Northern States Power Company

Prairie Island Nuclear Generating Plant

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Technical Specification 4.12.E

U S Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

PRAIRIE ISLAND NUCLEAR GENERATING PLANT
Docket Nos. 50-282 License Nos. DPR-42
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1997 Unit 1 Steam Generator Inspection Results

In accordance with Technical Specification 4.12.E.1, the following information on steam generator tube inspection and repair is provided for the information of the NRC Staff:

Following the recent inservice inspection of the Unit 1 steam generators, 173 tubes were plugged for the first time. The percentage of tubes plugged is 4.4% in 11 steam generator and 8.9% (equivalent) in 12 steam generator. The inspection results are summarized in Attachment 1.

In accordance with Technical Specification 4.12.E.2, this information will be expanded upon in the Inservice Inspection Report for Unit 1 which will be submitted within 90 days of the end of the current refueling outage. Also Table 4.3-13 of the Prairie Island Updated Safety Analysis Report will be updated in the next revision.

In accordance with Generic Letter 95-05, the 90 day report required for implementation of the voltage based repair criteria in Unit 1 will be submitted within 90 days of Unit 1 startup.

The results of the inspection of 11 Steam Generator and 12 Steam Generator were classified as Category C-3 in accordance with Technical Specification 4.12 because more than 1% of the inspected tubes in each Steam Generator were defective. The NRC Staff was informed of the Category C-3 classification by telephone on October 27, 1997. In accordance with Technical Specification 4.12.E.3, a 30 day special report on the Category C-3 steam generator inspection is provided as Attachment 2 to this letter.

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During the inspection and repair of tubes, F-Star (F*) Alternate Repair Criteria was utilized and rerolling was done using the improvements implemented during the Unit 2 January 1997 outage. There are 125 tubes classified as F* tubes. In accordance with Technical Specification 4.12.E.4, the identification of F* tubes by Row and Column and the location and extent of degradation are included in Attachment 3 to this letter.

Attachment 1 to this letter contains one new NRC commitment which is shown in italics. Please contact Gene Eckholt (612-388-1121) if you have any questions related to this letter.

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Attachments:
1. Steam Generator Plugged Tube and F* Tube Summary
2. Prairie Island Unit 1 Steam Generator Category C-3 Tube Inspection Special Report
3. F* Tube Report
4. Prairie Island Unit 1 In Situ Test List - October 1997 Refueling Outage

ATTACHMENT 1

Steam Generator Plugged Tube and F* Tube Summary

11 Steam Generator Plugged Tube and F* Tube Summary

Summary

New Indications Plugged this Outage:	54
Total Plugged Tubes:	149
Total F* Tubes:	119
11 Steam Generator % Plugged:	4.40%

Inspection Scope

All open tubes were examined full length with the bobbin coil, except for Rows 1 and 2 U-bends.

All Rows 1 and 2 U-bends were examined with rotating probes.

All hot leg tubes were examined with rotating probe technology (including the +Point™ coil) from tube end hot to 3 inches above the top of the tubesheet. Twenty percent of the cold leg tubes were examined with rotating probe technology (including the +Point™ coil) from tube end cold to 1 inch above the top of the tubesheet.

New Indications

One hundred forty-one tubes were identified with the following types of degradation:

1. Wastage:

   Sixteen tubes were plugged for thinning at the cold leg tube support plate. One tube with an indication of wastage at a cold leg tube support plate was tested in situ with zero leakage. Two tubes with wastage or pitting type indications above the cold leg tubesheet were tested in situ with zero leakage and were plugged.

2. Secondary Side IGA/SCC in Hot Leg Tubesheet Region

   Three tubes contained single or multiple indications in the tubesheet crevice region indicative of secondary side IGA/SCC occurring in the tubesheet region. One of these tubes also contained an indication at the roll transition zone. Two tubes were tested in situ with zero leakage. All three tubes were plugged. Two tubes had volumetric indications above the tubesheet. One was tested in situ with zero leakage and the other tube was pulled for metallurgical examination of the volumetric indication at the top of the tubesheet and a distorted indication at the 01H tube support plate.

3. Secondary Side IGA/SCC at Tube Support Plates

Twenty two tubes contained volumetric indications at tube support plates indicative of secondary side IGA/SCC and/or wastage. Two tubes were pulled from 11 steam generator from tube end hot to just below 04H tube support plate. Three intersections were leak and burst tested and partial metallurgical examination has been completed. One intersection with a volumetric indication contained a small thinned region possibly due to wastage in addition to shallow, multiple axial ODSCC indications. One intersection with a distorted indication contained typical outside diameter intergranular stress corrosion cracking. One intersection with no detectable degradation burst outside the tube support plate and has not yet been metallurgically examined.

Due to regulatory uncertainty concerning whether the volumetric eddy current indications at tube support plates were in compliance with Technical Specification 4.12.D.4.a, all of the tubes with volumetric indications not associated with qualified sizing techniques were plugged.

All but two of the tube support plate intersections with distorted bobbin coil indications were examined by rotating coil probes. All confirmed indications and the two tubes not inspected with rotating coil probes were plugged.

4. Primary Water Stress Corrosion Cracking (PWSCC) at the Hot Leg Roll Transition Zone

Twelve tubes (9 new) contained single or multiple axial indications at the Roll Transition Zone. Three tubes became F* tubes after successful Additional Roll Expansions. Six tubes were plugged due to unsuccessful Additional Roll Expansion. One tube was pressure tested in situ with zero leakage.

5. Primary Water Stress Corrosion Cracking (PWSCC) at the Rows 1 and 2 U-bends

There were no indications of tube degradation in the rows 1 and 2 u-bends.

6. Possible PWSCC Near the Tube End

One hundred thirteen tubes (84 new) contained short axial indications near the hot leg tube end. These tubes were all classified as F* tubes.

7. Other

Two tubes contained free span volumetric indications which were pressure tested in situ with zero leakage and then plugged.

One wear scar due to a possible loose part was not changing, but was conservatively plugged.

Maximum Length of Roll Transition Zone Indications

The maximum length of the indications in the Roll Transition Zone was 0.2 inches.

Visual Tube Plug Inspection

A visual inspection was done of all installed tube plugs. No plug anomalies were identified.

Visual Tube Leak Inspection

A visual inspection for tube leakage was conducted following the reroll repairs and welded tubesheet plug installations with the secondary side pressurized to greater than 100 psig following repairs. There were no signs of leakage.

Tube Plug Removal

No tube plugs required repair. All the Westinghouse Alloy 600 mechanical plugs have been replaced in 11 steam generator.

