December 30, 2002

Mr. Mark B. Bezilla
Vice President
FirstEnergy Nuclear Operating Company
Beaver Valley Power Station
Post Office Box 4
Shippingport, PA 15077

SUBJECT: BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2 (BVPS-1 and 2) REQUEST FOR ADDITIONAL INFORMATION (RAI) REGARDING RISK-INFORMED INSERVICE INSPECTION PROGRAM PLANS INSERVICE INSPECTION (ISI) PROGRAM RELIEF REQUEST, L-02-066 (TAC NOS. MB5687 AND MB5688)

Dear Mr. Bezilla:

By letter dated July 24, 2002, FirstEnergy Nuclear Operating Company (FENOC) submitted a relief request to allow implementation of a Risk-Informed ISI Program as an alternative to the current American Society of Mechanical Engineers Section XI ISI requirements for piping at the Beaver Valley Power Station, Unit Nos. 1 and 2.

The Nuclear Regulatory Commission (NRC) staff has conducted an initial review of your submittal and has determined that additional information is required in order for the NRC staff to complete its review. Enclosed is the NRC staff's RAI associated with your application. The questions in the enclosed RAI were discussed with the BVPS-1 and 2 staff in a conference call on November 26, 2002. Subsequent to that call, the tentative schedule for your response was discussed with Mr. B. Sepelak of your staff, and 45 days from the date of your receiving this RAI was agreed to as a target date for submittal of FENOC's response. Please contact me as soon as possible if circumstances arise that require changes to this proposed schedule. If you have any questions, please contact me at 301-415-1427.

Sincerely,

/RA/

Daniel S. Collins, Project Manager, Section 1
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-334 and 50-412

Enclosure: RAI

cc w/encl: See next page

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Beaver Valley Power Station, Units 1 and 2

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REQUEST FOR ADDITIONAL INFORMATION (RAI)

BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2

DOCKET NOS. 50–334 AND 50-412

The U.S. Nuclear Regulatory Commission (NRC) staff is reviewing FirstEnergy Nuclear Operating Company's July 24, 2002, Inservice Inspection (ISI) Program Relief Request (L-02-066) for the Beaver Valley Power Station, Unit Nos. 1 and 2 (BVPS-1 and 2), which would implement a risk-informed ISI program.

The NRC staff has identified the following questions or concerns that require clarification or additional information in order to complete its review:

A. UNITS 1 AND 2

1. Section 3.8 of the licensee's submittal addresses additional examinations. It states, "The evaluation will include whether other elements on the segment or segments are subject to the same root cause and degradation mechanism. Additional examinations will be performed on these elements up to a number equivalent to the number of elements initially required to be inspected on the segment or segments. If unacceptable flaws or relevant conditions are again found similar to the initial problem, the remaining elements identified as susceptible will be examined. No additional examinations will be performed if there are no additional elements identified as being susceptible to the same service related root cause conditions or degradation mechanism."

   ASME Code directs licensee's to perform these sample expansions in the current outage. Confirm that the sample expansions of elements identified as being susceptible to the same service related root cause conditions or degradation mechanism will be completed during the outage that identified the flaws or relevant conditions.

2. Will the risk-informed ISI program be updated every 10 years and submitted to the NRC consistent with the current requirements of Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code?

3. Under what condition will the risk-informed ISI program be resubmitted to the NRC before the end of any 10-year interval?

4. You state that the BVPS-1 relief request used the 6/98 version of the probabilistic risk assessment (PRA) and the BVPS-2 relief request used the 10/97 version of the PRA. You describe an administrative procedure that requires a staggered 3-year update cycle and a continuous evaluation of potential changes that may require more frequent updates. Even given the time to perform the risk-informed ISI analysis, the staggered 3-year update appears inconsistent with the age of the PRAs used. You also state that the current BVPS-1 and 2 models reflect the actual design, construction, and

Enclosure

operational practices, and that an evaluation based on the Electric Power Research Institute probabilistic safety assessment Applications Guide was performed to confirm that the PRA conforms to the industry state of the art with respect to completeness of coverage of potential scenarios. Clarify which parts of the discussion contained in the June 2002 relief request refer to the procedures and reviews that were applied to the 6/98 and 10/97 version of the PRA's and which are applied to the "current" version.

Confirm that all of the PRA quality discussion are applicable to the PRAs used to develop the risk-informed ISI relief request. Otherwise describe the procedures and reviews applied to ensure that the 6/98 and the 10/97 PRAs used to support the relief requests adequately reflected the actual design, construction, and operational practices at the time that the relief request evaluation was initiated or during its development.

