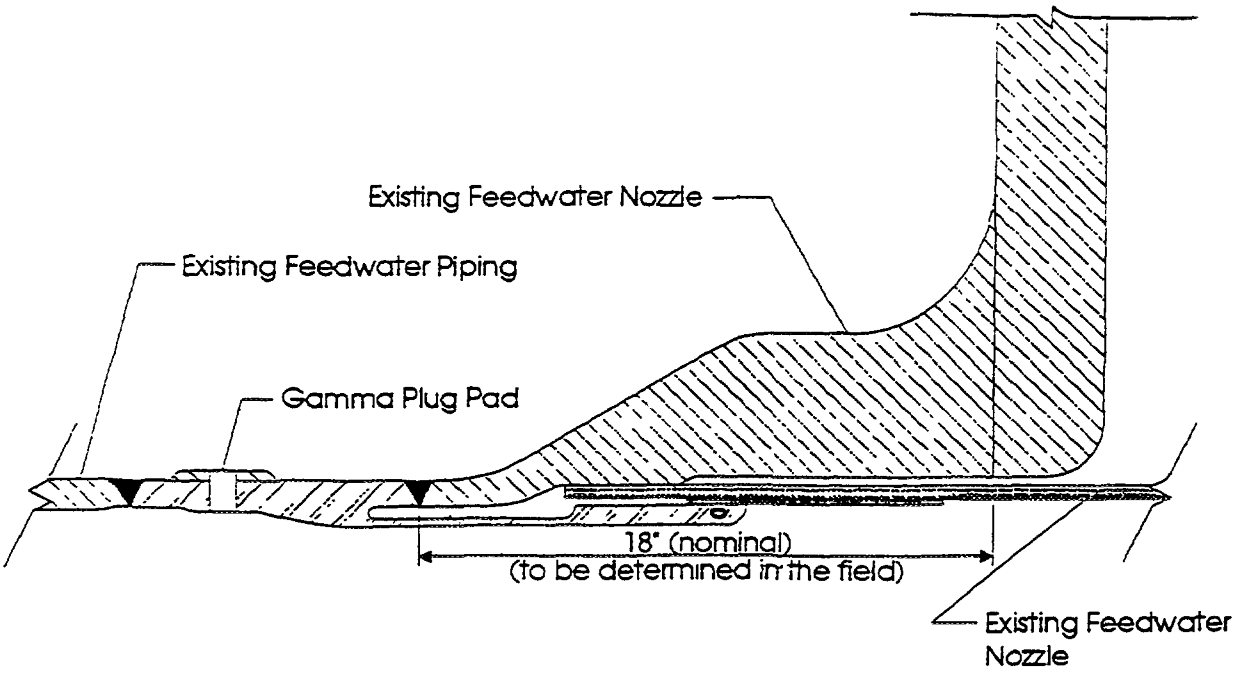


FIG. 31. Schematic diagram of tuning fork repair used in feedwater nozzles (From Cofie et al. 1994). Copyright American Society of Mechanical Engineers; reprinted with permission.

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 [Stoller 1990].

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 Fig. 12b. 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.

At Diablo Canyon Unit 1, erosion-corrosion of the outside surface of the carbon steel thermal sleeve caused thinning of the sleeve [NRC Information Notice 92-21, 1992]. 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 (Section 4.5.4). Thermal sleeves are being repaired with a new tuning fork design, shown schematically in Fig. 31. 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 [Burns 1994]. There is a region of stagnated water in the gap between sleeve and nozzle, but no flow [Cofie et al. 1994]. Several plants have also replaced the affected portion of the piping adjacent to the feedwater nozzle.

8.7. 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 tubesheet and shell structures.

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 prestressed concrete containments. The replacement of PWR steam generators also introduces difficulties in fitup 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 tubesheet 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.

8.7.1. 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 Tables I through IV) 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 in 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