Rotating Probe Inspections

In order to best identify those tubes which have minor degradation in the tubesheet region and which could leak during the next fuel cycle, and in accordance with the requirements of Generic Letter 95-03, a complete examination of the hot leg tubesheet region of all inservice tubes was conducted using a Rotating Coil Probe which contained three different coils. These coils were a 0.115 inch pancake coil, a 0.080 inch pancake coil for discrimination of inside versus outside diameter signals and the +Point™ coil.

A +Point™ probe was also used to examine all dents greater than 5 volts and to resolve distorted signals called by the bobbin probe eddy current inspection.

In addition, a rotating coil examination was conducted of twenty percent of the tubes on the cold leg side from tube end cold to 1 inch above the top of the tubesheet. No indications were found in the cold leg examination which required expansion of the examination scope. The indications found at the top of the cold leg tubesheet were also identifiable by the bobbin coil examination.

Circumferential Indications

No circumferential indications were found.

Category C-3

The results of this inspection program of 11 Steam Generator were classified as Category C-3 by Technical Specification 4.12 because more than 1% (including rotating probe indications) of the inspected tubes in 11 Steam Generator were defective. The NRC staff was informed of the Category C-3 classification by telephone on October 27, 1997.

12 Steam Generator Plugged Tube and F* Tube Summary

Summary

New Indications Plugged this Outage:	119
New Indications Sleeved this Outage	222
Total Plugged Tubes:	271
Total Sleeved Tubes	852
Total F* Tubes:	6
12 Steam Generator % Plugged:	8.90% (equivalent)

Inspection Scope

All open tubes were examined full length with the bobbin coil, except for Rows 1 and 2 U-bends and the sleeve sections of sleeved tubes. The sleeves were inspected with the rotating coil probe.

All Rows 1 and 2 U-bends were examined with rotating probes.

All hot leg tubes were examined with rotating probe technology (including the +Point™ coil) from tube end hot to 6 inches above the top of the tubesheet. Twenty percent of the cold leg tubes were examined with rotating probe technology (including the +Point™ coil) from tube end cold to 1 inch above the top of the tubesheet.

New Indications

Two hundred ninety-six new tubes were identified with the following types of degradation:

1. Wastage

Fifteen tubes were plugged for thinning at the cold leg tube support plate.

Two tubes with wastage or pitting type indications above the cold leg tubesheet were plugged. One tube pressure tested in situ with zero leakage.

2. Secondary Side IGA/SCC in Hot Leg Tubesheet Region

Seventy-five tubes contained single or multiple indications or volumetric indications in the tubesheet crevice region indicative of secondary side IGA/SCC occurring in the tubesheet region. Ten of these tubes also contained an indication of primary water stress corrosion cracking at the roll transition zone.

Twelve tubes bounding these indications were tested in situ with zero leakage. All of these tubes were plugged or sleeved.

Four tubes had volumetric indications above the tubesheet. One tube was tested in situ with zero leakage. All four of these tubes were plugged or sleeved. Eight tubes had axial indications above the tubesheet. Three tubes were tested in situ with zero leakage. All eight of these tubes were plugged or sleeved.

3. Secondary Side IGA/SCC at Tube Support Plates

Forty tubes contained volumetric or axial indications at tube support plates indicative of secondary side IGA/SCC and/or wastage. One tube was pulled from 12 steam generator from tube end hot to just below 04H tube support plate. One intersection with an axial indication was leak and burst tested and partial metallurgical examination has been completed. Metallurgical examination of this intersection showed that the corrosion morphology is primarily axial IGSCC with minor ICC components that disappear rapidly with depth.

Due to regulatory uncertainty concerning whether the volumetric eddy current indications at tube support plates were in compliance with Technical Specification 4.12.D.4.a, all of the tubes with volumetric indications not associated with qualified sizing techniques were plugged.

All of the tube support plate intersections with distorted bobbin coil indications were examined by rotating coil probes. All confirmed indications were plugged.

4. Primary Water Stress Corrosion Cracking (PWSCC) at the Hot Leg Roll Transition Zone

One hundred fifty three tubes (150 new) contained single or multiple axial indications at the Roll Transition Zone. Six tubes were pressure tested in situ with zero leakage. Three tubes became F* tubes after successful Additional Roll Expansions. The remaining tubes were plugged or sleeved.

5. Primary Water Stress Corrosion Cracking (PWSCC) at the Rows 1 and 2 U-bends

One tube was plugged due to a single axial indication in a row 1 u-bend. This tube was pressure tested in situ with zero leakage.

6. Previously Installed Sleeves

Three sleeves were plugged due to restrictions which prevented examination with a rotating coil probe. Forty-five sleeves contained weld zone indications which only marginally met or did not meet the new acceptance criteria for ABB CE sleeves and were plugged. One of these sleeves with a weld zone volumetric indication was removed for metallurgical examination. Three sleeves were pressure tested in situ with zero leakage. Sleeve selection for in situ pressure testing was based on the extent and the voltage of the eddy current signal.

7. Other

One tube contained a free span volumetric indication which was pressure tested in situ with zero leakage and then plugged.

Visual Tube Plug and Sleeve End Inspection

A visual inspection was done of all installed tube plugs and sleeves. No plug or sleeve end anomalies were identified.

Post Maintenance Visual Tube Leak Inspection

A visual inspection for tube leakage was conducted following the reroll repairs and sleeve and welded tubesheet plug installations with the secondary side pressurized to greater than 100 psig following repairs. There were no signs of leakage.

Tube Plug Removal

No tube plugs required repair. All the Westinghouse Alloy 600 mechanical plugs have been replaced in 12 steam generator.

Rotating Probe Inspections

In order to best identify those tubes which have minor degradation in the tubesheet region and which could leak during the next fuel cycle, and in accordance with the requirements of Generic Letter 95-03, a complete examination of the hot leg tubesheet region of all inservice tubes was conducted using a Rotating Coil Probe which contained three different coils. These coils were a 0.115 inch pancake coil, a 0.080 inch pancake coil for discrimination of inside versus outside diameter signals and the + Point™ coil.

A + Point™ probe was also used to examine all dents greater than 5 volts and to resolve distorted signals called by the bobbin probe eddy current inspection.

In addition, a rotating coil examination was conducted of twenty percent of the tubes on the cold leg side from tube end cold to 1 inch above the top of the tubesheet. No indications were found in the cold leg examination which required expansion of the examination scope.

Circumferential Indications

No circumferential indications were found in tubes. Nine sleeves contained weld zone circumferential weld zone indications attributable to previous weld cleanliness problems. These sleeves were plugged.

