APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-528/94-27
50-529/94-27
50-530/94-27

Licenses: NPF-41
NPF-51
NPF-74

Licensee: Arizona Public Service Company
P.O. Box 53999
Phoenix, Arizona

Facility Name: Palo Verde Nuclear Generating Station, Units 1, 2, and 3

Inspection At: Maricopa County, Arizona

Inspection Conducted: August 15-24,1994

Inspector: I. Barnes, Technical Assistant
Division of Reactor Safety

Accompanied By: W. Sifre, Reactor Engineer, Technical Support Staff
Division of Reactor Projects

Approved: John L. Pellet 9-29-94
John L. Pellet, Acting Deputy Director Date
Division of Reactor Safety

Inspection Summary

Areas Inspected (Units 1, 2, and 3): Regional initiative, announced inspection of steam generator secondary chemistry history and program initiatives to mitigate conditions contributing to tube degradation.

Results (Units 1, 2, and 3):

- The lower incidence of inservice degradation in the Unit 3 steam generators was considered to be related to preventive tube plugging performed prior to commercial operation, and tighter process controls being used during manufacture of the Unit 3 steam generator tubing (Section 2.1).

- The current absence of "arc" region upper tube bundle defect indications in the Unit 1 steam generators was considered to be potentially related

to the maintenance of lower molar ratio values in this unit and to the more limited exposure of this unit to out-of-specification secondary water chemistry conditions (Sections 2.1 and 2.3).

- The development of larger sludge piles in the Unit 1 steam generators than those in Units 2 or 3, which has resulted in a greater Unit 1 incidence of stress corrosion cracking at the tube sheet location, was viewed as probably being caused by the more limited Unit 1 use of abnormal rate blowdown in the steam generators (Section 2.2).

- The licensee has been successful in progressively reducing sodium ingress into the steam generators in all three units (Section 2.3).

- The licensee has aggressively responded to identified steam generator tube degradation by implementation of three secondary water chemistry program initiatives (i.e., use of ethanolamine, reduction of crevice molar ratios by ammonium chloride injection, and boric acid treatment). These initiatives which are based, in part, on Electric Power Research Institute recommendations should be of benefit in both reducing iron transport to the unit steam generators (with resulting reduction in sludge and deposit buildup) and reducing crevice pH to a range where resistance to stress corrosion cracking is improved (Sections 3.1, 3.2, and 3.3).

- Insufficient data is currently available, due to the relatively recent implementation of the chemistry initiatives, to allow an assessment of their impact (Sections 3.1, 3.2, and 3.3).

Summary of Inspection Findings:

- Inspection Followup Item 528;529;530/9415-01 was reviewed but not closed (Section 4.1).

- Inspection Followup Item 529/9415-03 was closed (Section 4.2).

- Inspection Followup Item 528;529;530/9415-05 was closed (Section 4.3).

Attachment:

- Attachment - Persons Contacted and Exit Meeting

DETAILS

1 STEAM GENERATOR TUBE INTEGRITY REVIEW (79501, 79502)

An initial steam generator tube integrity review inspection was performed during April 19-29 and May 9-13, 1994, which was documented in NRC Inspection Report 50-528;-529;-530/94-15. The objectives of the initial inspection were: (a) to ascertain the history and material condition of the Units 1, 2, and 3 steam generator tubing; and (b) to assess the effectiveness of licensee programs in detection and analysis of degraded tubing, repair of defects, and correction of conditions contributing to tube degradation. This second inspection was performed to complete reviews of steam generator secondary water chemistry history and program initiatives to mitigate conditions contributing to tube degradation.

2 SECONDARY WATER CHEMISTRY HISTORY

2.1 Off-Normal Secondary History

During this inspection, the inspectors requested information from the licensee in regard to the accumulated hours that secondary water chemistry in individual steam generators had exceeded Action Levels 1, 2, or 3 as defined in Electric Power Research Institute Document EPRI TR-102134, "PWR Secondary Water Chemistry Guidelines," Revision 3. This request was made in order to ascertain whether differences existed in operational chemistry history between units that were of a magnitude which would provide insights into the observed apparent difference in unit steam generator tubing degradation rates (see Section 4.1 below). Data furnished by the licensee in response to this request is summarized below in Table 1.

