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U.S. Nuclear Regulatory Commission
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Donald C. Cook Nuclear Plant Unit 2
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION ON
STEAM GENERATOR TUBE SURVEILLANCE INTERVAL EXTENSION
(TAC NO. MB0156)

Reference: 1) Letter from R. P. Powers (I&M) to Nuclear Regulatory Commission (NRC) Document Control Desk, "License Amendment Request – Steam Generator Tube Surveillance Interval Extension," C0900-04, dated September 30, 2000.

2) Letter from J. F. Stang (NRC) to R. P. Powers (I&M), "Donald C. Cook Nuclear Plant – Request for Additional Information (RAI) Regarding License Amendment Request, 'Steam Generator Tube Surveillance Interval Extension,'" dated November 1, 2000 (TAC No. MB0156).

In Reference 1, Indiana Michigan Power Company (I&M), the Licensee for Donald C. Cook Nuclear Plant Unit 2, proposed to amend Facility Operating License, DPR-74. I&M proposed to add a condition to DPR-74 to allow an extension of the steam generator tube inspection surveillance requirements of Technical Specification Surveillance Requirement 4.4.5.3. The surveillance is required to be completed by March 5, 2001. I&M proposed to allow the inspection to be performed during the refueling outage following the current operating cycle (cycle 12), but no later than June 30, 2002.

In Reference 2, the staff requested additional information. I&M is providing the requested information in the attachment to this letter.

In preparing the response to this RAI, a discrepancy was noted in information reported in Reference 1. The corrected information is provided in the attachment to this letter.

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I&M has reviewed the attached information and concludes that the evaluation of significant hazards considerations contained in Attachment 4 to Reference 1 is not affected. There are no new commitments made in this submittal.

Should you have any questions, please contact Mr. Wayne J. Kropp, Director of Regulatory Affairs, at (616) 697-5056.

Sincerely,

M. W. Rencheck
Vice President Nuclear Engineering

/dmb

Attachments

c: J. E. Dyer
MDEQ - DW & RPD
NRC Resident Inspector
R. Whale

ATTACHMENT TO C1100-06

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

Indiana Michigan Power Company (I&M), the Licensee for Donald C. Cook Nuclear Plant (CNP) Unit 2, provides the following response to the Nuclear Regulatory Commission (NRC) letter, "Donald C. Cook Nuclear Plant – Request for Additional Information (RAI) Regarding License Amendment Request, 'Steam Generator Tube Surveillance Interval Extension,'" dated November 7, 2000 (TAC No. MB0156).

NRC Question 1

"Provide a condition monitoring and operational assessment for the D. C. Cook steam generators. Ensure that it addresses the applicable questions/issues raised below (e.g., frequency of inspection, etc.)"

I&M Response to Question 1

Nuclear Energy Institute (NEI) document NEI 97-06, "Steam Generator (SG) Program Guidelines," contains requirements for condition monitoring and operational assessments. NEI 97-06 was issued in December 1997, and endorsed Revision 5 of the Electric Power Research Institute (EPRI) Pressurized Water Reactor (PWR) SG Examination Guidelines.

The last CNP Unit 2 SG tube inspection was conducted in October of 1997 using the guidance contained in Revision 4 of the EPRI PWR SG Examination Guidelines. Condition monitoring and operational assessments were not recommended until Revision 5 of these guidelines, which was issued in September 1997 with a six-month implementation period. Therefore, condition monitoring and operational assessments were not performed during the 1997 inspection.

In July 2000, I&M reevaluated the 1997 inspection data and performed an operational assessment to predict tube integrity based on the intent of NEI 97-06 and the EPRI Steam Generator Integrity Assessment Guidelines. The details of this assessment are provided in Appendix A. Dominion Engineering, Inc. (DEI) has also performed an Operational Assessment for CNP Unit 2, Cycle 12. The final results of this assessment are not yet available, but the initial draft report has been reviewed by I&M. The conclusions of the DEI assessment support those in Appendix A.

In addition, Framatome Technologies, Incorporated (FTI), the contractor for the 1997 CNP Unit 2 inspection, prepared an assessment in 1997 of the largest wear indication detected in SG 24. The FTI assessment is included as Appendix B. Updated sizing estimates on the four indications in SG 24 were completed by FTI in November 2000. These estimates, which are smaller than the original unqualified estimates from 1997, are described in the FTI report included as Appendix C.

The condition monitoring portion of the assessment is normally performed during the actual tube inspection and is used to verify end-of-cycle tube integrity, check previous operational assessment predictions, and identify tubes requiring repair. I&M did not perform a condition monitoring assessment because inspection activities had already been completed, operational assessments for previous cycles had not been performed, and tubes requiring repair had already been identified.

NRC Question 2

"Describe in detail the tube inspections performed in each steam generator following the replacement along with the results of these inspections. In particular, address the maximum length of time between inspections for all tubes. Discuss the acceptability of the proposed interval between inspections, given the industry guidelines in this area and the observations that wear and loose parts have resulted in degradation in your steam generators. Use these results in the condition monitoring and operational assessment."

I&M Response to Question 2

A baseline pre-service inspection was performed in 1988. It included a full-length bobbin coil inspection of 100% of the tubes in all four SGs, with the exception of the one tube that was plugged prior to delivery due to a manufacturing defect. No indications of degradation were found and no tubes were plugged. Inspection results were submitted to the NRC in the 1988 Annual Operating Report dated February 28, 1989.

In 1990, 6.5% of the tubes in SGs 22 and 23 were inspected with a bobbin coil. No degradation was detected and no tubes were plugged. Inspection results were submitted to the NRC in the 1990 Annual Operating Report dated February 28, 1991.

In 1992, 6.5% of the tubes in SGs 21 and 24 were inspected with a bobbin coil. No degradation was detected and no tubes were plugged. Inspection results were submitted to the NRC in the 1992 Annual Operating Report dated February 26, 1993.

In 1994, 6.5% of the tubes in SGs 22 and 23 were inspected with a bobbin coil. In addition, a special inspection with a bobbin coil was performed in limited areas due to damage resulting from pressure pulse cleaning in SGs 22 and 23. Nine tubes were plugged due to mechanical damage; however, no in-service degradation was detected. Inspection results were submitted to the NRC in the 1994 Annual Operating Report dated February 24, 1995.

In 1997, approximately 50% of the tubes in all four SGs were inspected with a bobbin coil. One tube was found to be degraded and was plugged. This tube had a wear indication sized at 28% through-wall that was apparently caused by a foreign object. An additional 20% sample inspection with a motorized rotating pancake coil (MRPC) was conducted in SG 24 at the top of

the hot leg side of the tubesheet to address issues identified in Generic Letter 95-03, "Circumferential Cracking of Steam Generator Tubes." This inspection detected four tubes with indications of foreign object induced wear, which were subsequently plugged. Inspection results were submitted to the NRC in the 1997 Annual Operating Report dated May 14, 1998.

The proposed interval between inspections is consistent with the EPRI PWR SG Examination Guidelines, Revision 5, which base inspection intervals on operational time or refueling outage cycles. These guidelines also recommend that, during each refueling outage, an inspection be performed of all tubes not inspected within the previous 60 effective full power months (EFPMs) of operation. In 1997, I&M expected that the EPRI guidance would eventually replace the current Technical Specification (T/S) requirements for inspection scope and interval. Accordingly, to avoid having to perform a 100% inspection during one outage, I&M inspected 50% of the tubes in all four SGs in 1997, and planned to inspect the remaining tubes in a subsequent refueling outage. I&M plans to inspect all of the CNP Unit 2 SG tubes that were not examined in 1997 during the next refueling outage. This would satisfy the EPRI guideline of inspecting 100% of the tubes within a rolling 60 EFPM period. Inspecting all of the tubes within 60 EFPM represents a significantly more comprehensive inspection than that required by T/S.

A population in excess of 50% of the tubes has been inspected full-length with a bobbin coil probe since the 1988 pre-service inspection. While a population of tubes remains uninspected since 1988, no significant degradation is expected to reside within this population. This is based on the absence of any active degradation in the inspected population, the general lack of alloy 690 tube degradation throughout the industry, and the results of expanded inspections that have been performed in each case where a damaged or degraded tube was detected.

While fretting caused by loose parts has been detected, expanded inspections were performed in the areas where the fretting was detected and around the periphery of the tube bundle where a loose part would have entered the bundle. Sludge lancing and secondary side inspections have been performed on all four SGs. The results of these activities provide confidence that degradation due to foreign objects does not threaten tube integrity. Therefore, the proposed interval is considered acceptable considering degradation induced by foreign objects.

Two tubes inspected to date were identified as having support plate wear. The indications ranged in size from 4% to 11%. This mechanism does not progress while the unit is shut down. Therefore, assuming a similar distribution and relative size in the unexamined tube population, this mechanism is not a concern.

