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Engineering Report Cover Sheet

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Indian Point 3 Steam Generator Program

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Revision Summary

Rev. No.	Description	Changes
5	Major revision	Incorporation of revision 6 of the EPRI PWR SG Examination Guidelines 3R12 steam generator maintenance inspection results Changes to the long-term steam generator maintenance and inspection plan Deletion of the appendix with the eddy current data analysis guidelines Added discussion of plant uprate Added results of SG tubing structural limit calculations Reformatted the report to meet engineering report standards; because of the major reorganization, revision bars are not shown.
6	Minor revision	Adds statements in various sections that SGMP interim guidance letters will be followed in addition to EPRI guidelines. Adds current interim guidance letters to References section. Deletes references to Appendix A that was deleted in Revision 5.
7	Minor revision	Updated wording in Section 4.3 to be consistent with EPRI guidelines and operations procedures on primary-to-secondary leakage. Updated SG tube structural limits in Section 5.5 for stretch power uprate.
8	Major Revision for new Technical Specification requirements and results from 3R14	

Table of Contents

1. Purpose

The purpose of this report is to document the implementation of the steam generator program at Indian Point 3 (IP3). The purpose of the steam generator program is to maintain the steam generators in optimal condition to assure their continued operation until the end of plant life and to support plant life extension.

The SG program formalizes and integrates the various inspections, maintenance, chemistry and operational activities performed on the steam generators and provides the basis for making strategic decisions to optimize steam generator reliability and performance.

The elements of the steam generator program consist of the following: degradation assessments, inspections, maintenance and repairs, tube integrity assessments, chemistry control and initiatives and reporting. This program is structured following the guidance given in the Nuclear Energy Institute's Steam Generator Program Guidelines (NEI-97-06) and its referenced documents. This program report is updated as necessary to remain current with inspection information and as required by Steam Generator Management Project (SGMP) administrative documents.

2. Background

2.1. Steam Generator Design Information

The original Westinghouse Model 44 steam generators (SGs) at IP3 were replaced in 1989 with Westinghouse Model 44F SGs, with a nominal 43,467 square feet of heat transfer area. Each steam generator contains 3214 thermally treated U-tubes fabricated from Alloy 690 (ASME-SB-163 Alloy UNS N06690 to Code Case N-20). There are 46 fewer tubes than the 3260 in the original SGs for two reasons. The tube support stay rods were relocated from the periphery to the middle of the tube bundle and quatrefoil tube openings in the tube support plates required elimination of some peripheral tubes to maintain a minimum ligament thickness around the holes.

The nominal OD of each tube is 0.875 in. and the nominal tube wall is 0.050 in. thick. During assembly, the ends of the tubes were expanded in the tubesheet with a urethane plug and then seal welded to the cladding on the primary side of the tubesheet. The seal welds were checked with helium, reworked if necessary and then the tubes were hydraulically expanded the full depth of the tubesheet to within 0.25 inches of the secondary face.

The U-bend bending process was tightly controlled to maintain very tight tube ovality specifications of less than 3 percent. The low ovality specification allowed for thicker anti vibration bars (AVBs) and tighter gaps between the tubes and the AVBs than the original SGs. The tube centerline radii of the U-bends range from 2.19 to 56.50 inches for rows 1 and 45 respectively. The first eight rows of tubes were heat treated after the tube bending process to relieve residual stresses in the tubing.

The tubes are supported on the primary side by the tubesheet. The tubesheet is a low alloy steel (ASME-SA-508 Class 3) forging with a minimum thickness of 21.81 inches. That portion of the

tubesheet primary side in direct contact with the primary coolant is clad with weld deposited Ni-Cr-Fe alloy (SFA5.14 Cl. ERNiCr-3/SFA 5.11 Cl. ENiFe-3) to a minimum depth of 0.150 inches.

The tubes are supported on the secondary side by six 1.125" thick tube support plates (TSP). The tube support plate material is stainless steel (ASME-SA-240 Type 405). The holes where the tubes pass through the tube support plates are quatrefoil shaped produced by broaching. The lower 5 TSPs have 6 flow slots down the tube lane 14.22 inches long by 1.75 inches wide. These slots are narrower than the original SGs. The top TSP has two rows of 90 circular holes 0.883 inches in diameter down the tube lane to provide additional stiffness to the TSP.

A flow distribution baffle (FDB), located between the lowest tube support plate and the tubesheet, was designed to minimize the number of tubes exposed to low velocity flow in the vicinity of the tubesheet. The FDB material is stainless steel (ASME-SA-240 Type 405) 0.75" thick and has a circular cutout in the center approximately 34 inches in diameter. This FDB design controls the cross-flow velocity so that the low velocity region (and sludge deposition zone) is located at the center of the tube bundle, near the blowdown intake. The holes where the tubes pass through the FDB are octafoil shaped. The octafoil shape was chosen to minimize the deposition of corrosion products between the FDB and the tubing. Earlier Model 44F replacement steam generators (RSGs) used drilled holes in the FDB and the cutout was about 60 inches in diameter.

Three sets of anti-vibration bar (AVB) assemblies stiffen the tube bundle in the U-bend region and restrain tube vibration. This is one more set than previous Model 44 F RSGs and provides shorter distances between AVB/tube contact points. The V-shaped AVB assemblies also maintain proper tube spacing and alignment in the U-bend region. The first set of AVB assemblies is installed into the U-bend to a depth supporting the apex of the U-bend centerline of the ninth row U-tubes and has an included angle of 147 degrees. U-tubes 1 through 8 do not require AVB support. The remaining two sets of AVB assemblies are installed to depths supporting the U-bend apexes of the fourteenth and twenty-fifth row U-tubes with included angles of 111 and 67 degrees respectively. The AVB material is 405 stainless steel with a cross-section of 0.690 by 0.354 inches. Stainless steel provides lower tube wear rates than the chrome plated Alloy 600 square bars used in earlier model 44F replacement SGs. The design specifications are detailed in D-Spec 408A21, Rev. 4, "Model 44F Replacement Steam Generator provided by Westinghouse".

These units were constructed in accordance with the 1983 ASME Boiler and Pressure Vessel Code, Section III, through the Summer 1984 addenda. The code stress report for the replacement steam generators is documented in Westinghouse report WNEP-8805 and conforms with the 1965 ASME Code, through the Summer 1966 Addenda which was the design code.

2.2. Plant History

Indian Point 3 started commercial operation in August 1976. The original steam generators had numerous degradation issues and in 1989 the replacement steam generators were installed. Activities that are significant with regard to the maintenance of the steam generators are outlined below. Since the steam generators were replaced in 1989, all information previous to that date is given for historical information only. Any mention made in this report to steam generators refers to the replacement generators unless the term original steam generator is used.

1976	Began commercial operation utilizing AVT chemistry (ammonia/hydrazine). Phosphate chemistry was never used at IP3.
1982	The MSR tubing was replaced with stainless steel tubing. 2971 steam generator tubes were sleeved due to sludge pile pitting.
1985	The brass feedwater heater tubing was replaced with stainless steel tubing. The brass tubing in the main condenser was replaced with titanium tubing and a titanium tube sheet.
1986	Installed a full flow condensate polishing facility.
1987	Installed a blowdown recovery system with demineralization rated at 250 gpm total flow. Installed ultrafiltration system on the effluent of the water treatment system to reduce organics.
1989	Replaced the steam generators with Westinghouse Model 44Fs. SG blowdown pipe size for 31 and 34 SGs was increased to allow higher blowdown flowrates s overboard (not utilized). Replaced the brass gland steam exhaust and air ejector condensers with stainless steel ones. Replaced ammonia chemistry with morpholine and increased hydrazine concentration to > 200 ppb. Boric acid added to secondary as proactive measure against stress corrosion cracking. Condensate polisher operated in partial flow (about 30% of condensate flow) to support morpholine chemistry.
1990	Steam generator 34 hot leg channel head and tubesheet impacted by a fuel assembly alignment pin from the reactor upper internals (see Section 3.11 for a more detailed description of the event).
1998	Changed secondary chemistry from morpholine to ethanolamine (ETA) to further reduce iron transport to the SGs. Condensate polisher bypassed except during startups.
1999	Steam generator boric acid concentration reduced from a range of 5 to 10 ppm to 3 to 5 ppm.
1999	Nominal steam generator blowdown flow reduced from 200 to 150 gpm (total) to improve thermal efficiency.
1999	During 3R10 significant BOP pipe replacement was made to a more resistant material. This lead to a drop in feedwater iron concentration in the following cycles.
2000	Secondary chemistry changes were made in November. The feedwater hydrazine concentration was reduced to 100 to 150 ppb with a minimum of 40 times the condensate dissolved oxygen concentration. In addition, boric acid injection to the steam generators was terminated to evaluate effects on iron transport.
2000	A contractor water treatment system was installed that uses a combination of EDI, RO, IX and UF. The existing in-house system was retired in place.
2001	The steam generator tube inspection program was changed from prescriptive to performance based under revision 5 of the EPRI PWR SG Examination Guidelines. Based on this change, eddy current inspections were not required or performed in 3R11.
2002	The plant output was uprated by 1.4% with virtually no change in

	operating temperatures.
2003	The steam generator inspection program adopted revision 6 of the EPRI PWR SG examination guidelines and shifted the program from performance back to prescriptive based.
2005	The HP turbine and MSR internals were replaced to support a stretch power uprate of 4.8%.
2007	Implemented new Technical Specification requirements consistent with TSTF-449, Rev. 4, "Steam Generator Tube Integrity" License Amendment 233

2.3. Sludge Lance History

Sludge lancing was performed on all four steam generators every refueling outage from replacement through 3R11 in 2001. The objective is to remove as much sludge as possible to minimize the potential for corrosion in the sludge pile. Historically, both the flow distribution baffle and the tubesheet in each steam generator have been sludge lanced.

In 3R11, a high volume bundle flush was performed in all 4 SGs prior to sludge lancing. This process recirculated demineralized water from the bottom of the SG and sprayed the water over the tubes and support plates at approximately 2000 GPM. This process washed loose deposits from the tubes and support plates down to the tubesheet where it was removed by sludge lancing. The sludge lance process was modified by using a rail mounted lance operating at 2500-3000 psig versus the historical 2000 psig and the suction return was taken from the 90 degree hand holes. When taking into account the reduction of iron transport to the SGs, the amount of sludge removed appeared to be about half from the tubesheet and half from the upper surfaces of the SGs. Unfortunately, the rail lance used unknowingly rubbed against some row 1 tubes causing measurable wear in 8 of the tubes. This was not discovered until eddy current examinations performed in 3R12.

In-bundle top of tubesheet inspections over the course of time have revealed the gradual buildup up hard deposits at the base of some tubes. These deposits were predominantly under the cutout of the flow distribution baffle with the majority on the hot leg side. In 3R12 a new cleaning process was employed in 33 and 34 SGs in an attempt to reduce the buildup of hard sludge deposits in the central or "kidney" region of the SGs. The original plan was to soak the top of the tubesheet with an advanced scale-conditioning agent (ASCA) followed by an application of ultra sonic energy cleaning (UEC). After the UEC process the tubesheet was to be soaked with a copper rinse agent and then conventional sludge lancing would be performed to removed the weakened deposits. The UEC could not be performed due to unforeseen required plant conditions so that portion of the process was de-scoped. The schedule did not support cleaning of 31 and 32 SGs.