Table 1

Unit Cumulative Secondary Water Chemistry Action Level Hours

SECONDARY WATER CHEMISTRY ACTION LEVEL HOURS (1987-1994)								
Unit 1			Unit 2			Unit 3		
*SG 11	*SG 12	Total	*SG 21	*SG 22	Total	*SG 31	*SG 32	Total
596	284	880	643	752	1395	1315	1554	2869

*SG - Steam Generator

The above data indicated to the inspectors that the degree of conformance with secondary water chemistry program requirements had differed between the three units, with Unit 3 showing a significantly greater number of accumulated action level hours than the other two units. The inspectors previously noted in NRC Inspection Report 50-528;-529;-530/94-15, Section 2.1, that the accrued effective full power years of operation as of April 1994 were not

significantly different between the units (i.e., 4.89, Unit 1; 4.95, Unit 2; and 4.43, Unit 3). This effective full power year data indicated that the differences in secondary water chemistry action level hours between units did not occur simply as a result of differences in time of operational service. The inspectors noted that, despite Unit 3 having accumulated the greatest number of secondary water chemistry action level hours, the number of steam generator inservice tube repairs was currently significantly lower for this unit than for Units 1 and 2. The inspectors did not believe sufficient information was available to fully define the reasons for the lower inservice degradation in the Unit 3 steam generators. The inspectors considered, however, that it was related, in part, to preventive tube plugging being performed prior to commercial operation, and tighter process controls being used during manufacture of the Unit 3 steam generator tubing.

The inspectors also noted that Unit 1, which had accumulated the lowest total action level hours, was the only one of the three units in which outside diameter stress corrosion cracking had not currently been identified in the upper tube bundle of the steam generators. These upper bundle defects, which have principally been detected in Unit 2 steam generators, were concentrated on the hot-leg side of the steam generators in an "arc" region of tubes near the periphery of the tube bundle. Thermal-hydraulic analysis performed by the licensee confirmed that this region and location of the steam generator would be subject to dryout and resulting buildup of deposits. The inspectors considered that the current absence of "arc" region upper bundle defect indications in the Unit 1 steam generators was potentially related to the more limited exposure to out-of-specification secondary water chemistry conditions, which would result in a reduced concentration of impurities in dryout areas.

The inspectors previously noted in NRC Inspection Report 50-528;-529; -530/94-15, Section 2.4.4, that the incidence of stress corrosion cracking in steam generator tubing was higher, for each unit, in the second steam generator than the first. Review of the data in Table 1 did not indicate to the inspectors any clear relationship between secondary water chemistry action level hours for the individual steam generators and extent of inservice repairs.

2.2 Use of Abnormal Rate Blowdown

During the inspection, the inspectors reviewed licensee Report, "Status of PVNGS Steam Generator Activities" dated August 1994, which was transmitted to the NRC by Letter 102-03083 dated August 11, 1994. In this report, the licensee identified that pre-1993 tube sheet sludge piles were larger in Unit 1 than in either Units 2 or 3. The report also noted, with respect to stress corrosion cracking in tubes at this location, that there was a consistent sludge pile/defect relationship. The inspectors previously noted

in NRC Inspection Report 50-528;-529;-530/94-15, Section 6.1, that review of monthly performance monitoring reports (in the time period February 1991 though April 1994) indicated that variations had occurred between units in the use of abnormal rate blowdown. The data obtained from the review is listed below in Table 2. This data shows that the Unit 1 average hours/month use of abnormal rate blowdown was approximately half of that used in Units 2 and 3. The inspectors viewed the difference in abnormal rate blowdown use as the probable reason for the Unit 1 steam generators developing larger sludge piles than those in Units 2 or 3, and hence showing a greater incidence of stress corrosion cracking in the Unit 1 steam generators at this location.