No additional degradation mechanisms have been observed. A condition monitoring assessment was not performed, as discussed in the response to Question 1. The operational assessment is discussed in the response to Question 1 and in Appendix A. Results of the 1997 inspection were used in the operational assessment; however, the maximum length of time between inspections for all tubes was not specifically evaluated in this assessment.

In summary, continued operation until the end of the current cycle is acceptable based on inspection history. No corrosion or cracking has been detected. The limited degradation that has occurred was due to mechanical damage and wear mechanisms that are not expected to challenge tube integrity. All degradation discovered was appropriately investigated and mitigated.

NRC Question 3

"Please provide a summary (or the report itself) of the Electric Power Research Institute's (EPRI's) findings from their review of your program. The EPRI review was referenced in your license amendment request dated September 30, 2000."

I&M Response to Question 3

The EPRI Non-Destructive Examination (NDE) Center completed the review of the CNP Unit 2 1997 tube inspection on September 28, 2000, and did not note any adverse findings. EPRI reviewed a sampling of the eddy current data, the data analysis guidelines, and the associated eddy current calibration standard drawings. Additionally, the EPRI representative met with a CNP SG program engineer to discuss details on past inspection practices and inspection history. Based upon this review, EPRI concluded the following:

- The inspections were planned and performed in accordance with the EPRI PWR SG Examination Guidelines, with the exception of the current guideline for a 100% inspection after the first cycle of operation. (This recommendation was not in effect at the conclusion of the first operating cycle.)

- All degradation was investigated to determine the cause and was mitigated.

- The operating characteristics of the SGs appear to be consistent over several cycles, based upon inspection results.

- The proposed extended inspection interval is justified based upon the information provided and reviewed, provided the operational assessment supports continued operation through the end of the current cycle.

As documented in Appendix A, the operational assessment supports continued operation through the end of the current cycle. Therefore, the EPRI review supports the conclusion that the extended interval is acceptable.

NRC Question 4

"Given the lessons learned from Indian Point 2, discuss the extent to which your program is not affected by these concerns (e.g., data quality, noise levels, qualification program did not "bound" site specific conditions, etc.). Discuss the basis for your conclusions."

I&M Response to Question 4

The Indian Point 2 event, as well as other related industry experience, was considered during the preparation of the extension request. A brief discussion of some of these issues was provided in Attachment 6 of the extension request. I&M subsequently reviewed NRC Regulatory Issue Summary (RIS) 2000-22, "Issues Stemming from NRC Staff Review of Recent Difficulties Experienced in Maintaining Steam Generator Tube Integrity," dated November 3, 2000. In addition, I&M reviewed the letter from the chairman of the NEI Steam Generator Management Program (SGMP), "SGMP Information Letter Concerning Lessons Learned from a Review of Recent Steam Generator Related Issues," dated September 29, 2000. The issues addressed in these two documents were evaluated for applicability to CNP Unit 2 and the proposed surveillance interval extension. Some topics, such as in situ pressure test results and issues specific to plants that have experienced significant degradation due to corrosion and cracking, are not concerns at CNP Unit 2 because in situ testing has not been performed and corrosion and cracking have not been observed since the SGs were installed. These topics are not addressed in detail in this response. Other issues, including NDE samples and recommendations for future condition monitoring and operation assessments, are also not addressed in detail here. This is because these issues are applicable for future inspection activities, but are not pertinent to the proposed extension request, which is based on demonstrated performance and assessments that have already been completed. The applicable issues are discussed below.

Issues identified in SGMP letter dated September 29, 2000

1. Degradation Assessment/Operational Assessment/Condition Monitoring

SGMP stressed the need to follow industry guidelines for the preparation of degradation assessments. Required preparatory actions should be completed. In addition, licensees should appropriately incorporate industry operating experience and use industry-recommended assessment and inspection techniques.

Industry guidance regarding degradation, operational, and condition monitoring assessments is relatively new and was not in place at the time of the last CNP Unit 2 SG tube inspection. CNP steam generator program procedures have been developed to address the development of degradation assessments and the requirement for performing operational assessments and condition monitoring in future inspections.

2. Data Quality

SGMP made three recommendations regarding data quality: (1) define data quality requirements; (2) evaluate abnormal signals; and (3) use site-qualified NDE techniques.

During the 1997 inspection, the CNP Unit 2 data analysis guidelines contained specific data quality requirements and provided direction in the event these requirements were not met. The following details from the data analysis guidelines exemplify these requirements:

- Data that contain quantitative noise criteria resulting from electrical noise, tube noise, or calibration standard noise shall be re-inspected.

- Tube Noise: Tubes identified with noise associated with inside diameter chatter or pilgering at tube support plates in excess of 5 volts shall be inspected with MRPC.

- Electrical Noise: Noise due to a failing or intermittent probe in excess of 0.3 volts at support plate locations shall be reported as retest bad data. The quality shall be monitored to ensure that a minimum 3:1 signal-to-noise ratio is maintained.

- Calibration standard noise: This will be determined by observing the beginning and standard runs for changes in noise levels. Large changes could mask indications. Tubes will be retested when standard noise distorts the flaws and calibrations cannot be performed.

The calibration standards used during the inspection helped alleviate data quality concerns. The standards were manufactured from tubing of the same heat numbers and lots that were used in the manufacturing of the CNP Unit 2 tubes. The use of this material allowed setup parameters to accurately reflect the installed SG tube conditions. Based upon the above, data quality during the 1997 inspection was adequately addressed.

The potential significance of abnormal signals is emphasized to all analysts by instructions in the data analysis guidelines. These guidelines require the lead analyst to review all repairable indications or anomalies. They also require all analysts (resolution, shift lead, and production) to alert the lead analyst to conditions present in the data that are not addressed in the guidelines. The data analysis guidelines assign responsibilities to ensure abnormal signals received a high level of review.

In the event that acceptable data quality is not obtained for a given tube, the tube is reexamined until acceptable data quality is obtained. If acceptable data quality cannot be obtained for a given tube, the tube is repaired or removed from service. A review of the 1997 eddy current data confirmed that, while some retests were required, no tubes with unacceptable data quality were left in service.

3. Probability of Detection (POD)

SGMP recommended that licensees check SG conditions against the NDE performance database prior to an outage to ensure that variables like POD and measurement uncertainty are not unacceptably altered. Adjustments should be made if deviations are identified.

In 1997, inspection techniques were chosen based upon discussions with the steam generator service provider, the types of degradation expected, and the techniques that were qualified to Appendix H of the EPRI PWR SG Examination Guidelines in place at the time of the inspection. I&M intends to continue this practice and to supplement future inspections by complying with the suggestion in the SGMP letter that utilities stay current with the information collected by EPRI to address POD issues. There are industry guidelines currently under development to resolve recent questions regarding POD. I&M uses the applicable EPRI data to ensure accurate, up-to-date information is used at the time of the inspection. I&M has implemented requirements for a review of all eddy current techniques by a qualified data analyst prior to use.

4. In Situ Pressure Testing of Tubes

SGMP addressed several issues regarding evaluation of SGs at Arkansas Nuclear One Unit 2 (ANO-2). SGMP recommended that utilities review industry experience and use NEI references to help ensure the best and latest industry guidance is being used.

This issue is not applicable to the 1997 CNP Unit 2 inspection. No tubes warranted in situ pressure testing.

5. Risk Analysis

SGMP noted that risk analysis may be another way to support the operational assessment if the performance criteria of NEI 97-06 cannot be satisfied or adequately evaluated.

Risk analysis is an optional method that can be used to support an operational assessment with reduced tube structural integrity margin. This method has not been needed at CNP Unit 2.

6. Steam Generator Program Ownership and Implementation

The SGMP identified several examples of how roles and responsibilities must be clearly defined so that the steam generator program can be effectively maintained.

Senior plant management, having recently replaced the Unit 1 steam generators, is well aware of the importance of a strong steam generator program and actively supports continual programmatic improvement. The engineering programs section has also instituted a plan aimed at continually assessing and refining various plant programs. The SG program is included in this

plan. I&M has established program procedures which define responsibilities and direct implementing actions to ensure that the T/S and NEI 97-06 requirements are satisfied.

Issues identified in RIS 2000-22

1. Consideration of relevant operating experience and appropriate diagnostic, corrective, or compensatory measures to ensure tube integrity

The NRC identified that the event at Indian Point 2 (IP2) was caused by the same mechanism that caused the tube rupture at Surry 2 in 1976. Therefore, the NRC identified the need to identify relevant operating experience and appropriate diagnostic, corrective, or compensatory measures to ensure tube integrity.

