10 CFR 50.90

CP&L
A Progress Energy Company

Serial: RNP-RA/02-0086

United States Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

JUN 1 9 2002

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
DOCKET NO. 50-261/LICENSE NO. DPR-23

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION ON AMENDMENT REQUEST REGARDING ONE-TIME EXTENSION OF CONTAINMENT TYPE A TEST INTERVAL (TAC NO. MB4658)

Ladies and Gentlemen:

By letter dated March 26, 2002, Carolina Power and Light (CP&L) Company submitted a request for amendment to the Technical Specifications (TS) regarding a one-time extension of the containment Type A test interval for H. B. Robinson Steam Electric Plant (HBRSEP), Unit No. 2. The NRC has requested additional information that is required to complete the review of the proposed amendment by letter dated May 23, 2002.

Attachment I provides an affirmation as required by 10 CFR 50.30(b). Attachment II contains the responses to the NRC Request for Additional Information (RAI) in support of the proposed TS change.

In accordance with 10 CFR 50.91(b), CP&L is providing the State of South Carolina with a copy of this response.

The responses to the NRC RAI provide additional information that does not affect the basis or justification for the proposed TS change, including the evaluation of No Significant Hazards Consideration provided within the March 26, 2002, submittal.

If you have any questions concerning this matter, please contact Mr. C. T. Baucom.

Sincerely,

B. L. Fletcher III
Manager - Regulatory Affairs

CWS/cws

A047

Robinson Nuclear Plant
3581 West Entrance Road
Hartsville, SC 29550

Attachments:

I. Affirmation

II. Response To Request For Additional Information On Amendment Request Regarding One-Time Extension Of Containment Type A Test Interval

c: Mr. L. A. Reyes, NRC, Region II
Mr. H. J. Porter, Director, Division of Radioactive Waste Management (SC)
Mr. R. M. Gandy, Division of Radioactive Waste Management (SC)
Mr. R. Subbaratnam, NRC, NRR
NRC Resident Inspector, HBRSEP
Attorney General (SC)

AFFIRMATION

The information contained in letter RNP-RA/02-0086 is true and correct to the best of my information, knowledge and belief; and the sources of my information are officers, employees, contractors, and agents of Carolina Power and Light Company. I declare under penalty of perjury that the foregoing is true and correct.

Executed on: 19 June 2002

JWMoyer
J. W. Moyer
Vice President, HBRSEP, Unit No. 2

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION ON AMENDMENT REQUEST REGARDING ONE-TIME EXTENSION OF CONTAINMENT TYPE A TEST INTERVAL

By letter dated May 23, 2002, the NRC issued a Request for Additional Information (RAI) regarding Carolina Power and Light (CP&L) Company's request for amendment to the Technical Specifications (TS) regarding a one-time extension of the containment Type A test interval for H. B. Robinson Steam Electric Plant (HBRSEP), Unit No. 2. The proposed change revises TS 5.5.16, "Containment Leakage Rate Testing Program," to allow a one-time exception to the ten-year interval of the performance-based leakage rate testing program for Type A tests as required by Nuclear Energy Institute (NEI) 94-01, "Nuclear Energy Institute Industry Guideline For Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," Revision 0, July 26, 1995. The one-time exception applies to the requirement of NEI 94-01, Section 9.2.3, to perform Type A testing at an interval of up to ten years, with allowance for a 15-month extension. The exception will require Type A testing within 15 years from the last Type A test, which was performed on April 9, 1992. Responses to the RAI are provided below.

NRC Question

1. The stainless steel bellows were found to be susceptible to transgranular stress corrosion cracking, and the leakages through them are not readily detectible by Type B testing. If this issue applies to your containment, please explain how such behavior has been factored into the risk assessment and provide information regarding inspection and testing of the bellows at HBRSEP2.

CP&L Response

NRC Information Notice 92-20, "Inadequate Local Leak Rate Testing," discussed inadequate Type B local leak rate testing of two-ply stainless steel bellows. The evaluation of this issue for HBRSEP, Unit No. 2, dated May 6, 1993, determined that the Type B testing issue for two-ply stainless steel bellows was not applicable. At the time of the evaluation, the Penetration Pressurization System (PPS) provided a constant indication of the leak tightness of penetrations and valves it served. The PPS was originally designed to provide a means of continuously pressurizing the positive pressure zones incorporated into the containment penetrations in order to maintain these zones above the maximum containment post-accident pressure, and to provide a means for continuous or intermittent monitoring of the leakage status of the containment penetrations. During Refueling Outage 17, the PPS was modified from a continuous monitoring system to an intermittent monitoring system. Local leak rate tests on containment penetrations are currently performed using the PPS as an intermittent monitoring system.