Table 2

Unit Abnormal Rate Blowdown Data

Unit	Hours Used	Months	Mean Hours/Month
1	5,198	34	153
2	8,689	29	300
3	10,112	36	281

Use of abnormal (increased) blowdown rates is the practice used to restore discrepant steam generator secondary water chemistry values to within program limits. The inspectors were informed by licensee personnel that the lower number of action level hours in Unit 1 would result in a lower utilization of abnormal rate blowdown than in Units 2 or 3. The inspectors agreed with this comment. The inspectors noted, however, from review of historical chemistry control instructions that use of abnormal rate blowdown for a period of hours each day appeared to have been a common practice in Units 2 and 3, irrespective of the status of conformance of steam generator secondary water chemistry with program requirements. Routine use of abnormal rate blowdown was not as evident in the Unit 1 steam generators when secondary water chemistry conformed to program requirements.

2.3 Chemistry Trend Information

In addition to the information discussed in Section 2.2 regarding sludge pile differences between Unit 1 and the other two units, the licensee included in its August 1994 status report chemistry information that was considered pertinent to explaining the current absence of upper tube bundle outside diameter stress corrosion cracking in the Unit 1 steam generators. Included in this information was a statement to the effect that 1988-1993 recorded data showed that Unit 1 had maintained lower sodium levels than Units 2 and 3. The inspectors questioned licensee staff concerning this information, in that

graphical trend information seen by the inspectors during the inspection indicated that annual Unit 1 sodium values were not consistently lower than the corresponding values for the other two units in each of the referenced years. Licensee personnel explained that the data the report statement was based on was the unit average sodium values (at 20 percent power or greater) for the entire 1988-1993 period. These values were ascertained by the inspectors to be 4.0 ppb for Unit 1, 4.8 ppb for Unit 2, and 4.6 ppb for Unit 3. The graphical trend information indicated to the inspectors that the licensee has been successful in progressively reducing sodium ingress into the steam generators in all three units. For example, the average sodium values for the three units ranged in 1988 from approximately 7 to 10.5 ppb, as compared to a range of approximately 2.5 to 3.5 ppb in 1993.

Unit 1 condensate dissolved oxygen values were also indicated by the August 1994 status report to historically have been lower than the other units. The inspectors confirmed that this information was accurate for the time period 1991 to present, with the average values determined to be 2.5 ppb for Unit 1, 5.1 ppb for Unit 2, and 4.1 ppb for Unit 3. This data was developed from measurements made using inline analyzers. Problems were identified with the reliability of the method used prior to 1991, which precluded meaningful assessment for that time period. The inspectors considered the licensee dissolved oxygen information to be significant in regard to the possible result of reduced iron transport to and lower electrochemical potential conditions in the Unit 1 steam generators.

The inspectors additionally confirmed a statement made in the August 1994 status report (regarding Unit 1 having always maintained the lowest molar ratio of the three units) by review of average annual molar ratio values for operation at 20 percent power or greater. The annual data values were found to be consistently lower for Unit 1, with the average molar ratio values for the time period from 1988 through the first quarter of 1994 determined to be 1.3 for Unit 1, 1.9 for Unit 2, and 2.6 for Unit 3. The inspectors concluded that it was reasonable to expect that the history of lower overall molar ratios in Unit 1 could result in a lower incidence of caustic-induced stress corrosion cracking in the upper tube bundle than in the other units. The current more limited incidence of upper tube bundle degradation in Unit 3 steam generators, compared to those in Unit 2, is inconsistent with the molar ratio history. The inspectors noted that the Unit 3 overall average value was significantly influenced by the values obtained during 1988 and 1989 (i.e., 6.8 and 3.8, respectively), with the subsequent values being significantly lower. The inspectors viewed the lower incidence of upper tube bundle degradation in the Unit 3 steam generators in the same manner as discussed in Section 2.1 above regarding action level hours.