I&M has reviewed SG tube inspection data from EPRI, the NRC, and SG vendors. No operating experience on corrosion or cracking of thermally treated alloy 690 tubing was found. Primary and secondary side inspections have not identified any abnormal conditions that threaten tube integrity or would require additional consideration when developing the eddy current inspection plan. No indications of corrosion or active degradation have been detected and only minimal tube plugging has been required. I&M plans to base future inspections on an approved degradation assessment that ensures both site specific and relevant industry experience is considered when developing the inspection scope.

2. Assessment of the root causes of all degradation mechanisms at a plant and appropriate diagnostic, corrective, or compensatory measures to ensure tube integrity

The NRC identified that the primary water stress corrosion cracking (PWSCC) at the apex of the small radius U-bends was detected for the first time and was not adequately evaluated in the 1997 inspection at IP2.

The root causes of all detected degradation have been fully assessed at CNP Unit 2. Details regarding mechanical damage are provided in response to Question 9, and wear/fretting is discussed in the response to Question 10. Appropriate measures have been taken to ensure tube integrity, including conservatively removing tubes from service and expanding the scope of tube inspections.

3. Data quality

The NRC identified that four indications were missed during the 1997 inspection at IP2 because of data quality issues.

This is addressed under issue 2 of the September 29, 2000, SGMP letter.

4. Non-destructive examination qualification programs that include tube samples with flaws that truly represent flaws in the field

Techniques for qualification data sets for PWSCC and outside diameter stress corrosion cracking (ODSCC) in small radius U-bends consist largely of fabricated specimens, rather than actual tube samples. The fabricated specimens could produce larger amplitude signals and higher signal-to-noise ratios than comparably sized cracks, resulting in non-conservative inspection results.

This issue addresses the methods used for the nuclear industry's NDE qualification programs. CNP is a member of the EPRI NDE Center and uses the techniques that have been qualified by EPRI. When flaws from pulled tubes are available, characterization of these flaws is used in the qualification process. I&M continues to monitor industry direction on this issue and will continue to use the best data available.

5. Site-specific qualifications of generically qualified techniques ensuring an application is consistent with site-specific conditions and that appropriate NDE performance capabilities are considered in operational assessments (e.g., POD of flaws and flaw size measurement error)

The NRC found that the techniques used in the 2000 inspections performed at IP2 were not applicable to site-specific conditions. The EPRI PWR SG Examination Guidelines state that site-specific qualification of NDE techniques is necessary to ensure that the technique performance capabilities obtained from the generic technique qualification are applicable to site-specific conditions.

As noted previously, the 1997 CNP Unit 2 inspection was performed using the guidance in Revision 4 of the EPRI PWR SG Examination Guidelines. I&M followed standard industry practice at the time by using the techniques in Appendix H of these guidelines. The bobbin coil and MRPC techniques used were qualified based on the potential degradation expected at the site. The Appendix H qualification of the two probes used during the 1997 inspection is as follows:

Bobbin Coil: General degradation – Detection of intergranular attack/ODSCC at the tubesheet crevice, detection and sizing of pitting and thinning above the top of tubesheet, detection and sizing of thinning and wear in tube support plates without dents and detection and sizing of wear at anti-vibration bars.

MRPC: Detection of PWSCC/ODSCC at expansion transitions, PWSCC at the tubesheet crevice, ODSCC above the top of tubesheet, PWSCC/ODSCC at tube support plates with and without dents.

6. Consideration of flaw size measurement error when applying the threshold screening criteria for selection of in situ pressure test results

The NRC found that the selection criteria used in 1999 at ANO-2 did not appropriately allow for flaw size measurement errors when selecting tubes for in situ pressure testing.

For the four indications of foreign part wear discovered in SG 24 in 1997, the selection criteria used to determine if in situ pressure testing was required consisted of a comparison of the detected indications with the critical crack size. This method is described in Appendix B. A qualified sizing technique for these indications was not available and hence, flaw size measurement error was not considered in screening these tubes for in situ pressure testing. Sufficient margin was available such that any measurement error, if available, would have been small in comparison. Prior to 1997, there were no defective or degraded tubes discovered; therefore, consideration of flaw size measurement error for in situ pressure test screening was not an issue.

7. Rigorous analysis of the results of in situ pressure tests that are terminated when leakage exceeds the capacity of the test system

The in situ pressure testing conducted at ANO-2 in 1997 resulted in leakage that prevented the test pressure from reaching the burst pressure. Although it was concluded by the licensee that a margin against tube rupture consistent with the plant's licensing basis could be maintained until the scheduled refueling outage, the NRC found the results did not satisfactorily demonstrate that applicable performance criteria would be maintained.

This issue is not applicable at CNP Unit 2 because in situ pressure testing has not been performed since the steam generators were replaced as addressed in issue 6 above.

8. Laboratory and in situ pressure test procedures utilizing pressurization rates that do not influence burst pressure results

The NRC identified issues related to laboratory burst and leak tests performed to support the ANO-2 in situ pressure test results discussed under issue 7 above.

This issue is not applicable at CNP Unit 2 because in situ pressure testing has not been performed since the steam generators were replaced as addressed in issue 6 above.

9. Use of a fractional flaw method or other similar methods for determining a beginning-of-cycle (BOC) flaw distribution may lead to nonconservative results when used in conjunction with a POD parameter that varies as a function of flaw size or voltage

The NRC considered a finding related to the fractional flaw method use in an operational assessment of small radius U-bend PWSCC at IP2 to be unrealistic.

This issue is not applicable at CNP Unit 2 because the fractional flaw method is not used. BOC flaw distribution is not determined in conjunction with a POD parameter that varies as a function of flaw size or voltage. The guidelines for determining BOC flaw distribution were not in effect during the 1997 inspection; therefore, this determination has not been made for CNP Unit 2. The issues with potentially non-conservative methodologies will be considered when the next BOC flaw distribution is determined.

10. Benchmarking operational assessment methodologies against actual operating experience to ensure realistic results

The NRC found that an operational assessment performed for ANO-2 in 1999 did not accurately predict the degradation that was observed in the following inspection. The licensee credited increased sensitivity of the bobbin coil inspection, but failed to recognize increased noise levels, resulting in errors in POD and growth rate parameters.

Degradation in the CNP Unit 2 SGs has been very limited since they were replaced. Most degradation mechanisms have not been observed and are not expected during the current operating cycle. The operational assessment performed for CNP Unit 2, cycle 12, was the first operational assessment performed since the SGs were replaced. Therefore, there are not any data to benchmark actual operating experience against. I&M intends to benchmark the cycle 12 operational assessment results against actual operating experience at the end of cycle 12.

Conclusion

I&M has considered the lessons learned from IP2 and other industry issues, and evaluated them for applicability to the proposed extension request. In addition, EPRI reviewed details of the 1997 CNP Unit 2 tube inspection, as discussed in the response to question #3. This review, conducted with the understanding of the events and issues at IP2, concluded that the proposed extension is justified.

I&M recognizes that technology in this field changes continually, and there are opportunities to improve future inspection and assessment activities based on knowledge gained from recent industry events. However, no significant weaknesses were discovered that impact the bases for the extended surveillance interval. Considering this, the conclusions in the extension request are not affected and the proposed surveillance interval remains justified.

NRC Question 5

"Page 4 of Attachment 1 of the amendment request indicates that no tubes in service were found to be degraded (i.e., 20% or more through-wall). This appears to contradict page 4 of Attachment 6 which indicates that R1C70 was found to have 28 percent through-wall degradation. Please clarify. A similar observation was made in Attachment 4."

I&M Response to Question 5

The statement in the extension request, "There are no tubes in service in any of the Unit 2 steam generators that were found to be degraded," was intended to communicate the fact that no degraded tubes were left in service. The tube with the 28% indication was considered degraded; however, it was removed from service by plugging. There are no tubes with indications sized at greater than 11% through-wall that remain in service.

NRC Question 6

"The wording in the proposed change to the facility operating license (attachment 3) is not clear. The NRC recommends putting the extension in terms of calendar months consistent with the Technical Specifications."

I&M Response to Question 6

I&M proposes the following statement to replace the wording of the license condition submitted in the extension request:

"For the period beginning November 1997, the steam generator tube inspection surveillance interval of T/S 4.4.5.3 has been extended to a one-time maximum interval of 56 months."

NRC Question 7

"In attachment 4, the licensee indicated that offsite dose considerations from steam generator tube failures are limited by the primary-to-secondary leak rate program and not the tube inspection program; therefore, the proposed change has no impact on offsite dose. Please provide the basis for this statement. For example, is this statement implying that a normal operating leak-rate limit (i.e., the limit in the Technical Specifications) is sufficient to ensure leakage integrity for steam generators under the full range of accident conditions (e.g., leakage under main steamline break conditions)?"

