Rel

From: Rani Franovich NRR
To: RIV-Gary Sanborn; Jennifer Dixon-Herrity; OE Michael Tschiltz
Date: 12/22/03 8:32AM
Subject: Re: Comanche Peak and ANO SERPs in January

Thanks for the heads up, Gary. NRR should be able to support, but I'll let you know if we encounter a conflict.
Rani

>>> Gary Sanborn 12/21/03 12:31PM >>> RIV
Rani, Jennifer, Mike - The region is tentatively planning to conduct two SERPs in January. I am not aware of any other SERPs at this time. On January 15, we are planning to SERP the Comanche Peak S/G tube leak issue. I am attaching the worksheet to support that SERP. On January 29, we are planning to re-SERP the ANO fire protection case, hopefully to reach a final significance determination. I do not have anything to send you on that yet.
Gary

CC: Charles Marschall; Doug Coe; F. Mark Reinhart; John Minns; Linda Smith; Michael Tschiltz; Mike Franovich; N. Kaly Kalyanam; Peter Wilson; Rebecca Nease; Russell Gibbs; Stuart Richards; Thomas Alexion; William D. Johnson

CCC-1

all 0/5 RIV

SERP Worksheet for SDP-Related Findings

SERP Date: January 15, 2004

Cornerstone Affected and Proposed Preliminary Results :

This finding affects the Barrier Integrity Cornerstone because it directly resulted in a steam generator tube leak.

Licensee:	TXU Energy
Facility/Location:	Comanche Peak Steam Electric Station, Unit 1
Docket No(s):	50-445
License No:	NPF-87
Inspection Report No:	50-445/02-09, issued 1/9/2003
Date of Exit Meeting:	December 10, 2002
Issue Sponsor:	Dwight Chamberlain

Meeting Members:

Issue Sponsor:	Dwight Chamberlain
Technical Spokesperson(s):	Mike Tschiltz
Program Spokesperson:	Doug Coe
OE Representative:	Jennifer Dixon-Herrity

A. Brief Description of Issue

A failure to identify and correct a clearly detectable steam generator tube flaw indication during eddy current examinations in the 2001 refueling outage (1RF08) resulted in the tube remaining in service until it leaked in September of 2002. The tube subsequently failed in-situ testing, indicating that it would not have met design basis accident requirements.

B. Statement of the Performance Deficiency

Deficiency: The licensee failed to identify and correct a degraded steam generator tube during the Refueling Outage 1RF08 inspection conducted in 2001.

The secondary analyst failed to report the indication which was readily apparent. This failure by the analysts was caused in large measure by inadequate guidelines for data

analysis. During the subsequent operating cycle, the tube developed a leak at the flaw location. A similar crack located in a fabrication dent had been detected in 1RFO8 and should have alerted the licensee to the presence of that degradation mechanism in the unit 1 steam generators. The licensee's failure provide adequate data analysis guidance, which resulted in the failure to identify and correct the degradation in steam generator tube R41 C71 during refueling outage 1RF08 is a violation of 10 CFR 50, Appendix B, Criterion XVI. This finding was documented in NRC Inspection Report 50-445/2002009. This special inspection report is attached to this worksheet as **Attachment 1.**

The eddy current test techniques employed for Refueling Outages 1RF08 and 1RF09 included bobbin coil inspections of the tube from end-to-tube end and plus-point coil inspections at special interest locations described in additional detail below. Data analysis was performed in accordance with the Comanche Peak, Unit 1, steam generator eddy current analysis guidelines. The guidelines provided for independent analysis of all data by a primary analyst team and a secondary analyst team. A resolution analyst was responsible for resolving differences noted between the primary and secondary analysis reports. Two independent resolution analysts from the two analysis teams had to concur before changing an indication of degradation to a non-reportable status, which would not require further examination. Differences between the resolution analysts were resolved by the overall lead analyst with the concurrence of the licensee's Level III analyst. In addition, a Level III qualified data analyst sampled data to ensure that primary, secondary, and resolution analyst equipment setups were correct and that discrepancy resolutions were performed properly and the calls were correctly dispositioned.

The primary data analysis was performed by a computerized automatic data screener. The automatic data screener was a program that had been qualified to the same standards as the human analysts; i.e., Appendix G of the EPRI Steam Generator Examination Guidelines and the site-specific performance demonstration. The program used a rule base established by the licensee that incorporated the indication reporting criteria in the eddy current analysis guidelines. For each tube, the automatic data screener listed indications that satisfied the rule base. Each of these indications was manually dispositioned as part of the primary analysis process.

Freespan indications found by the primary or secondary analysts, and upheld during data resolution, were designated as freespan differential signals. A history check was then performed by the resolution analysts to identify a change in the signal response over time. Those freespan differential signals that satisfied the guideline change criteria were considered to be potential flaw indications and were assigned an "I-code." In the analysis guidelines for Refueling Outage 1RF08, the change criteria were a change in the phase angle response greater than 15 degrees, a 0.5 volt change in amplitude, or no prior indication over the last two cycles. If associated with a ding or dent, the change criteria was 10 degrees or no prior indication. A ding refers to localized tube wall deformation at locations between supports. A dent refers to localized wall deformation at tube support locations. All locations with an I-code were required to be inspected with a plus-point probe. All tubes with I-codes confirmed by plus-point were required to be plugged or repaired.

The team's review found that a clearly detectable indication was present at the leak location during the previous outage (1RF08) inspection in 2001. The flaw indication was in Tube R41C71 in Steam Generator 2. This indication measured 0.96 volts at 130 kHz with a phase angle of 93 degrees and 1.79 volts at 300 kHz with a phase angle of 122 degrees. The indication was outside (did not meet) the reporting criteria in the Refueling Outage 1RF08 analysis guidelines and was not reported by either the primary or secondary analyst in 2001.

The applicable reporting criteria during Refueling Outage 1RF08 for freespan bobbin indications in the absence of a dent or ding signal was a phase angle response corresponding to 0 percent through wall; i.e., a phase angle response of 84 degrees on the 130 kHz channel and 118 degrees on the 300 kHz channel. The presence of a dent or ding signal would cause a flaw signal to rotate out of the normal phase angle window.

In the presence of a detectable ding signal, the applicable reporting criterion was a phase angle response of at least 155 degrees on the 130 kHz channel. In the presence of a detectable dent signal, a distortion of the signal on the 550/130 kHz mix channel was reportable.

Dings and dents are reportable if they equal or exceed 2 volts on 550 kHz channel for dings or the 300/130 kHz mix channel for dents. Although dings and dents are not themselves reportable at less than 2 volts, the flaw indication reporting criteria are subject to the wider phase angle reporting window for dent/ding locations if dings or dents are detectable, irrespective of whether the ding or dent exceeds 2 volts.