Category C-3

The results of this inspection program of 12 Steam Generator were classified as Category C-3 by Technical Specification 4.12 because more than 1% (including rotating probe indications) of the inspected tubes in 12 Steam Generator were defective. The NRC staff was informed of the Category C-3 classification by telephone on October 27, 1997

Summary of 11 and 12 Steam Generator Inspections and Repairs

An inservice inspection consisting of inspection of 100% of the full length of tubing with the bobbin coil and 100% of hot leg and 20% of the cold tubesheet regions, 99.6% of the sleeves and the row 1 and 2 u-bends with mechanical rotating probe with + Point™ coil was conducted on Unit 1 Steam Generators from October 23, 1997 through November 22, 1997. In addition, post maintenance visual inspections were conducted for indications of leakage with the secondary side pressurized.

As a result of the visual and eddy current inspections, 5.2% (173 of 3293) of the inspected tubes in 11 Steam Generator contained defects requiring repair. Fifty-four of these tubes were plugged and the remaining tubes were left in service using previous and new Additional Roll Expansions and the F-Star (F*) alternate repair criteria. Repairs were completed on November 22, 1997

As a result of the visual and eddy current inspection, 10.7% (347 of 3236) of the inspected tubes in Steam Generator 12 contained defects requiring repair. One hundred nineteen of these tubes were plugged, 222 tubes were sleeved, and 6 tubes were left in service using previous and new Additional Roll Expansions and the (F*) alternate repair criteria. Repairs were completed on November 22, 1997.

Although the voltage based repair criteria was implemented this outage on Unit 1, all but two of the distorted tube support plate indications were examined by rotating coil probes. Indications defined as primarily volumetric in nature were plugged.

It was discovered by the System Engineer and the Eddy Current Specialist on October 29, 1997 that rotating coil inspection of all dents had not been done as stated in the NSP response, dated April 8, 1996, to an NRC Request for Additional Information on Generic Letter 95-03, "Circumferential Cracking of Steam Generator Tubes". The answer to the first part of Question 1 stated that "All dents greater than 5 volts were examined by the +point rotating coil technology in the Unit 1 9601 inspection and that "All dents greater than 5 volts will be examined by the +point in the Unit 2 9701 inspection. In the future, a 20% sample will be done." Contrary to this statement, only dents at tube support plate intersections, at the top of the hot leg tubesheet, and some of the free span locations were inspected with the +point coil rotating probe. The 132 free span dents in Unit 1 and 26 free span dents in Unit 2 identified in the April 8, 1996 letter had not all been inspected by the +point point coil probe. This information was initially reported to the NRC by a telephone conference call on October 30, 1997 and a follow-up conference call on October 31, 1997 and was reported as a 10 CFR 50.9 issue. It is also noted that the referenced letter stated that there were no NRC commitments made in the letter.

The inspection of all free span dents in 11 and 12 steam generators with a bobbin voltage greater than 5 volts using the +point probe was completed on November 2, 1997. There were 171 free span dents examined by the +point coil probe. For all of the dent locations in Unit 1 steam generators, there was no detectable degradation found by the rotating coil examination.

The results of the Unit 2 1997 examination were reviewed. There are 17 free span dents remaining to be inspected, all in the u-bend region. For all of the other dent locations inspected in Unit 2 steam generators, there was no detectable degradation found by the rotating coil examination.

Therefore, in the last inspection on each unit, 381 of 398 dented locations have been inspected by rotating coil examination with no detectable degradation in any of the dents. ***The remaining uninspected free span dents in Unit 2 will be inspected during the Fall 1998 Unit 2 refueling outage.***

ATTACHMENT 2

Prairie Island Unit 1 Steam Generator Category C-3 Tube Inspection Special Report

Prairie Island Unit 1 Steam Generators
Category C-3 Tube Inspection
Special Report

Purpose

This report fulfills the special reporting requirements of Prairie Island Technical Specification 4.12.E.3. This report is required whenever the steam generator tube inservice inspection finds more than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective. This report summarizes the inspection results, the causes of degradation, the condition monitoring assessment, and the operational assessment.

Summary

An inservice inspection consisting of inspection of 100% of the full length of tubing with the bobbin coil and 100% of hot leg and 20% of the cold tubesheet regions and the row 1 and 2 u-bends with mechanical rotating probe with + Point™ coil was conducted in Unit 1 Steam Generators from October 23, 1997 through November 22, 1997.

As a result of the visual and eddy current inspections, 5.2% (173 of 3293) of the inspected tubes in 11 Steam Generator contained defects requiring repair. Fifty-four of these tubes were plugged and the remaining tubes were left in service using previous and new Additional Roll Expansions and the F-Star (F*) alternate repair criteria. Repairs were completed on November 22, 1997

As a result of the visual and eddy current inspections, 10.7% (347 of 3236) of the inspected tubes in 12 Steam Generator contained defects requiring repair. One hundred nineteen of these tubes were plugged, 222 tubes were sleeved, and 6 tubes were left in service using previous and new Additional Roll Expansions and the (F*) alternate repair criteria. Repairs were completed on November 23, 1997.

Background

Table 1 provides data on the Prairie Island Nuclear Generating Plant which is significant for the steam generators.

Table 1: PRAIRIE ISLAND PLANT DATA

Location: On Mississippi River near Red Wing Minnesota
Nuclear Steam Supply System: Westinghouse 2-Loop 560 MWE
Steam Generators: Westinghouse Model 51
Mill-Annealed Alloy 600 Tubing
Open Tubesheet Crevices - 2.75 inch hard roll at bottom of tube
Circulating Water: Mississippi River/Cooling Towers
Secondary Systems Tubing: Stainless Steel/Carbon Steel
Startup Dates : Unit 1 - December 16, 1973
Unit 2 - December 21, 1974
Effective Full Power Years as of End of Previous Cycle:
Unit 1 (EOC 18) - 19.6 EFPY's
Unit 2 (EOC 17) - 18.8 EFPY's
HOT LEG TEMPERATURE: 590 degrees Fahrenheit

The current status of each steam generator at Prairie Island is shown in the attached Table 2: "Prairie Island Steam Generator Tube Plug and Sleeve Status."

Causes of Major Tube Degradation

There are two major causes of the degradation of tubes in Unit 1 steam generators. Secondary side intergranular attack and stress corrosion cracking (IGA/SCC or ODSCC) is occurring in the hot leg tubesheet crevice region, at the top of the hot leg tubesheet, and in the hot leg tube support plate intersection. This cause was identified by metallurgical examination of three hot leg tubesheet region sections of the Inconel 600 tubing removed from Steam Generator 12 in January 1985. This was confirmed by examination of a parent tube section removed during the sleeve pulls in 1996. The degradation is characterized as single or multiple axial indications. Except for the early years, these axial indications are located in the lower one half of the tubesheet crevice region. In addition, tube pulls during this outage have confirmed the presence of ODSCC in three hot leg tube support plate locations.