2.4 Condenser Tube Leakage History

The licensee stated in its August 1994 status report that Unit 1 has had the lowest condenser leak rate average of the three units, which pointed to lower contaminant ingress from the Unit 1 condenser. The inspectors requested information from the licensee on condenser tube leakage history and were

provided a document entitled, "Condenser Tube Leak Assessment," which was dated August 1992. This document reported the respective history of condenser tube leaks to be five for Unit 1, eight for Unit 2, and two for Unit 3. The individual tube leak rates varied between 0.01 gpm and 0.24 gpm for Unit 1, 0.02 gpm and 154 gpm for Unit 2, and 0.04 gpm and 0.72 gpm for Unit 3. The respective overall average leak rates were 0.07 gpm for Unit 1, 22 gpm for Unit 2, and 0.38 gpm for Unit 3, which confirmed that Unit 1 has had the lowest average leak rate. The inspectors noted that the highest average condenser tube leak rate occurred in Unit 2, the unit with the highest incidence of steam generator tube degradation. The inspectors reviewed steam generator chemistry history in the time frame of the worst Unit 2 condenser tube leak (i.e., 154 gpm in 1990) in order to assess whether significant ingress of contaminants had occurred. Laboratory data indicated that the demineralizers successfully prevented ingress of contaminants. The inspectors recognized, however, that minor ingress may not have been detectable in the hot-leg blowdown samples due to hideout.

2.5 Hideout Return Data

The inspectors performed a limited review of available hideout return data to ascertain whether it provided any insights in regard to apparent differences in unit steam generator tube degradation rates (see Section 4.1 below). An extract of data reviewed is listed below in Table 3.

Table 3

Summary Unit Hideout Return Data

Unit	1						2				3			
Date	1/1992		2/1992		9/1993		8/1991		10/1991		3/1991		8/1991	
Fin. Temp.*	380		317		338		380		305		339		401	
SG**	11	12	11	12	11	12	21	22	21	22	31	32	31	32
Sodium gm	26	40	51	91	13	13	33	18	202	133	25	14	27	33
Chloride gm	12	18	6	12	3	4	0.8	2	2	2	3	6	4	5
Sulfate gm	80	113	26	39	564	379	99	44	130	60	337	26	21	24
M.R.#	3.4	3.5	14	12	7.7	6.8	70	13	147	97	13	3.5	12	14

*Fin. Temp. - Final Temperature °F
**SG - Steam Generator
#M.R. - Molar Ratio (Na+K/Cl)

The inspectors considered the most significant aspects of the above data to be: (a) the high Unit 2 sodium return (and resulting high molar ratio) measured in October 1991, which indicated strongly alkaline crevice conditions; and (b) the high Unit 1 sulfate return measured in September 1993. The high Unit 3 sulfate return that was obtained in March 1991 in only Steam Generator 31 was considered by the inspectors to be of questionable accuracy. Overall, the inspectors did not view the data as providing any insights regarding the greater incidence of stress corrosion cracking in the second steam generator of each unit.

2.6 Chemical Cleaning and Sludge Lancing

The installation of inspection hand holes in the vicinity of the steam generator tube sheets during 1993 (Units 1 and 2) and 1994 (Unit 3) allowed both inspection of the tube sheet region and performance of sludge lancing. The licensee also performed chemical cleaning of the Unit 2 steam generators in January 1994 and of the Unit 3 steam generators in April 1994, with the main focus being the removal of deposits in the upper tube bundle areas. Similar chemical cleaning of the Unit 1 steam generators is planned to be performed during the next refueling outage (1R5) in 1995. Sludge lancing was performed subsequent to the chemical cleaning activity to remove residual deposits on the tube sheets. Sludge lancing was also performed of the Unit 1 steam generator tube sheets following the hand hole installation in November 1993. No data was reviewed by the inspectors regarding the sludge quantities that were removed from the Unit 1 steam generators. The quantities of iron oxide (magnetite) removed during chemical cleaning of the Units 2 and 3 steam generators are listed below in Table 4.