I&M Response to Question 7

The intent of the referenced statement in attachment 4 is to indicate that the dose consequences of accidents are not increased by the proposed inspection interval and, therefore, the margin of safety to the dose limit is not reduced. The statement is not related to the margin of safety to tube failure under accident conditions.

The CNP Unit 2 T/S primary-to-secondary leak rate limits are used in the accident dose analyses. The analyses show that dose consequences are within 10 CFR 100 acceptance limits. Tube integrity is maintained by the tube surveillance program and plugging tubes that could fail under accident conditions.

The main steam line break analysis uses the leak rate limit from CNP Unit 2 T/S 3.4.6.2. The faulted SG leak rate is 500 gallons per day (gpd). The intact SGs have a maximum total leak rate of one gallon per minute (gpm) minus 500 gpd through the faulted SG, or 940 gpd. The leak is assumed to persist for 30 days following the accident at a constant rate.

The SG tube rupture analysis uses the leak rate limit from CNP Unit 2 T/S 3.4.6.2. The intact SGs are conservatively assumed to have a total primary-to-secondary leak rate of one gpm for 30 days following the accident.

The rod cluster control assembly ejection, loss-of-load, and loss-of-offsite power analyses use the leak rate limit from Unit 2 T/S 3.4.6.2. The SGs are conservatively assumed to have a total primary-to-secondary leak rate of one gpm for 30 days following the accident.

Other related factors influencing the dose consequences are the initial primary coolant activity, initial secondary coolant activity and the reactor coolant iodine appearance rate increase due to the accident. Primary and secondary coolant activities are conservatively assumed to be at the limits of T/S 3.4.8 and 3.7.1.4. The iodine appearance rate is conservatively assumed to be 500 times the equilibrium rate due to the accident.

For a large-break loss-of-coolant accident (LOCA), the primary coolant activity is insignificant compared with the release from the core and is not used in the analysis. The secondary side is not used for cooling and there are no secondary side releases assumed. The accident analysis does not assume additional tube failures due to the accident.

NRC Question 8

"In attachment 4, the licensee indicates that the T/S leakage limit of 500 gallons per day in one steam generator is based on ensuring tube integrity in the event of a steamline rupture or loss-of-coolant accident. While this may be the basis for D. C. Cook, Unit 2 (Regulatory Guide 1.121 indicates it should be the leakage associated with a crack size that bursts at three times the

normal operating pressure differential), operating experience indicates this not to be the case. Discuss the effect of this observation on your conclusions."

"The licensee indicated that Information Notice 91-43 indicated that tubes typically leak before failing, so leak rate monitoring can reduce the probability of a steam generator tube rupture (SGTR). While the staff agrees that leak rate monitoring may reduce the probability of SGTRs, the staff observes that tubes do not necessary leak at values in excess of T/S and/or administrative limits prior to SGTR (i.e., leak rate monitoring and taking action per T/S limits will not necessarily prevent an SGTR). Discuss any implications on your conclusions.

Given that primary-to-secondary leak rate monitoring may provide an indication of impending tube failure, discuss the need to reduce the primary-to-secondary leakage limit consistent with current industry guidance."

I&M Response to Question 8

The 500 gpd limit per steam generator is intended to ensure that through-wall cracks that leak at rates up to this limit during normal operation will not propagate and result in tube rupture under postulated accident conditions, consistent with the criteria of Regulatory Guide 1.121. The statement in the extension request that the leakage limit is "based on ensuring tube integrity" was not intended to imply that leakage limits will prevent all tube failures. The 500 gpd limit gives reasonable confidence that tube integrity will be maintained under accident conditions. T/S leakage limits are not credited for preventing tube ruptures. I&M is aware of operating experience regarding tube failures that have occurred at normal operating pressure and with initial leak rates well below T/S limits. This operating experience does not affect the conclusions in the extension request.

The statement in the extension request that referred to Information Notice (IN) 91-43 was intended to acknowledge that a primary-to-secondary leak rate program exists and that it has some value in reducing the tube rupture probability. The extension request essentially restates the following information published by the NRC in IN 91-43: "Leak rate monitoring programs can provide for early detection and response to rapidly increasing leak rates and, thus, can be an effective approach for minimizing the frequency of steam generator tube ruptures." The statement in the extension request was not intended to imply that the primary-to-secondary leak rate program would prevent all tube ruptures. No credit was taken for this program to prevent a SGTR. There is no effect on the conclusions in the extension request.

I&M has more conservative administrative controls in place that address industry guidance on primary-to-secondary leak rate programs. Primary-to-secondary leak rate monitoring is addressed in the extension request on page 9 of Attachment 6. No primary-to-secondary leakage was detected during the previous operating cycle, and none has been detected to date during the current operating cycle. Administrative limits for primary-to-secondary leakage include

requirements for a unit shutdown in the event leakage exceeds a total of 75 gpd. Increased monitoring is required at leakage rates as low as five gpd total. The industry, through NEI, is preparing a generic SG program licensing document that will address many SG issues, including leak rate programs. I&M has endorsed this program and will consider amending T/S limits to incorporate this industry guidance after it is issued. The current T/S leak rate limits are considered acceptable and consistent with the accident analyses.

NRC Question 9

"In Attachment 6, the licensee indicates that nine tubes were plugged in 1994 due to mechanical damage during pressure pulse cleaning. Please provide the basis for the conclusion that the damage was mechanical in nature (e.g., Was an inspection done prior to the pressure pulse cleaning indicating no degradation of the tube followed by a subsequent inspection (visual or eddy current) which indicated degradation? What was the nature of the damage? What confidence do you have that the inspections bounded the problem (i.e., all affected tubes were inspected)? Was pressure pulse cleaning performed in the steam generators that weren't inspected during this outage?

As part of this review, the NRC reviewed the D. C. Cook, Unit 2, steam generator inspection summary provided in your 1994 annual report. In this report, you indicated that the inspection for the 'mechanical damage' from the pressure pulse cleaning was part of a 'special eddy current maintenance inspection.' It was during this 'special inspection' that the nine tubes requiring plugging were identified. The staff notes that if service-induced degradation was found during these 'special inspections,' the staff expects that the inspection would be expanded consistent with the T/S requirements (i.e., all inspections must follow the T/S inspection and repair criteria regardless of whether the inspections are 'over and above' T/S minimum sample size requirements)"

I&M Response to Question 9

During the 1994 CNP Unit 2 outage, the only planned SG activities were related to the secondary side cleaning and inspections. Specifically, pressure pulse cleaning (PPC), followed by sludge lancing, was scheduled for all four SGs. Primary side eddy current testing was not planned, and tube inspections were not performed prior to the PPC.

Following the completion of the PPC on the first SG, a visual inspection was performed to judge the effectiveness of the cleaning operations. During this examination, mechanical damage of the SG tubes near the hand holes was noted. An investigation was initiated to determine the cause of the mechanical damage. The PPC nozzles, consisting of flexible stainless steel hoses tipped with solid stainless steel rings, were inspected and found to be damaged. Based on visual inspection, these nozzles were determined to clearly be the cause of the damage to the tubes.

The in-progress PPC operations on the second SG were immediately stopped. Subsequent inspection confirmed similar damage in this SG. PPC operations on the remaining two SGs were cancelled before they were started.

An eddy current contractor was mobilized to determine the extent of the damage in the two affected SGs, 22 and 23. This inspection was considered a "special inspection" since it only included those portions of tubes necessary to bound the damage inflicted by the PPC nozzles. Due to the known size and placement of the nozzles, the population of potentially affected tubes and the susceptible regions of the tubes were readily determined. The areas that could have been reached by the PPC nozzles were limited to an area above the tubesheet and below the flow distribution baffle. With one exception, all of these tubes were inspected from 3" above the flow distribution baffle to the tube end on both the hot and cold legs. In addition, the remaining row 1 tubes were inspected to the same extent. The one exception involved a tube in SG 23 that was damaged to the extent that it could not be inspected with a qualified technique; this tube was plugged. While some tubes were found severely damaged, no tubes were determined to be thinned or to contain cracks. However, because the eddy current testing could not assure that the damaged tubes were acceptable for continued service, nine damaged tubes were removed from service, in accordance with the 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," and the EPRI PWR SG Examination Guidelines. All potentially damaged tubes were examined, and no service-induced degradation was found during these inspections. Therefore, no expansion of the inspection scope was required. I&M is confident that the inspections bounded the problem.

Because personnel and equipment were already being mobilized for the special inspection, the opportunity was used to perform a separate inspection in order to satisfy T/S surveillance requirements. This consisted of a 6.5% bobbin coil inspection of SGs 22 and 23, which exceeded the 6% required by T/S 4.4.5.2. No service-related degradation was found during this inspection and, therefore, no expansion of the inspection scope was necessary.