Rotating pancake coil (MRPC) of the tube samples and experience gained from other utilities provides tools to confirm the type of degradation occurring in the tubesheet region. MRPC examinations of all tubes with non-quantifiable indications in the tubesheet region have been done routinely since February, 1987. The MRPC results have confirmed the type of degradation as secondary side IGA/SCC.

Also, tubes with indications representative of primary water stress corrosion cracking (PWSCC) at the roll transition region have been identified by MRPC and by metallurgical examination of one roll transition zone removed during the sleeve pulls in 1996.

Comparison of Number of Defective Tubes in Unit 1 Steam Generators, January 1996 to October 1997

The number of new defective tubes identified in Unit 1 Steam Generators did not change significantly in the tubesheet crevice region. However, in 12 steam generator, roll transition zone PWSCC has become more dominant than ODSCC. A substantial number of sleeves were removed from service due to weld zone indications, all of which were previously present, using the improved inspection techniques and conservatively interpreting the acceptance criteria. Indications at hot leg tube support plates increased due to ODSCC occurring and identification of wastage type indications. Further details will be provided in the 90 day report for the voltage based repair criteria.

Examination Results for Tube Cleaning of Sleeve Locations

The following table summarizes the results of the post cleaning visual examinations of 223 sleeve locations:

Cleaning	First	Second	Third	Fourth
Number Cleaned	167	56	13	4
Percent Accepted per Cleaning	75%	77%	69%	100%

There was no correlation to the number of brush usages, to tubes which required additional cleaning operations. The visual examination was very worthwhile since additional cleaning efforts provided very successful weld inspection results. All 223 sleeves installed were accepted by UT, VT, and ET. (One sleeve was plugged due to a welding error).

Condition Monitoring

Condition Monitoring evaluates the as found condition of the steam generator tubing against leakage and structural integrity criteria. There were no tubes identified which exceeded the structural integrity requirement of no tube burst at three times the normal operating differential pressure. Degradation mechanisms located in the tubesheet crevice region can not burst due to the constraints of the tubesheet. Axial degradation mechanisms are not expected to burst unless the indication is greater than 0.38 inches long in the free span. There were no tubes identified by in situ pressure testing which exceeded leakage limits at main steam line break conditions.

In Situ Tests

To demonstrate adequate leakage and structural integrity, thirty four tubes were tested in situ. Tubes were selected based on largest extent and voltage of the eddy current indications and each type of degradation was tested. Tests were done at Main Steam Line Break (MSLB) conditions for indications in the tubesheet crevice region. Tests were done at Main Steam Line Break pressure and at three times normal operating differential pressure (3dp) for indications in free span regions. The test pressure for Main Steam Line Break conditions was 2816 psig and for 3dp conditions was 5624 psig. The list of tubes tested in situ is in Attachment 4. No tubes challenged the structural integrity criteria of 3 times normal operating differential pressure. No tubes leaked at Main Steam Line Break pressures.

Operational Assessment for Each Degradation Mechanism

Unit 1 Cycle 18 length was 565 EFPD. Unit 1 Cycle 19 length is planned to be 483 EFPD.

1. **Wear at Tube Bundle Structural Components and Foreign Objects (Loose Parts)**

   There were 29 active AVB wear locations this outage. No AVB locations required plugging. The maximum growth seen for indications which were greater than 10% last cycle was 7%. The AVB wear degradation mechanism growth rate does not challenge structural integrity during the next cycle. One wear scar due to a possible loose part was not changing, but was conservatively plugged.

2. **Thinning at the Cold Leg Tube Support Plates**

   There were 81 active CLTSP thinning locations this outage. Thirty one of these locations required plugging. The largest percent call was 59% which had increased from 36% the previous outage. The maximum growth seen for indications which were greater than 10% last cycle was 23%. The average growth rate was 2% since 41 indications had negative or zero growth rate. The cold leg tube support plate degradation mechanism does not challenge structural integrity during the next cycle.

3. **Assessment of Secondary Side IGA/SCC in the Tubesheet Region**

Secondary side IGA/SCC is identified as axial or volumetric indications and is repaired on detection and thus growth rates are not available. The maximum length of IGA/SCC seen in the tubesheet region was a 10.3 inch MAI in 12 SG R9C7. This tube was pressure tested in situ with zero leakage. Seventeen of the secondary side indications were pressure tested in situ and all had zero leakage under MSLB conditions. Therefore, the secondary side IGA/SCC does not present a challenge to structural or leakage integrity for the next cycle.

4. **Secondary Side IGA/SCC at the Top of the Tubesheet Region**

There were 15 volumetric or axial indications located at the top of the tubesheet. These indications are plugged or sleeved on detection. Five indications were pressure tested in situ at MSLB conditions and at 3 times normal operating differential pressure. There was no leakage at MSLB pressure and there was no rupture at 3dp. Therefore, none of the indications at the top of the tubesheet presented challenges to structural or leakage integrity and new indications are not expected to present challenges during the next cycle.

5. **Assessment of Primary Water Stress Corrosion Cracking at the Roll Transition Zones (PWSCC at RTZ)**

Seven of the approximately 167 new indications of PWSCC at RTZs were pressure tested in situ including the largest voltage indications. No leakage was identified. This is the second inspection using the +Point coil of the roll transition zones. Since these indications did not leak, new indications are not expected to leak either and do not present leakage or structural integrity concerns during the next cycle.

6. **Primary Water Stress Corrosion Cracking at the Low Row U–bends (PWSCC at U–bends)**

This is the second u-bend indication in Unit 1 and it was plugged. The indication was about 0.2 inches long. It did not leak or burst under 3 times normal operating pressure differential conditions. Since the +Point coil was used to examine all of the row 1 and 2 u-bends, there is reasonable assurance that u-bend degradation growth will not exceed structural and leakage integrity for the next cycle.

7. **Secondary Side IGA/SCC at the Tube Support Plates**

All but two distorted bobbin coil indications at the tube support plates were examined by +Point coil. All which were confirmed as volumetric and not associated with cold leg tube support plate thinning and the two not examined by

+Point were plugged. None of the bobbin coil indications at IGA/SCC locations exceeded 2 volts. In accordance with Tech Specification 4.12 and Generic Letter 95-05, a report will be submitted for the voltage based repair criteria within ninety days of Unit 1 startup. Preliminary operational assessment calculations meet the acceptance criteria for main steam line break leakage and for conditional probability of burst. Therefore, this degradation mechanism does not appear to present leakage or structural integrity concerns during the next cycle.

8. Manufacturing Burnishing Marks in crevice regions

All manufacturing burnishing marks could be traced back to 1988 and showed no change. Therefore, there does not appear to be any degradation associated with the manufacturing burnishing marks.

9. Degradation at Dented Tube Support Plates and All Other Locations

All dents > 5.0 volts were examined with +Point. No indications of degradation were found.