Table 4

Iron Oxide Removed During Chemical Cleaning

UNIT	STEAM GENERATOR	IRON OXIDE (lbs)
2	21	5375
	22	4827
3	31	4668
	32	4658

The inspectors also noted during review of licensee Report, "Unit 3 Steam Generator Inspection Report," dated July 1994, which was transmitted to the NRC by Letter 102-03082 dated August 11, 1994, that the licensee had included additional information regarding chemical cleaning of the Unit 3 steam generators. This data indicated that a total of 5387 and 5123 lbs of deposit were removed from Steam Generators 31 and 32, respectively, during chemical cleaning and sludge lancing. Total weights of sludge removed from Steam

Generators 31 and 32 were, respectively, 525 lbs and 257 lbs. Other significant deposit constituents that were removed during chemical cleaning were nickel oxide (Steam Generator 31-121 lbs, Steam Generator 32-130 lbs) and manganese dioxide (Steam Generator 31-59.9 lbs, Steam Generator 32-61 lbs). Less than 8 lbs of copper was removed from each Unit 3 steam generator, which was to be expected with the condenser tube sheets being the only copper alloys in the secondary side of the plant.

The inspectors also reviewed sludge composition data that was documented in licensee Report 93-001-419.5, "Unit 1 S/G Sludge Analysis - 1R4," and ABB Combustion Engineering Report V-PENG-TR-002, "Palo Verde Nuclear Generating Station Unit 1 Steam Generator Deposit Analysis Report, Fall 1993 Sludge Lancing," Revision 00. The inspectors noted no significant aspects to the data, with the iron content of the sludge determined to be 87 percent and 86 percent for Steam Generators 11 and 12, respectively, and present in the form of magnetite. The copper composition of the sludge was found to be 855 ppm for Steam Generator 11 and 1285 ppm for Steam Generator 12.

2.7 Conclusions

- The lower incidence of inservice degradation in the Unit 3 steam generators was considered to be related to preventive tube plugging being performed prior to commercial operation, and tighter process controls being used during manufacture of the Unit 3 steam generator tubing.

- The current absence of "arc" region upper tube bundle defect indications in the Unit 1 steam generators was considered to be potentially related to the maintenance of lower molar ratio values in this unit and to the more limited exposure of this unit to out-of-specification secondary water chemistry conditions.

- The development of larger sludge piles in the Unit 1 steam generators than those in Units 2 or 3, which has resulted in a greater Unit 1 incidence of stress corrosion cracking at the tube sheet location, was viewed as probably being caused by the more limited Unit 1 use of abnormal rate blowdown in the steam generators.

- The licensee has been successful in progressively reducing sodium ingress into the steam generators in all three units.

3 SECONDARY CHEMISTRY PROGRAM INITIATIVES

In an effort to improve secondary water chemistry and control intergranular attack/stress corrosion cracking, the licensee has initiated implementation of the following Electric Power Research Institute recommended programs.

- Alternative amine injection for iron transport reduction.

- Ammonium chloride injection for crevice molar ratio control.
- Boric acid treatment to reduce caustic environments in the crevices.

In addition to these programs, the licensee included a requirement in Procedure 74AC-9CY04, "System Chemistry Specifications," Revision 11, to reduce power to 86 percent within 8 hours if steam generator blowdown sodium or sulfate levels exceeded 20 ppb (i.e., the Electric Power Research Institute Action Level 1 value for these impurities). Reduction in power to 86 percent minimizes the occurrence of dryout conditions in the upper tube bundle, thus, similarly limiting concentration of contaminants in upper tube bundle deposits.

3.1 Alternative Amine Program

In April 1993, the licensee initiated tests on Unit 1 to compare the performance of ethanolamine against ammonium hydroxide (the pH additive in use since start up) for control of pH and iron transport. The inspectors reviewed the licensee Test Report, "Secondary Chemistry Improvements Ethanolamine (ETA)," and Procedure 74TI-1SC02, "ETA Tests," Revision 00.01. The inspectors ascertained from their review that ethanolamine was chosen for its relatively low volatility which causes preferential distribution in the liquid phase where it may provide improved protection. The licensee's basis for using ethanolamine was Electric Power Research Institute guidelines and past industry experience.