The actions taken to address the damaged tubes were evaluated by NRC inspectors at the time of the inspection, as documented in NRC Inspection Report 315-316/94020, dated November 17, 1994. This report indicated acceptance of the inspection and repair activities with the following statement: "The inspectors consulted with the material engineers from the Office of Nuclear Reactor Regulation and the engineers were satisfied with the results of the eddy current inspections and the actions taken by the licensee to plug the tubes which were found damaged."

<u>NRC Question 10A</u>

"In Attachment 6, the licensee indicates that 4 tubes with volumetric indications were found in one steam generator but that a through-wall percentage could not be assigned to these indications due to the lack of a qualified sizing technique. The indications were found with a rotating pancake coil near the top of the tubesheet. It was further indicated that the indications

were plugged as a 'conservative measure.' Furthermore, the licensee indicated that the indications were not considered degraded or defective since the damage was representative of foreign-object-induced wear and was not a result of progressive degradation due to design, manufacturing errors, or typical inservice conditions. With respect to these indications please address the following concerns:

Given that the sizes are not known, discuss the basis for assuming the indications were not greater than 20 percent or 40 percent through-wall (i.e., defective or degraded). Discuss the implications on the categorization of the results."

I&M Response to Question 10A

As discussed in the eddy current examination plan for the 1997 Unit 2 inspection, 50% of all installed tubes were to be examined full-length with the standard bobbin coil technique, using dual guide tubes where feasible. This examination population was chosen in anticipation of the acceptance of Revision 5 of the EPRI PWR SG Examination Guidelines prior to the next scheduled inspection.

The 50% full-length bobbin coil examination was performed by zones to maximize manipulator efficiency. The inspection population was separated into seven groups, each with a sample size (S) of approximately 7% of the installed tubes. By using a sampling plan comprising 1S, 2S, and 4S populations, the total scope encompassed 50% of the tubes. This scope satisfied CNP Unit 2 T/S 4.4.5.2, including potential expansions of scope that would have been called for if results were found to be in the C-2 category. The scope also satisfied the EPRI PWR SG Examination Guidelines, Revision 5.

This 50% examination revealed only one degraded tube, R1C70 in SG 21, which was sized by bobbin coil at 28% through-wall and was ultimately plugged. This indication was determined to be the result of loose part wear. Upon completion of the T/S examination, all four SGs remained in degradation category C-1.

In addition to the T/S inspection, a supplemental examination was conducted in SG 24 of 20% of the in-service tubes with a 3-coil MRPC probe. The purpose of this inspection was to confirm the absence of circumferential cracking, in response to Generic Letter 95-03. This technique was qualified for detection only and was not considered within the scope of the T/S inspection. While no cracking was detected, the supplemental inspection revealed four tubes with damage on one side of each tube. All four of these tubes had been inspected with the bobbin coil as part of the T/S inspection. The indications did not have a recordable depth when inspected with the bobbin coil.

Indications detected during the supplemental inspection were dispositioned, commensurate with their safety significance, in accordance with 10 CFR 50, Appendix B, Criterion XVI, "Corrective

Action." The affected tubes were not categorized as degraded or defective by T/S definitions because they were not judged to be degraded or defective with the approved sizing technique. It was conservatively determined that the inspection techniques used could not positively assure the tubes were adequate for continued operation. Therefore, the tubes were plugged. This action did not affect the categorization of the T/S inspection results. The structural/leakage assessment performed by FTI supports this determination. All actions recommended in this assessment were completed. The FTI assessment is included as Appendix B, and updated information is provided in Appendix C.

NRC Question 10B

"Discuss the basis for assuming that the indications were representative of wear. Given that sludge lancing was done in the outage (assuming the presence of sludge at the top of the tubesheet) and pressure pulse cleaning in the previous outage, discuss the possibility that this degradation is intergranular attack or some other form of volumetric degradation."

I&M Response to Question 10B

The indications were considered representative of wear (fretting) for several reasons. The apparent geometry of the indications was representative of wear. All of the indications were located in the same SG, near the tubesheet and close to the periphery of the tube bundle. This is a typical location for loose part wear to occur. Three of the four indications were on adjacent tubes, such that a single object located in this vicinity could have caused the damage. In the case of the fourth indication, a foreign object was found and removed from this same location. This object is suspected to have caused the damage.

As stated in the response to Question 9, pressure pulse cleaning has not been performed in SG 24; therefore, damage associated with this process is not a possibility in this SG.

The sludge removed from the CNP Unit 2 SGs has always been "soft sludge" that does not tend to pack around tubes and lead to an environment conducive to tube degradation. During the sludge lancing performed in 1997, the sludge was again found to be "soft sludge" and have an absence of quantifiable lead, indicating a low potential for corrosion damage. Therefore, sludge is not considered a contributing factor for the initiation of intergranular attack or some other form of volumetric degradation for the Unit 2 SGs.

Intergranular attack has not been reported in SGs with alloy 690 thermally treated tube material. This is the case even for domestic and international plants that have considerably more operational time than the CNP Unit 2 SGs. EPRI and other organizations have noted that this tube material is highly resistant to intergranular attack. While intergranular attack or some other form of volumetric degradation can not be ruled out completely, based on the design, materials,

and water chemistry in the Unit 2 steam generators and their inspection history, these mechanisms are considered unlikely.

NRC Question 10C

"If the indications were 'wear-like' in nature, why were they not sized? Was the technique used to [inspect] the steam generators at D. C. Cook, Unit 2, qualified for sizing wear indications?

Given that the indications were found with a rotating pancake coil, discuss the basis for not expanding the inspection at the top of the tubesheet with this technique."

I&M Response to Question 10C

The bobbin coil probe, which was qualified for detecting and sizing wear indications, did not detect the indications, apparently due to their small size. Therefore, bobbin coil sizing was not possible with the approved sizing technique. The 3-coil MRPC probe used to locate the indications was qualified for detecting but not sizing, so it could not be used to assure that the tubes were adequate for continued service. Therefore, as a conservative measure, the tubes with indications from the MRPC were plugged. Although there were no qualified techniques available to size these indications at the time of the inspection, initial unofficial sizing estimates were performed by FTI in 1997. The indications were recently reevaluated by FTI at the request of I&M, and estimates made based on current techniques that have been qualified for sizing wear at anti-vibration bars. These estimates confirm that none of the tubes were defective. Details are provided in Appendix C.

The scope of the supplemental MRPC examination at the top of the tubesheet in SG 24 was expanded twice, once after a volumetric indication was detected in a tube and once after a possible loose part was detected. The first MRPC expansion included the tubes surrounding the volumetric indication detected at R33C16. The second MRPC expansion was performed in the area surrounding a suspected indication of a foreign part near R38C71. These expansions were consistent with the EPRI PWR SG Examination Guidelines. Three of the four damaged tubes were discovered during these expanded inspections. As a further check, a bobbin coil was used to examine the tubes around the periphery of the tube bundle where the damaged tubes were located to assure that there were no other damaged tubes. In addition, the secondary side foreign object search and retrieval examination was expanded to the tubes surrounding the indications and along the periphery of the tube bundle. No additional degradation was discovered.

NRC Question 11

"The D. C. Cook, Unit 2, steam generators were one of the first installed in the United States with alloy 690 tubes. As a result, the operating experience with this type of material is somewhat limited; however, trends in degradation modes may be inferred from other similarly operated

steam generators. Discuss the extent to which the results of steam generator tube inspections from other plants with alloy 690 tubes with similar, or longer, operating times as D. C. Cook, Unit 2, were considered in your analysis. If considered, do they support your conclusion that no active degradation mechanism is occurring? Also discuss the similarity of operating conditions (e.g., T-hot, water chemistry, etc.)."

I&M Response to Question 11

A review of the EPRI SG degradation database identified several domestic plants with alloy 690 steam generator tubes with similar or longer operating time. V. C. Summer, Indian Point 3, North Anna 1, and North Anna 2 have reported very little tube repair work since installing their replacement SGs. The following table summarizes applicable data from these plants:

Plant	EFPM*	T-hot (°F)	No. of Tubes Plugged	Basis for Plugging
V. C. Summer	72	619	8	Fabrication
Indian Point 3	67	595	0	N/A
North Anna 1	78	618	1	Preventative
North Anna 2	47	614	0	N/A
CNP 2	71	607	15	Fabrication, wear, mechanical damage

* as of the date of last tube inspection

Based upon the small percentage of plugged tubes and no reports of any active degradation mechanisms, none of these alloy 690 plants appear to demonstrate any adverse trend in alloy 690 degradation.

A review of hot leg temperatures shows that the 607°F value at CNP Unit 2 is relatively low. This would indicate that CNP Unit 2 should not be more susceptible to temperature-sensitive degradation than these plants.