10. Indications at Tube Ends

There is an increasing number of indications associated with the tube ends in 11 steam generator. The number has increased from 29 in 1996 to 113 in 1997. These indications are located at or below the seal weld. There is sufficient hard roll present above these indications to meet F* criteria. These indications do not present a structural or leakage integrity concern.

11. Degradation in Sleeves

Forty six old sleeves and one new sleeve contained weld zone indications requiring resolution. One old sleeve left in service in 1996 with a volumetric indication could not be examined in 1997 due to physical restrictions in the sleeve. Thirteen of the sleeve weld zone indications appeared to be new, but upon reanalysis of the 1996 ET data were determined to be unchanged from 1996. One old indication and the one new indication were accepted for continued service and the remaining 45 sleeves were plugged.

In 1996, 34 volumetric indications had been left in service under Safety Evaluation 436. There were 13 additional sleeve weld zone indications identified this outage. Upon review of the eddy current data from 1996, it was determined that all 13 of these new indications existed in 1996 and had not changed. This increase in number of indications is attributed to the knowledge gained from the Prairie Island 1996 sleeve pulls, the Site Specific Performance Demonstration for the eddy current analysts, and analyst performance tracking which gives analysts daily feedback on their performance compared to the final resolution calls. Only one new sleeve contained an ET weld zone indication. This indication was a volumetric indication above the weld centerline.

All tubes with sleeves with eddy current indications which did not meet the new eddy current acceptance criteria for location of weld zone indications above the weld centerline were plugged. In addition, weld zone indications for which the location with respect to the weld centerline were ambiguous were plugged. The only remaining weld zone indications in service (R5C20 and R13C67) are volumetric indications located significantly above the weld centerline.

Previous operation with the sleeves did not present a safety issue based on the results of the 1996 sleeve pull analysis and based in situ pressure tests with zero leakage of three sleeves during the 1997 inspection. As stated in NSP's June 27, 1996 letter to the NRC on sleeving issues, the root cause of the ET indications and the discontinuities in the sleeve welds was inadequate removal of the contaminants and oxide from inside of the parent tube prior to sleeve insertion resulting in oxide inclusions captured in the sleeve weld. The improved cleaning process was 100% successful this outage.

12. Degradation in Additional Roll Expansions (Re-Rolls)

There were no F* rerolls with new degradation.

13. Structural Degradation of the Tube Support Plates

During the October 1997 eddy current examination of 11 SG, bobbin coil data was analyzed to determine if indications of possible tube support plate ligament anomalies were present. When bobbin coil data identified such anomalies, they were coded PSI and rotating coil technology (RPC) was used to reexamine the PSI intersections. From the RPC data, 6 tube support plate intersections in 11 SG and 3 tube support plate intersections in 12 SG were confirmed to have indications of possible tube support plate ligament "cracks". Three indications in 11 steam generator are at patch plate locations. Three of the indications in 11 SG and the three indications in 12 SG are in the outer periphery suspect locations identified in Westinghouse letter WOG-97-186, "Transmittal of NEI Sponsored Steam Generator Internals Degradation Interim Inspection Guidelines".

The Plus-Point eddy current probe characterization showed that none of these indications reflected significant missing ligaments. (The largest possible ligament gap was less than 50 degrees. The minimum gap that would permit a tube to move into a larger displacement mode under flow induced vibration is 146 degrees).

It is also noted that there is no detectable tube degradation at the locations of the possible degraded tube support plate ligaments. Therefore, none of these indications required plugging.

The bobbin coil data for these possible support plate ligament indications was reviewed from 1988 and found to be unchanged. Thus it is likely that these conditions reflect steam generator as-built conditions which resulted from misalignment of drilling of flow holes or tube holes as has been visually verified at Diablo Canyon.

Therefore, since there is no indication of active degradation in the tube support plates or in the tubes at the suspect locations, the possible support plate ligament cracks do not represent a concern for the forthcoming operating cycle. The exact cause of the source of the indications is not known.

14. Potential Degradation in Tube Plugs

All tube plugs were examined visually. No indications of leakage were found.

Summary of Operational Assessment

An evaluation of all indications of degradation confirms that none of the forms of degradation occurring presents a structural or leakage integrity concern for the next cycle of operation.

Remedial Actions

Northern States Power has participated in utility funded research on steam generator related issues beginning with the Steam Generator Owners Group II in 1982 and continuing to the present EPRI funded Steam Generator Management Project. Remedial actions to reduce and/or prevent tube degradation due to primary water stress corrosion cracking and secondary side IGA/SCC have been used by the industry with only limited success. Prairie Island has evaluated, and in most cases, implemented the following remedial actions:

> Reduced Operating Temperature: Prairie Island has been a low temperature plant having operated with Thot at 590 °F since startup. This has slowed, but not eliminated, growth of PWSCC and IGA/SCC in the Prairie Island steam generators. Additional temperature reduction has not been warranted.
>
> Chemistry Control: Prairie Island has used state of the art analytical equipment since startup and has followed both the original equipment manufacturer's water chemistry guidelines as well as the EPRI secondary water chemistry guidelines. The amounts of material found from hideout return tests during shutdowns have been small.

Steam generators are sludge lanced every other outage on a cycling basis with less than 80 pounds of sludge removed from the steam generator per outage. The PWSCC degradation is relatively independent of chemistry and occurs in regions of high residual stress. Plasticor repairs of the condenser tubesheets has reduced circulating water in leakage to a very low level.

High Hydrazine Control: Prairie Island maintains a hydrazine control band of 125 +/- 25 ppb.

Molar ratio control to reduce secondary side corrosion: Molar ratio control has been attempted by adjustments to steam generator blowdown resin ratios during the last operating cycle. Operating molar ratios are normally less than 1. The object of molar ratio control is to maintain the cation to anion ratio (sodium to chloride plus sulfate) at less than one so that free sodium hydroxide can not form in the crevice regions.

Conduct Crevice Flushing Operations with Boric Acid: Prairie Island started crevice flushing in 1986 using two days of time. Since then we have added boric acid to the crevice flushing procedure. The time has been reduced to 24 hours since only a small amount of contaminants are being removed. This effects only the tubesheet crevice region.

On-line addition of Boric Acid: Following the report of favorable laboratory results in 1986, Prairie Island began on-line addition of boric acid in Unit 1 in March 1987. The effectiveness of this remedial action remains controversial within the industry (EPRI IGA/SCC workshops in May 1991 and December 1992). Prairie Island will continue to use boric acid until such time as an inhibitor of equal or greater effectiveness is justified for on-line use. One of the recommended boric acid practices, low power soaks, has not been implemented at Prairie Island.