The chemical soak followed by sludge lancing in 3R12 had very little effect on the hard deposits. The chemicals did have the effect of dissolving about 1 pound of copper per SG from the sludge.

No secondary side cleanings or visual inspections were performed in 3R13. In preparation for SG maintenance activities scheduled for 3R14, different secondary cleaning methods were evaluated. In addition to the hard sludge previously observed, there was a concern for large numbers of small foreign objects on the tubesheet as a result of the major modifications performed on balance of plant equipment to support the stretch power uprate. This material was

observed in the IP2 replacement SGs the year before following a similar uprate. Due to budget constraints, the use of the CECIL high pressure lance was not possible so the SG management team decided to allot additional sludge lancing time for each SG. In addition, a new sludge lance nozzle block was used that had two jets (aka scale buster) in combination with the conventional nozzle block featuring eight water jets. This was successful in removing most of the foreign objects and all of the loose sludge. This combination of lancing was not successful at removing the hard sludge. The flow distribution baffle was not lanced because there has historically been very little deposits at this location.

The number of sludge lance passes made each outage is listed in the table below.

Number of Sludge Lance Passes[1] by Outage			
RFO	Year	Passes on flow distribution baffle (FDB)	Passes on tubesheet (TS)
3R07	1990	6	6
3R08	1992	4	6
3R09	1997	4	6
3R10	1999	2	6
3R11	2001	2	6
3R12	2003	Not performed	6 (33/34 SGs only)
3R13	2005	Not Performed	Not Performed
3R14	2007	Not Performed	6 (31 SG) 8 (32-34 SGs)[2]

Notes: (1) The sludge lance equipment can not go past the center of the steam generator because of the center stay rod. A sludge lance pass covers the area from the handhole to the center of the SG and a coverage is defined as completion of two passes.
(2) Two of the passes utilized a two-nozzle lance head (scale buster) in each SG to facilitate foreign object removal

The amount of sludge removed each outage is quantified and the results are tabulated below. More detailed information is contained in the Westinghouse outage reports.

Historical Sludge Removal Data (pounds) by Outage						
RFO	Year	SG 31	SG 32	SG 33	SG 34	Total
3R07	1990	42	43	31	39	156
3R08	1992	56	76	74	76	282
3R09	1997	50	63	55	55	223
3R10	1999	62	56	70	57	245
3R11	2001	106		103		209
3R12	2003	Not performed		55	25	80
3R13	2005	Not Performed		Not Performed		n/a
3R14	2007	56.2	81.5	43.5	41.5	222.7

During sludge lancing, samples of the sludge from each steam generator are collected and analyzed for form and content. The samples collected during 3RFO12 in 2003 were not analyzed because the deposits were treated with chemicals that dissolved some of the iron and copper so the results would not be comparable with previous samples. Detailed results are presented in the individual sludge analysis reports listed in the references section. Of primary concern to IP3 is the amount of copper and iron present in the sludge so those results are tabulated below. The results for 3R14 were not available at the time this report was revised.

Percent of Iron Oxide in Sludge Removed from the SGs						
RFO	Year	SG 31	SG 32	SG 33	SG 34	Avg
7	1990	68	76	51	77	68
8	1992	87	58	66	50	65
9	1997	57	44	60	57	55
10	1999	93	91	88	92	91
11	2001	91.75		83.86		88
12	2003	Sludge lancing not performed – no samples taken		Not analyzed due to application of ASCA chemical agents		n/a
13	2005	Sludge lancing not performed – no samples taken				n/a
14	2007					

Percent of Elemental Copper Removed from the SGs						
RFO	Year	SG 31	SG 32	SG 33	SG 34	Avg
7	1990	28.5	20.2	45.0	19.0	28
8	1992	10.5	38.3	31.2	46.3	32
9	1997	32	41	28	33	36
10	1999	5.9	8.4	11	7.2	8.1
11	2001	6.54		14.46		10.5
12	2003	Sludge lancing not performed – no samples		Not analyzed due to application of ASCA chemical agents		n/a
13	2005	Sludge lancing not performed – no samples				n/a
14	2005					

Note: Sludge analysis for 3R14 in progress at the time of this revision

Steam Generator Sludge Analysis Summary

	3R07	3R08	3R09	3R 10	3R11	3R12	3R13	3R14
Powder Magnetite (% Fe3O4)	68	65	55	91	88	Analyses not performed	Sludge Lancing not performed	
Powder Copper (%)	28	32	36	8.1	10.5			
Powder Copper Oxide (%)	ND	ND	6	ND	ND			
Powder Lead (%)				.006	0.02			
Sludge Collar Magnetite (%)				75	26			
Sludge Collar Copper (%)				25	14			
Sludge Collar Lead (%)				.08	.07			
Scale Magnetite (%)				99	92			
Scale Copper (%)				<1	.9			

Copper oxide has been shown to increase the risk of corrosion in steam generators. Prior to SG replacement all the copper bearing components in the secondary system were replaced with ferrous materials. Copper was expected in the steam generators in the outages following SG replacement with the source being the piping surfaces that were plated with copper from years of exposure to corrosion products from the copper bearing components. The copper concentration in the sludge was expected to drop with each succeeding outage but this trend was not seen until the fourth outage after replacement. The experience is comparable to experience at the H.B. Robinson plant. The copper in the sludge has been in the elemental state each refueling outage

except for a small amount of copper oxide found in 3R09 samples as described in the next paragraph. IP3 maintains a reducing environment in the steam generators by using hydrazine concentrations at least 20 times greater than the condensate dissolved oxygen concentration during plant operation and by minimizing the time the steam generator secondary side is exposed to oxygen during maintenance conditions.

Sludge samples taken during R-9 did have measurable copper oxide concentrations in the range of 3 to 6 w%. The reason for the copper oxide is unknown. One possibility is the oxidation of the copper during the extended shutdown that occurred during cycle 9. Sludge samples from 3R10 and 3R11 had no detectable copper oxide so results from 3R09 are considered an anomaly.

To further quantify the extent of copper in the steam generators, the samples from 3R10 were segregated in to powder, tube scale and tube collars. It was determined that the copper in the tube scale was less than 1 percent by weight. Sludge collars are hard deposits covering about 20% of the top of tube sheet. The sludge collars contained about 20 to 30% copper. The copper was in the elemental form and not considered a concern because of the reducing environment maintained in the steam generators.

Lead has been implicated as an initiator of stress corrosion cracking in alloy 600TT in the field and alloy 690TT in the laboratory. Analysis of lead in sludge samples is difficult and the results are frequently suspect. Typically, lead levels in the powdered sludge are about 100 ppm. During the sludge collar analysis on 3R10 samples lead was found at concentrations ranging from 800 to 1600 ppm. Based on industry experience, these levels are not considered detrimental to the steam generator tubing.

2.4. History of Tube Plugging and Tube Sleeving

During SG fabrication two tubes were plugged in 34 SG due to ding indications at row 44, col 57 and row 45, col 52. Both ends of each of these tubes were plugged with a welded tapered tube plug fabricated from Alloy 600 material that was given an additional special heat treat by Westinghouse to optimize the plug material microstructure.

No inservice tube plugging was performed until 3R12 in 2003 when 13 tubes were administratively plugged for one of 3 reasons. One tube had a permeability variation that reduced the sensitivity of eddy current to identify potential degradation. Three tubes had small volumetric indications between 15 and 23% through wall (TW) at the top of the tubesheet that were attributed to loose part wear when identified in 1999. However no foreign objects were found that could be linked to the degradation so the tubes were administratively plugged in 2003 because the cause could not be reasonably ascertained. The remaining 9 tubes were plugged administratively after detecting wear scars that were attributed to contact with the sludge lance rail system used for the first and only time in 2001. The wear scars had lengths ranging from 0.6 to 2.45 inches and depths initially ranging from 20 to 47% that were later re-evaluated to be 8 to 26% TW. The tubes were plugged because the degradation was not anticipated and the appropriateness of the sizing technique was in question at the time of the inspection. The tubes plugged in 3R12 are listed in the table below.

In 3R14, two tubes were preventatively plugged due to the presence of a wedged metallic object in 31 SG. The tubes were evaluated for potential stabilization which was determined as unnecessary due to the limited circumferential contact with the foreign object.

No tube sleeving has been performed or planned until the advent of a degradation mechanism that affects numerous tubes that makes the process economical or plugging would force the plant to derate its output capacity. Currently, the SGs have excess thermal capacity on the order of 10%.

Tube Plugging List from 3R12

SG	Tube	Location	Indication	Degradation Depth Percent TW
31	R28 C29	-4.96 to 5.04	PVN	n/a
32	R41 C28	TSH +0.15	VOL	34%
32	R40 C29	TSH +0.0	VOL	32%
32	R41 C29	TSH +0.05	VOL	24%
32	R1 C85	TSH +16.70	VOL	11%*
32	R1 C9	TSC +16.01	VOL	8%*
32	R1 C66	TSC +18.16	VOL	13%*
33	R1 C66	TSH +15.62	VOL	26%*
33	R1 C27	TSH +18.04	VOL	16%*
		TSC +17.86	VOL	12%*
33	R1 C8	TSC +16.51	VOL	9%*
34	R1 C8	TSH +16.69	VOL	10%*
34	R1 C84	TSC +16.92	VOL	11%*
*These volumetric indications were attributed to wear from sludge lance equipment and were evaluated using an amplitute based curve constructed from as built depths developed using the ASME flat bottom hole standard.				

Tube Plugging List from 3R14

SG	Tube	Location	Indication	Degradation Depth Percent TW
31	R29 C79	TSH	PLP	0%
31	R29 C80	TSH	PLP	0%

IPEC00243564

Tube Repair Summary for IP3

	SG 31	SG 32	SG 33	SG 34	Total
Total Number of Tubes	3214	3214	3214	3214	12856
Number of Sleeved Tubes	0	0	0	0	0
Number of Plugged Tubes	3	6	3	4	16
% of Tubes Plugged to Date	0.09%	0.19%	0.09%	0.12%	0.12%
Effective Tube Plugging %	0.09%	0.19%	0.09%	0.12%	0.12%

Note: Since there are no sleeves installed and the safety analyses credit plugged tubes with the same value regardless of location, the effective tube plugging is equivalent to the percentage of tubes plugged.