No ding signal was reported at the flaw location during Refueling Outage 1RF08 by the primary or secondary analysts. The 0 percent through-wall phase angle criteria was applied to the 130 and 300 kHz signal. This indicated that the analysts did not see evidence of a ding signal, irrespective of voltage. The team agreed that there is no clear evidence of a ding in the Refueling Outage 1RF08 signal response. However, the team observed a large amount of horizontal noise (about 1.75 volts at 550 kHz) attributable to probe wobble, which could easily mask a 2 volt ding signal.

The team found that the analysis guidelines provided discretion that may be exercised by the human analysts when interpreting the signals. Paragraph 1.3 of the TXU eddy current guidelines stated:

> "The guidance on signal interpretation is not intended to restrict the analysts. Conditions encountered which are not clearly addressed in the guidelines shall be brought to the attention of the lead analyst and the TXU Eddy Current Level III for concurrence and inclusion into the guidelines. No deviation from the current guidelines is permitted."

Paragraph 6.4.3 of the guidelines stated, in part,

> "However, signals may be observed that act like flaws yet cannot be quantified due to signal distortion . . . In such a case, one of the appropriate I-codes may be used to characterize the indication."

The team concluded that an experienced analyst should recognize that the large wobble signal could mask a dent that could distort or rotate an indication outside the reportable phase angle response criteria. In such a case, the guidelines enabled the analyst to bring the indication to the attention of the lead analyst and the TXU Level III analyst and for assigning an I-code. The team determined that the analyst should have recognized the large wobble signal and should have assigned an I-code.

The team concluded that the following factors contributed to the failure to detect the flaw indication during Refueling Outage 1RF08:

1. The probe wobble signal masked a ding signal at the flaw location.

2. Non-conservative reporting criteria were applied to the flaw signal. As a result, the ding signal was not identified.

3. The primary analysis was strictly rule based (being computerized) and, thus, had no opportunity to exercise discretion in calling the indication.

4. The secondary analyst failed to report the indication, which was readily apparent. It appeared that the analyst dismissed the indication based on strict application of the guideline reporting criteria for non-dinged locations and failed to recognize that the large wobble signal could potentially mask dings, which could rotate the indication outside the reportable phase angle response criteria.

The direct consequence of failure to detect the flaw in Tube R41C71 during Refueling Outage 1RF08 was that the tube was not removed from service and, therefore, subsequently degraded to the point that it leaked and no longer satisfied the applicable tube integrity performance criteria. This occurred because the examination methods used during Refueling Outage 1RF08, including the analysis guidelines, were not effective for ensuring that tubes would maintain their integrity until the next scheduled inspection. The team also concluded that the guideline phase angle reporting criteria were inappropriate in the u-bend region where the high potential existed for large probe wobble signals, which may mask the presence of dents or dings.

The finding is greater than minor because it adversely affected the reactor safety barrier integrity cornerstone and degraded the ability to meet the cornerstone objective of controlling reactor coolant system leakage. The finding also was determined to have potential safety significance greater than very low significance because it resulted in a steam generator tube leak and the tube failed in situ testing, indicating that it would not have met the design basis requirements for withstanding analyzed transients.

The team concluded that for the reasons stated above, the licensee clearly missed an opportunity to have identified the indication during the previous inspection. The failure to identify and correct the degraded tube during Refueling Outage 1RFO8 is an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI.

C. Significance Determination Basis

1. Reactor Inspection for IE, MS, B cornerstones

a. **Phase 1 screening logic, results and assumptions**

The team determined that a Significance Determination Process Phase 2 analysis was required because the issue resulted in the failure of a reactor coolant system barrier, specifically a steam generator tube leak.

b. **Phase 2 Risk Evaluation**

In accordance with Inspection Manual Chapter 0609, Appendix A, the inspectors conducted a Phase 2 estimation using the Risk-Informed Inspection Notebook for Comanche Peak Steam Electric Station, Unit 1, Revision 1. The dominant affected accident sequences are provided in Table b-1. This finding increases the likelihood of an initiating event, specifically, the Steam Generator Tube Rupture, therefore the initiating event likelyhood was increased by one order of magnitude in accordance with Manual Chapter 0609, Appendix A, Attachment 2.

The Phase 2 estimation resulted in a preliminary WHITE finding. The applicable Phase 2 worksheets are provided as **Attachment 2** to this SERP worksheet. The licensee analysts stated that the Phase 2 worksheets were overly conservative. Therefore, the analyst determined that the finding should be evaluated using the Phase 3 process.

Table b-1
Phase 2 Dominant Accident Sequences

Initiating Event	Sequence	Contribution
Steam Generator Tube Rupture (SGTR)	SGTR-EQ1/ISO-SDC	8
	SGTR-EIHP-EQ2/ISO	7
	SGTR-AFW-MKRWST	6
	SGTR-AFW-FB	6
	SGTR-AFW-EIHP	7

c. **Phase 3 Analysis**

The analysts conducted an assessment of the Comanche Peak steam generator tube degradation that was as independent as was feasible while using the licensee's information to make the assessment specific to

Comanche Peak. By reviewing the differences in the analysts' and licensee's underlying assumptions of the physical phenomena involved in this analysis, the licensee identified some appropriate sensitivity studies to perform on both analyses. Upon consideration of all results, the analysts concluded that the best estimate point value of the change in large early release frequency (ΔLERF) for this performance deficiency was 5.5×10^{-7}/year. This frequency range corresponds to a "white" finding in the significance determination process.

The assessment of risk for this degraded tube was evaluated for the following three types of severe accident sequences:

1. Core Damage Sequences Initiated by Spontaneous Tube Rupture:

   In this case, the *in-situ* test demonstrated that the tube was capable of withstanding pressure differentials in the range encountered during normal operation, so the analysts concluded that there was no increase in risk associated with spontaneous tube rupture sequences.

2. Core Damage Sequences Initiated by Secondary Depressurization Events that Induce Tube Rupture:

   Because the *in-situ* test was not capable of reaching the pressure difference that would be created by a design-basis secondary depressurization event, it was necessary to use information from the eddy current inspections to estimate the burst pressure for the flawed tube. The predicted burst pressure was greater than the differential pressure that would be experienced during a design-basis depressurization event. However, the predicted burst pressure also had a significant amount of uncertainty, leaving some probability that the tube would actually have burst if exposed to the elevated pressure differential.

   A probability distribution for the burst pressure was developed based on the *in-situ* test results and the predicted uncertainty in the model. The analysts estimated the induced rupture probability as the fraction of this probability distribution that was below the pressure difference created by the accident sequence. The analysts increased estimated induced rupture probability as a function of time to account for crack growth during the last operating cycle. The analysts used a series of burst probabilities for specific time periods during the last year of operation with the flawed tube.