Use of other chemical inhibitors: At the present time, NSP supports EPRI research for other chemical inhibitors. Our current evaluations centers around the use of titanium compounds to inhibit the growth of IGA/SCC. A titanium chelate, TYZOR LA Titanate has been added since January 1994.

Preventive sleeving: Sleeving is one method of reducing the probability of tube leak outages. The down side of preventive sleeving is the inability to follow the degradation mechanism and the reduction in the ability to examine tube support plate intersections above the sleeves. NSP has made the strategic decision to sleeve on an as-needed basis, to insure that we are able to best follow the tube support plate problems and to reduce our overall cost of steam generator repair and maintenance.

F* Repair Criteria: The F-Star Alternate Repair Criteria allows tubes to remain in service with indications below the F* distance. Additional Roll Expansion adds a new F* distance to the steam generator tubing and allows additional tubes to remain in service which have degradation in the lower tubesheet crevice region.

Detailed Inspection Plans: Although not a recommendation for remedial actions, but rather a current inspection guideline, 100% of the full length of all tubes in service are routinely examined at Prairie Island. This was started in 1982. In addition, all tubes with indications which can not be quantified, such as NQI's, DSI's, MBM's (in the tubesheet) are examined with the rotating coil probe due to its higher sensitivity. Repair decisions, in those cases, are based on the RPC results.

Table 2: Prairie Island Steam Generator Tube Degradation and Repair Status

Type of Degradation	11 SG	12 SG	21 SG	22 SG
Cold Leg TSP Thinning	57	33	71	130
Antivibration Bar Wear	24	3	9	31
Tubesheet Sec Side IGA/SCC Only	10	716	22	4
Roll Transition Zone PWSCC Only	14	255	462	224
RTZ PWSCC and Sec Side IGA/SCC	2	36	6	0
Hot Leg Tube Support Plate	22	41	0	0
U-Bend PWSCC	1	2	1	0
Loose Parts	8	0	2	2
Free Span & Top of Tubesheet	13	16	4	6
Tube End Axial Indications	113	0	82	53
Other	4	3	6	4
Total Tubes Defective	**268**	**1105**	**665**	**454**

Type of Repair				
Tubes Plugged	149	271	165	193
Tubesheet Sleeves (IGA/SCC)* (1)	0	852	0	0
F*0 Alternate Repair Criteria	113	0	82	53
F*1 & F*2 ARC w/ Additional Roll Expansions	6	6	418	208
Total Tubes Repaired	268	1129	665	454
% Equivalent Plugged	**4.40%**	**8.90%**	**4.87%**	**5.70%**
% Equivalent Plugged per Unit	***6.65%***		***5.28%***	

(1)Includes 26 preventive sleeves in 12 SG, *28 Sleeves = 1 plug

ATTACHMENT 3

F* Tube Report

11 STEAM GENERATOR F*0 TUBES, November 23, 1997

GEN	LEG	ROW	COL	INDICATION	LOCATION & EXTENT	RPRSTAT
11	H	2	14	SAI	TRH - 2.7TO- 2.5	F*0
11	H	3	14	SAI	TRH - 2.7TO- 2.6	F*0
11	H	1	15	SAI	TRH - 2.8TO- 2.7	F*0
11	H	2	17	SAI	TRH - 2.9TO- 2.8	F*0
11	H	3	21	MAI	TRH - 3.0TO- 2.9	F*0
11	H	1	25	MAI	TRH - 2.8TO- 2.6	F*0
11	H	4	25	MAI	TRH - 2.7TO- 2.5	F*0
11	H	5	25	MAI	TRH - 2.6TO- 2.5	F*0
11	H	10	25	SAI	TRH - 2.6TO- 2.5	F*0
11	H	20	25	SAI	TRH - 2.6TO- 2.5	F*0
11	H	1	27	MAI	TRH - 2.8TO- 2.5	F*0
11	H	6	27	SAI	TRH - 2.7TO- 2.6	F*0
11	H	1	28	SAI	TRH - 2.8TO- 2.6	F*0
11	H	1	29	MAI	TRH - 2.9TO- 2.8	F*0
11	H	5	29	SAI	TRH - 2.7TO- 2.5	F*0
11	H	19	29	MAI	TRH - 2.5TO- 2.4	F*0
11	H	20	29	SAI	TRH - 2.6TO- 2.5	F*0
11	H	1	30	SAI	TRH - 2.7TO- 2.6	F*0
11	H	5	30	SAI	TRH - 2.6TO- 2.5	F*0
11	H	7	30	SAI	TRH - 2.7TO- 2.5	F*0
11	H	9	30	SAI	TRH - 2.8TO- 2.7	F*0
11	H	13	30	SAI	TRH - 2.8TO- 2.7	F*0
11	H	14	30	SAI	TRH - 2.6TO- 2.5	F*0
11	H	19	30	MAI	TRH - 2.8TO- 2.7	F*0
11	H	20	30	SAI	TRH - 2.5TO- 2.5	F*0
11	H	21	30	SAI	TRH - 2.6TO- 2.6	F*0
11	H	1	31	SAI	TRH - 2.6TO- 2.5	F*0
11	H	5	31	SAI	TRH - 2.5TO- 2.4	F*0
11	H	7	31	MAI	TRH - 2.5TO- 2.5	F*0
11	H	9	31	MAI	TRH - 2.6TO- 2.6	F*0
11	H	10	31	SAI	TRH - 2.7TO- 2.6	F*0
11	H	13	31	SAI	TRH - 2.6TO- 2.5	F*0
11	H	15	31	MAI	TRH - 2.5TO- 2.4	F*0
11	H	19	31	MAI	TRH - 2.6TO- 2.5	F*0
11	H	21	31	SAI	TRH - 2.6TO- 2.5	F*0
11	H	1	32	MAI	TRH - 3.0TO- 2.8	F*0
11	H	6	32	SAI	TRH - 2.6TO- 2.6	F*0
11	H	13	32	SAI	TRH - 2.6TO- 2.5	F*0
11	H	2	33	SAI	TRH - 2.5TO- 2.5	F*0
11	H	12	33	SAI	TRH - 2.6TO- 2.6	F*0