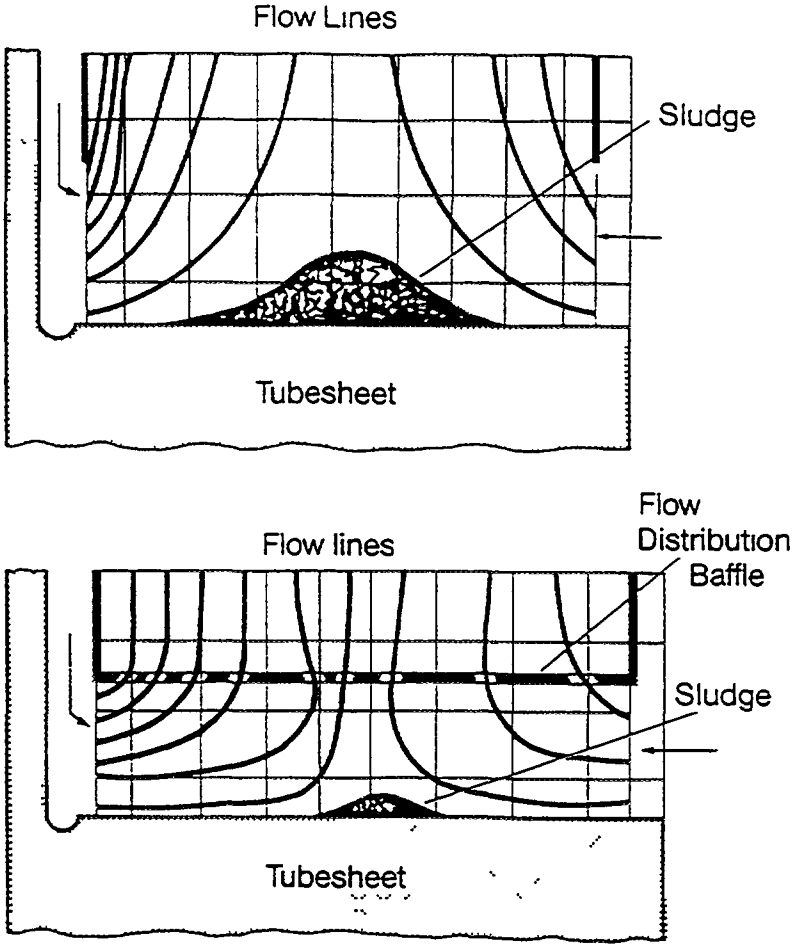


FIG. 32 Flow distribution baffle to increase the velocity above tubesheet, minimize the flow stagnation zones, and minimize deposits on tubesheet (Courtesy of P J Meyer, Siemens A G.)