   As shown in Table c-1, the analyst used a frequency of 1×10^{-3} per reactor-year for the frequency of a secondary depressurization event, a probability of 0.25 (1 out of 4) that the depressurization event affects the steam generator with the

flawed tube, and a conditional probability of 1×10^{-2} that the combined secondary depressurization event and tube rupture will result in core damage. The time periods in Table c-1 are based on the licensee's estimated crack growth rate. Summing the risk contributions for all time periods in the year produces a result of 2.35×10^{-8} per reactor-year for the increase in core damage frequency.

The analysts adjusted these values to reflect a slower crack growth rate than was estimated by the licensee. The analysts used the 95th percentile crack growth rate (15% of the wall thickness per year) from a Westinghouse database, instead of the licensee's estimate of 27% per year. The slower crack growth rate increased the risk estimate by predicting that the crack had been in a condition susceptible to rupture for a longer period of time before it was discovered. The adjustment in the growth rate resulted in a frequency of 4.2×10^{-8}/year. Because the tube rupture and secondary pressure boundary failure create a direct path to the atmosphere, this result is also the ΔLERF.

Table c-1
Results of Staff's Analysis for Secondary Depressurization Sequences

Initiating Event Frequency (per year)	Time Period (fraction of last year)	Probability SG 2 Affected	Burst Probability	CCDP	Core Damage Frequency (per year)
1×10^{-3}	3/12	1/4	0	1×10^{-2}	0
1×10^{-3}	4.5/12	1/4	0.004	1×10^{-2}	3.75×10^{-9}
1×10^{-3}	1.5/12	1/4	0.009	1×10^{-2}	2.81×10^{-9}
1×10^{-3}	1/12	1/4	0.015	1×10^{-2}	3.13×10^{-9}
1×10^{-3}	1/12	1/4	0.024	1×10^{-2}	5.00×10^{-9}
1×10^{-3}	0.9/12	1/4	0.039	1×10^{-2}	7.31×10^{-9}
1×10^{-3}	0.1/12	1/4	0.072	1×10^{-2}	1.50×10^{-9}
TOTAL					**2.35×10^{-8}**

3. Core Damage Sequences Initiated by Other Phenomena that Induce Tube Rupture by Creating Abnormally High Temperatures in the Tube Material:

The burst pressure predicted in the previous section for the flawed tube is based on its strength at normal operating temperatures. If a core damage accident occurs in a manner that does not depressurize the reactor coolant system before the reactor core melts, physical testing has demonstrated that the hot gases from the core will reach and overheat the steam generator tubes. The increase in temperature substantially reduces the burst pressure of the tube. The pressure difference across the tubes in a steam generator with a depressurized secondary side would be sufficient to rupture this cracked tube at the higher temperatures. Consequently, the portion of the plant's baseline core damage frequency that produces the conditions necessary to rupture the cracked tube becomes an additional contribution to the large early release frequency because of the crack.

The staff's analysis for this contribution starts with the frequency of the plant damage states (PDSs) in the licensee's PRA that have the characteristics necessary to heat the tubes with the reactor coolant system at high pressure. This is multiplied by the probability that the reactor coolant system will not become depressurized before the tube ruptures and by the probability that the secondary side of the steam generator does become depressurized. The product is further reduced by a factor of 0.5 to account for the probability that the tube is in the part of the steam generator tube bundle that heats up most rapidly. The next reduction factor is the fraction of the last year of operation during which the degradation of the tube made it susceptible to failure under these severe conditions. Finally, the licensee's baseline contribution to the large early release frequency is subtracted from the result to produce the incremental change caused by the flaw. An outline of the calculation is presented in Table c-2.

The analysts total risk estimate for the subject finding is the sum of the estimated change in risk for the three types of severe accident sequences documented in the preceding sections. This summation is provided in Table c-3. The result falls into the "white" range for the ΔLERF.

Table c-2 Analysis for Severe Accident Sequences that Induce Tube Rupture	
Data Used:	Frequency (per year) or Probability:
Sum of Relevant PDS Frequencies:	4.0×10^{-5}
Probability of RCS Depressurization during Core Damage Progression:	x 0.5
Probability that Steam Generator Containing the Flaw is Depressurized:	x 0.1
Probability that the Flaw is in Hottest Part of the Tube Bundle:	x 0.5
Fraction of Last Year that the Flaw was Vulnerable to Rupture:	x 0.57
Total Estimated LERF with Flaw:	5.7×10^{-7}
IPE Baseline LERF from Severe Accident Induced Tube Rupture:	$- 5.6 \times 10^{-8}$
Total Estimated ΔLERF:	5.1×10^{-7}

Table c-3 Staff's Total Risk Estimate	
Type of Tube Rupture:	ΔLERF (per year)
Spontaneous	0
Induced by Secondary Depressurization Events	$+ 4.2 \times 10^{-8}$
Induced by Core Damage Accidents	$+ 5.1 \times 10^{-7}$
Total ΔLERF	5.5×10^{-7}

Attachment 3 to this Worksheet is the complete report of the evaluation performed by SPSB related to the subject finding. This report contains a thorough description of the evaluation conducted, and documents the review of materials that have been submitted by the licensee, including submissions related to its Individual Plant Examination and Individual Plant Examination of External Events as well as the materials submitted specifically to support the subject significance determination. The basis for data used and objections to certain portions of the licensee's material is explored in the attachment. The sources of the additional material used by the staff are referenced. The sensitivity of the conclusions to some alternative assumptions and parameters was also considered.

D. Proposed Enforcement.

a. Regulatory requirement not met.

Tittle 10 CFR Part 50, Appendix B, Criterion XVI states, in part, that measures shall be taken to assure that conditions adverse to quality such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected.

b. Proposed citation.

During an NRC inspection conducted on October 7 through November 1, 2002 a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," NUREG-1600, the violation is listed below:

> Tittle 10 CFR Part 50, Appendix B, Criterion XVI states, in part, that measures shall be taken to assure that conditions adverse to quality such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected.
>
> Contrary to the above, the licensee failed to identify and correct a clearly detectable steam generator tube flaw indication during the Unit 1, 2001 refueling outage (1RF08). This failure directly resulted in the tube remaining in service until it leaked in September of 2002.

This violation is associated with a White SDP finding.

c. Historical precedent.

Typical failure to take corrective action violation.

E. Determination of Follow-up Review (as needed)

It is proposed that NRR review the final determination letter prior to issuance.