The tests consisted of the injection of ethanolamine in varying concentrations while monitoring cation conductivity, specific conductivity, pH, soluble and insoluble metals, total organic carbons, anions, cations, and condensate polisher performance. Although ammonium hydroxide was not added to the feedwater during the tests, ammonia was present due to the decomposition of hydrazine. The licensee collected baseline iron transport data for various pH values using only the more volatile ammonium hydroxide. With pH values from 9.15 to 10.0, the feedwater iron concentration ranged from approximately 15 ppb at low pH values to approximately 8 ppb at a pH of 10.0. A substantial reduction in iron transport was achieved with a pH of 10.0. However, the high concentration of ammonium hydroxide required to achieve a pH of 10.0 caused a significant reduction of condensate polisher throughput due to ammonia loading of the resins. A summary of the licensee's ethanolamine test results is shown in Table 5. Full-flow polishing was used during the test except as indicated. Test results revealed that the lowest iron concentration was achieved when ethanolamine was combined with ammonia from hydrazine. Overall, the results indicated to the inspectors that the use of ethanolamine was effective in reducing iron transport to the steam generators. The decomposition of ethanolamine resulted in total organic compounds measuring as high as 8 ppm. The licensee determined that the ethanolamine contributed 0.3 ppm organic compounds per ppm of ethanolamine.

Table 5

Ethanolamine Injection Test Results

ETHANOLAMINE (ppm)	AMMONIA (ppm)	pH	IRON (ppb)
1.5 - 2.0	0.1	9.3 - 9.4	8 - 6
2.7	0.1	9.3 - 9.5	6
2.5 - 3.0	0.3 - 0.5	9.4 - 9.6	4 - 6
4.0	5 *	9.7 - 9.9	3

* Increased ammonia concentration due to cycling of polishers to maintain feedwater conductivity < 20 μS/cm.

The inspectors ascertained that subsequent tests performed by the licensee confirmed the results of the initial test. The ethanolamine program was fully implemented in Unit 1 in December 1993 and in Unit 2 in January 1994. The licensee stated that implementation of ethanolamine injection in Unit 3 was projected for August 1994. The inspectors did not see any iron transport data or assessments of the performance of the ethanolamine program since its implementation in Units 1 and 2.

3.2 Ammonium Chloride Injection

In May 1994, the licensee initiated ammonium chloride injection into the secondary systems of Units 1 and 2 for crevice molar ratio control. The same program was implemented in Unit 3 in June 1994. The inspectors reviewed licensee Document 94-001-419.1, "The Injection of Ammonium Chloride to Achieve Steam Generator Crevice Molar Ratio Control," and licensee Procedure 74DP-9SC04, "Ammonium Chloride Injection," Revision 0. The inspectors ascertained that the licensee based its decision to inject ammonium chloride into the secondary systems on Electric Power Research Institute recommendations for molar ratio control, ABB-Combustion Engineering and Westinghouse vendor recommendations, and research of industry experience. The licensee procedures required chemistry personnel to monitor steam generator blowdown and feedwater sodium and chloride levels for the purpose of calculating molar ratio and determining ammonium chloride injection rates. The procedure prescribed a molar ratio band of 0.2 to 0.6 and a limit of 20 ppb chloride in the steam generators.

The inspectors reviewed licensee molar ratio data and trend information. The average molar ratios for various time periods prior to implementation of ammonium chloride injection are shown in Table 6. There was considerable scatter in the data. The majority of the molar ratio values for Units 1 and 2 were in a 0.5 to 1.8 band. The Unit 3 molar ratios ranged from 0.6 to 2.2.

After the implementation of ammonium chloride injection, the data for Unit 1 showed a substantial reduction in scatter, with a majority of the values near 0.5. The data for Unit 2 with ammonium chloride injection retained a considerable amount of scatter, but the band shifted to a range of 0.3 to 1.5. The limited data for Unit 3 with ammonium chloride injection indicated a trend toward the desired molar ratio range.