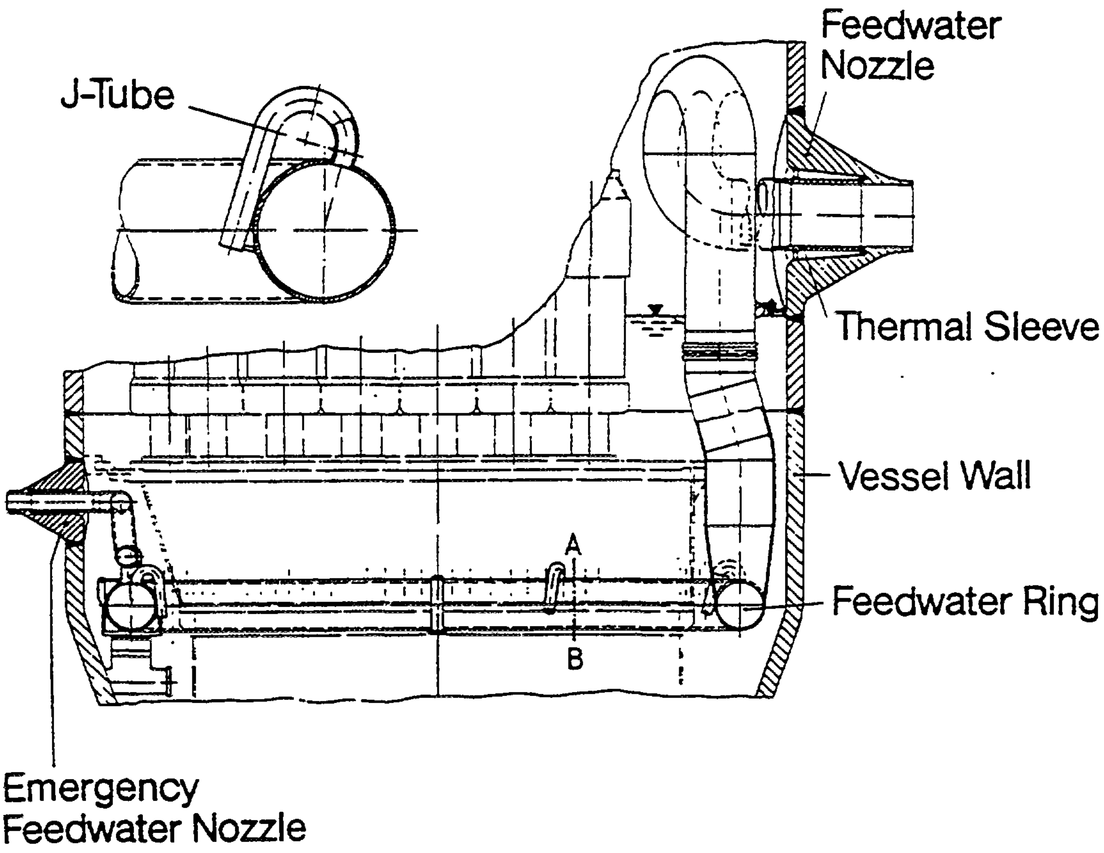


FIG. 33. Siemens/KWU feedwater distribution system with an antistratification loop. (Courtesy of P. J. Meyer, Siemens AG.)

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, trifoil, and eggcrate designs) prevent fluid and impurity stagnation in the tube/tubesheet annuli. Finally, new tube/tubesheet 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 800M tubing is being used in Belgium, Canada, Germany, and Spain. The tube-support structures in new steam generators are now being fabricated with 12% chromium ferrotic 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 tubesheet at a velocity sufficient to minimize sludge deposition on the tubesheet (Fig. 32); 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 (Fig. 33); 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 tubesheet 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.

8.7.2. CANDU Replacement Designs

The current design of steam generators for CANDU units has stabilized Alloy 800M 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.

8.7.3. WWER Replacement Designs

As mentioned in Section 2.4, the WWER-1000U steam generator has been designed to replace the original WWER-1000 steam generators as needed. The WWER-1000U has the perforated areas of the collectors fabricated from titanium-stabilized austenitic stainless steel (the same steel used for the tubes and the WWER-440 collectors), somewhat fewer tubes (9157 versus 11 000), and a somewhat larger specific heat flux. The WWER-1000U design details are listed in Table IV.

9. STEAM GENERATOR AGEING MANAGEMENT PROGRAMME

The information presented in this 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 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 Fig. 34 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 Practice "Implementation and Review of Nuclear Power Plant Ageing Management Programme."

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 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);