Tube Plugging History for IP3

Year	Outage	SG31	SG32	SG33	SG34	Total
1988	Pre-service	0	0	0	**2**	**2**
1990	3RO7	0	0	0	0	0
1992	3R08	0	0	0	0	0
1997	3R09	0	0	0	0	0
1999	3R10	0	0	0	0	0
2001	3R11	0	0	0	0	0
2003	3R12	**1**	**6**	**3**	**2**	**12**
2005	3R13	0	0	0	0	0
2007	3R14	**2**	0	0	0	**2**
Total Plugged		3	6	3	4	16
Percent Plugged		0.16%	0.19%	0.09%	0.12%	0.12%

2.5. IP3 Plugging Limit

The steam generators are required to allow a minimum amount of reactor coolant flow through the tubing as well as provide a minimum amount of heat transfer capability. Plugging tubes affects both parameters and must be kept within the bounds of the accident analyses. Current accident analyses assume SG plugging levels of 10% to support implementation of the 4.8% stretch power uprate. Therefore the current tube plugging limit is 10%.

2.6. History of Tube Leakage / Tube Rupture Events

To date there has been no identified primary to secondary leakage across the RSGs. The detection limit for primary to secondary leakage is less than 0.5 gallons per day.

2.7. Chemistry Transients

Chemistry transients can stress the steam generator materials and should be evaluated to determine if compensating actions should be taken. Transients greater than action level 2 are considered significant enough for evaluation. The following is a list of all SOP-SG-02 Action Level 2 chemistry transients. There have not been any action level 3 chemistry transients since SG replacement. A brief description of each transient has also been included. More detailed information is available in the source documents.

On January 5, 1991 the cation conductivity in steam generators 32 and 34 increased to 2.04 and 2.08 μS/cm respectively immediately after placing 31 heater drain pump into service following maintenance.

December 18, 1992, Steam generator cation conductivity increased rapidly to 4.9 μS/cm immediately after placing condensate polisher E vessel into service following maintenance. The contamination was organic and did not have significant levels of chloride or sulfate. Organic acids are considered benign with respect to SG corrosion.

Since that time there have been no Action 2 steam generator chemistry excursions.

2.8. Summary of In-situ Pressure Test Results

No in-situ pressure tests of steam generator tubing have been performed since the replacement steam generators were installed. Any required in-situ pressure tests will be performed in accordance with the latest revision of EPRI Guidelines (EPRI TR-107620) "Steam Generator In-Situ Pressure Test Guidelines, and any Steam Generator Manage Project (SGMP) Interim Guidance.

2.9. Summary of Pulled Tube Test Results

No tubes have been pulled from the replacement steam generators.

2.10. Thermal Performance Monitoring

IP3 has a thermal performance monitoring program in place for the steam generators. The thermal performance of the steam generators is monitored on a weekly basis and there has been no appreciable loss of thermal performance since the steam generators were replaced in 1989. Small fluctuations in main steam pressure on the order of a few pounds have been observed, particularly after a plant trip. This is attributed to a disruption in the thin film of tube scale on the tube surfaces and typically recovers in about three weeks.

2.11. Steam Generator 34 Hot Leg: Impacted Channel Head and Tubesheet

During the 1990 refueling outage a foreign object was found partially lodged in a tube end at location Row 1 - Column 34 in the hot leg of steam generator 34. The object was removed and determined to be a fuel assembly alignment pin from the reactor upper internals. Visual examinations revealed that the foreign object had made numerous indentations on the channel head surfaces. An inspection was performed of all 3212 open tube ends, the tubesheet, tube to

tubesheet welds, the divider plate, and all cladding. Some tube ends indicated minor deformation from the loose part impact. Indian Point staff and Westinghouse evaluated the tube ends from a thermal hydraulic and structural point of view and determined them to be acceptable as is. The channel head condition was also evaluated and determined that the structural integrity of the indented components was not degraded and that no repairs were required.

During the 1992 refueling outage a follow up visual inspection was performed on the hot leg channel head of steam generator 34 which had been subjected to impacting by the fuel assembly alignment pin. The visual inspection was performed with a high resolution video camera and observed by a person qualified in accordance with SNT-TC-1A, "Recommended Practice for NDT Personnel Qualification and Certification". A person familiar with weld design requirements participated in the review. The videotape of this inspection and the original inspection, performed in 1990, were comparatively reviewed using side-by-side viewing equipment. The inspection and comparative results showed no change in the channel head since the first inspection.

2.12. Steam Generator Secondary Side In-Bundle Inspection

There have been secondary-side in-bundle remote video inspections performed on the steam generators during all refuel outages since the steam generators were replaced except for 3RFO13 where no secondary side SG work was performed. Several inspections are performed after sludge lancing. The first is a cleanliness inspection to verify the adequacy of the sludge lancing. The second is a search for foreign objects that could detrimentally impact the operation of the steam generators. This inspection typically covers the annulus and tube lane. Retrieval is attempted on all foreign objects that are considered detrimental to SG tube integrity. If retrieval is not successful, an evaluation is performed to justify operation with the object left in the SG. The third inspection is in-bundle where typically every 5^{th} column is examined for the buildup of hard deposits.

Additional inspections are periodically performed on selected steam generators. An inspection is done of the tops and bottoms of the tube support plates (TSP) in the vicinity of the flow slots. The purpose of this inspection is to look for fouling of the broach holes and SG tubing. Another inspection is done at the top support plate. This inspection looks at the top of this support plate, the underside of the U-bends, ligament cracking and a sampling of the tubes in-bundle. These extensive inspections are performed to look for some of the corrosion product precursors to tube degradation and to get a feeling for the condition of the OD of the tubes.

Copies of the videotape reports from previous in-bundle visual inspections are maintained by engineering programs.

2.13. Steam Generator Secondary Side Upper Internals Inspection

In November 1993 an inspection was performed on the upper internals portion of all four steam generators. This inspection was performed to meet the recommendation contained in the steam generator owners manual and because industry experience in the areas of erosion, corrosion, tube denting, sludge deposition, and loose parts monitoring have emphasized the prudence of visual inspection of steam generator internals as a means of preventive maintenance to preclude lost time due to failures. The equipment examined consisted of the major internal components

contained in the upper internals portion of the steam generator. Those components are the primary separators, the secondary separators, the feedring and the feedring J-nozzles. The complete report from the inspection is contained in Reference 48.

The NRC Information Notices 96-09 and 96-09, Supplement 1, identified several modes of degradation in the secondary side of pressurized water reactor (PWR) steam generators (SGs) operated in Europe by Electricite de France (EDF). During R09 in June 1997, a comprehensive inspection of secondary side internals was performed in 34 SG. The inspection looked at the following areas: primary separator/swirl vanes, transition cone to upper shell weld, secondary separator, J-nozzle and feedwater ring, top support plate ligament cracking, anti-vibration bars (AVBs), upper wrapper supports, upper wrapper support anti-rotation keys and wedges, lower wrapper support keys and the wrapper weld seam. The results are reported in Field Service Report INT-20 and summarized as follows:

"From the collective observations …, these steam generators, to the extent inspected during this outage by procedure NSD-FP-1997-7966, do not exhibit any advance degradation, and only exhibit the possible initiation of some deterioration modes that should be observed in the future to establish the rate of progression. These possible initiations of deterioration include:

1) Upper tube support plate "G" tube hole blockage in select areas that are only now beginning to show as scale build-up between the tube support plate quatrefoil hole lands and the tube.
2) Feedwater ring J-tube discharge impingement on the feedring pipe outer diameter surface and/or on the primary separator riser barrels, now observed as only a "washed" areas void of magnetite build-up and having no discernible depth of base material.
3) J-tube to feedwater ring inner diameter surface joint erosion-corrosion of the feedwater pipe base material, only identified during this outage as possibly starting for the J-tube closest to the feedwater nozzle and "T" section.
4) Sludge collection on the lower deck plate where washing off is prevented by the lower deck skirt attached at the periphery of the deck; now showing as a uniform sludge depth of approximately $^{1}/_{16}$ inch and a few local piles up to ½ inch deep."

In December 1998, Westinghouse evaluated the susceptibility of model 44F steam generators to the internals degradation exhibited in the French steam generators and determined that the IP3 replacement steam generators were not susceptible. This was documented in a report prepared for the Westinghouse Owners Group (WOG).

During 3R10 in 1999, the steam drum in 33 SG was visually inspected. The steam drum was in good shape with the only anomaly being some streaks on the inside diameter of the feedring indicative of J-nozzle discharge impacting on the feedring surface. The maximum estimate of wear is 10 mils on a 0.500" thick pipe so there is currently no concern.

A steam drum inspection was performed in 32 SG during 3R11 in 2001. No anomalies were noted and the steam drum was noted to appear cleaner than previous steam drum inspections in the other steam generators. Based on the positive results of the previous steam drum inspections, the inspection of the 31 SG steam drum scheduled for 3R12 was deferred to 3R14.

In 3R14, the steam drums of 31 and 32 steam generators were inspected. Both steam drums looked very good with no anomalies noted. There were washed out areas on the feedring below the outlet of the J-nozzles comparable to what was observed in 34 SG in 1997 with negligible

loss of base material from the carbon steel feed ring. The primary and secondary separators were clean with no buildup of deposits and no structural issues were identified.

3. Steam Generator Performance Criteria

The steam generator performance criteria described below identify the standards against which performance is to be measured. Meeting the performance criteria provides reasonable assurance that the steam generator tubing remains capable of fulfilling its specific safety function of maintaining reactor coolant pressure boundary (RCPB) integrity.

Performance criteria used for steam generators shall be based on tube structural integrity, accident induced leakage, and operational leakage as defined in the Indian Point 3 Technical Specifications are listed below.

3.1. Structural Integrity Performance Criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads. (TS 5.5.8 b 1)

3.2. Accident-Induced Leakage Performance Criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the) Operational Leakage Performance Criterion leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 0.3 gpm per SG and 1 gpm through all SGs. (TS 5.5.8 b 2)

3.3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, "RCS Operational LEAKAGE" which limits RCS operational leakage to:

150 gallons per day primary to secondary LEAKAGE through any one steam generator (SG). (TS LCO 3.4.13 d)

The primary-to-secondary leakage limit referred to in the performance criterion is 150 GPD at room temperature conditions from any one steam generator. The EPRI Primary to Secondary Leak Guidelines require a plant to enter Mode 3 (hot shutdown) within certain timeframes if a leak equals or exceeds 75 GPD in a single steam generator depending on nature of the leak. The

IP3 Operations procedures have adopted the most conservative guideline shutdown period of 3 hours should a leak equal or exceed 75 GPD to simplify operator actions.

4. Steam Generator Program

4.1. Steam Generator Program Responsibilities

The Engineering Programs Group in the Entergy Nuclear Northeast corporate office has overall responsibility for the steam generator program at IP3 with support derived from corporate and station personnel. Detailed responsibilities are described in procedure EN-DC-317.

4.2. Assessment of Potential Degradation Mechanisms

Entergy Nuclear Northeast prepares a steam generator degradation assessment prior to scheduled SG inspection as required by NEI 97-06. The purpose of this assessment is to identify both existing and potential degradation mechanisms, identify inspection techniques for those mechanisms, establish the number of tubes to be inspected, establish the structural limits for the tubing flaws and establish flaw growth rates.