Table 6

Average Molar Ratios

TIME PERIOD	UNIT 1	UNIT 2	UNIT 3
8/92 - 12/92	1.5	2.5	1.5
1/93 - 8/93	0.8	1.9	1.0
9/93 - 12/93	1.1	1.4	1.6
1/94 - 3/94	0.9	2.9	1.9

3.3 Boric Acid Treatment

In November 1993, the licensee initiated a boric acid treatment program in the Unit 1 secondary system to control intergranular attack/stress corrosion cracking caused by caustic conditions in the crevices. The program was comprised of a 300 ppm boron low power soak and a sustained 5-10 ppm boron concentration during full power operation. A crevice flush with 2000 ppm boron was added to the program when the program was implemented in Unit 2, in March 1994. The boric acid treatment commenced in Unit 3 in May 1994. The inspectors reviewed licensee Document 93-161-419, "Effect of Boric Acid Treatment on Secondary Side Components," dated November 19, 1993, ABB-Combustion Engineering Report TR-MCC-93-224, "Engineering Study For the Evaluation of Boric Acid Treatment for the Secondary System at Palo Verde Unit 2," dated January 20, 1994, and licensee Procedures 74DP-9ZZ15, "Steam Generator Boric Acid Addition," Revision 1 and 42OP-2ZZ13, "Boric Acid Crevice Flush of the Steam Generators," Revision 0. The inspectors ascertained from review of the program and discussions with licensee personnel, that the boric acid program was based on research of industry experience with boric acid addition, including Electric Power Research Institute recommendations and an engineering analysis of the effect of boric acid addition to the secondary system at Palo Verde. The inspectors found that the program requirements were in agreement with the Electric Power Research Institute Report NP-5558-SL, "Boric Acid Application Guidelines for Intergranular Corrosion Inhibition," Revision 1.

The licensee's boric acid treatment program consisted of the following four phases.

- Ambient Soak - The steam generators were filled with a boric acid solution containing 50 ppm boron at wet-layup temperatures for a period of 3 to 4 days following an extended outage. The aim of this phase was the dissolution of soluble impurities in the crevice regions.

- Crevice Flush - A solution containing 2000 ppm boron was applied to the steam generators at approximately 300°F with a nitrogen overpressure. The steam dump valves were cycled to produce periodic rapid depressurization of the steam generators. The rapid depressurization induced localized boiling in the crevices. The aim of this phase was the further dissolution of crevice impurities.

- Low Power Soak - A boric acid solution was applied to the secondary system following an outage, while still below 30 percent power. The boron concentration used depended on the length of the outage. The licensee's program prescribed a 300 ppm boron solution following outages greater than 30 days and a 50 ppm solution following shorter outages. The duration of the soak was determined by a calculated boron demand. The boron demand was a measure of the change in boric acid concentration as it dissolved crevice impurities. When the boric acid concentration stopped declining, the low power soak was concluded.

- On Line Addition - During power operation, the boron concentration of the secondary was maintained between 5 and 10 ppm on the premise that it would aid in preventing the deposition of impurities in the crevice regions.

The inspectors reviewed licensee Document 94-042-404, "Closure Summary for CRDR No. 080266 Action 16." The referenced condition report/disposition request action required the implementation of a boric acid treatment in the secondary side of the Unit 2 steam generators. In this document, the licensee calculated an approximation of the impurities removed and boric acid deposited in the crevices. Based on these approximations the licensee assessed the performance of the Unit 2 crevice soak as a "complete success." The inspectors reviewed steam generator downcomer blowdown chemistry trend data from the Unit 2 crevice flush and found it to be reasonably supportive of the licensee's assessment. However, hideout return data from subsequent outages was considered by the inspectors as a better vehicle for gaining a more accurate indication of the effectiveness of the boric acid treatment program.

3.4 Conclusions

- The licensee has aggressively responded to identified steam generator tube degradation by implementation of three secondary water chemistry program initiatives (i.e., use of ethanolamine, reduction of crevice molar ratios by ammonium chloride injection, and boric acid treatment). These initiatives which are based, in part, on Electric Power Research

Institute recommendations should be of benefit in both reducing iron transport to the unit steam generators (with resulting reduction in sludge and deposit buildup) and reducing crevice pH to a range where resistance to stress corrosion cracking is improved.

- Insufficient data is currently available, due to the relatively recent implementation of the initiatives, to allow an assessment of their impact.