ATTACHMENT 1
Excerpted from Comanche Peak IR 02-09 issued January 9, 2003

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-445
License:	NPF-87
Report No.:	50-445/02-09
Licensee:	TXU Energy
Facility:	Comanche Peak Steam Electric Station, Unit 1
Location:	FM-56 Glen Rose, Texas
Dates:	October 7 through November 1, 2002, onsite
Team Leader	W. C. Sifre, Senior Reactor Inspector Engineering and Maintenance Branch
Inspector:	E. Murphy, Senior Materials Engineer Materials and Engineering Branch Office of Nuclear Reactor Regulation
Accompanying Personnel:	C. Dodd, Consultant
Approved By:	Charles S. Marschall, Chief Engineering and Maintenance Branch Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000445-02-09; TXU Energy; on 10/07-11/01/2002; Comanche Peak Steam Electric Station; Unit 1, Special Inspection.

The inspection was conducted by a team of three inspectors, one regional inspector, one headquarters inspector, and one contractor. The inspection identified three findings. Two of the findings are characterized as a noncited green violation and one is characterized as an apparent violation of NRC regulatory requirements. The significance of this apparent violation has yet to be determined; therefore, the finding remains unresolved. The risk significance of the apparent violation remains unresolved. The significance of issues is indicated by their color (green, white, yellow, red) and will be determined using the Significance Determination Process described in NRC Inspection Manual Chapter 0609. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG 1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. Inspector-Identified Findings

Cornerstone: Barrier Integrity

TBD. A failure to identify and correct a clearly detectable steam generator tube flaw indication during eddy current examinations in the 2001 refueling outage (1RF08) resulted in the tube remaining in service until it leaked in September of 2002. This is an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI.

The risk significance of the finding is unresolved pending completion of a significance determination. This finding is greater than minor because it degraded the ability to meet the cornerstone objective with reactor coolant system leakage. The finding had potential for greater than very low safety significance because the tube failed the in situ testing, indicating that it would not have met the design basis requirements for withstanding analyzed transients. (Section 02.01)

GREEN. Inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI for two examples of failure to perform adequate steam generator eddy-current examination in the 2002 refueling outage (1RF09). The inadequate examinations resulted in analyst failure to properly characterize two steam generator tube flaws until the licensee took corrective actions in response to questions from the NRC inspectors.

This finding is greater than minor because it degraded the ability to meet the cornerstone objective of reactor coolant system pressure boundary. The failure to identify the flaws could have resulted in flawed tubes that might have developed leaks if left in service. The significance of this finding is very low because the in situ tests demonstrated that the tubes would have met the design basis requirements for withstanding analyzed transients, and prior to returning the plant to operation the licensee removed the flawed tubes from service (Section 02.02).

Report Details

SPECIAL INSPECTION ACTIVITIES

01 Inspection Scope

The team conducted a special inspection in response to a primary-to-secondary leak that began on September 26, 2002, and the resultant shutdown on September 28, 2002. The team also reviewed the associated steam generator inspections. The team used Inspection Procedure 93812, "Special Inspection Procedure," to evaluate the effectiveness of the examination methods used to examine the degraded tube during the previous outage, and determine whether licensee evaluators missed an opportunity to identify the degraded tube during the previous outage. The team also evaluated the effectiveness of the examination methods used during the current outage as it related to detecting flaws similar to that in the leaking tube. The team assessed the effectiveness of this approach in precluding the recurrence of this type of event. During the inspection, the team developed a complete sequence of events related to the primary-to-secondary leak first identified on September 26, 2002. The team also reviewed the licensee personnel's root cause evaluation for completeness and accuracy, and Independently verified key assumptions and facts of that evaluation.

In addition, the team evaluated the corrective actions and ensured that the extent of condition was evaluated.

The team reviewed procedures, logs, and corrective action documents. The team also reviewed the steam generator eddy current data, and interviewed key personnel, including eddy current analysts.

02 Special Inspection Areas

02.01 Overview of Shutdown and Sequence of Events

a. Inspection Scope

The inspectors reviewed the licensee's response to the steam generator tube leak and verified that appropriate actions were taken.

b. Findings

On September 26, 2002, Comanche Peak, Unit 1, was at 99 percent reactor power, coasting down with the refueling outage scheduled to begin on October 5. At 5:41 a.m. the Unit 1 control room received a condenser off-gas alarm, Condenser Off-Gas-182, with a reading of 4.92E-6 uCi/mL. The alarm setpoint was 4.86E-6 uCi/mL and the licensee determined by review of the data that the parameter had been running close to the setpoint for the previous 24 hours. Operators notified the chemistry technicians. At 12:43 p.m. the Condenser Off-Gas 182 alarm actuated with a reading of 6.07E-6 uCi/mL and the No. 2 steam generator main steam line N-16 monitor went into alarm. A correlation curve reflecting the theoretical equation for the condenser off-gas monitor was created by chemistry and distributed to the control room. The condenser off-gas alarm setpoints were adjusted to reflect 30 gallons per day (gpd) and 40 gpd,

respectively. At 30 gpd, the plant would enter Action Level 1 in accordance with Procedure ABN-106 and administrative limits. At 40 gpd, maintained for greater than 1 hour, management decided the plant should shut down in a controlled manner. At 10:24 p.m., the N-16 alarm cleared and the reading continued to trend downward.

On September 27, 2002, at 12:19 a.m., the Condenser Off-Gas 182 alarm cleared. At 10:25 a.m., the N-16 alarm returned at an estimated 5.00 gpd. At 10:40 a.m., the Condenser Off-Gas 182 alarm came in with 9.81E-6 uCi/mL followed by the Condenser Off-Gas 182 Hi alarm at 10:51 a.m. with a reading of 1.17E-5 uCi/mL. At 1:06 p.m., these alarms cleared and peak readings were determined to be 12.8 gpd. These alarms came in twice more on this day. At 7:54 p.m., the Condenser Off-Gas 182 alarm reached a peak value of 1.7E-5 uCi/mL and at 10:32 p.m., the Condenser Off-Gas 182 HiHi alarm was greater than the 40 gpd limit at 1.8E-5 uCi/mL. The alarms cleared in less than an hour so that the shutdown criteria established by licensee management was not exceeded.

On September 28, 2002, at 1:40 a.m., the Unit 1 control room operators commenced power reduction in response to the 1-02 steam generator tube leak. The operators' target was to be off-line in 2 hours. The Unit 1 control room operators entered Section 3.0 of Procedure ABN-106. At 3:12 a.m., the Unit 1 control room operators performed a planned trip of the Unit 1 reactor and entered Mode 3.

Subsequent inspection and testing by the licensee determined the source of the leakage to be a stress corrosion crack initiating from the outer diameter surface in the u-bend region of Tube R41C71 of Steam Generator 2. The licensee also determined through pressure testing that the tube failed to exhibit structural and accident leakage integrity margins consistent with the plant design and licensing basis.