4.3. Steam Generator Tubing Inspection Requirements

Following the degradation assessment, an inspection plan is prepared in accordance with the adopted revision of the EPRI PWR Steam Generator Examination Guidelines and any SGMP interim guidance in effect. This inspection plan also takes into account the requirements of plant technical specifications (TS). A summary of the regulatory and industry requirements for each refueling outage as well as the inspections performed are presented in Attachment 4 of this report.

The implementation of improved technical specifications in 2000 added a statement to the SG program section that surveillance intervals may be extended by a factor of 1.25 applied to SG inspection intervals. The IP3 TS define two inspection intervals of 12-24 calendar months and 40 calendar months. The IP3 SG inspection results to date permit 40 calendar month inspection intervals but two operating cycles are typically 48 calendar months. The TS bases for the applying the surveillance factor of 1.25 states that it the factor should not be applied for the purpose of routinely extending surveillance intervals except for consistency with refueling intervals. The IP3 SG program considers that inspecting SGs on 48 calendar month intervals to be consistent with every other refueling outage to be an appropriate use of the 1.25 surveillance factor.

In 2000, IP3 changed its tubing inspection program from deterministic to performance based. Under this type of program the performance of the tubing dictates the inspection frequency. Entergy contracted EPRI to evaluate when degradation is anticipated in the IP3 SGs. That evaluation determined that degradation is not anticipated for several cycles so technical specification requirements are the limiting factor in performing SG inspections.

Revision 6 of the EPRI PWR SG Examination Guidelines requires NRC approval to implement a performance based inspection program (section 4) so the IP3 SG inspection program reverted back to a prescriptive based program in accordance with section 3 of revision 6. The inspection

performed in the spring of 2003 met the requirements of both revision 5/section 4 and revision 6/section 3.

4.4. Tube Integrity Assessment

After each steam generator inspection, Entergy Nuclear Northeast prepares an assessment of the steam generator tubing integrity. This is a two-part assessment that ensures the performance criteria have been met for the pervious operating period (condition monitoring) and will continue to be met for the next period (operational assessment). A preliminary assessment is performed prior to closeout of the steam generators and the final assessment must be completed within 90 days after startup.

4.5. Repair Limits

The Indian Point 3 Technical Specifications specifies a tube repair limit of 40% through-wall (TW). Any tube degradation greater than 40% TW must be plugged or repaired. Any degradation that cannot be sized must also be plugged or repaired.

As part of the Appendix K power uprate of 1.4%, the structural limits for the steam generator tubing were calculated in accordance with draft regulatory guide 1.121. The results are documented in WCAP-15920.

In 2005, a stretch power uprate SPU of 4.8% was implemented. The structural limits for the steam generator tubing were recalculated in Calculation Note Number CN-SGDA-03-147. Two operating conditions were evaluated, high Tave and low Tave corresponding to steam pressures of 715 and 650 psia respectively. IP3 currently operates with a steam generator steam pressure of 730 psig which corresponds to the high T_{ave} operating conditions.

The table below summarizes the IP3 RSG tube structural limits.

Structural Limits for IP3 Replacement Steam Generators

Location / Wear Scar Length	Structural Limit (%)(1)		
	1.4% Uprate	4.8% SPU high T_{ave}	4.8% SPU low T_{ave}
Straight Leg and Anti-Vibration Bar(2) / ≥1.50" (Tube Rows 9-16 and 25-27)	56.00	**54.00**	52.00
Anti-Vibration Bar(2) / 0.9" (Tube Rows 17-24 and 28-45)	62.00	**60.20**	58.20
Flow Distribution Baffle / 0.75"	64.60	**62.80**	61.00
Tube Support Plate / 1.125"	59.00	**57.00**	55.20

(1) Structural Limit = $[(t_{nom} - t_{min})/t_{nom}] \times 100\%$ where $t_{nom} = 0.050$ inches

(2) For tube / AVB tangent points, straight leg structural limits apply. Tube / AVB tangent point correspond to Row 9 for the inner set of AVBs, Row 14 for the

intermediate set of AVBs, and Row 25 for the outer set of AVBs. For tube / AVB intersections that are not tangent points, but exceed the 0.9" wear scar length, straight leg structural limits also apply.

4.6. Maintenance and Repairs

Prior to any repairs on steam generator tubing, IP3 must qualify and implement the repair method in accordance with industry standards. After a repair is made a baseline inspection of the repair must be performed in accordance with the latest revision of the EPRI PWR Steam Generator Examination Guidelines and any SGMP interim guidance in effect. Additional guidance is also available in the EPRI PWR Steam Generator Tube Plug Assessment Document and the EPRI PWR Sleeving Assessment Document.

4.7. Primary-to-Secondary Leakage Monitoring

Primary-to-secondary leak monitoring is conducted in accordance with IP3 procedures 3-AOP-SG-1 and 0-CY-2450. These procedures follow the guidance contained in revision 3 of the EPRI PWR Primary-to-Secondary Leak Guidelines. A plant shutdown is required when leakage exceeds 75 gallons per day (GPD). This limit is more conservative than the EPRI guidelines so that operators do not have to monitor the rate of change in observable leakage. To date, primary-to-secondary leakage has not been observed in the replacement steam generators.

4.8. Secondary Side Water Chemistry

The IPEC chemistry department is responsible for the secondary-side water chemistry program at IP3. Procedures have been established for monitoring and controlling secondary-side water chemistry that follow the guidance contained in the EPRI PWR Secondary Water Chemistry Guidelines. IPEC chemistry has also developed a site-specific "Secondary Strategic Water Chemistry Plan" (Document ID SSWCPR00).

The upper tier chemistry procedures at IPEC are 0-CY-2410, "Secondary Chemistry Specifications" and EN-CY-101, "Chemistry Activities", which reiterates the chemistry commitment to NEI 97-06.

4.9. Primary Side Water Chemistry

The IPEC chemistry department is responsible for the primary-side water chemistry program at IP3. Procedures have been established for monitoring and controlling primary-side water chemistry that follow the guidance contained in the EPRI PWR Primary Water Chemistry Guidelines. IPEC chemistry has also developed a site-specific "Primary Strategic Water Chemistry Plan (Document ID PSWCPR00).

The upper tier chemistry procedures at IP3 are 3-SOP-RCS-006 "Reactor Coolant System Chemistry Control" and 0-CY-2310, "Reactor Coolant System Specifications and Frequencies" as well as EN-CY-101 which reiterates the chemistry commitment to NEI 97-06.

4.10. Foreign Material Exclusion

4.10.1. Secondary-Side Visual Inspections

Since steam generator replacement in 1989, IP3 has conducted foreign object search and retrieval (FOSAR) inspections in all four SGs at each refueling outage. The FOSAR inspection is controlled under procedure NSD-FP-1997-7965, "Remote Examination & Removal of Foreign Objects from Steam Generator Secondary Side, Indian Point 3". This inspection is performed after sludge lance operations and encompasses a visual inspection at the tube sheet level around the annulus of the steam generator.

Another inspection typically performed in any SG after sludge lancing is a visual in-bundle at the tubesheet level every 5th column of both the hot and cold legs. The purpose of this inspection is to monitor for the buildup of sludge not removed by sludge lancing. Periodically the support plates are inspected in selected SGs. In this inspection a camera is inserted in the SG handhole and sent up through a flow slot. The tool used is called the support plate inspection device or SID. The tops and bottoms of the support plates are inspected for sludge buildup on the tubes, on the tube support plates (TSP) and in the quatrefoil openings of the TSPs. The two SGs are rotated each outage for this inspection.

The top of the uppermost support plate cannot be inspected using SID so the top support plate in selected SGs is inspected from the three-inch inspection port located just above the TSP. This inspection looks at sludge buildup on the support plate and on the underside of the tubing at the U-bend. In addition, the camera probe is sent in-bundle at selected locations to look at the weld attachments of the wrapper to the TSP and to look for ligament cracking. The SGs are typically inspected on a rotating basis.

Lastly, starting with 3R09, the steam drum area in one SG was inspected on a rotating basis each refueling outage through 3R11. The purpose of this inspection is to look for degradation that might affect the integrity of the SG tubing or impact the overall operation of the SG. This inspection is performed by personnel entering the steam drum area with camera equipment to look at components such as the J-nozzles, feed ring, primary and secondary separators. Based on the positive results of previous steam drum inspections, the steam drum inspection planned for 3R12 was deferred to 3R14. In 3R14 the steam drums in 31 and 32 SGs were inspected and no anomalies noted. Based on these results, the next steam drum inspections will be in 33 and 34 SGs in 3R17.

A table of the inspections performed to date and considered for the future is contained in Attachment 6.

4.10.2. Control and Monitoring of Foreign Objects and Loose Parts

Station IP-SMM-MA-118 provides the requirements for foreign material control during maintenance activities at IP3.

In general, retrieval is attempted on all foreign objects identified during SG inspections unless the objects are considered so small that they do not challenge the integrity of the tubing. Any loose parts left in the SG are evaluated to support plant operation with parts remaining. A listing of the loose parts left in the replacement SGs is provided in attachment 5.

During plant operations, the steam generators are monitored for loose parts via the metal impact monitoring system (MIMS). Any alarms from this system should be evaluated to determine if

any special inspections should be performed when the steam generator is opened for maintenance.

4.11. Maintenance of Steam Generator Secondary-Side Integrity

Routine preventative maintenance of the steam generator secondary-side is essential for maximizing the operating life of the steam generators. Sludge accumulation can increase the risk of tubing corrosion. To that end, IP3 performs periodic maintenance of secondary side to remove sludge. In 3R11, a high volume bundle flush was performed to wash loose deposits from the tubing and tube support plates. In 3R12 plans were made to perform a top of tubesheet chemical soak to soften hard sludge followed by ultrasonic energy cleaning to break up the hard sludge prior to removal with sludge lancing but the ultrasonic cleaning had to be aborted because of conflict between outage plant conditions and the conditions the process was qualified under. Past work and planned future work is shown in Attachment 6.

Secondary-side steam generator components may have the capability to prevent the steam generator from fulfilling its intended safety-related function. The degradation assessment discussed previously in this report addresses potential secondary-side degradation that could affect the safety-related function of the steam generator and the appropriate inspections that should be performed. Currently, the only actions that need to be taken are to visually look for a drop in the wrapper if any hand hole covers are removed.

4.12. Self-Assessment

Entergy Nuclear Northeast is required to perform a periodic self-assessment of the steam generator program by NEI 97-06. The assessment must address all the program elements listed above. The self-assessment must be performed by qualified personnel and may include industry peers in accordance with EN-LI-104 "Self-Assessment and Benchmark Process".

5. Reports to the NRC

Several reports associated with the steam generators are required to be filed with the NRC. They are listed in the table below. Reports are also prepared in accordance with ASME Section XI.