Plant chemistry is similar among the plants listed due to the common acceptance of the EPRI PWR Secondary Water Chemistry Guidelines. Therefore, chemistry is not expected to cause significant variation in the degradation rates. I&M is not aware of any other significant differences in operating conditions that would affect steam generator tube degradation rates. In general, I&M believes the CNP Unit 2 inspection results are representative of the domestic industry experience with alloy 690. This experience does not alter the CNP Unit 2 inspection findings that support the determination of no active degradation.

NRC Question 12

"In your 1997 annual report, you provided the D. C. Cook, Unit 2, steam generator inspection results. Please discuss the codes used for the indications detected (e.g., MBH, INR, DNH, INF). For those indications indicating mechanical damage or manufacturing defects, discuss the extent to which these indications can be traced to the preservice inspection. If they can not be traced back to the preservice inspection, discuss whether further mechanical damage can occur."

I&M Response to Question 12

The following indication codes are defined in the data analysis guidelines that were used during the 1997 inspection:

- Manufacturing Burnish Mark (MBM) – Condition where tube manufacturing anomalies are detected. Recorded using the free span flow chart.
- Manufacturing Burnish Mark History (MBH) - Used by resolution analyst for MBM locations that have been looked up in prior examinations and determined that no change has occurred.

- Indication Not Reportable (INR) - Indications previously reported that are not reportable under new procedure or customer requirements. Volts, degrees, and location are recorded for INRs.

- Dent (DNT) – Condition where the tubing inside diameter is less than nominal. Recorded in process channel P1 if 3.0 volts and above including free span dents.

- Dent History (DNH) - Used by resolution analyst for DNT locations that have been looked up in prior examinations and determined that no change has occurred.

- Indication Not Found (INF) - Condition where a previously reported indication is not detectable or is not detected within reason of its previous location. This call is reported with the same location as the previous indication. Volts and degrees are not recorded for INFs. INFs should be brought to the attention of the lead if the analyst feels the tube number may be in question.

The MBH and DNH codes apply to indications that were reported in 1997 and then confirmed to exist in the 1988 pre-service inspection eddy current data. In addition to the confirmation, a determination was made by that the indication(s) had not changed in size or characteristics. After the pre-service data review the reported MBM (or DNT) code was changed to MBH (or DNH) to indicate in the database that a historical review has been performed. Therefore, by definition, all MBM and DNH indications can be traced back to the pre-service examination.

The INR and INF codes, as indicated by the definitions, represent previously noted indications that are no longer reportable or in the case of the INF code, found at the specified location. They do not reflect a manufacturing defect or damage mechanism.

Correction of Errors in Original Submittal

In preparing the overall response to this RAI, a discrepancy was noted in previously reported information. The scope expansions discussed in Attachment 6, page 4 of the extension request for SG 21 and 24 were based upon information contained in the 1997 Framatome Inspection Report. Recent review by I&M and Framatome has confirmed that these expansions were not accurately reflected in the report. Therefore, the following statements from the original submittal require correction:

Statement: "The initial bobbin coil examination in steam generator 21 was expanded to ensure 100% of the tubes in rows 1-3 were inspected."

Correction: 100% of the area within rows 1-3 were not inspected. Approximately half of these tubes were inspected.

Statement: "Because of the foreign object concern, the initial bobbin coil inspection scope in steam generator 24 was expanded to include 100% of the row 1-3 tubes and all tubes around the periphery (two rows in)."

Corrections: 100% of the area within rows 1-3 were not inspected. Approximately half of these tubes were inspected.

All tubes around the periphery of the hot leg side were inspected, with the exception of R1/C1, R2/C1, and R3/C1.

I&M has reviewed the corrected inspection data, and has determined that the conclusions in the original extension request are not affected. These errors do not affect the finding of No Significant Hazards Consideration in the original submittal.

APPENDIX A
DETAILS OF UNIT 2 CYCLE 12 OPERATIONAL ASSESSMENT

INTRODUCTION

This operational assessment was performed using the Electric Power Research Institute (EPRI) Steam Generator Integrity Assessment Guidelines, Revision 1, as a general guideline.

In preparing the assessment, several important considerations were made:

1. Alloy 690 tubing has no history of corrosion-related degradation based upon site specific and industry experience. Therefore, degradation due to corrosion was not considered a concern for the current operating cycle.

2. Previous foreign object damage was mitigated by the removal of an object, expanded inspections in susceptible locations, plugging of all tubes exhibiting damage, and sludge lancing. Additional confidence is provided by the Donald C. Cook Nuclear Plant (CNP) foreign material exclusion program and the secondary side visual inspections. Therefore, due to these considerations and the random nature of this mechanism, further predictions were not addressed in the operational assessment.

3. Before the 1997 inspection, no tubes had been removed from service due to in-service degradation. In fact, there were no degraded tube indications before the 1997 inspection. Therefore, the only indications considered in the operational assessment were those identified in the 1997 inspection. These indications were a result of support plate wear, were not crack like, and were well below through-wall depth. As the inspected tube population in 1997 was approximately 50% in each steam generator, a similar population and size of flaws was assumed to exist in the uninspected tube population. The largest flaw was determined to be well below the calculated operational assessment limit. Because the flaw was not crack-like or through-wall, this flaw and the assumed population of smaller flaws did not contribute to leakage integrity.

1997 INSPECTION SUMMARY

The planned 1997 inspections encompassed a 50% bobbin coil inspection in all steam generators (SGs) as well as a 20% motorized rotating pancake coil (MRPC) inspection in SG 24. The following table presents the base tube count included in each inspection plan.

Exam Type	SG 21 Tube Count	SG 22 Tube Count	SG 23 Tube Count	SG 24 Tube Count
Bobbin Coil Full Length	1799	1796	1796	1799
MRPC Hot Leg Tubesheet	N/A	N/A	N/A	719

The inspection findings resulted in expanded inspections in SGs 21 and 24 due to foreign object concerns. The findings for each SG are provided below.

SG 21

Several wear indications were identified at tube support plates during the full-length bobbin coil examination. The tube number, support locations, and depth of the wear were as follows:

Row	Column	Support	Depth
6	53	5th Hot	6% Outside Diameter (OD)
		6th Hot	11% OD
6	54	4th Hot	7% OD
		5th Hot	4% OD
1	70	1st Cold	28% OD

The wear indications reported in Row 6 Column 53 and Row 6 Column 54 were determined by eddy current data review to have been caused by fretting at the lower edge of the support. No growth rate information was available for these tubes, as this was the first time they had been inspected since the 1988 baseline examination. The indications were below the T/S repair limit (40% through-wall). Based on the assumption that all of the degradation occurred during the previous operating cycle, the indications were projected to remain below the T/S repair limit through the next cycle. Therefore, these tubes were left in service.

The wear indication in Row 1 Column 70 was believed to have been caused by a burr or a small foreign object near the center of the quatrefoil support. The eddy current low frequency (15 kHz) response of the MRPC exam confirmed the presence of the burr or foreign object at the wear location. Due to a lack of previous inspection history, a growth rate history could not be established. Assuming a growth rate based on all of the degradation occurring during the previous operating cycle, the indication could have exceeded the T/S repair limit before the next inspection. Therefore, this tube was plugged.

The initial bobbin coil examination was expanded to determine if similar indications were present in additional tubes. No further degradation was detected in the expanded inspection.

Special interest MRPC examinations were also conducted on the three tubes with the wear indications to help characterize the degradation.

Additionally, the bobbin coil examination reported 32 tubes with manufacturing burnish marks (MBMs) and 2 tubes with free span differential (FSD) signals. These signals were reviewed in the eddy current data from the 1988 pre-service inspection and no changes were noted. Dents that were reported during this examination were also reviewed in the 1988 data. No new denting was detected.

SG 22

There were 33 tubes with MBM indications and one tube with an FSD indication reported during the bobbin coil examination. These signals were reviewed in the 1988 pre-service inspection data and were found not to have changed. Dents that were reported during the 1997 examination were also reviewed against the 1988 data, which confirmed that no new denting was occurring.

SG 23

There were 23 tubes with MBM indications and no tubes with FSD indications reported during the bobbin coil examination. These signals were reviewed against the 1988 pre-service inspection eddy current data and were found not to have changed. Dents that were reported during the 1997 examination were also reviewed against the 1988 data, and no new denting was observed.

SG 24

There were 38 tubes with MBM indications and one tube with an FSD indication reported during the bobbin coil examination. These signals were reviewed in the 1988 pre-service inspection eddy current data and no changes were noted. Dents that were reported during this examination were also reviewed in the 1988 data with no changes noted. Three dents could not be reviewed because the pre-service data would not duplicate from digital tape to optical disc. The signals from all three dents were less than four volts. As none of these signals represents a degradation mechanism, tubing integrity was not an issue and tube repair was not a consideration.