5. State when, and which version, of your PSA has been peer reviewed by the Westinghouse Owner's Group peer review process.

6. Your submittal describes an improved methodology for a weakness identified by the staff in your Individual Plant Examination and concluded that, "[s]ystem unavailability resulting from human errors is therefore accounted for in the current models." Was this improved methodology implemented in the 6/98 and 10/97 versions of the PRAs? If the methodology was not implemented in the 6/98 and 10/97 versions or otherwise incorporated into the evaluation used to support the relief request, incorporate the improved methods into the results or provide an explanation as to why no impact on the results is expected

7. Are there any piping segments that include piping of different diameters? If so, how were the failure frequencies estimated for these segments? For segments including piping of different diameters and where the Perdue method could be applied, how were the number of locations to be inspected determined? How does the methodology for determining the failure frequency comport with the methodology described on page 71 of the Westinghouse Owners Group WCAP-14572, Revision 1-NP-A, "Westinghouse Owners Group Application of Risk-Informed Methods to Piping Inservice Inspection Topical Report," (WCAP-14572), dated February 1999? How does the methodology for determining the number of inspections comport with the methodology described on pages 170, 171, and 174 of the WCAP?

8. Aside from three segments discussed in Unit 1's submittal, you state that all segments in Regions 1 and 2, as discussed on page 167 of WCAP-14572, were evaluated using the Perdue model. The Perdue model is not applied to locations in Region 1A where 100 percent of the locations should be inspected. Explain this apparent discrepancy.

9. Attachment 3 to the submittal is the table, "Comparison of BVPS-1 and BVPS-2 Postulated Consequences by System." In some cases differences appear to be physical differences such as the first entry in the Steam Generator Blowdown System differences (page 1) stating, "Unit 2 has a 2" line connected to the S/G steam space, which was modeled as a steam line break." In other cases, the differences appear to be PRA modeling differences. For example, the first entry in the Steam Generator

Feedwater System differences (page 4) states, “Main Feedwater Line Break is not modeled in the current Unit 1 PRA model. It was treated as part of the Total Loss of Main Feedwater events.” In the second example, the total loss of main feedwater event(s) may not fully reflect all the spatial effects associated with the break of the main feedwater piping evaluated in the risk-informed ISI. Confirm that,

a) The physical differences between the units are appropriately reflected in the PRA models used to develop the risk-informed ISI evaluation for each unit,

b) The PRA model differences that reflect the use of less detailed models or less developed modeling techniques for one of the units have been evaluated and found to have a negligible impact on the risk-informed ISI results or were incorporated into the risk-informed ISI evaluation as appropriate.

B. UNIT 1

10. How many weld locations or other potential inspection locations are there in segments QS-001, and QS-002, respectively? To which system do these segments belong and what degradation mechanism are present in these segments? What is the rationale for selecting one location in each segment?

11. Will the one potential inspection location in QS-042 be inspected as part of the risk-informed ISI program? Explain why or why not.

12. On page 18 you state that all 9 segments in Region 1 were exposed, or are susceptible, to a failure mechanism. Yet on page 25, at least one segment in the Main Steam System is only in Region 1B. Explain why there are no locations placed in Region 1A (e.g., susceptible locations)?

13. On page 24, at least one segment in the Chemical and Volume Control System is only in Region 1A. Are 100% of the elements in this segment inspected (e.g., the VT-2 segments in footnote e)?

14. In general, segments in Region 1 require at least two inspection locations, one in Region 1A and one in Region 1B. Since 100% of susceptible locations (Region 1A) require inspections, more than two locations is normally expected. Segments in Region 2 require at least one inspection location. Based on information in Section 3.8 of your submittal, this would indicate a minimum total number of inspections of 2X9 (Region 1) plus 109 (Region 2) or 127 locations. Table 5-1 indicates a total of 124 inspection locations. Explain this apparent discrepancy.

C. UNIT 2

15. On page 17 you state that all 10 segments in Region 1 were exposed, or are susceptible, to a failure mechanism. Yet on page 24, at least one segment in the Main Steam System is only in Region 1B. Explain why there are no locations placed in Region 1A (e.g., susceptible locations).

16. In general, segments in Region 1 require at least two inspection locations, one in Region 1A and one in Region 1B. Since 100% of susceptible locations (Region 1A) require inspections, more than two locations is normally expected. Segments in Region 2 require at least one inspection location. Based on information in Section 3.8 of your submittal, this would indicate a minimum total number of inspections of 2X10 (Region 1) plus 97 (Region 2) or 117 locations. Table 5-1 indicates a total of 115 inspection locations. Explain this apparent discrepancy.