NRC Reporting Requirements

Condition	Reports Required
Completion of an inspection performed in accordance with the Specification 5.5.8, Steam Generator (SG) Program.	A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection. (TS 5.6.8)
Failure to meet a performance criterion.	Reports required by 10CFR50.72 and 50.73 including a root cause evaluation identifying the performance criterion exceeded and an Operational Assessment establishing the basis for the next operating cycle. (NEI 97-06)

6. Summary of Results

Through the end of operating cycle 14 when the last steam generator inspections were performed, the IP3 replacement steam generators have not exhibited any service related degradation. Some maintenance related degradation has been identified and plugged. The inspection performed in 3R14 met the requirements of both the EPRI PWR SG examination guidelines and IP3 Technical Specifications. The operational assessment based on the inspection results and degradation predictions concluded that SG tube integrity will be maintained for two operating cycles when the next inspection is scheduled.

7. Evaluations

7.1. Sludge Lance Tube Wear

Westinghouse issued a nuclear safety advisory letter (NSAL-03-5) to notify users of its Series II sludge lance rail that the system could potentially cause wear in selected row 1 tubes. IP3 used this rail system in 2001 and identified tube wear during the 2003 eddy current inspection. The eddy current examination scope was increased to include the row one tubes adjacent to the rail latching mechanism. Additional wear indications were found during the scope expansion. In the NSAL, Westinghouse further identified four row 1 tubes that conservatively could have been contacted by Delrin guide blocks containing metal pins. Those columns for IP3 were 1, 3, 90 and 92. Columns 1 and 90 were inspected as part of the original bobbin scope at IP3 in 2003. No wear indications were found in those rows and Westinghouse reports that to date, there has been no reported wear among Series II rail users in the vicinity of the Delrin block. No wear was anticipated in columns 3 and 92 at IP3 but

those tubes were included in the bobbin inspection scope for 3R14 as well as any row 1 tubes not inspected since 2001. In 3R14, there were no wear indications found in previously uninspected row 1 tubes. However two row 1 tubes previously inspected with no wear indications had wear identified in 3R14 at TTS+16" consistent with sludge lance rail wear scars. The indications were just above the detection threshold and not considered missed indications in the previous inspection. The wear was sized conservatively at 26 and 29% TW and the tubes were left in service.

7.2. Top of Tubesheet Volumetric Indications in 32 Steam Generator

In 1999, volumetric indications were found in three hot leg peripheral tubes in 32 SG at the secondary face of the tubesheet with plus point RPC eddy current probe. These indications were never identified with bobbin probes and this was the first inspection of those tubes with RPC. The depths of the indications were 15, 21 and 23% when sized against an ASME flat bottom hole standard. The cause could not be determined but the possibilities were manufacturing or wear from loose parts. No loose parts were found at the tube locations so the indications were not expected to increase in size so the tubes were left in service.

Prior to the 2003 eddy current inspection, the 1999 data for the three tubes was reviewed. It was determined that the indications in two of the tubes extended into the expansion transition. This extent makes it impossible for the indications to be due to contact with loose parts so the most likely cause is manufacturing. During the 2003 eddy current inspection the tubes were re-examined and found to be the same size as in 1999. A decision was made to administratively plug the three tubes because

8. Conclusions

The Indian Point 3 (IP3) steam generator program maintains the steam generators in optimal condition to assure their continued operation until the end of plant life and to support plant life extension. The program formalizes and integrates the various inspections, maintenance, chemistry and operational activities performed on the steam generators and provides the basis for making strategic decisions to optimize steam generator reliability and performance.

9. Recommendations

9.1. Long Term Maintenance and Inspection Plan

Attachment 6 contains a table outlining the past maintenance and inspection work that has been performed on the replacement SGs at IP3 along with tentative future plans. The frequency of future eddy current inspections is driven by technical specifications. The number of tests is driven by both technical specifications and the need to acquire enough information to support the operating interval between inspections. The inspection plans are the results of degradation assessments performed prior to each SG eddy current inspection.

Secondary side maintenance and inspections are performed as needed in a balance between the cost and perceived benefits of those activities. Periodic cleaning reduces sludge deposits that could support corrosion and it enhances the ability to perform visual inspections. Visual

inspections are most valuable in their ability to monitor the buildup of sludge and to detect foreign objects not detectable by eddy current that could challenge tube integrity during the operating interval.

10. References

10.1. Regulatory Documents

1. American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, 1983 Edition, Summer 1983 addenda
2. Indian Point 3 Technical Specifications, Sections 5.5.8, 5.6.8
3. CFR Part 50 Appendix A, General Design Criteria for Nuclear Power Plants, and Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.
4. CFR § 50.65, Maintenance Rule
5. CFR § 50.72, Immediate Notification Requirements for Operating Nuclear Power Reactors, and § 50.73, Licensee Event Report System

10.2. Industry Guidelines

6. Nuclear Energy Institute, Steam Generator Program Guidelines, NEI 97-06, Revision 2, May 2005
7. Steam Generator Management Program Administrative Procedures. EPRI Report 1011274 (Rev. 1, December 2004)
8. PWR Primary-to-Secondary Leak Guidelines, EPRI Report 1008219 (Rev. 3, December 2004)
9. PWR Steam Generator Examination Guidelines, EPRI Report TR-107569 (Rev. 6, October 2002) and SGMP Interim Guidance Letters dated 4/22/2003 and 3/16/2004.
10. PWR Secondary Water Chemistry Guidelines, EPRI Report 1008224 (Rev. 6, December 2005)
11. PWR Primary Water Chemistry Guidelines, EPRI Report 1002884 (Rev. 5, September 2003)
12. Steam Generator Integrity Assessment Guidelines, EPRI Report 1012987, (Rev 2, July 2006)
13. Steam Generator In Situ Pressure Testing Guidelines, EPRI Report TR-1007904 (Rev. 2, August 2003) and SGMP Interim Guidance Letter dated 5/11/2004.
14. PWR Steam Generator Tube Plug Assessment Document, TR-109495 (Rev. 1, December 1997)
15. EPRI PWR Sleeving Assessment Document TR-105962, (Rev 0, December 1995)
16. Westinghouse Nuclear Services Division, "Steam Generator Secondary Side Maintenance Guidelines, July 1998
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21. "SGMP-IG-05-02, NEI 97-06 Revision 2, 'Steam Generator Program Guidelines'", transmittal letter dated October 10, 2005
22. "Interim Guidance on EPRI Steam Generator In Situ Pressure Test Guidelines, Revision 2, Chapter 10", transmittal letter dated May 11, 2004
23. "Steam Generator Management Program (SGMP) Interim Guidance for EPRI Steam Generator Examination Guidelines, revision 6 Sections 6.2.4, 6.3.3.3, 6.5 and Appendix H Supplements H1 and H2", transmittal letter dated March 16, 2004
24. "Interim Guidance on Steam Generator Tube Leak at Comanche Peak Unit 1", transmittal letter dated April 22, 2003

10.3. Entergy Nuclear Procedures & Reports

25. Inservice Inspection / Test Program, IP-SMM-DC-906, (IP Site Management Manual Procedure)
26. Self Assessment and Benchmark Process, EN-LI-104, (Entergy Nuclear Northeast Nuclear Management Manual Procedure)
27. Chemistry Activities, EN-CY-101, (Entergy Nuclear Management Manual Procedure)
28. Entergy Steam Generator Administrative Procedure, EN-DC-317, (Entergy Nuclear Management Manual Procedure)
29. Foreign Material Exclusion and Control, IP-SMM-MA-118, (IP Site Management Manual Procedure)
30. Reactor Coolant System Specifications and Frequencies, 0-CY-2310 (IPEC Procedure)
31. Reactor Coolant System Chemistry Control, 3-SOP-RCS-006 (IPEC Procedure)
32. Secondary Chemistry Specifications, 0-CY-2410 (IPEC Procedure)
33. Primary to Secondary Leak, 0-CY-2450 (IPEC Procedure)
34. Steam Generator Tube Leak, 3-AOP-SG-1 (IPEC Procedure)
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44. Entergy Nuclear Northeast, "Steam Generator Degradation Assessment for 3R14 Refueling Outage", IP-RPT-06-00186, Rev 1, March 9, 2007

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47. Westinghouse Electric Company, "Steam Generator Degradation Assessment for Indian Point Unit 3 RFO-12, Report Number SG-SGDA-02-42, February 2003

48. Westinghouse Electric Company, "SG Degradation Assessment for Indian Point 3 R11 Refueling Outage", report number 00-TR-FSW-024 Revision 1A, February 2001 (note: this report also contains the operational assessment for fuel cycle 12)

49. Westinghouse Electric Company, "Indian Point 3, RF10 Condition Monitoring Assessment and Operational Assessment", report number SG-99-10-003, October 1999

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Attachment 1 - List of Definitions

The following definitions are provided to ensure a uniform understanding of terms used in this report.

Accident Induced Leakage: Primary-to-secondary leakage that occurs in a faulted steam generator as a result of a limiting accident.

Burst: the gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation.

Condition Monitoring: A comparison of the as-found inspection results against the performance criteria for structural integrity and accident leakage. Condition monitoring assessment is performed at the conclusion of each operating cycle.

Degradation-Specific Repair Criteria: Repair criteria developed for a specific degradation mechanism and/or location, e.g., a degradation specific repair criteria for ODSCC at tube support plates or for PWSCC at the tube sheet expansion.

Deterministic Approach: An approach that is based on the deterministic addition of parameter values to determine a limit.

Faulted: The state of the steam generator in which the secondary side has been depressurized due to a main steam line break such that protective system response such as main steam line isolation, reactor trip, safety injection, etc., has occurred.

Limiting Design Basis Accident: In the context of steam generator primary-to-secondary pressure boundary integrity, it is the accident that results in either the largest differential pressure across the steam generator tubes for structural considerations or the minimum margin to the applicable dose limits for accident leakage considerations.

Operational Assessment: Forward looking prediction of the steam generator tube conditions that is used to ensure that the structural integrity and accident leakage performance criteria will not be exceeded during the next cycle. The operational assessment needs to consider factors such as NDE uncertainty, indication growth, and degradation-specific repair limits.

Performance Criteria: Criteria to provide reasonable assurance that the steam generator tubing has adequate structural and leakage integrity such that it remains capable of sustaining the conditions of normal operation, including anticipated operational occurrences, design basis accidents, external events, and natural phenomena.

Probabilistic Approach: An approach that uses probabilistic simulations, e.g., Monte Carlo simulations, to determine appropriate limits.

Probability of Burst (POB): The probability of burst of a steam generator tube if a limiting accident occurs.

Probability of Detection (POD): The probability of detecting a flaw during a steam generator inspection.

Repair Limit: An NDE parameter value at which steam generator tube repair is required. The repair limit will be determined by either subtracting margins for NDE uncertainty and growth from the structural limit or by conducting a probabilistic analysis.

Normal Makeup Capacity: The ability of the makeup system to maintain reactor coolant system inventory without the manual or automatic actuation of engineered safeguards features, e.g., safety injection. Manual starting of redundant or standby pumps may be credited as normal makeup capacity if the additional pumps are provided for in plant procedures.

Steam Generator Degradation-Specific Management (SGDSM): The use of inspection and/or repair criteria developed for a specific degradation mechanism, e.g., outside diameter stress corrosion cracking at tube support plates.

