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U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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Limerick Generating Station, Units 1 and 2
Facility Operating License Nos. NPF-39 and NPF-85
NRC Docket Nos. 50-352 and 50-353

Subject: Response to Request for Additional Information - Supplement
License Amendment Request - Proposed Technical Specifications Change to Relocate Surveillance Test Intervals to a Licensee-Controlled Program (Risk-Informed Initiative 5b)

References:
(1) Letter from M. P. Gallagher, Exelon Generation Company, LLC, to U. S. Nuclear Regulatory Commission, dated June 11, 2004

(2) Letter from T. R. Tjader, U. S. Nuclear Regulatory Commission, to B. Bradley, Nuclear Energy Institute, and M. P. Gallagher, Exelon Nuclear, dated April 12, 2005.

(3) Letter from P. B. Cowan, Exelon Generation Company, LLC, to U. S. Nuclear Regulatory Commission, dated December 12, 2005

In Reference 1, Exelon Generation Company, LLC (Exelon), requested a change to the Technical Specifications (TS), Appendix A, of Facility Operating License Nos. NPF-39 and NPF-85 for Limerick Generating Station (Limerick), Units 1 and 2, respectively. The proposed change relocates the surveillance test intervals (STIs) of various TS surveillance requirements from the TS to a new licensee program, the Surveillance Frequency Control Program. This license amendment request (LAR) was submitted as a pilot in support of the Boiling Water Reactor Owners' Group (BWROG) Risk-Informed Initiative 5b, "Relocate Surveillance Test Intervals to Licensee Control."

In Reference 2, the NRC requested additional information concerning the Limerick pilot LAR (Enclosure 1 to the Reference 2 letter). In Reference 3, Exelon's response to the NRC request for additional information indicated that a supplement to the response would provide a summary of the results of a quantitative assessment for an additional surveillance test interval (STI) example. The attachment to this letter provides the supplemental information.

Exelon has concluded that the information provided in this supplemental response does not impact the conclusions of the: (1) Technical Analysis, (2) No Significant Hazards Consideration under the standards set forth in 10 CFR 50.92(c), or (3) Environmental Consideration as provided in the original submittal (Reference 1).

There are no regulatory commitments contained within this letter.

If you have any questions or require additional information, please contact Glenn Stewart at 610-765-5529.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 28th day of February, 2006.

Respectfully,

DBN

Pamela B. Cowan
Director - Licensing & Regulatory Affairs
Exelon Generation Company, LLC

Attachment: Supplemental Response to Request for Additional Information

cc:	Regional Administrator - NRC Region I	w/attachment
	NRC Senior Resident Inspector - Limerick Generating Station	"
	NRC Project Manager, NRR - Limerick Generating Station	"
	NRC Project Manager - BWROG	"
	NRC Project Manager - RITS Task Force	"
	Director, Bureau of Radiation Protection - Pennsylvania Department of Environmental Protection	"

ATTACHMENT

Limerick Generating Station, Units 1 and 2
Docket Nos. 50-352 and 50-353

Proposed Technical Specifications Change to Relocate Surveillance Test Intervals to a Licensee-Controlled Program (Risk-Informed Initiative 5b)

Supplemental Response to Request for Additional Information

In Reference 1, Exelon Generation Company, LLC (Exelon), requested a change to the Technical Specifications (TS), Appendix A, of Facility Operating License Nos. NPF-39 and NPF-85 for Limerick Generating Station (Limerick), Units 1 and 2, respectively. The proposed change relocates the surveillance test intervals (STIs) of various TS surveillance requirements from the TS to a new licensee program, the Surveillance Frequency Control Program. This license amendment request (LAR) was submitted as a pilot in support of the Boiling Water Reactor Owners' Group (BWROG) Risk-Informed Initiative 5b, "Relocate Surveillance Test Intervals to Licensee Control."

In Reference 2, the NRC requested additional information concerning the Limerick pilot LAR (Enclosure 1 to the Reference 2 letter). In Reference 3, Exelon's response to the NRC request for additional information indicated that a supplement to the response would provide a summary of the results of a quantitative assessment for an additional surveillance test interval (STI) example. The supplemental information is provided below.

Supplemental Information

In Question No. 10 in Enclosure 1 to Reference 2, the NRC requested that Exelon perform an additional probabilistic risk assessment (PRA) to provide helpful insights regarding supporting requirements that are identified as less than Capability Category II, and to address a broader scope of PRA gap analysis findings and key sources of uncertainty than those associated with the original examples discussed in Reference 1.

As a result, Limerick evaluated one additional STI example for interval adjustment on a high risk system that challenges the limits of Regulatory Guide (RG) 1.174. Limerick selected the High Pressure Coolant Injection (HPCI) system due to the overall high risk importance of this system based on its Risk Achievement Worth (RAW) in the Limerick PRA. The specific STI evaluated was the HPCI Pump, Valve, and Flow test that implements a quarterly surveillance requirement. This evaluation was a hypothetical example since it would require relief from the American Society of Mechanical Engineers (ASME) Section XI requirements for quarterly pump and valve testing. Nonetheless, this STI was evaluated but the assessment was limited to a PRA quantitative perspective only. No qualitative aspects were assessed. As such, no Integrated Decisionmaking Panel (IDP) review was performed nor was a detailed review of the quantitative information performed at this time for this hypothetical example. The analysis includes the information requested, including PRA gap analysis findings relative to ASME Capability Category II and also key sources of uncertainty. This quantitative assessment followed the revised draft NEI 04-10 methodology (Reference 4) to consider total and cumulative impacts from all risk contributors for the HPCI STI adjustment.