Single volumetric indications were detected in four tubes during the hot leg tubesheet MRPC examination. These indications were believed to be caused by a loose part. The tubes were plugged upon detection of the indications because there was no qualified eddy current technique for sizing these indications. The tube number and locations of the indications are as follows:

Row	Column	Location
33	15	Tubesheet Hot + 0.49 inches
33	16	Tubesheet Hot + 0.05 inches
33	17	Tubesheet Hot + 0.84 inches
38	72	Tubesheet Hot + 0.07 inches

No evidence of a loose part was found near Row 33 Columns 15, 16, or 17. A possible loose part was reported in tubes Row 39 Column 69, Row 38 Column 70, and Row 38 Column 71. A secondary side foreign object search and retrieval program was initiated for this region and resulted in the removal of a small metal weld wire from this area. The loose part indications were not detected with the bobbin coil probe.

Due to the foreign object concern, the initial bobbin coil inspection scope was expanded to include an additional 247 tubes. This population included the outermost two rows around the periphery of the tube bundle. Additionally, a special interest MRPC inspection was also performed in the tubes surrounding the loose part volumetric indications.

ASSESSMENT

Operational Assessment Evaluation

The EPRI Steam Generator Integrity Assessment Guidelines present implementation procedures for performing operational assessment evaluations. SG integrity may be addressed by one of three methodologies: arithmetic, simplified statistical, or Monte Carlo. Selection of the most appropriate methodology depends upon plant needs, analysis complexity, and available data. As noted above, the eddy current results from the Unit 2 inspection revealed relatively few indications. The only degradation mechanism that required further review was support plate wear. This mechanism was addressed using the simplified statistical method. The results are shown below.

Structural Integrity Assessment

An operational assessment limit for cycle 12 support plate wear can be established by calculating the structural limit, which accounts for the performance criteria margins, for the specific degradation mechanism (tube support plate wear) and then evaluating the uncertainties associated with tubing material properties, eddy current uncertainties and growth rate information. The structural integrity performance criteria can then be evaluated by comparing the projected size of the limiting wear indication at the end of the next cycle against the operational assessment limit.

The following formulas and supporting text are included within this assessment to illustrate the methodologies employed to determine the operational assessment limit. The structural limit determination and operational assessment limit were formally calculated by Framatome

Technologies, Inc. (FTI). The associated vendor documents have been reviewed and approved by Indiana Michigan Power Company (I&M) and are available for review.

The operational assessment limit can be expressed using the following formula:

Operational Assessment Limit = SL – U_T – GR, where

SL = structural limit
U_T = total uncertainty (material & eddy current)
GR = growth rate

Structural Limit
The SG tubing structural limit calculation was developed in order to determine the structural limits associated with the various potential degradation mechanisms that could impact the Unit 2 SGs. This calculation includes a margin of 3.0 against burst under normal steady state power operation and a margin in excess of 1.4 against burst under the limiting design basis accident. The calculation identifies 59.5% through-wall (TW) as the structural limit for tube support plate wear. Therefore, SL = 59.5% TW.

Material Property Uncertainty
As tubing properties differ between tubing lots and even particular tubes, the structural limit must be adjusted downward to account for anticipated material uncertainties. The methodology for addressing material property errors is identified in the EPRI Steam Generator Integrity Assessment Guidelines. The material uncertainty is the difference of the structural limit using the mean material properties vs. the structural limit when using 90% probability/50% confidence material properties. Material uncertainty was calculated to be 1.41%.

Eddy Current Uncertainty
In addition to the uncertainties arising for material properties, the structural limit must also address uncertainties associated from the eddy current technique used and analyst performance.

The technique uncertainty was calculated to be 4.37% TW, and the standard error associated with the eddy current data analyst when using the bobbin coil technique for support plate wear was determined to be 0.86% TW. The total eddy current uncertainty is then determined by correcting the technique and analyst uncertainty terms for probability and confidence levels. These values are then corrected to the 90% probability/50% confidence level by multiplying them by the standard sigma value of 1.28. The manipulation yields the following:

Technique uncertainty = (4.37)(1.28) = 5.59% TW
Analyst uncertainty = (0.86)(1.28) = 1.10% TW

Total Uncertainty

The effect of the material and eddy current uncertainties can be combined using the square root of the sum of the squares for material, technique and analyst uncertainties resulting in a total uncertainty (U_T). This treatment is consistent with the methodology outlined in the EPRI Steam Generator Integrity Assessment Guidelines, and was previously calculated as:

$$U_T = [1.41^2 + 5.59^2 + 1.10^2]^{1/2} = 5.87\% \text{ TW}$$

Growth Rate

The final factor involved in establishing the operational assessment limit is the growth rate term, which is used to adjust the structural limit downward to account for potential growth over the operating cycle. The bounding indication was located at R6/C53 in SG 24 at the sixth hot leg support, and was sized at 11% through-wall using the bobbin coil probe. This tube had not been inspected since the pre-service examination; therefore, there is no previous data to develop a detailed growth rate. Therefore, it is assumed that all the growth occurred over the previous operating cycle. Dividing the bounding growth (11% TW) by the length of the previous cycle (1.26 effective full-power years (EFPY)) yields a growth rate (GR) of 8.73% TW per EFPY or 13.05% TW for an 18 effective full power month (EFPM) cycle.

Operational Assessment Limit

Based upon the inputs noted above, the overall operational assessment limit for support plate wear can be determined as follows:

$$\begin{aligned} \text{Operational Assessment Limit} &= SL - U_T - GR \\ &= (59.5) - (5.87) - (13.05) \\ &= 40.58\% \text{ TW} \end{aligned}$$

Performance Criteria Assessment

The limiting indication was sized during the eddy current examination as 11% TW. By adding the projected growth rate of 13.05% TW, which was determined in the previous section, the predicted limiting flaw size for cycle 12 tube support plate wear is 24.05% TW. This value is below the 40.58% TW operational assessment limit. This signifies that the worst case projected degradation is less than the operational assessment limit and, therefore, will satisfy the performance criteria and the end of the current operating period.

Leakage Integrity Assessment - Operational

Operational leakage is the expected value of leakage associated with all tubes within an SG exhibiting degradation under normal operating conditions. In order to satisfy the performance criteria, the operational leakage must be the lower of the Technical Specification (T/S) 4.4.6.2 value of 500 gpd or the EPRI primary-to-secondary leak guidelines value of 150 gpd.

No operational leakage was observed before the shutdown at the end of cycle 11. Accordingly, no tubes were identified with through-wall defects during the end of cycle 11 inspection. Following the return to service, no primary-to-secondary leakage has been detected. Therefore, as the operational leakage is essentially zero, the operational leakage performance criterion has been met.

Leakage Integrity Assessment – Accident

Accident-induced leakage is the primary-to-secondary leakage that occurs during the limiting design basis accident (other than an SG tube rupture). Per review of the accident analysis assumptions and dose calculations, the limiting primary-to-secondary leakage rate is one gpm. In order to satisfy the accident induced leakage integrity performance criterion, the faulted SG leakage must be below this value.

Degradation Due to Tube Defects

As noted earlier in this assessment, the largest indication that was detected and remains in service was sized at 11% TW. This value is well below operational assessment limit of 40.58% TW. As the bounding indication is less than the operational assessment limit, it can be considered not to leak. This is consistent with the guidance contain in the EPRI Steam Generator Integrity Assessment Guidelines. Therefore, no leakage is attributed to in-service tube degradation.

Tube Repairs (Plugs)

Tubes have been plugged in each of the four SGs. One set of welded plugs was installed in 1988 and is considered leak-tight. The remaining tube plugs are of a mechanical design and are considered leak-limiting. However, in order for primary-to-secondary leakage to occur, a through-wall penetration is necessary. Nine tubes were administratively plugged in 1994 with Westinghouse plugs due to denting cause by pressure pulse cleaning operations. No through-wall defects were identified and, therefore, no leakage path exists for these tubes.

The remaining five tubes were plugged with FTI plugs in 1997 due to wear-related degradation. The indications could not be sized given the available eddy current technique. Therefore, for the purpose of this leakage assessment, they were considered through-wall. These tubes were calculated to leak at a rate of 0.000003 gpm at normal operating temperature and pressure. The one plugged tube in SG 21 and four in SG 24 result in a total of 0.000015 gpm through all four SGs.

Based upon the combined contribution of in-service indications and tube repairs, SG 24 has the largest projected primary-to-secondary leakage, 0.000012 gpm. The total through all SGs of 0.000015 gpm is well below the limiting accident analysis value of one gpm. The accident-induced leakage performance criterion is satisfied.