Steam Generator Tube Rupture (SGTR): A tube rupture or burst is a gross failure of the tube such that the formation of a primary-to-secondary opening with an area affiliated to that of a double-ended guillotine break occurs. For burst testing of limited length axial cracks, approximately two inches or less in length, the phenomenon requires extension of the crack tips. In most situations, extension of the degradation is necessary to achieve the level of opening needed.

Attachment 2 - List of Acronyms

ARC ....Alternative Repair Criteria
ASME ....American Society of Mechanical Engineers
AVT ....All Volatile Treatment
CFR............................Code of Federal Regulations
EOC............................End of Cycle
EPRI...........................Electric Power Research Institute
GDC ....General Design Criteria
GPD............................Gallons Per Day
INPO ....Institute of Nuclear Power Operations
ISI...............................In-service Inspection
MSLB.........................Main Steam Line Break
MSLB-SGTR.............Main Steam Line Break-Steam Generator Tube Rupture
NDE ....Non-Destructive Examination
NEI.............................Nuclear Energy Institute
NRC ....Nuclear Regulatory Commission
NSSS..........................Nuclear Steam Supply System
ODSCC ....Outer Diameter Stress Corrosion Cracking
POB............................Probability of Burst
POD............................Probability of Detection
PWR...........................Pressurized Water Reactor
PWSCC......................Pressurized Water Stress Corrosion Cracking
RCPB ....Reactor Coolant Pressure Boundary
SF ....Safety Factors
SG ....Steam Generator
SGDSM......................Steam Generator Degradation Specific Management
SGMP.........................Steam Generator Management Project
SGTR ....Steam Generator Tube Rupture
SL...............................Structural Limit
SLB ....Steam Line Break
TR ....Technical Report
TSP.............................Tube Support Plate

Attachment 3 - Industry Guideline Deviations

There are currently no deviations to Industry Guidelines in effect for the IP3 Steam Generator Program.

Attachment 4 - SG Outage Inspection Summary

Technical specifications required different inspection scopes for the first 3 in-service inspections. The EPRI PWR SG Examination Guidelines have been revised several times since SG replacement and those revisions have changed the SG inspection requirements. A description of the requirements at the time of each refueling outage and the SG inspections performed to meet those requirements is presented below.

3R07 – September 1990

Requirements: This was the first refueling outage after SG replacement and the first in-service inspection (ISI) for the replacement steam generators (RSGs). The TS requirement was to perform and inspection between 12 and 24 calendar months since the last inspection. TS also required that at least 6% of the tubes in each of 2 SGs be inspected and the tubes to be inspected should be selected on a random basis. Revision 2 of the EPRI GL was in effect at the time and required that 20% of the tubes in all SGs be inspected.

Inspection: The 3R07 inspection was performed 17 calendar months after the post installation inspection performed in April 1989. Twenty percent of the tubes in each SG were selected on a random basis and inspected over their full length with a bobbin probe. No degradation was found and the inspection was classified C-1 per TS.

3R08 – May 1992

Requirements: This was the second refueling outage after SG replacement and the second ISI for the RSGs. The TS requirement was to inspect a minimum of 12% of the tubes in one of the 2 SGs not previously inspected between 12 and 24 months subsequent to the last inspection. Again the tubes to be inspected should be selected on a random basis. Revision 2 of the EPRI GL were still in effect requiring 20% of the tubes in all SGs to be inspected.

Inspection: The 3R08 inspection was performed 20 calendar months after the previous inspection. Twenty percent of the tubes in each SG were selected on a random basis and inspected over their full length with a bobbin probe. No degradation was found and the inspection was classified C-1 per TS. TS permits extending SG inspection intervals to 40 calendar months following two consecutive C-1 inspection results.

3R09 – May 1997

Requirements: This was the third refueling outage after SG replacement and the third ISI for the RSGs. The TS requirement was to inspect a minimum of 12% of the tubes in the SG not previously inspected within 40 calendar months since the last inspection since the previous two inspection results were classified C-1. Prior to reaching the end of the 40-month interval in September 1995, a license amendment request (LAR) was submitted to extend the inspection interval to the 3R09 refueling outage. The LAR tried to apply the 1.25 surveillance extension to the 40-month interval to reduce the amount of the extension. The NRC approved the request but called out that application of the 1.25 was not appropriate for SG inspections. Reference Tech Spec Amendment #166.

Prior to 3R09 there was an industry concern about using appropriate inspection techniques since the rotating pancake coil (RPC) probe was qualified to detect circumferential degradation that

the bobbin probe could not. The NRC issued a letter requesting each utilities plans for using the relatively new RPC probe. It its letter to the NRC, IP3 staff committed to inspecting just 3% of the hot leg expansion transitions and row 1 and 2 U-bend regions with the RPC probe on a one-time basis at the next inspection (3R09).

Revision 4 of the EPRI GL was in effect prior to 3R09. The revision permitted inspection of just half the SGs provided the sample size was increased to 40% of the tubes in those SGs. Revision 4 also stipulated that no SG shall operate more than two cycles between inspections and that 100% of the tubes were inspected over their full length within 60 effective full power months (EFPM). This revision also permitted the selection of tubes to be inspected on either a random or systematic basis provided the selection was evenly distributed across the SG. Another requirement implemented in revision 3 and carried on in revision 4 was to inspect 100 percent of the tubes over their full length with a general purpose eddy current probe (bobbin) in the first ISI after replacement but this requirement was not retroactive to SGs already beyond the first ISI.

Inspection: IP3 decided to shift from inspecting 20% of the tubes in all 4 SGs to 40% of the tubes in two SGs each refueling outage as a more economical alternative to inspecting all 4 SGs each refueling outage.

In 3R09 IP3 began inspecting alternating pairs of generators and performed the following inspection on steam generators 33 and 34:

- 60% full-length bobbin (completing 100% inspection in both generators)
- 20% of the hot leg expansion transitions with plus point RPC probe- hot leg (selected on a random basis)
- 20% MRPC of rows 1 &2 U-Bend (selected on a random basis)
- ALL dings and dents greater than 5 volts with plus point
- ALL previously identified areas with loose parts left in those generators
- ALL partial length inspections performed previously were re-examined.

The inspection results showed no degradation and were categorized as C-1 permitting the continuation of 40 calendar month inspection intervals.

3R10 – October 1999

Requirements: This was the fourth refueling outage after SG replacement and the fourth ISI. The TS requirement was to inspect 12% of the tubes in one SG on a rotating basis provided the previous inspections demonstrate that the SGs are performing in a like manner which was the case. Another option is to inspect 3% of the tube tubes in all 4 SGs. EPRI had released revision 5 of the examination guidelines one month prior to the outage was not required to be implemented until after the outage so the revision 4 requirements were in effect. This meant that SGs 31 and 32 had to be inspected such that 100% of the tubes would be inspected over 60 EFPM.

Inspections: In 3R10 SGs 31 and 32 were examined at 29 calendar months since the last inspection. The following inspections performed in those SGs:

- 100% full-length bobbin excluding the U-Bend areas
- 40% of the expansion transition with plus point RPC probe-hot leg

· 40% of rows 1 &2 U-Bend with plus point RPC probe-hot leg

· ALL dings and dents greater than 5 volts with plus point probe

· ALL previously identified areas with loose parts left in those generators were also inspected

The inspection identified 2 tubes with degradation (=>20% through wall) but the inspection results were still classified as C-1 maintaining 40-month inspection intervals. The two tubes were left in service because revision 4 of the EPRI GL did not require an Appendix H qualified sizing technique to leave degraded tubes in service.

3R11 – May 2001

Requirements: This was the fifth refueling outage after SG replacement but no ISI inspection was performed. The TS requirement was to inspect at least 12% of the tubes in one SG within 40 calendar month intervals. Another option is to inspect 3% of the tubes in all 4 SGs. The following outage (3R12) was scheduled 42 calendar months after the 3R10 inspection but implementation of improved technical specifications added a specific statement under the SG section that the surveillance margin of 1.25 applied to SG inspections. (TS amendment 205) The basis section for applying this margin states that it could be applied to extend surveillance intervals to be consistent with refueling intervals.

Revision 5 of the EPRI GL was in effect at this time. Revision 5 presented two options for SG inspections; prescriptive and performance based. The prescriptive requirements were the same as in revision 4. The performance based approach was new and allowed the condition of the SGs to determine the inspection intervals provided no SG operated more than two cycles between inspections and all tubes were inspected on a rolling 60 EFPM basis.

Inspections: IP3 elected to adopt a performance based SG inspection program that determined that no inspections were required in 3R11. The 1.25 surveillance margin was applied to satisfy TS requirements and technical justifications for deviating from the two cycle and 60 EFPM requirements were prepared as well. The SG operational assessment supported deferring inspections until the next refueling outage.

3R12 – April 2003

Requirements: 3R12 was the sixth outage following SG replacement and the fifth ISI for the RSGs. The TS requirements were to inspect at least 12% of the tubes in one SG in a 40 calendar month interval. Another option is to inspect 3% of the tubes in all 4 SGs. The surveillance margin of 1.25 times the interval could be applied meaning the inspection could be performed at 50 months provided it was consistent with refueling intervals. 3R12 was 42 calendar months since the last SG inspection. TS also stated that the inspection population should be selected at random.

IP3 had adopted the requirements for performance based SG inspections under revision 5 of the EPRI GL. Evaluations determined that inspections were not required in 3R12 but IP3 opted to inspect all 4 SGs to be conservative while inspecting one SG to meet TS requirements. Revision 6 of the EPRI GL were issued prior to the 3R12 outage but implementation was not required until after the outage. Inspection requirements from the prescriptive based section in revision 6

were considered in the inspection scope recognizing that staying in a performance based program would require NRC approval.

Inspections: The following scope of inspections was performed in all four SGs unless otherwise noted:

25% of the tubes with bobbin along the full-length in a patterned inspection

20%/30% of the hot leg expansion transitions in 31/32 and 33/34 SG respectively with plus point RPC bringing the cumulative population examined to date to 50% in all 4 SGs.

80%/100% of the row 1 and 2 U-bends in 31/32 and 33/34 SGs respectively with plus point MRPC bringing the cumulative population examined to date to 100% in all 4 SGs.

8% of the cold leg expansion transitions in all 4 SGs comprising all the peripheral tubes of the annulus and tube lane with plus point RPC to provide low level detection capability for potential small volumetric indications attributable to loose part wear.

A sampling of hot leg dents and dings with plus point MRPC.

Some minor degradation was found in this degradation but the inspection results were still classified as C-1. The 25% patterned inspection with bobbin in all 4 SGs was considered to comply with the TS statement that the 3% TS sample "should be selected on a random basis". Nine indications of wear in 8 row 1 tubes attributed to contact with sludge lance equipment used in 3R11. One of the wear indications was initially sized conservatively at 47%. This is considered a defective tube by both technical specifications and the EPRI SG examination guidelines and prompted a sample expansion. Because the wear could positively be attributed to sludge lance equipment, the potential wear indications could be confined to just row 1 tubes. The initial inspection scope encompassed 25% of the row one tubes. TS required a minimum sample size of 3 percent and an expansion size of twice that so the TS requirement was considered met by the initial 25% sample. The EPRI guidelines recommended an expansion of 20% in the affected SGs so an additional 20 tubes or 22% of the row 1 tubes were inspected to meet the guideline requirement. Because the wear was due to a latching mechanism in two locations on each side of the SG, the tubes were systematically selected to ensure several tubes on each side of the latching mechanism were inspected.