11 STEAM GENERATOR F*0 TUBES, November 23, 1997

GEN	LEG	ROW	COL	INDICATION	LOCATION & EXTENT			RPRSTAT
11	H	14	33	MAI	TRH	-	2.7TO- 2.6	F*0
11	H	18	33	SAI	TRH	-	2.6TO- 2.5	F*0
11	H	19	33	SAI	TRH	-	2.8TO- 2.7	F*0
11	H	1	34	SAI	TRH	-	2.8TO- 2.7	F*0
11	H	6	34	SAI	TRH	-	2.5TO- 2.4	F*0
11	H	9	34	SAI	TRH	-	2.7TO- 2.6	F*0
11	H	10	34	SAI	TRH	-	2.5TO- 2.4	F*0
11	H	13	34	SAI	TRH	-	2.6TO- 2.5	F*0
11	H	14	34	SAI	TRH	-	2.6TO- 2.5	F*0
11	H	1	35	SAI	TRH	-	2.8TO- 2.7	F*0
11	H	2	35	SAI	TRH	-	2.6TO- 2.5	F*0
11	H	15	35	SAI	TRH	-	2.4TO- 2.4	F*0
11	H	1	36	MAI	TRH	-	3.1TO- 2.9	F*0
11	H	13	36	MAI	TRH	-	2.7TO- 2.6	F*0
11	H	16	36	MAI	TRH	-	2.5TO- 2.4	F*0
11	H	21	36	SAI	TRH	-	2.6TO- 2.5	F*0
11	H	2	37	MAI	TRH	-	3.0TO- 2.9	F*0
11	H	9	37	SAI	TRH	-	2.9TO- 2.8	F*0
11	H	14	37	MAI	TRH	-	2.9TO- 2.8	F*0
11	H	16	37	MAI	TRH	-	2.6TO- 2.4	F*0
11	H	1	38	SAI	TRH	-	2.6TO- 2.5	F*0
11	H	8	38	MAI	TRH	-	2.6TO- 2.5	F*0
11	H	13	38	SAI	TRH	-	2.7TO- 2.7	F*0
11	H	14	38	SAI	TRH	-	2.9TO- 2.8	F*0
11	H	16	38	SAI	TRH	-	2.7TO- 2.7	F*0
11	H	22	38	SAI	TRH	-	2.8TO- 2.7	F*0
11	H	1	39	MAI	TRH	-	2.6TO- 2.5	F*0
11	H	2	39	SAI	TRH	-	2.6TO- 2.5	F*0
11	H	7	39	SAI	TRH	-	2.5TO- 2.4	F*0
11	H	20	39	SAI	TRH	-	2.8TO- 2.7	F*0
11	H	22	39	SAI	TRH	-	2.9TO- 2.8	F*0
11	H	35	39	SAI	TRH	-	2.6TO- 2.5	F*0
11	H	1	40	MAI	TRH	-	2.6TO- 2.5	F*0
11	H	4	40	SAI	TRH	-	2.5TO- 2.4	F*0
11	H	22	40	SAI	TRH	-	2.5TO- 2.4	F*0
11	H	1	41	SAI	TRH	-	2.6TO- 2.5	F*0
11	H	4	41	SAI	TRH	-	2.8TO- 2.7	F*0
11	H	18	41	SAI	TRH	-	2.7TO- 2.7	F*0
11	H	20	41	SAI	TRH	-	2.9TO- 2.8	F*0
11	H	20	42	SAI	TRH	-	2.9TO- 2.8	F*0
11	H	21	42	SAI	TRH	-	2.4TO- 2.3	F*0

11 STEAM GENERATOR F*0 TUBES, November 23, 1997

GEN	LEG	ROW	COL	INDICATION	LOCATION & EXTENT	RPRSTAT
11	H	1	43	SAI	TRH - 2.6TO- 2.5	F*0
11	H	17	43	MAI	TRH - 2.5TO- 2.4	F*0
11	H	22	43	SAI	TRH - 2.6TO- 2.5	F*0
11	H	1	44	SAI	TRH - 2.7TO- 2.6	F*0
11	H	10	44	SAI	TRH - 2.6TO- 2.5	F*0
11	H	17	44	SAI	TRH - 2.7TO- 2.6	F*0
11	H	19	44	SAI	TRH - 2.5TO- 2.4	F*0
11	H	21	44	SAI	TRH - 2.5TO- 2.4	F*0
11	H	22	44	SAI	TRH - 2.6TO- 2.5	F*0
11	H	1	45	SAI	TRH - 2.5TO- 2.6	F*0
11	H	6	45	SAI	TRH - 2.4TO- 2.6	F*0
11	H	19	45	MAI	TRH - 2.6TO- 2.5	F*0
11	H	21	46	MAI	TRH - 2.8TO- 2.7	F*0
11	H	1	48	SAI	TRH - 2.8TO- 2.9	F*0
11	H	2	49	SAI	TRH - 2.7TO- 2.6	F*0
11	H	1	50	MAI	TRH - 2.7TO- 2.6	F*0
11	H	1	51	SAI	TRH - 2.6TO- 2.5	F*0
11	H	1	54	MAI	TRH - 2.6TO- 2.5	F*0
11	H	1	55	SAI	TRH - 2.6TO- 2.4	F*0
11	H	5	55	MAI	TRH - 2.5TO- 2.4	F*0
11	H	1	56	SAI	TRH - 2.5TO- 2.5	F*0
11	H	1	58	SAI	TRH - 2.7TO- 2.8	F*0
11	H	1	59	SAI	TRH - 2.9TO- 2.8	F*0
11	H	19	60	MAI	TRH - 2.5TO- 2.3	F*0
11	H	12	63	SAI	TRH - 2.6TO- 2.5	F*0
11	H	1	65	SAI	TRH - 2.8TO- 2.9	F*0
11	H	1	70	MAI	TRH - 2.7TO- 2.6	F*0
11	H	1	72	SAI	TRH - 2.8TO- 2.8	F*0
11	H	1	73	SAI	TRH - 2.8TO- 2.7	F*0
11	H	1	76	SAI	TRH - 2.8TO- 2.7	F*0
11	H	1	78	SAI	TRH - 2.8TO- 2.5	F*0
11	H	1	87	SAI	TRH - 2.7TO- 2.5	F*0

Grand Count 113

F*0 = F* TUBE WITHOUT ADDITIONAL ROLL EXPANSION
MAI = MULTIPLE AXIAL INDICATION
SAI = SINGLE AXIAL INDICATION
TRH = TOP OF ROLL HOT LEG

11 STEAM GENERATOR F*1 TUBES, November 23, 1997

GEN	LEG	ROW	COL	INDICATION	LOCATION & EXTENT	RPRSTAT
11	H	23	17	SAI	1BH - 2.1TO- 1.8	F*1
11	H	23	17	MAI	1BH - 2.0TO- 2.4	F*1
11	H	8	27	SAI	TRH - 0.1TO+ 0.1	F*1
11	H	30	46	SAI	TRH - 0.0TO+ 0.1	F*1
11	H	5	56	SAI	1BH - 1.4TO- 1.3	F*1
11	H	5	57	SAI	TRH - 0.1TO+ 0.1	F*1
11	H	8	78	MAI	1BH - 2.9TO- 2.2	F*1