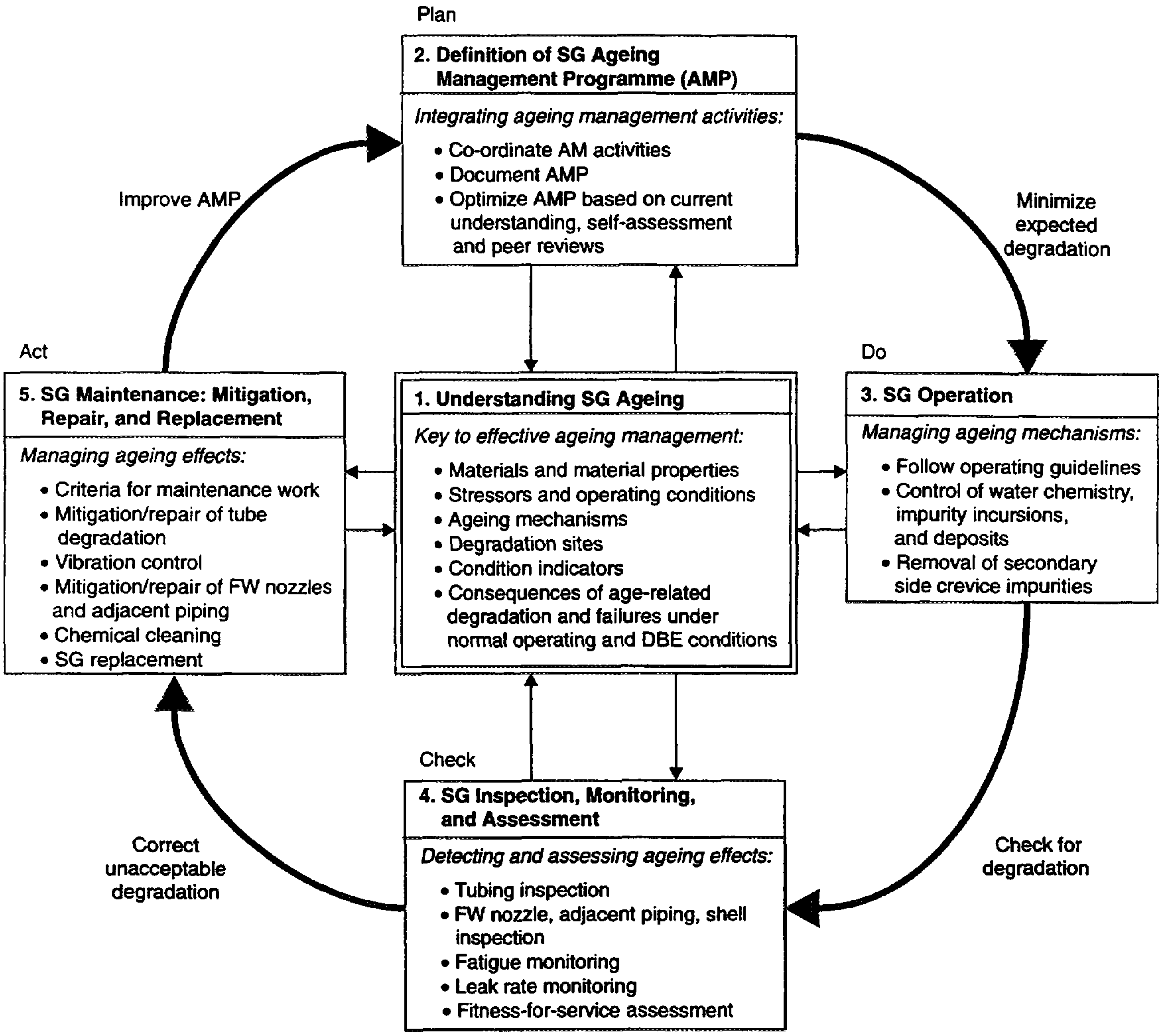


FIG. 34. Key elements of steam generator ageing management programme (AMP) and their interfaces. Based on Plan-Do-Check-Act elements.

- 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); and
- 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 ongoing 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 Fig. 34.

9.1. 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 AMP, managing ageing mechanisms through prudent operating procedures and practices; detecting and assessing ageing effects through effective and practical inspection, monitoring and assessment methods; and managing ageing effects using proven maintenance methods. This understanding consists of a knowledge of steam generator materials and material properties, stressors and operating conditions, likely degradation sites and ageing mechanisms, condition 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.

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 (a) steam generators of similar design, materials of construction and fabrication; (b) steam generators operated under similar water chemistry or with similar tube alloy material, even if the steam generator designs are different; and (c) 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 TECDOC is a source of such information. However, this information has to be kept current using feedback mechanisms provided, for example, by owners' groups. External experience can also be used when considering the most appropriate inspection method, maintenance procedure and tooling.

9.2. DEFINITION OF STEAM GENERATOR AMP

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.

9.3. STEAM GENERATOR OPERATION

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 coolant 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 (a) one or more amines to maintain cycle pH, (b) moderate to high concentrations of hydrazine to maintain a reducing environment and scavenge small amounts of dissolved oxygen, and (c) 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, makeup 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 of the condensate polishing system, recycling of the blowdown water, lead contamination and removal of copper from the secondary coolant system. The condenser must be essentially leaktight 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 corrodents. They need to be used with care. 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 coolant system 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 tubesheet and tube-to-tube support plate crevices, the sludge pile, and under freespan crud (bridging) deposits. Steam generator hot soaks and flushes 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 can be used whenever possible when the steam generator is in a shutdown condition. The feedwater pH should be between 8.8 and 9.2 for plants with copper alloys and above 9.3 for all ferrous plants. The blowdown system should continuously remove and clean about 1% of the main steaming rate, and up to 7% of the main steaming rate during short transients. And, maybe most importantly, sludge lancing should be performed periodically to remove hard crud.

9.4. INSPECTION, MONITORING AND ASSESSMENT

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.

9.4.1. Inspection and Monitoring

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.

9.4.2. Assessment

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 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.

(1) 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 7.1.1.

(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 7.1.2.

(3) 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 Section 7.4.

9.5. MAINTENANCE: MITIGATION, REPAIR AND REPLACEMENT

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 rotopeening, 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 molar ratio control, chemical cleaning, and ultimately steam generator replacement.

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ABBREVIATIONS

AMP	ageing management programme
AVB	antivibration bar
ASME	American Society of Mechanical Engineers
BWR	boiling water reactor
CANDU	Canada deuterium-uranium reactor
EDF	Électricité de France
EFPY	effective full power years
EPRI	Electric Power Research Institute
IGA	outside diameter intergranular attack
IGSCC	outside diameter intergranular stress corrosion cracking
ISI	in-service inspection
MRPC	multifrequency rotating pancake coil
NUSS	IAEA Nuclear Safety Standards
ODSSC	outside diameter stress corrosion cracking
PWR	pressurized water reactor
PWSSC	primary water stress corrosion cracking
RSG	recirculating steam generator
WWER	water cooled energy reactor

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