3R13 – April 2005

Requirements: This is the seventh refueling outage since SG replacement and no inspections were performed during this outage. The TS requirements call for a minimum inspection of 12% of the tubes in one SG in a 40 calendar month interval. Other options include 6% of the tubes in two SGs or 3% of the tubes in all four SGs. 3R14 is scheduled for 48 calendar months after the 3R12 inspection. If necessary the 1.25 surveillance margin could be used to defer SG inspections until 3R14 but it is more likely that new technical specifications will be in place that are consistent with Revision 6 of the EPRI PWR Steam Generator Examination Guidelines. This TS change is TSTF-449 which the NRC made available to the industry on May 2, 2005 via the Consolidated Line Item Improvement Process (CLIIP).

Revision 6 of the EPRI GL were in effect at the time of this outage. Revision 6 permits SGs with Alloy 690TT tubing to operate as long as 96 EFPM between inspections provided the entire population of tubes is inspected at different intervals over the life of the SGs. 3R14 will be the

outage nearest the end of the first inspection interval of 144 EFPM as measured from the first ISI.

Inspections: No SG inspections were performed for 3R13.

3R14 – April 2007

Requirements: In February 2007, a license amendment was implemented incorporating the requirements of TSTF-449 Rev 4 on Steam Generator Tube Integrity The TS requirements for steam generator inspections during 3R14 were to inspect any tubes not previously inspected since the first ISI during 3R7 in 1990 for potential degradation as defined in the degradation assessment. This is because the SGs had accumulated 137 effective full power months (EFPM) of operation since the first ISI and 3R14 was the refueling outage closest to the end of the first inspection period of 144 EFPM.

The potential degradation mechanisms for the SGs at this time were wear at support structures and wear due to foreign objects. Prior to 3R14, 100% of the tubes in 31 & 32 SGs were inspected over the full length except for 19 and 21 low row U-bend sections in 31 and 32 SG respectively. In 33 & 34 SGs, 100% of the low row U-bend sections had been inspected but approximately 240 tubes in each SG had not had a full length bobbin inspection. To meet the TS requirement those tubes and sections add to be inspected along with a 20% minimum sample to meet EPRI guideline requirements.

Another consideration in determining the inspection scope was the need to assess potential AVB wear in the U-bend section since the prior operating cycle was under stretch power uprate conditions. A 50% full length bobbin sample was selected to provide enough information to support a planned 3 cycle operation following the inspection.

Inspections: The following SG inspection scope was performed on all 4 SGs except as noted:

1. Bobbin inspection over the full length of 50% of the tubes in rows 3-45 (about 1515 tubes/SG) in a patterned inspection of every other pair of columns.
    a. In addition, those tubes not inspected since the first ISI in 1990 and not captured in this pattern were added to the inspection plan. This added 324 and 117 tubes in 33 and 34 SGs respectively.
2. Bobbin inspection of the hot and cold straight leg sections of 50% of the tubes in rows 1 and 2 aligning with the same columns as the patterned inspection for full length bobbin. (about 92 tubes/SG)
    a. In addition, those tubes in row one on both hot and cold legs not inspected in 2003 and not captured in this pattern were added to the inspection plan.
3. Plus-point inspection of the U-bend sections of those row 1 and 2 tubes inspected in item 2 above but not item 2(a) (about 92 tubes/SG) plus any row 3 tubes that could not pass a nominal size bobbin probe. Plus-point probes were used in rows 1 and 2 because the tight radius of the bend does not permit quality data to be collected with the bobbin probe.
    a. In addition, those tubes whose row 1 and 2 U-bend sections were not inspected since the first ISI in 1990 were added to the inspection plan. This added 19 and 21 tubes to 31 and 32 SG respectively.

4. Plus-point inspection of the HOT leg expansion transitions from TTS+3 to TTS-3 inches of 20% of the tubes in a patterned inspection (about 643 tubes/SG) that captured tubes not previously inspected in prior patterns to the extent practical. The purpose of this inspection was to collect baseline information of the tube expansion transition region for comparison should this region be considered for potential degradation mechanisms.
5. Plus-point inspection of the HOT leg expansion transitions from TTS+3 to TTS-3 inches of all HOT leg peripheral tubes (defined as 3 tubes in from the annulus in column, row and diagonal directions and all row 1 and 2 tubes) (about 550 tubes/SG not covered by 20% patterned inspection). The purpose for this inspection was to identify possible loose parts and loose part wear in what are considered the most susceptible regions of the SG.
6. Plus-point inspection of the COLD leg expansion transitions from TTS+3 to TTS-3 inches of all COLD leg peripheral tubes (defined as 3 tubes in from the annulus in column, row and diagonal directions and all row 1 and 2 tubes) (about 700 tubes/SG). The purpose for this inspection was to identify possible loose parts and loose part wear in what are considered the most susceptible regions of the SG.
7. Special interest inspections as necessary to disposition possible degradation signals from the routine inspections including all dents/dings ≥ 5 volts and a 20% sample of dents/dings 2.00 – 4.99 volts in the HOT leg straight sections.

Attachment 5 - SG Loose Parts Inventory

NOTE: The most recent outage list is considered the current loose part inventory because the same areas are inspected each outage. Any material from a previous outage is considered removed, most likely by sludge lancing activities.

Loose Parts Remaining after Refueling Outage 7

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
1990	31	C			periphery between cols 59 & 71	weld slag	0.031	0.500	0.500	
1990	32	H			periphery between cols 59 & 71	congealed sludge	0.063	0.333	0.333	
1990	33	H			periphery between cols 53 & 59	congealed sludge	0.500	0.250		
1990	34	H			periphery between cols 58 & 59	congealed sludge	0.375	0.250		
1990	34	C			periphery between cols 45 & 58	congealed sludge	0.375	0.250		

Loose Parts Remaining after Refueling Outage 8

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
1992	31	H	40	29		flexitallic gasket	0.500			
1992	31	H	29	26		flexitallic gasket	1.000			
1992	31	H	37	25		flexitallic gasket	1.000			
1992	31	H	32	17		flexitallic gasket	0.500			
1992	31	C	39	25		flexitallic gasket	3.000			
1992	31	C	42	45		flexitallic gasket	2.000			
1992	31	C	43	46		flexitallic gasket	1.500			
1992	31	C	43	47		flexitallic gasket	1.500			
1992	31	C	42	63		flexitallic gasket	1.000			
1992	32	H	42	46		wire	2.375	0.031	0.031	
1992	32	H	44	38		flexitallic gasket	2.000			
1992	32	H	42	53		flexitallic gasket	1.500	0.031		
1992	32	H	41	55		flexitallic gasket	3.000			
1992	32	H	40	56		flexitallic gasket	2.000			
1992	33	H	40	65		flexitallic gasket	4.500			
1992	33	H	43	56		flexitallic gasket	0.500			
1992	34	H	0	61	hot leg past 3rd blocking device	flexitallic gasket	1.250			length estimated as 1-1.5
1992	34	H	0	64	3 tube lanes from 3rd blocking device	flexitallic gasket	1.000			
1992	34	C	35	75		sludge formation	0.375	0.375		3/8 dia
1992	34	H	32	17		flexitallic gasket	3.000			
1992	34	H	23	85		flexitallic gasket	0.250			

Loose Parts Remaining after Refueling Outage 9

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
1997	31	H	22	40		flexitallic gasket	0.375	0.250	0.125	
1997	31	C	19	44	C44/45	flexitallic gasket	3.000	0.250	0.125	length noted as 2.5-3.5
1997	31	C	38	43		flexitallic gasket	0.333	0.250	0.125	
1997	31	C	19	5	annulus	wire bristle	1.000	0.016	0.016	1/64 dia wire
1997	34	H	38	61		flexitallic gasket	0.333	0.250	0.125	
1997	34	H	43	51		sludge rock (fixed in place)	0.333	0.125	0.125	
1997	34	H	37	40		flexitallic gasket	0.333	0.250	0.125	
1997	34	H	37	45		flexitallic gasket	0.333	0.250	0.125	
1997	34	H	30	44		flexitallic gasket	0.333	0.250	0.125	

Loose Parts Remaining in SGs after Refueling Outage 10

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
1999	33	C	20	84	R20/21, C82/86	Flexitallic gasket	5.000	0.125	0.125	
1999	33	H	41	38	R41/42, C37/38	wire	1.000	0.031	0.031	1/32 dia wire
1999	34	C	28	25	R28/29	wire	0.750	0.031		1/32 dia
1999	34	C	27	25	R27/28	coiled metal chip	0.375	0.031	0.375	1/32 dia
1999	34	C	27	25	R27/28	wire	1.000	0.031	0.500	1/32 dia
1999	34	C	39	31	R39/40	sludge rock	0.750	0.250	0.250	
1999	34	C	37	31	R36/38,C30/31	wire	3.000	0.016		1/64 dia
1999	34	C	23	31	C30/31	wire	1.500	0.031		1/32 dia
1999	34	C	41	37	R41/42	sludge rock	0.375	0.375	0.375	
1999	34	C	40	37	R40/41,C37/38	sludge rock	0.750	0.188	0.188	
1999	34	C	39	37	R39/40	sludge rock	0.188	0.188	0.188	
1999	34	C	37	39	C39/40	metal chip	0.250	0.031	0.125	
1999	34	C	37	36	C36/37	wire	1.000	0.031		1/32 dia
1999	34	C	44	44	R44/45,C44/45	sludge rock	0.375	0.188	0.188	
1999	34	C	35	40	C40/41	wire	0.250	0.031		1/32 dia
1999	34	H	36	25	R36/37	wire	0.500	0.016		1/64 dia
1999	34	H	42	30	C30/31	wire	0.750	0.031	0.125	
1999	34	H	31	37	R31/32	wire	0.750	0.031		1/32 dia
1999	34	H	27	37	R27/28	wire	0.750	0.031		1/32 dia
1999	34	H	33	41	R33/34	sludge rock	0.063	0.188	0.063	
1999	34	H	36	41		wire	0.250	0.031		1/32 dia
1999	34	H	35	40	R35/36	sludge rock	0.375	0.375	0.375	
1999	34	H	32	40	R32/33,C40/41	wire	0.750	0.031		1/32 dia
1999	34	H	39	45	R39/40	sludge rock	0.750	0.375	0.375	
1999	34	H	36	45	R36/37	wire	0.750	0.031		1/32 dia
1999	34	H	34	56	R34/35	sludge rock	0.375	0.375	0.375	
1999	34	H	40	51	R40/41	metal wafer	0.375	0.031	0.375	

Note: No known loose parts were left in 31 and 32 steam generators during RF-10.