Grand Count 7

NOTE: ONE TUBE IS COUNTED TWICE

1BH	=	BOTTOM OF ADDITIONAL HARD ROLL 1
F*1	=	F* TUBE WITH ONE ADDITIONAL ROLL EXPANSION
MAI	=	MULTIPLE AXIAL INDICATION
SAI	=	SINGLE AXIAL INDICATION
TRH	=	TOP OF ROLL HOT LEG

12 STEAM GENERATOR F*1 TUBES, November 23, 1997

GEN	LEG	ROW	COL	INDICATION	LOCATION & EXTENT	RPRSTAT
12	H	34	31	MAI	1BH - 1.2TO- 1.1	F*1
12	H	37	38	MAI	1BH - 1.3TO- 1.1	F*1
12	H	31	46	SAI	TRH + 0.1TO+ 0.3	F*1
12	H	31	46	SAI	1BH - 1.2TO- 1.1	F*1
12	H	31	47	MAI	TRH + 0.1TO+ 0.1	F*1
12	H	32	47	MAI	TRH + 0.1TO+ 0.2	F*1
12	H	4	71	MAI	1BH - 1.6TO- 1.2	F*1

Grand Count 7
NOTE: ONE TUBE IS COUNTED TWICE

1BH = BOTTOM OF ADDITIONAL HARD ROLL 1
F*1 = F* TUBE WITH ONE ADDITIONAL ROLL EXPANSION
MAI = MULTIPLE AXIAL INDICATION
SAI = SINGLE AXIAL INDICATION
TRH = TOP OF ROLL HOT LEG

ATTACHMENT 4

Prairie Island Unit 1 In Situ Test List - October 1997 Refueling Outage

Prairie Island Unit 1 October 1997 Steam Generator In Situ Pressure Tests

SG	Row	Column	Indication	Location	Voltage	Reason	Length inch	Width deg	Leakage Result	Max Pressure	Eddy Current Change
11	17	50	MAI	TRH + 2.3 to 4.2	0.41	ODSCC	1.9		0	2850	NO
11	3	64	SAI	TRH + 0.1 to 0.2	1.39	RTZ PWSCC	0.1		0	2850	NO
11	3	64	SAI	TRH + 1.0 to 2.8	0.32	ODSCC	1.8		0	2850	NO
11	25	65	VOL	06H + 44.1 to 44.6	1.74	Free Span VOL	0.5	52	0	5700	NO
11	6	2	VOL	TSC + 0.0 to 0.7	0.86	Top TSC VOL	0.7	52	0	5650	NO
11	12	15	VOL	TSC + 0.4 to 0.7	0.82	Top TSC VOL	0.3	48	0	5650	NO
11	25	24	VOL	TSC + 23.8 to 24.0	0.61	Free Span VOL	0.[illegible]	43	0	5650	NO
11	27	20	VOL	TSH + 0.0 to 0.1	0.44	Top TSH VOL	0.1	47	0	5650	NO
11	20	89	VOL	01C + 0.1 to - 0.3	1.82	CLTSP Wastage VOL	0.4	82	0	5650	NO
12	42	47	SAI	TSH + 0.3 to 0.7	1.32	ODSCC	0.4		0	5300	NO
12	17	48	SAI	TSH + 0.1 to 0.6	1.22	ODSCC	0.5		0	5300	YES
12	14	41	SAI	TSH + 0.1 to 0.8	1.91	ODSCC	0.7		0	5300	Yes(1)
12	9	7	MAI	TRH + .5 to 10.8	0.48	ODSCC	10.3		0	2900	Yes
12	4	8	MAI	TRH + 0.5 to 9.5	1.19	ODSCC	9.0		0	2900	Yes
12	9	9	MAI	TRH + 1.2 to 10.3	0.52	ODSCC	9.1		0	2900	Yes
12	16	12	MAI	TRH + 4.1 to 10.0	0.63	ODSCC	5.9		0	2900	Yes
12	13	14	SAI	TRH + 0.4 to 9.7	0.2	ODSCC	9.3		0	2900	Yes
12	24	47	SAI	TRH + 4.8 to 8.3	1.2	ODSCC	3.5		0	2900	Yes
12	19	76	SAI	TRH + 7.2 to 12.2	0.66	ODSCC	5.0		0	2900	Yes
12	2	77	MAI	TRH + 0.6 to 3.2	1.03	ODSCC	2.6		0	2900	Yes
12	12	68	SAI	TRH + 0.0 to 0.1	1.76	RTZ PWSCC	0.1		0	2900	NO
12	12	68	SAI	TRH + 1.2 to 10.8	0.34	ODSCC	9.6		0	2900	Yes
12	11	32	VOL	TRH + 0.3 to 3.1	0.41	TSH VOL	2.8	45	0	3000	NO(1)
12	24	32	VOL	TRH + 3.5 to 3.7	0.68	TSH VOL	0.2	61	0	3000	Yes (1)
12	24	32	VOL	TRH + 4.6 to 4.8	0.56	TSH VOL	0.2	43	0	3000	Yes (1)
12	14	21	MAI	TRH - 0.1 to + 0.0	7.32	RTZ PWSCC	0.1		0	2900	Yes (1)
12	34	30	SAI	TRH + 0.1 to 0.2	3.45	RTZ PWSCC	0.1		0	2900	NO
12	27	47	SAI	TRH + 0.05 to 0.12	5.1	RTZ PWSCC	0.1		0	2900	NO(1)
12	16	51	MAI	TRH + 0.1 to 0.2	5.02	RTZ PWSCC	0.1		0	2900	Yes (1)
12	4	72	MAI	TRH + 0.1 to 0.3	7.93	RTZ PWSCC	0.2		0	2900	NO
12	1	46	SAI	07H + 3.7 to 3.9	2.53	U-Bend PWSCC	0.2		0	5300	NO
12	42	48	VOL	TSH + 0.5 to 0.7	1.32	Top TSH VOL	0.2	71	0	5700	NO
12	44	59	VOL	TSH + 13.3 to 13.5	0.65	Free Span VOL	0.2	41	0	5700	NO
12	26	78	VOL	TSC - 0.1 to + 0.2	2.17	Top TSC VOL	0.2	58	0	5700	NO
12	6	45	SCI	WCH - 0.1 to 0.1	2.1	Weld Inclusion	0.2	187	0	5700	NO
12	23	67	VOL	WCH - 0.3 to + 0.1	1.5	Weld Suckback	0.4	71	0	5700	NO
12	7	68	VOL	WCH - 0.2 to + 0.3	16.21	Weld Suckback	0.5	105	0	5700	N.A. (2)

(1) New axial indications representative of ODSCC appeared after in situ pressure test

(2) In Situ Tool became stuck and could not be removed. No post ET examination was conducted