No other type of repair, such as tube sleeving or tube re-roll, has been performed on the Unit 2 SGs.

CONCLUSION

Structural and leakage integrity performance criteria are projected to be satisfied for the entire 18 EFPM Unit 2 operating cycle 12.

APPENDIX B

FRAMATOME TECHNOLOGIES, INCORPORATED (FTI)
DC COOK-2: INTEGRITY EVALUATION OF TUBES 33-16 & 38-71 IN SG 24

FRAMATOME TECHNOLOGIES

ENGINEERING INFORMATION RECORD

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Title DC COOK-2: INTEGRITY EVALUATION OF TUBES 33-16 & 38-71 IN SG 24

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Date	11/2/97	Date	11/2/97

Technical Manager Statement: Initials TAC

Reviewer is Independent.

Remarks:

This document summarizes the tube integrity evaluation of tubes 33-16 and 38-71 in SG 24 at DC Cook Unit 2. The first tube has a volumetric flaw at the top of the tubesheet. The other tube has a possible loose part. This document provides information on similar flaws in the industry and provides recommendations for dispositioning this flaw.

Background

DC Cook Unit 2 is a four loop Westinghouse PWR with Model 54F steam generators. These are replacement steam generators which commenced service in 1988. A baseline eddy current examination was performed prior to service in 1988. Each Model 54F steam generator contains 3592 U-bend tubes of thermally-treated Alloy 690 material with nominal dimensions of 0.875 inch outside diameter and 0.050 inch wall thickness. The current inspections of 1997 represent the fourth in-service inspections of the replacement steam generators. The scope of the current inspections includes a full length bobbin probe examination of 50% of the tubes and an MRPC examination of 20% of the hot leg top-of-tubesheet region.

Evaluation of S/G 24, Row 33, Column 16 Indication

Indication Characteristics

During the course of a 20% sample MRPC inspection of the top of tubesheet area in DC Cook Unit 2, steam generator 24, a single volumetric indication (SVI) was detected in a periphery tube, Row 33,Col 16. This indication has been reviewed in detail by the onsite FTI Level III as well as FTI ECT and engineering personnel Lynchburg. The location and physical characteristics of the indication are representative of a fretting wear phenomenon from a loose part. Eddy current testing with both bobbin and MRPC coils was unable to detect a loose part at this location. No other similar indications were detected from the remainder of the 20% sample MRPC inspection or in the 50% bobbin coil exam. Furthermore, the indication was boxed in by bobbin coil and MRPC, 1 tube along each side with no other damage detected. A bobbin coil examination expansion of the entire periphery extending two tubes in also showed no other indications.

An extensive MRPC scope expansion beyond the 20% already examined is not warranted based on the characteristics of this single indication. The nature of loose parts are typically a singular incident in most cases only affecting a small number of tubes. Industry experience has shown loose parts to be very isolated and not a mechanism that expands into other locations..

The indication has been sized by MRPC as having a circumferential extent of 0.41 inches and an axial extent of 0.29 inches. The depth has been estimated by MRPC to be about 51% through wall originating from the outside diameter. The voltage response from the MRPC coil is 0.8 volts. Comparing to a single flat bottom hole of 20% through wall and 0.35 inches diameter in the calibration standard which gives a voltage response of 0.9 volts, the indication in tube R33 C16 is of similar size and representative of similar missing metal volume indicating a fretting wear damage mechanism, and not a corrosion mechanism in this Alloy 690 tubing.

Due to the extremely small size and location next to the tubesheet, this indication was not detected by the bobbin coil examination. However , as fretting damage progresses to larger volumes of removed metal, the bobbin coil examination becomes a reliable tool to detect and size flaws of significance.

The indication in tube R33 C16 is similar in location and signal characteristics to an indication found several years ago at another operating plant. The previous indication was located in a periphery tube and was confirmed by visual inspection to be caused by a piece of weld slag. The weld slag was not detected by eddy current from the damaged tube location, but was noted from eddy current inspections in surrounding tubes. The previous indication had an MRPC voltage response of about 13 volts compared to a 100% through wall hole response of 20 volts. The previous indication was larger and deeper than the indication in tube R33 C16.

Structural /Leakage Assessment

The volumetric indication in R33 C16 does not represent a challenge to the structural and leakage integrity of the tubing. Based on the EPRI evaluations of expansion zone cracking (NP-6864-L and similar reports), the critical structural integrity flaw dimensions for 0.875 inch OD x 0.050 inch wall tubing for throughwall crack-like flaws are approximately 0.45 inches in axial extent and approximately 2 inches in circumferential extent. Based on the MRPC assessment, the volumetric indication in R33 C16 is not crack-like, is not throughwall, and has dimensions significantly below that of the critical flaw described above. Therefore, in-situ pressure testing of this indication is not necessary to ensure the integrity of the subject tube.

Recommendations

1) A secondary side visual inspection of the area surrounding tube R33 C16 is recommended to search for evidence of a loose part that may have caused the fretting damage.

2) An MRPC inspection of the tubes adjacent to R33 C16 is recommended to search similar indications and for evidence of a loose part that may have caused the fretting damage.

3) A review of previous sludge lancing and/or secondary side visual inspections is recommended to search for evidence of a loose part that may have caused the fretting damage.

4) Plugging of tube R33 C16 is recommended.

Evaluation of S/G 24, Row 38, Column 71 Indication

Indication Characteristics

During the course of a 20% sample MRPC inspection of the top of tubesheet area in DC Cook Unit 2, steam generator 24, a possible loose part (PLP) was detected beside a near-periphery tube, Row 38,Col 71. As determined by ECT and engineering review, the location and physical characteristics of the indication are representative of a loose part. No damage to the tube wall was detected. No other similar indications were detected from the remainder of the 20% sample MRPC inspection or in the 50% bobbin coil exam. Furthermore, the PLP indication was boxed in by bobbin coil and MRPC, 1 tube along each side with no damage detected. A bobbin coil examination expansion of the entire periphery extending two tubes in also showed no other indications.

An extensive MRPC scope expansion beyond the 20% already examined is not warranted based on the characteristics of this single indication. The nature of loose parts are typically a singular incident in most cases only affecting a small number of tubes. Industry experience has shown loose parts to be very isolated and not a mechanism that expands into other locations.
An extensive MRPC scope expansion beyond the 20% already examined is not warranted based on the characteristics of this single indication.

Structural /Leakage Assessment

The possible loose part indication in R38 C71 does not represent a challenge to the structural and leakage integrity of the tubing as no tube degradation has occurred. In-situ pressure testing of this tube is not necessary.

Recommendations

1) A secondary side visual inspection of the area surrounding tube R38 C71 is recommended to search for evidence of the possible loose part that may eventually cause fretting damage. If a loose part is found, retrieval of the loose part should be attempted.

2) An MRPC inspection of the tubes adjacent to R38 C71 is recommended to search similar indications and for evidence of a loose part that may have caused the fretting damage.

3) A review of previous sludge lancing and/or secondary side visual inspections is recommended to search for evidence of a loose part that may cause fretting damage.

4) If fretting damage is evident in tube R38 C71 or any of the adjacent tubes and if loose part retrieval is not successful, plugging of the damaged tubes is recommended.

APPENDIX C

FRAMATOME TECHNOLOGIES, INCORPORATED (FTI)
DC COOK-2 EDDY CURRENT TESTING (ECT) OUTAGE INDICATION SIZING

FRAMATOME
TECHNOLOGIES

November 13, 2000
FTI-00-2806

Mr. Phil Monk
American Electric Power
Cook Nuclear Plant
One Cook Place
Bridgman, MI 49106

Subject: DC Cook Unit 2 1997 ECT Outage Indication Sizing

Dear Sir:

The 1997 data you requested to be measured and sized was acquired using the 3-coil RPC probe. All measurements and sizing were accomplished using the .115 pancake probe. A three-point amplitude curve using the AVB wear 42%, 22% and 0% notch was setup for sizing. The standard used for calibration was an ASME/EDM guide tube calibration standard, serial number 1268464. All measurements (Circ and Axial) were performed using the clip plot method. Listed in Table 1 below are the results by tube number. The sizing was performed on a best effort basis using EPRI qualified technique for wear, ETSS 96911 as a reference.

TABLE 1

Tube Number	Percent TW	Circ length	Axial length	Location
R 33 – C 15	10%	0.17	0.20	TTS H/L +0.49
R 33 – C 16	20%	0.31	0.20	TTS H/L +0.05
R 33 – C 17	7%	0.17	0.18	TTS H/L +0.84
R 38 – C 72	12%	0.17	0.13	TTS H/L +0.07

Please advise me if you should have any questions.

Sincerely,

B. J. Merdich

Brian J. Merdich
Project Manager

BJM-77:gl

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