Loose Parts Remaining in SGs after Refueling Outage 11

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
2001	31	H	32	20		Flexitallic gasket	.25	.25		
2001	31	C	39	40	R39-40	Wire	0.125	0.010		
2001	31	C	38	44	R39-39	Machine remnant	0.125	0.25		
2001	31	C	38	44	R38-39	Wire	0.25	0.010		
2001	31	C	34	44	R34-35	Wire	0.125	0.010		
2001	31	C	36	52		Wire	0.25	0.010		
2001	31	C	34	52		Wire	0.25	0.010		
2001	31	C	31	52		Wire	0.375	0.010		
2001	31	C	30	52		Wire	0.375	0.010		
2001	31	H	36	62	R36-37	Wire	0.375	0.010		
2001	31	H	20	62		Wire	0.062	0.010		
2001	31	H	18	62		Wire	0.062	0.010		
2001	31	H	18	57		Wire	0.300	0.010		
2001	32	C	21	10		Wire	0.125	0.010		
2001	33	C	30	53		Wire	0.125	0.010		
2001	33	C	19	53		Wire	0.125	0.010		
2001	33	C	38	36		Wire	0.125	0.010		
2001	33	C	18	53		Wire	0.310	0.020		
2001	34	H	10	5		Wire	0.125	0.010		
2001	34	H	18	10		Wire	0.750	0.010		
2001	34	H	28	24		Wire	0.125	0.010		
2001	34	H	31	31		Wire	0.125	0.010		
2001	34	C	7	15		Wire	0.125	0.010		
2001	34	C	31	21		Wire	0.125	0.010		
2001	34	C	34	21		Wire	0.125	0.010		
2001	34	C	12	21		Wire	0.125	0.010		
2001	34	C	38	40		Wire	0.125	0.010		
2001	34	C	32	40		Wire	0.125	0.010		
2001	34	C	5	44		Wire	0.125	0.010		
2001	34	TL		41		Wire	0.125	0.010		

Loose Parts Remaining in SGs after Refueling Outage 12

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
2003	31	C	45	50		MSR wire	0.125	0.010		
2003	31	C	38	71		MSR wire	0.125	0.010		
2003	31	C	36	74		MSR wire	0.125	0.010		
2003	31	C	33	78		MSR wire	0.125	0.010		
2003	31	C	25	85		MSR wire	0.125	0.010		
2003	31	C	26	84		MSR wire	0.125	0.010		
2003	31	TL	01	84		MSR wire	0.50	0.010		
2003	31	H	29	26		MSR wire	0.125	0.010		
2003	33	TL		44		MSR wire	0.375	0.010		
2003	34	H	1	01	R1-5	MSR wire	0.125	0.010		
2003	34	H	27	10		MSR wire	0.125	0.010		
2003	34	H	38	21		MSR wire	0.50	0.010		
2003	34	H	40	31		MSR wire	0.125	0.010		
2003	34	H	08	40		MSR wire	0.125	0.010		
2003	34	C	16	05		MSR wire	0.125	0.010		
2003	34	C	35	31		MSR wire	0.125	0.010		
2003	34	C	39	44		MSR wire	0.125	0.010		
2003	34	C	37	44		MSR wire	0.25	0.010		
2003	34	C	21	44		MSR wire	0.25	0.010		
2003	34	C	33	74		MSR wire	0.25	0.010		
2003	34	C	39	65		MSR wire	0.25	0.010		
2003	34	C	38	56		MSR wire	0.25	0.010		
2003	34	C	37	56		MSR wire	0.25	0.010		
2003	34	C	36	56		MSR wire	0.25	0.010		
2003	34	C	42	48		MSR wire	0.25	0.010		
2003	34	C	38	48		MSR wire	0.25	0.010		
2003	34	C	38	48		MSR wire	0.25	0.010		
2003	34	C	34	48		MSR wire	0.375	0.010		

Loose Parts Remaining in SGs after Refueling Outage 14

Year	SG	Side	Rw	Cl	Note	Object	Lngth	Wdth	Hght	Note
2007	31	H	28	11		Slag	0.25	0.125	0.125	
2007	31	H	27	12		MSR wire	0.25		0.16	
2007	31	H	34	17		Scale pile	0.36	0.312	0.125	
2007	31	H	36	19		Scale pile	0.36	0.312	0.125	
2007	31	H	37	20		Scale pile & MSR wire	0.36	0.312	0.125	
2007	31	H	36	21		Sludge rock pile	0.36	0.312	0.125	
2007	31	H	38	22		Sludge rock pile	0.36	0.36	0.125	
2007	31	H	38	23		Sludge & scale pile	0.36	0.36	0.125	
2007	31	H	39	24		Sludge & scale pile	0.36	0.36	0.125	
2007	31	H	40	25		Sludge & scale pile	0.36	0.36	0.125	
2007	31	H	40	26		Sludge & scale pile	0.36	0.36	0.125	
2007	31	H	40	28		Sludge rock	0.36	0.36	0.125	
2007	31	H	42	30		Sludge rock	0.36	0.125	0.125	
2007	31	H	42	67		MSR wire	1.0		0.016	
2007	31	H	38	70		Sludge rock	0.36	0.125	0.125	
2007	31	C	38	22		Gasket	0.25	0.125	0.125	
2007	31	C	38	23		Metal object	0.25	0.125	0.125	
2007	31	C	39	27		Slag	0.125	0.125	0.125	
2007	31	C	40	27		Slag	0.375	0.125	0.125	
2007	31	C	44	53		Sludge rock	0.25	0.125	0.125	
2007	31	H	27	15		Gasket	0.25	0.06	0.125	
2007	31	H	36	20		MSR wire pile	0.12	0.015		
2007	31	C		80	Annulus	Machine remnant	0.5	0.125	0.25	
2007	32	C	44	40		Scale & MSR wire pile	0.33	0.33	0.33	
2007	32	H	42	55		MSR wire pile	0.2	0.2	0.2	
2007	33				No objects found					
2007	34	H	13	15		Sludge rock	0.3	0.3	.3	

IPEC00243599

Attachment 6 - SG Work Scope Chart

Long Term Maintenance and Inspection Plan for the Indian Point 3 Steam Generators

5/29/2007

Cycle EFPD	394.3	413.9	564.8	654.4	541	661.2	669.3	686.2	684	684	684	684	684	684	684	684	684	684
Plant EFPY	7.84	8.97	10.52	12.31	13.79	15.60	17.43	19.31	21.19	23.06	24.93	26.80	28.68	30.55	32.42	34.30	36.17	38.04
EFPY since SGR	1.08	2.21	3.76	5.55	7.03	8.84	10.67	12.55	14.43	16.30	18.17	20.04	21.92	23.79	25.66	27.54	29.41	31.28
EFPM since SGR	13.0	26.6	45.1	66.6	84.4	106.1	128.1	150.6	173.1	195.6	218.1	240.5	263.0	285.5	308.0	330.4	352.9	375.4
Month/Year	09/90	04/92	05/97	09/99	04/01	03/03	03/05	03/07	03/09	03/11	03/13	03/15	03/17	03/19	03/21	03/23	03/25	03/25
Refueling Outage #	3R07	3R08	3R09	3R10	3R11	3R12	3R13	3R14	3R15	3R16	3R17	3R18	3R19	3R20	3R21	3R22	3R23	3R24
Secondary Cleanings																		
Sludge Lance	1,2,3,4	1,2,3,4	1,2,3,4	1,2,3,4	1,2,3,4	, ,3,4		1,2,3,4			1,2,3,4		1,2,3,4			1,2,3,4		1,2,3,4
Hi Vol Bundle Flush					1,2,3,4													
TTS ASCA/CU rinse						, ,3,4												
TTS UEC						aborted												
CECIL Lancing											1,2,3,4					1,2,3,4		
Chemical Cleaning?																		
Lbs Sludge Removed	156	283	223	245	209	80	0	223										
Est lbs Iron Xported	975	1035	1304	1288	555	372	467	338	350	350	350	350	350	350	350	350	350	350
tube scale (lbs/SG)			1700	1500														
Secondary Inspections																		
FOSAR	1,2,3,4	1,2,3,4	1,2,3,4	1,2,3,4	1,2,3,4	1,2,3,4		1,2,3,4			1,2,3,4		1,2,3,4			1,2,3,4		1,2,3,4
20% TTS In-bundle	1,2,3,4	1,2,3,4	1,2,3,4	1,2,3,4	1,2,3,4	, ,3,4		1,2,3,4			1,2,3,4		1,2,3,4			1,2,3,4		1,2,3,4
Top TSP (G)	, ,3,4	1,2, ,	, ,3,4	, ,3,4	1,2, ,			1,2 , ,			, ,3,4		1,2, ,			, ,3,4		1,2, ,
C-F TSP (SID)	, ,3,4	1,2, ,	, ,3,4	, ,3,4	1,2, ,													
Steam Drum		1,2,3,4	, , ,4	, ,3,	,2, ,			1,2, ,			, ,3,4		1,2, ,			, ,3,4		1,2, ,
Primary Inspections																		
Full length bobbin	1,2,3,4	1,2,3,4	, ,3,4	1,2, ,		1,2,3,4		1,2,3,4			1,2,3,4		1,2,3,4		1,2,3,4	1,2,3,4	1,2,3,4	1,2,3,4
% of tubes/SG	r20	r20	r60	100		25		50/55			50		50		50	50	50	50
R1&2 U-bend RPC			, ,3,4	1,2, ,		1,2,3,4		1,2,3,4			1,2,3,4		1,2,3,4		1,2,3,4	1,2,3,4	1,2,3,4	1,2,3,4
% of tubes/SG			r20	40		60/100		61/50			50		50		50	50	50	50
HL Tubesheet RPC			, ,3,4	1,2, ,		1,2,3,4		1,2,3,4			1,2,3,4		1,2,3,4		1,2,3,4	1,2,3,4	1,2,3,4	1,2,3,4
% of tubes/SG			r20	40		20/30		37			60		60		60	60	60	60
CL Tubesheet RPC						1,2,3,4		1,2,3,4			1,2,3,4		1,2,3,4		1,2,3,4	1,2,3,4	1,2,3,4	1,2,3,4
% of tubes/SG						8		22			22		22		22	22	22	22
Inspection Periods	13.0	13.6	32.2	53.7	***71.4***	93.2	115.1	***137.7***	16.2	38.6	***61.1***	83.6	***106.1***	20.5	***43.0***	***65.5***	***27.9***	***50.4***
Period Milestones	1st ISI				72			144			54		108		36	72	30	60
Plugging																		
SGs plugged (Note 1)						1,2,3,4		1,2,3,4										
# tubes plugged						1,6,3,2		2,0,0,0										
Rev & Sec of Exam GL	2	2	4	5/3	5/4	5/4	6/3	6/3										

Legend: 1,2,3,4 represents work performed in 31, 32, 33 and 34 SGs
where there are two percentage numbers in a cell, it represents inspections performed in 31/32 and 33/34 SGs respectively
Note 1: two tubes were plugged in 34 SG in the fabrication shop (1988) with specially heat treated Alloy 600 welded plugs.