A review of the 10 CFR 50, Appendix J Program and supporting documentation has shown no evidence that HBRSEP, Unit No. 2, has tested between the plies of two-ply bellows. The routine penetration sleeve testing is performed from outside of containment via test connections that are installed into the sleeve end plate such that the entire sleeve, including bellows, is tested as one unit. There have been no known occurrences of excessive leakage identified during a Type A test that had not been identified by a Type B test. A review of local leak rate testing results from the last three outages has shown that the total leakage from Type B and Type C testing is less than 25% of the acceptance criteria of 0.6La. Type B and C testing is currently performed in accordance with 10 CFR 50, Appendix J, Option A, at each refueling outage. In summary, this issue does not apply to the HBRSEP, Unit No. 2, containment.

NRC Question

2. Inspections of some reinforced and steel containment systems have found degradation on the uninspectible (embedded) side of the drywell steel shell and steel liner of the primary containment. These degradations cannot be found by visual examinations until they are through the thickness of the shell liner, or when 100% of the uninspectible surfaces are examined by ultrasonic testing. Please indicate how potential leakages during core damage accidents are factored into the risk assessment related to the extension of the integrated leak rate testing. In the submittal, you stated that you have made measurements on a sample of liner panels. How were the remaining uninspected panels considered in the risk assessment? Calvert Cliffs Nuclear Power Plant recently provided information (ADAMS Accession No. ML020920100) in response to a similar request to address this issue. It would be desirable to consider the Calvert Cliffs Nuclear Power Plant's response when amending the current submittal.

CP&L Response

The HBRSEP, Unit No. 2, reactor containment structure is a steel lined concrete shell in the form of a vertical right cylinder with a hemispherical dome and a flat base supported by means of piles. The structure consists of sidewalls measuring 126 feet from the liner on the base to the spring line of the dome, and an inside diameter of 130 feet. The containment liner is designed as a leakproof membrane and is not relied upon for the structural integrity of the containment except for resisting tangential shears in the dome. It is anchored to the concrete by means of "KSM" shaped steel studs. The liner is not anchored to the concrete base slab and hence does not act compositely with it. The cylindrical portion of the liner and a section of the dome liner are insulated. The face of the liner plate in contact with the concrete has no primer or paint applied; the intimate contact with the concrete provides corrosion protection. The design of the containment structure is discussed in the HBRSEP, Unit No. 2, Updated Final Safety Analysis Report, Section 3.8.1.

The letter dated March 26, 2002, described nine requests for relief from certain requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section IX, involving containment inspections at HBRSEP, Unit No. 2. Of these nine relief requests, two concerned inspections of the containment liner and moisture barrier. Relief Request IWE/IWL-01, authorized by the NRC in a Safety Evaluation dated July 26, 1999, provided relief from performing a VT-3 visual examination of 100% of the accessible surface areas of containment. The removal and reinstallation of the insulation sheathing panels was determined to be time consuming and result in hardship and unusual difficulty. The alternative authorized by the NRC is to perform a VT-3 visual examination on those portions of the insulated containment liner that are exposed when a maintenance activity requires removal of the liner insulation. Relief Request IWE/IWL-02 authorized a similar alternative for visual inspection of the containment moisture barrier in the Safety Evaluation dated July 26, 1999. Approximately 100 of the insulation sheathing panels have been removed, allowing visual inspections of the exposed portions of the containment liner. In addition to the VT-3 visual inspections, the exposed portions of the containment liner were also subjected to Ultrasonic Testing (UT). As stated in the March 26, 2002, letter, the UT measurements did not indicate degradation of the embedded side of the containment liner.

Additional Liner Corrosion Analysis

The following assessment, based on information contained in the Calvert Cliffs Nuclear Power Plant, Unit No. 1, response dated March 27, 2002 (Accession No. ML020920100), is supplied as requested in the RAI. This assessment provides a conservative evaluation of the change in likelihood, due to extending the integrated leak rate test (ILRT) interval, of detecting liner corrosion. This likelihood was then used to determine the resulting change in risk. The following issues are addressed:

- Differences between the containment basemat and the containment cylinder and dome;
- The historical liner flaw likelihood due to concealed corrosion;
- The impact of aging;
- The liner corrosion leakage dependency on containment pressure; and
- The likelihood that visual inspections will be effective at detecting a flaw.

<u>Assumptions</u>

1. A half failure is assumed for basemat concealed liner corrosion due to the lack of identified failures. (See Table 1, Step 1.)

2. The success data was limited to 5.5 years. Although it has been 5.75 years since September 1996, when 10 CFR 50.55a started requiring visual inspections, the use of 5.5 years is consistent with the Calvert Cliffs Nuclear Power Plant, Unit No. 1, response, and is considered to be a conservative assumption. Additional success data was not used to limit the aging impact of this corrosion issue, even though inspections were being performed prior to this date and there is no evidence that liner corrosion issues were identified. (See Table 1, Step 1.)