02.02 Effectiveness of Previous Examinations

c. Inspection Scope

The team independently reviewed eddy current test data from the previous (1RF08) inspection in 2001 for the specific tube location where the leakage developed in September 2002. The team also reviewed the Comanche Peak, Unit 1, Steam Generator Eddy Current Analysis Guidelines for Refueling Outage 1RF08, Revision 0.

d. Findings

Introduction. An apparent violation with risk to be determined was identified in that the licensee failed to identify and correct a degraded steam generator tube during Refueling Outage 1RF08 and this failure directly resulted in a steam generator tube leak.

Description. The eddy current test techniques employed for Refueling Outages 1RF08 and 1RF09 included bobbin coil inspections of the tube from end-to-tube end and plus-point coil inspections at special interest locations described in additional detail below. Data analysis was performed in accordance with the Comanche Peak, Unit 1, steam generator eddy current analysis guidelines. The guidelines provided for independent analysis of all data by a primary analyst team and a secondary analyst team. A resolution analyst was responsible for resolving differences noted between the primary and secondary analysis reports. Two independent resolution analysts from the two

analysis teams had to concur before changing an indication of degradation to a non-reportable status, which would not require further examination. Differences between the resolution analysts were resolved by the overall lead analyst with the concurrence of the licensee's Level III analyst. In addition, a Level III qualified data analyst sampled data to ensure that primary, secondary, and resolution analyst equipment setups were correct and that discrepancy resolutions were performed properly and the calls were correctly dispositioned.

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The applicable reporting criteria during Refueling Outage 1RF08 for freespan bobbin indications in the absence of a dent or ding signal was a phase angle response corresponding to 0 percent through wall; i.e., a phase angle response of 84 degrees on the 130 kHz channel and 118 degrees on the 300 kHz channel. The presence of a dent or ding signal would cause a flaw signal to rotate out of the normal phase angle window.

In the presence of a detectable ding signal, the applicable reporting criterion was a phase angle response of at least 155 degrees on the 130 kHz channel. In the presence of a detectable dent signal, a distortion of the signal on the 550/130 kHz mix channel was reportable.

Dings and dents are reportable if they equal or exceed 2 volts on 550 kHz channel for dings or the 300/130 kHz mix channel for dents. Although dings and dents are not themselves reportable at less than 2 volts, the flaw indication reporting criteria are subject to the wider phase angle reporting window for dent/ding locations if dings or dents are detectable, irrespective of whether the ding or dent exceeds 2 volts.

No ding signal was reported at the flaw location during Refueling Outage 1RF08 by the primary or secondary analysts. The 0 percent through-wall phase angle criteria was applied to the 130 and 300 kHz signal. This indicated that the analysts did not see evidence of a ding signal, irrespective of voltage. The team agreed that there is no clear evidence of a ding in the Refueling Outage 1RF08 signal response. However, the team observed a large amount of horizontal noise (about 1.75 volts at 550 kHz) attributable to probe wobble, which could easily mask a 2 volt ding signal.

The team found that the analysis guidelines provided discretion that may be exercised by the human analysts when interpreting the signals. Paragraph 1.3 of the TXU eddy current guidelines stated:

> "The guidance on signal interpretation is not intended to restrict the analysts. Conditions encountered which are not clearly addressed in the guidelines shall be brought to the attention of the lead analyst and the TXU Eddy Current Level III for concurrence and inclusion into the guidelines. No deviation from the current guidelines is permitted."

Paragraph 6.4.3 of the guidelines stated, in part,

> "However, signals may be observed that act like flaws yet cannot be quantified due to signal distortion . . . In such a case, one of the appropriate I-codes may be used to characterize the indication."

The team concluded that an experienced analyst should recognize that the large wobble signal could mask a dent that could distort or rotate an indication outside the reportable phase angle response criteria. In such a case, the guidelines enabled the analyst to bring the indication to the attention of the lead analyst and the TXU Level III analyst and for assigning an I-code. The team determined that the analyst should have recognized the large wobble signal and should have assigned an I-code.

The team concluded that the following factors contributed to the failure to detect the flaw indication during Refueling Outage 1RF08:

1. The probe wobble signal masked a ding signal at the flaw location.

2. Non-conservative reporting criteria were applied to the flaw signal. As a result, the ding signal was not identified.

3. The primary analysis was strictly rule based (being computerized) and, thus, had no opportunity to exercise discretion in calling the indication.

4. The secondary analyst failed to report the indication, which was readily apparent. It appeared that the analyst dismissed the indication based on strict application of the guideline reporting criteria for non-dinged locations and failed to recognize that the large wobble signal could potentially mask dings, which could rotate the indication outside the reportable phase angle response criteria.

The direct consequence of failure to detect the flaw in Tube R41C71 during Refueling Outage 1RF08 was that the tube was not removed from service and, therefore, subsequently degraded to the point that it leaked and no longer satisfied the applicable tube integrity performance criteria. This occurred because the examination methods used during Refueling Outage 1RF08, including the analysis guidelines, were not effective for ensuring that tubes would maintain their integrity until the next scheduled inspection. The team also concluded that the guideline phase angle reporting criteria were inappropriate in the u-bend region where the high potential existed for large probe wobble signals, which may mask the presence of dents or dings.

Analysis. The finding is greater than minor because it adversely affected the reactor safety barrier integrity cornerstone and degraded the ability to meet the cornerstone objective of controlling reactor coolant system leakage. The finding also was determined to have potential safety significance greater than very low significance because it resulted in a steam generator tube leak and the tube failed in situ testing, indicating that it would not have met the design basis requirements for withstanding analyzed transients. The final risk determination is pending evaluation using the Significance Determination Process described in NRC Inspection Manual Chapter 0609.

Enforcement. The team concluded that for the reasons stated above, the licensee clearly missed an opportunity to have identified the indication during the previous inspection. The failure to identify and correct the degraded tube during Refueling Outage 1RFO8 is an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI (APV 50-445/0209-01). The licensee has documented this issue in Smart Form SMF-2002-003142-00. The risk significance of this apparent violation remains under review by the NRC.

02.03 Effectiveness of Current Examinations

a. Inspection Scope

The team reviewed the scope of the licensee's Refueling Outage 1RF09 inspection program and the results obtained. Primary attention was directed to the effectiveness of the licensee's inspection program for detecting freespan cracks such as the one in Tube R41C71 that was missed during the previous inspection during Refueling Outage 1RF08. The team also reviewed the Comanche Peak, Unit 1, Steam Generator Eddy Current Analysis Guidelines for Refueling Outage 1RF09, Revision 4.

b. Findings

Introduction. A Green noncited violation of 10 CFR Part 50 Appendix B, Criterion XVI, was identified for two examples of failure to identify steam generator tube flaw indications.