4 FOLLOWUP (92903)

4.1 (Open) Inspection Followup Item 528;529;530/9415-01: Review of reasons for apparent difference in unit steam generator tubing degradation rates

Reviews of various aspects of this inspection followup item were performed during this inspection which were documented in Sections 2.1 through 2.6 above. The inspectors drew certain insights in regard to differences in degradation rates between units, but noted no information that would reasonably explain the apparent greater incidence of stress corrosion cracking (for each unit) in the second steam generator than the first. The licensee has initiated an action to address this item. This inspection followup item will remain open pending review of the results of the licensee's action.

4.2 (Closed) Inspection Followup Item 529/9415-03: Review of the field eddy current examination results and burst test data for the Unit 2 tube samples sent to Babcock and Wilcox Nuclear Technologies for laboratory examination.

The inspectors ascertained from review of field eddy current examination data that the motorized rotating pancake coil information for the tubes sent to Babcock and Wilcox Nuclear Technologies qualitatively classified the defects that were present and did not include any estimates of defect depths. Bobbin coil examination results showed no defects were found in Tube R117L40, a 52 percent throughwall defect in Tube R22L13 at the flow distribution plate, and a 75 percent throughwall defect in Tube R29L24 at the flow distribution plate. Laboratory examination results showed an overcall by the bobbin coil on Tube R29L24 (i.e., two defects 21 percent and 32 percent maximum throughwall were found metallographically) and a slight undercall by the bobbin coil on Tube R22L13 (i.e., a 62 percent maximum throughwall defect was found by metallographic examination). The inspectors ascertained that burst tests were performed on Tubes R22L13 and R29L24. The results from both Tube R22L13 (8,948 psi for a sample containing a 56 percent maximum throughwall defect and 10,396 psi for a sample containing no defect) and Tube R29L24 (9,662 psi for a sample containing a 40 percent maximum defect) significantly exceeded the Regulatory Guide 1.121 minimum of three times the maximum primary to secondary differential (i.e., 3810 psi).

4.3 (Closed) Inspection Followup Item 528;529;530/9415-05: Review of the steam generator blowdown optimization plan results and pertinent operational experience information

During the previous inspection, the inspectors noted information which indicated that a chemical tracer injection test had identified that the normal blowdown flow rate in Steam Generator 11 was approximately twice the flow rate that was occurring in Steam Generator 12. This difference in blowdown rate was viewed by the inspectors as probably resulting in chemistry differences during power operations between steam generators, and potentially explaining differences in steam generator degradation rates. The inspectors ascertained during this inspection that the Unit 1 chemical tracer injection test did not, however, take into account leakage past the abnormal flow rate control valve, and was, thus, of questionable validity. Subsequent chemical injection tracer testing of Unit 2 eliminated any errors created by leakage through control valves by closing applicable upstream isolation valves. These tests did not show significant difference in blowdown rates between the Unit 2 steam generators and showed reasonable agreement with the thermal balance method that is used by system engineering to measure blowdown flow rates.

The inspectors reviewed available blowdown data that had been obtained by the thermal balance method, and concluded that the data showed reasonable agreement between steam generators in a unit for both normal and abnormal blowdown rates when discharged to the blowdown flash tank. The inspectors did note that there was a significant variation in the unit blowdown values that were obtained in different tests. The inspectors did not attempt to establish the reasons for the variations in test results.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

*J. Bailey, Vice President, Nuclear Engineering
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*R. Schaller, Manager, Steam Generator Project Group
*J. Scott, Director, Site Chemistry
*J. Shawver, Senior Technical Adviser, Site Chemistry
*R. Sorensen, Manager, Site Chemistry Support
*T. Weber, Licensing Engineer, Nuclear Regulatory Affairs

1.2 Other Personnel

*F. Gowers, Site Representative, El Paso Electric

1.3 NRC Personnel

H. Freeman, Resident Inspector
K. Johnston, Senior Resident Inspector
J. Kramer, Resident Inspector
A. MacDougall, Resident Inspector

In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

*Denotes those persons that attended the exit meeting on August 24, 1994.

2 EXIT MEETING

An exit meeting was conducted on August 24, 1994. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not express a position on inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.