3. The liner flaw likelihood is assumed to double every five years. This is based solely on judgment and is included in this assessment to address the increased likelihood of corrosion as the liner ages. The Calvert Cliffs Nuclear Power Plant, Unit No. 1, response provided sensitivity studies that address doubling this rate every ten years and every two years. (See Table 1, Steps 2 and 3.)

4. The likelihood of the containment atmosphere reaching the outside atmosphere given a liner flaw exists is a function of the pressure inside the containment. Even without the liner, the containment is an excellent barrier. However, as pressure in containment increases, cracks will form. If a crack occurs in the same region as a liner flaw, the containment atmosphere can communicate to the outside atmosphere. At low pressures, this crack formation is extremely unlikely. Near the point of containment failure, crack formation is virtually guaranteed. Anchored points of 0.1% at 20 psia and 100% at 145 psia were selected. Intermediate failure likelihoods are determined through interpolation. (See Table 1, Step 4.) The Calvert Cliffs Nuclear Power Plant, Unit No. 1, response provided sensitivity studies that increased and decreased the 20 psia anchor point by a factor of ten.

5. The likelihood of leakage escape (due to crack formation) in the basemat region is considered to be ten times less likely than the containment cylinder and dome region. (See Table 1, Step 4.)

6. Non-detectible containment over-pressurization failures are assumed to be large early releases. This approach avoids a detailed analysis of containment failure timing and operator recovery actions.

<u>Analysis</u>

Table 1
Containment Liner Corrosion Base Case

Step	Description	Containment Cylinder and Dome (83%)	Containment Basemat (17%)
1	**Historical Liner Flaw Likelihood** Failure Data: Containment location specific. Success Data: Based on 70 steel-lined containments and 5.5 years since the 10 CFR 50.55a requirement for periodic visual inspections of containment surfaces.	Events: 2 (Brunswick 2 and North Anna 2) 2/(70*5.5)=**5.2E-3**	Events: 0 (Assume a half failure) 0.5/(70*5.5)=**1.3E-3**

Step	Description	Containment Cylinder and Dome (83%)		Containment Basemat (17%)	
2	**Age Adjusted Liner Flaw Likelihood**	Year	Failure Rate	Year	Failure rate
		1 avg 5-10 15	2.1E-3 5.2E-3 1.4E-2	1 avg 5-10 15	5.0E-4 1.3E-3 3.5E-3
	During 15-year interval, assumed failure rate doubles every five years (14.9% increase per year). The average for 5th to 10th year was set to the historical failure rate. (See Calvert Cliffs Nuclear Power Plant, Unit No. 1, response.)	15 year avg=**6.27E-3**		15 year avg=**1.57E-3**	
3	**Increase in Flaw Likelihood Between 3 and 15 Years** Uses age adjusted liner flaw likelihood (Step 2), assuming failure rate doubles every five years. (See Calvert Cliffs Nuclear Power Plant, Unit No. 1, response.)	**8.7%**		**2.2%**	
4	**Likelihood of Breach in Containment Given Liner Flaw**	Pressure (psia)	Likelihood of Breach	Pressure (psia)	Likelihood of Breach
	The upper end pressure is consistent with the HBRSEP, Unit No. 2, Probabilistic Risk Assessment (PRA) Level 2 analysis. 0.1% is assumed for the lower end. Intermediate failure likelihoods are determined through interpolation. The basemat is assumed to be 1/10 of the cylinder/dome analysis.	20 57 (ILRT) 100 120 145	0.1% 0.8% 8.3% 25.2% 100%	20 57 (ILRT) 100 120 145	0.01% 0.08% 0.83% 2.52% 10.0%
5	**Visual Inspection Detection Failure Likelihood**	**100%** ~74% of the containment cylinder and dome liner is covered by insulation and is not readily visible. The remaining ~26% which is visible is examined each period as required by ASME Section XI, Subsection IWE.		**100%** Cannot be visually inspected.	

Step	Description	Containment Cylinder and Dome (83%)	Containment Basemat (17%)
6	**Likelihood of Non-Detected Containment Leakage** (Steps 3*4*5)	**0.07%** 8.7% * 0.8% * 100%	**0.0018%** 2.2% * 0.08% * 100%

The total likelihood of corrosion-induced, non-detected containment leakage is the sum of Step 6 for the containment cylinder and dome, and the containment basemat.