Description. The Refueling Outage 1RF09 steam generator inspection program included a full length bobbin coil examination of all tubes in all steam generators. All locations where I-codes were found by the bobbin coil examinations were subsequently examined by plus-point probes. For freespan I-codes, the extent of plus-point inspection was from the nearest support structure (e.g., tube support plate or anti-vibration support) on one side of the flaw to the nearest support structure on the other side of the flaw. Additional plus-point inspections were performed for freespan cracks at the following special interest locations:

- All tube spans between adjacent supports containing greater than 5 volt dents or dings.
- A 20 percent sample of u-bend spans between adjacent supports containing greater than 2 volt dents/dings.
- A 20 percent sample of spans between adjacent supports containing bobbin freespan differential signals, irrespective of whether they were dispositioned as I-codes based on history review.
- A 100 percent sample of spans between adjacent supports containing freespan differential signals in u-bends.

Revision 4 of the Comanche Peak, Unit 1, steam generator eddy current analysis guidelines was utilized for the Refueling Outage 1RF09 initial inspection program. As corrective action to preclude missing flaws, such as Tube R41C71 in Refueling Outage 1RF08, Revision 4 included the following key changes to the Refueling Outage 1RF08 inspection.

- The phase angle reporting criteria for freespan indications in the absence of dings/dents was changed to require only that the 130 kHz signal phase angle response be less than 160 degrees.
- A new reporting criterion added that freespan indications in the absence of dings/dents exhibit a 20 to 200 degree phase angle response at 550 kHz.
- The phase angle change criterion for historical review for freespan differential indications not associated with dings/dents was changed from 15 to 10 degrees. In addition, wording was clarified that a two cycle look back is required.

The rule base for the primary analysis auto data screener was updated to reflect the first two changes above. The third change only affected the resolution process. The team witnessed application of the auto data screener with the Revision 4 guideline rule base to Refueling Outages 1RF07 (1999) and 1RF08 (2001) raw bobbin data at the leak location. In both cases, the auto data screener identified a freespan differential indication at the location, which eventually leaked prior to Refueling Outage 1RF09.

The licensee's inspection program identified 20 single axial indications, including the leaker, affecting 11 tubes. The single axial indications fell into two different categories. The first category included 11 single axial indications (including the leaker), affecting 9 tubes, located between the uppermost hot-leg support (H10) and the uppermost cold-leg support (C10) including the u-bend region. All except 1 of these indications were associated with a detectable ding or dent. With the exception of the leak indication, these indications were short and exhibited low voltage responses, indicating that they had little structural significance.

The second category included 9 single axial indications affecting 2 tubes, R11C42 in Steam Generator 2 and R7C17 in Steam Generator 3. These indications were not associated with detectable dings or dents. They appeared to be oriented end-to-end along a straight line with some axial distance between them.

The team identified the following concerns with the effectiveness of the inspection:

- The secondary analyst failed to identify half of the single axial indications confirmed with the plus-point coil and not involving greater than 5 volt dents or dings.

- Similarly, half of the single axial indications not associated with greater than 5 volt dents had not been detected during the primary analysis of the bobbin data. In general, these indications exhibited bobbin coil amplitude responses less than 0.2 volts. The auto data screener is set up to identify only indications with amplitude responses above 0.2 volts. The secondary human analysis was not subject to an amplitude reporting criteria. In one case, the auto data screener did report a freespan differential indication, but it was inexplicably deleted by the analyst who prepared the primary analysis report.

- Eight of the single axial indications were not identified as freespan differential indications by either the primary or secondary analysts. These were found fortuitously rather than by programmatic implementation. The single axial indications were found only because the licensee performed a plus-point examination to address a freespan differential indication or large voltage dent found elsewhere in the same span.

Of particular concern to the team was a long single axial indication at 10.7 inches above the H5 hot-leg support in Tube R11C42 of Steam Generator 2. This indication was missed by both the primary and secondary analysts. The indication was 1.6 inches in length with a maximum voltage response of 0.26 volts. Depth estimates involve significant uncertainties for low voltage indications such as this. The measured depth at the location of the maximum voltage response was 64 percent through wall based on phase angle. The licensee is required to plug tubes with flaw indications greater than 40 percent through wall.

The failure of the licensee analysts to identify this indication is the first example of a violation of 10 CFR Part 50, Appendix B, Criterion XVI. Based on the licensee's corrective actions (documented in SMF-2002-003142-00), including pressure testing and removal of the affected tube from service, this violation is being treated as a

noncited violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50 445/0209 02).

To address the missed indication and to ensure that no additional indications were missed, the licensee elected to perform a complete manual re-analysis of the bobbin coil data.

Training of participating analysts was focused on the bobbin coil signals associated with the freespan single axial indications found by plus point probes during the initial data analysis. Particular attention was directed to the long freespan indications found in Tubes R11C42 and R7C17, including those missed by the secondary analysts.

The licensee prepared Revision 5 of the steam generator eddy current analysis guidelines to support the review. Revision 5 added the 300 kHz channel to the channels to be screened for a differential response. It also required complete history reviews during resolution. These reviews were now required to extend back to the first inservice inspection for the subject tube.

To increase confidence in the effectiveness of the analysts, the licensee also inserted "Judas Tube" signals into the data stream. A "Judas Tube" was a tube with known long single axial indications. The signals from this tube were inserted randomly into the actual data stream being analyzed. Presumably, the success of the analysts in detecting the Judas Tube signals from among the actual data under evaluation provided insight into the ability of the analysts to find similar indications from among the actual data. Signals for two Judas Tubes were inserted into the data stream. These signals were the 2002 (1RF09) and 2001 (1RF08) signals for the tube that was missed (R11C42). The analysts detected the three largest amplitude signals on the tube, which included the indication that was missed by both the primary and secondary analysts during the initial data analysis program and that was of particular concern to the team as previously discussed. The team concluded that the use of the Judas Tube signals had the additional benefit of heightening the alertness of the data analysts to potential freespan indications.

Tube R11C42 was one of two tubes pulled during Refueling Outage 1RF09 for laboratory testing and examination. Burst testing was completed for this tube at about the time the review was nearing completion. Preliminary information from the test was that the burst pressure was 8200 psi. The team concluded that this result provided further confidence that the analysts were capable of identifying free span cracks well before they become structurally significant.

Subsequent analysis led to the finding of additional freespan differential indications and I-codes. Plus-point examination of the I-codes identified six additional tubes with single axial indications. Three of these tubes were found to contain relatively short single axial indications at ding locations. The other three tubes contained long single axial indications or arrays of single axial indications not associated with detectable dents or dings. One of these tubes, R7C90, was found to contain a 15-inch long array of single axial indications above the H1 support, and four single axial indications above the H3 support. Only the largest single axial indication in each of the spans was identified as a freespan differential indication and designated as an I-code during the third resolution process. The single axial indications in these spans not identified by the third

analysis were very small amplitude indications (0.1 volts or less), less significant than some of the single axial indications found in Tube R11C42, which exhibited a high, 8200 psi, burst pressure.

However, the results for the other two tubes with long single axial indications, R7C117 and R4C51 in Steam Generator 3, raised a new issue regarding the effectiveness of the data resolution process at Comanche Peak. For Tube R7C117, the third analysis identified a freespan differential indication at 8.6 inches above the H8 support. The history review confirmed a change in signal and an I-code was assigned. The team observed, however, that both the primary and secondary analysts had previously identified a freespan differential indication at this location during the original Refueling Outage 1RF09 analysis. The resolution process at that time failed to identify a change in signal relative to 1999 in excess of the specified change criteria and thus, no I-code was assigned and no plus point probe examination was performed.

Based on a review of the data, the team found that the change in indication since 1999 was clearly observable. The plus-point examination following the third analysis revealed a relatively large single axial indication with a maximum voltage response of 0.82 volts. The single axial indication measured over 2.5 inches in length with a depth of 62 percent through wall at the peak voltage location based on measured phase angle. Amplitude-based depth measurements ranged as high as 85 percent through wall. This tube was in-situ pressure tested and successfully sustained three times normal operating differential pressure (4070 psi) without burst or leakage. The team observed that there is little basis for confidence that the pressure capacity of this tube was much above 4070 psi or that the tube would have continued to meet the 3 delta P criterion until the next refueling outage, given the uncertainty of the depth measurements. The licensee's representatives stated their intent to conduct additional testing of the tube and provide the results to the inspectors when they become available.

For Tube R4C51, freespan differential indications were identified during the third analysis at three locations above the H9 support. Each of these was designated during resolution as an I-code, and plus-point examination revealed single axial indications at each location. The team observed, however, that freespan differential indications had been identified at two of these locations by the primary analyst during the original Refueling Outage 1RF09 analysis. The resolution analyst had overruled one of these calls as "no detectable degradation" and had determined that the other had not indicated a change since 1999 in excess of the change criteria.

The failure of the licensee analysts to identify these indications is a second example of a violation of 10 CFR Part 50, Appendix B, Criterion XVI. Based on the licensee's corrective actions (documented in SMF-2002-003142-00), including removal of the affected tube from service, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-445/0209-02).

It was the team's opinion that the third analysis was effective in providing confidence that potentially significant indications were brought to the attention of the resolution analysts. However, the third analysis raised a new issue with respect to the effectiveness of the resolution process to ensure that potential freespan indications stemming from the front line analysis were addressed. In particular, there was concern

regarding the effectiveness of the historical review for changes relative to the change criteria.

The team discussed the concern with the licensee's representatives. To address the concern, the licensee elected to perform a new, supplemental history review of all freespan differential indications from the third analysis.

The licensee prepared guidelines for the supplemental history review, which were reviewed by the team. These guidelines incorporated a number of improvements, which the team considered to significantly improve the effectiveness of the analysis in identifying signals that were potentially changing since the first inservice inspection. These guidelines called for the historical reviews to be performed by two qualified data analysts working together as a team. The analysts were to consider all available data, including the low frequency absolute channel. This reflected a lesson learned from Tube R7C112 in Steam Generator 3, which showed a clear change in the absolute signal. Analysts were instructed not only to identify indications with changes exceeding the specified change criteria, but to identify any indication with a change which, in their experience and judgement, was beyond that associated with normal eddy current repeatability. The inspectors considered this change a significant improvement.

The team concluded that this review adequately evaluated each of the freespan differential signals identified during the third analysis.

Analysis. This finding is greater than minor because it is associated with reactor coolant system barrier integrity and degraded the ability to meet the cornerstone objective. The failure to identify the flaws could have resulted in flawed tubes that may have developed leaks if left in service. The risk significance of this finding is very low because the in situ tests demonstrated that the tubes would have met the design basis requirements for withstanding analyzed transients, and prior to returning the plant to operation the licensee removed the flawed tubes from service.

Enforcement. The failures of the licensee analysts to identify the significant indications are a violation of 10 CFR Part 50, Appendix B, Criterion XVI. Based on the licensee's corrective actions (documented in SMF-2002-003142-00) including removal of the affected tubes from service, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-445/0209-02).

02.04 Evaluation of Licensee's Root Cause Evaluation

a. Inspection Scope

The licensee performed root cause evaluations from two standpoints. First was the assessment of root cause from a crack mechanistic standpoint - why the crack occurred. Second was a root cause evaluation from a programmatic standpoint - why wasn't the crack detected and the tube removed from service before the leak occurred and before the tube integrity performance criteria were no longer satisfied. These evaluations were in progress while the team was onsite. The team reviewed DRAFT versions of both evaluations.

b. Findings

1. Mechanistic Root Cause

The general root causes of stress corrosion cracking are well documented in industry literature and include having a material that is susceptible to stress corrosion cracking, the presence of stress in the material, and an aggressive environment. Each of these causal factors are known to be present for all PWR steam generators, particularly those employing Inconel Alloy 600 mill-annealed tubing as is the case for Comanche Peak Unit 1. The aggressiveness of the cracking, in terms of time to crack initiation and crack growth rate, can be aggravated by the presence of residual stress or off-normal stress associated with dings, dents and scratches, material micro-structure, and secondary water chemistry.

One potential source of information concerning factors that may have hastened the onset of freespan cracking at Comanche Peak would be a removed tube sample containing the section of tubing with the leaking flaw. Because of the u-bend location of the leaking flaw, the licensee could not remove it for additional testing. However, sections for two other flawed tubes, i.e., R11C42 and R25C30, were pulled for laboratory analysis and may provide insights on causes for the cracking. The pulled tube samples were found by inspection to contain freespan cracks.

The license observed that the leaking flaw was located at a ding, which was apparent on the plus-point scan. Dings and dents are local deformations of the tube wall which lead to increased local stress levels. Dings are thought to be incurred during the tube fabrication and installation process. By contrast, dents occur due to the buildup of magnetite in crevices between the tubing and carbon steel support plates. Crack initiation at ding and dent locations has been noted by power reactor licensees.

The licensee had not reached a conclusion about the cause of the leak based on available information. The licensee's representatives stated that they would provide the inspectors with the final root cause determination based on further evaluation when it becomes available.