Total Likelihood of Non-Detected Containment Leakage = 0.07% + 0.0018% = 0.072%

The non-Large Early Release Frequency (non-LERF) Core Damage Frequency (CDF) due to internal events is 3.8E-5 per year, as provided in the letter dated March 26, 2002. The HBRSEP, Unit No. 2, Individual Plant Examination for External Events (IPEEE), dated June 1995, provided quantitative estimates of CDF contributions due to several external events. The total CDF due to these events was originally estimated to be 2.2E-4 per year. In a supplemental response, dated November 30, 1995, to Generic Letter 88-20, CP&L provided information indicating that various modifications and procedural enhancements at HBRSEP, Unit No. 2, would reduce the total CDF by approximately 1.28E-4 per year. However, the IPEEE total CDF is used in this assessment to provide an additional margin of conservatism. Combining the non-LERF HBRSEP, Unit No. 2, internal events frequency with the IPEEE total yields a value of 2.6E-4 per year. If non-detectable containment leakage events are considered to be LERF, then the increase in LERF associated with the liner corrosion issue is:

ΔLERF (Once per three years to once per 15 years) = 0.072% * 2.6E-4 = 1.9E-7 per year

The assessments contained in letter dated March 26, 2002, provided a calculated LERF increase of 4.69E-7 per year for the proposed change. The total increase in LERF for the change in the ILRT testing interval from once per three years to once per 15 years is:

ΔLERF = 4.69E-7 + 1.9E-7 = 6.6E-7 per year

This assessment is considered to represent a conservative estimate of the risk increase involved with the one-time change for the following reasons:

- The values provided in Step 1 were not changed from those used in the Calvert Cliffs Nuclear Power Plant, Unit No. 1, response, although changes based on the passage of additional time with no new failures and a differing interpretation of the appropriate exposure period were considered. Two failures have been detected by visual examination after an average exposure period of approximately 25 years for each of the 70 containments in the population. This implies a failure rate of about 1E-3 per containment-year instead of the value of 5.2E-3 per containment-year that was actually used. This introduces a substantial measure of conservatism into the calculation.

- Approximately 74% of the cylinder and dome liner is covered by insulation and is not readily accessible (see previous discussion of IWE/IWL relief requests). The remaining 26% of the liner, although visible, is not required to be inspected each outage. However, this visible portion of the liner is examined each period as required by ASME, Section IX, Subsection IWE. Therefore, assuming a containment visual inspection failure likelihood of 100% is a conservative assumption.

- The use of the IPEEE estimates of CDF contributions due to external events in lieu of the revised value introduces conservatism into the assessment.

- The potential for containment leakage is explicitly included in the risk assessment provided in letter dated March 26, 2002. By definition, the intact containment cases, Electric Power Research Institute (EPRI) Containment Failure Class 1, include a leakage term that is independent of the source of the leak. Similarly, the Containment Failure Class 3a and 3b cases model the potential leakage impact of the ILRT interval extension. These cases include the potential that the leakage is due to containment shell failure. The assessment shows that even with the increased potential to have an undetected containment flaw or leak path, the increase in risk is insignificant. This treatment of leakage through the containment liner is consistent with the risk assessments supporting similar TS changes for Waterford Steam Electric Station, Unit 3, in a Safety Evaluation dated February 14, 2002 (Accession No. ML020460272); Salem Nuclear Generating Station, Unit No. 2, in a Safety Evaluation dated April 11, 2002 (Accession No. ML020720154); and Diablo Canyon Nuclear Power Plant, Unit Nos. 1 and 2, in a Safety Evaluation dated April 22, 2002 (Accession No.ML013240531).

- The assessments contained in the letter dated March 26, 2002, provided a calculated LERF increase of 4.69E-7 per year for the proposed change. Using guidance provided in letters from NEI to NEI Administrative Points of Contact, dated November 13, 2001, and November 30, 2001, concerning one-time extensions of the containment integrated leak rate test interval, this was refined to an increase in LERF of 2.37E-7 per year, as shown in the March 26, 2002, letter. However, for simplicity the original value of 4.69E-7 per year was utilized in this assessment. This introduces an additional measure of conservatism into the calculation.

Regulatory Guide (RG) 1.174, "An Approach For Using Probabilistic Risk Assessments In Risk-Informed Decisions On Plant-Specific Changes To The Licensing Basis," dated July 1998, provides guidance for determining the risk impact of plant-specific changes to the licensing basis. Based on the guidance of RG 1.174, this change in LERF is considered to constitute a "small change" in risk. RG 1.174 states that applications involving an increase in the calculated LERF in the range of 1E-7 per year to 1E-6 per year will be considered only if it can be reasonably shown that the total LERF is less than 1E-5 per year.

The assessments provided in the letter dated March 26, 2002, concluded that the total LERF associated with this one-time change was 5.72E-6 per year. If the increase in LERF due to the liner corrosion issue is added to that value, the following result is obtained:

Total LERF = 5.72E-6 + 1.9E-7 = 5.91E-6 per year

This value remains below the total LERF criterion of RG 1.174 for changes that constitute a "small change" in risk, and indicates, considering the conservative nature of the assessment, that the proposed one-time change does not result in an unacceptable increase in risk.