2. Programmatic Root Cause

The team reviewed a number of licensee draft documents that address the leaking flaw and why it had been missed in Refueling Outage 1RF08 steam generator inspections in 2002. These documents included:

- A draft document entitled, "Anatomy of an Event," reviewed error precursors, flawed defenses, and latent organizational weaknesses that could have prevented the missed indication.

- A draft document entitled "September 2002 Unit 1 Primary to Secondary Leakage Summary Report."

- A note prepared by Steve Swilley (TXU) entitled "Comments about 1RF08 Inspection Practices and Application of Ding Technique."

These documents identified the following contributing factors:

The probe wobble signal masked a ding signal at the flaw location.

- The unseen ding signal caused the flaw signal to be distorted (rotated) beyond the phase angle reporting criteria which was applicable to non-dinged locations. The inspectors considered this criteria non-conservative for dinged locations.

- The primary analysis was rule-based (being computerized). Because the primary analysis failed to identify the dent, the reporting criteria for non-dinged locations was applied. Since the dent rotated the flaw beyond this criteria the analyst did not identify it.

- The secondary analyst failed to report the indication.

Although the team agreed with the above contributing factors, the team identified the following important contributing factors:

- Human error: The secondary analyst failed to report the indication which was readily apparent. The team determined that the analyst should have reported the indication. It appears likely the analyst dismissed the indication based on strict application of the guideline reporting criteria for non-dinged locations and failed to recognize that the large wobble signal could potentially mask dings which could rotate the indication outside the reportable phase angle response criteria.

- Procedural inadequacy: The phase angle reporting criteria for freespan cracks in the absence of dings or dents was inappropriate for two reasons. One, the reporting criteria for dings and dents was 2 volts. Dent and ding signals of less than 2 volts can distort or rotate a flaw indication beyond the phase angle reporting criteria. Two, a large probe wobble response capable of masking dent and ding signals up to 2.5 volts is an expected condition in the u-bend region. This procedural inadequacy directly caused the flaw indication to be missed by the primary automatic data screening analysis because it was entirely rule based. The human (secondary) analyst applied this guideline criterion directly and literally. The Figure 3 analysis flow chart in the Refueling Outage 1RF09 steam generator eddy current analysis guidelines provided no specific word of caution about the potential for probe wobble to distort the flaw indication, rendering the reporting criterion inappropriate. The team determined that procedure established unnecessarily conservative criteria for reporting flaws.

02.05 Evaluation of Licensee's Corrective Actions

a. <u>Inspection Scope</u>

The inspectors reviewed the licensee's corrective actions in response to the steam generator tube leak.

b. Fingings

The corrective actions implemented by the licensee have been previously discussed in this inspection report and involved three sets of actions as follows:

- The first set of actions was taken in direct response to the tube leak, and included opening up the phase angle window reporting criteria to ensure that all potential distorted indications would be subject to the resolution process for determination of whether an I-code should be applied to the indication.

- The second set of actions was taken in response to team concerns that (1) many freespan indications were too low in amplitude to be detected by the primary analysis automatic data screener and (2) that several freespan indications, found fortuitously by plus-point examination, had been missed by the secondary (human) analyst. This second set of actions included an independent third party review of the raw bobbin coil examination data by human analysts who had undergone training to sensitize them to the kinds of signals which had been missed during the original inspection program.

- The third set of actions was taken in response to team concerns regarding the effectiveness of the data resolution analyses implemented during the original inspection program and third analysis. In particular, the team was concerned that the history review analyses were not adequately identifying indications, which had undergone significant change and warranted an I-code designation. This third set of actions included analysis history reviews for all freespan differential signals that had not received an I-code designation during the third analysis.

The second and third sets of corrective actions were taken by the licensee to resolve NRC concerns. Although these actions did not reveal any additional tubes failing to meet the tube integrity performance criteria, one indication was found (in Tube R7C112) during the third analysis that could have challenged the tube integrity criteria during the next operating cycle as discussed in detail earlier in this report. Thus, the team found that the licensee's corrective action program in response to the leaking tube and implemented during the original Refueling Outage 1RF09 inspection program (i.e., the first set of corrective actions) was initially not adequate to establish the extent of condition and to support operation during the next operating cycle. In response to staff concerns, additional corrective actions were taken (i.e., the second and third sets of corrective actions) which led to the finding of several additional freespan indications including the significant indication in Tube R7C112.

The team found that the corrective actions listed above established a high confidence that significant indications, which could potentially challenge the tube integrity performance criteria early in the next cycle were identified and the subject tubes plugged or repaired. The inspectors considered these corrective actions acceptable. The licensee will perform an operational assessment to establish that there is a

sufficient bases to operate to its next scheduled refueling outage. This operational assessment may need to be revised or updated when the results of the tube pull examinations become available sometime in early 2003.

The team will review the results from the pulled tube examination and the licensee's operational assessment as follow up actions when the results become available.

04 Exit Meeting Summary

The team leader and NRC management representatives presented the special inspection results to Mr. C. L. Terry, and other members of licensee management on December 10, 2003, during a public exit meeting. No proprietary information was identified.

ATTACHMENT

PARTIAL LIST OF PERSONS CONTACTED

Licensee

S. Lakdawala, Engineering Programs Manager
B. Mays, Smart Team 1 Systems Manager
D. Snow, Senior Nuclear Specialist
M. Sunseri, System Engineering Manager
S. Swilley, Steam Generator Program Manager
C. Terry, Senior Vice President and Principal Nuclear Officer

NRC

D. Allen, Senior Resident Inspector
A. Sanchez, Resident Inspector

ITEMS OPENED AND CLOSED

Opened

50-445/02-09-01	APV	Failure to Identify and Correct a Degraded Steam Generator Tube during Refueling Outage 1RFO8 (Section 02.01).

Opened and Closed

50-445/02-09-02	NCV	Two Examples of Failure to Identify and Correct Steam Generator Tube Flaws (Section 02.02).

PARTIAL LIST OF DOCUMENTS REVIEWED

Comanche Peak Unit 1 Steam Generator Eddy Current Analysis Guidelines for 1RF08, Revision 0

Comanche Peak Unit 1 Steam Generator Eddy Current Analysis Guidelines for 1RF09, Revision 4

Comanche Peak Unit 1 Steam Generator Eddy Current Analysis Guidelines for 1RF09, Revision 5

Comanche Peak Unit 1 Steam Generator Eddy Current Analysis Guidelines for 1RF09, Revision 6

Westinghouse Vendor Procedure STD-FP-1996-7928, Field Procedure for In Situ Testing of 3/4" Steam Generator Tubes