The process identified in the draft version of NEI 04-10, Step 12, was performed to determine the total and cumulative effect on Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) from the proposed STI change for the HPCI Pump, Valve, and Flow test. Each of the sub-steps in the process and its application to the HPCI

STI assessment is described below. Additionally, the results of the sensitivity studies that were analyzed following the process defined in Step 14 of the draft version of NEI 04-10 are also discussed. The combined results of following the Step 12 and Step 14 processes would be summarized for presentation to the IDP as required in Step 15 of the methodology.

Step 12-A1: Calculate the ΔCDF and ΔLERF values from the Internal Events PRA
This step involved adjusting the HPCI pump/turbine fail-to-start value and associated HPCI/Reactor Core Isolation Cooling (RCIC) common cause failure probability. Note that all of the motor-operated valves (MOVs) that are tested in the HPCI Pump, Valve, and Flow Test are also tested by the HPCI Valve Test which is also performed quarterly. Therefore, the limiting condition is that the HPCI MOVs will still be tested at least quarterly, and no change to the HPCI MOV failure probabilities is warranted for this STI change assessment. Additionally, other components that may be uniquely exercised by this test were not explicitly considered in this initial hypothetical evaluation since the impact of the STI change is expected to be dominated by the HPCI pump/turbine fail-to-start value.

The total plant-specific failure probability for the HPCI pump/turbine is estimated in the Limerick 2004B PRA model to be 1.14E-2 per demand. Therefore, given this information, all of the contribution can be assumed to be time related (per the guidance in Step 8 of the revised draft NEI 04-10), and the impact of doubling the test interval would be to approximately double the total fail-to-start probability. The calculated change in CDF from internal events in this initial assessment after adjusting the HPCI pump/turbine fail-to-start and associated HPCI/RCIC common cause failure probability is 1.7E-07 per year and the calculated change in LERF is 1.3E-09 per year. These values are used to determine the ΔCDF and ΔLERF values for the contribution from the internal events model in Step 12-A2.

Step 12-B1: ΔCDF and ΔLERF Insignificant Based on Qualitative Analysis?
This step involves performing a qualitative assessment of the potential impact on CDF and LERF from external events and shutdown PRAs. For the HPCI pump/turbine, it cannot be qualitatively determined that the net impact of the STI change is negligible, so Step 12-B2 is examined for each contributor (i.e., external events and shutdown).

Step 12-B2: ΔCDF and ΔLERF Below 10^{-7} CDF and 10^{-8} LERF from Bounding Analysis?
A bounding analysis is performed for the shutdown risk assessment. HPCI is a steam driven system that is not required to be available (nor would it be useful) during shutdown periods when the reactor pressure vessel (RPV) pressure is low and the head is off. However, HPCI could be available for the short time frame when the head is on (about 3-5 days per outage), but the decay heat levels would be reduced and the total CDF is expected to be no worse than the at-power CDF. The increase in the annual CDF can be bounded by assuming that it is equivalent to the at-power internal events increase, but only for the applicable 5-day per year time frame. This results in a calculated change in CDF of 1.7E-07 * 5/365 = 2.3E-9 per year and the calculated change in LERF is 1.3E-09 * 5/365 = 1.8E-11 per year. As a bounding estimate, even if all of the CDF leads to LERF during this time frame when primary containment may not be established, the bounding LERF value would be 2.3E-9 per year. In either case, the CDF and LERF values satisfy the Step-B2 requirements, and therefore, the total impact from shutdown events is not included in the total impact assessment in Step 12-A2.

Step 12-B3: ΔCDF and ΔLERF Below 10^{-6} CDF and 10^{-7} LERF from Refined Analysis?
Since a detailed evaluation of the external events impact is not readily available at this time for this hypothetical example, it is estimated that the total impact from fire, seismic, etc. can be approximated by doubling the impact from internal events. This is deemed to be reasonable since the dominant external event scenarios at Limerick are similar to the dominant internal event scenarios, and therefore, the importance of HPCI is about the same as well. Assuming that a best-estimate external events impact would result in a CDF similar to the internal events, then the calculated change in CDF from external events in this initial assessment is 1.7E-07 per year and the calculated change in LERF is 1.3E-09 per year. These values are used to determine the ΔCDF and ΔLERF values for the contribution from the external events model in Step 12-A2.

Step 12-A2: Calculate Total Effect on CDF and LERF for Individual STI Change
This step involves summing the contributions from Step 12-A1 and Step 12-B3 (as applicable). Consequently, the total effect on CDF and LERF from all PRAs is initially estimated as 3.4E-7 per year and 2.6E-9 per year, respectively.

Step 12-A3: Total Change Below 10^{-6} CDF and 10^{-7} LERF?
In this hypothetical case, the total change is below the RG1.174 limits. Therefore, the methodology directs that the assessment continue with Step 12-A4 to evaluate the cumulative impacts of all STI changes.

Step 12-A4: Cumulative Change Below 10^{-5} CDF and 10^{-6} LERF?
In this hypothetical case, the total change would likely indicate that the cumulative change is below the RG1.174 limits. However, as an additional check on the margin available for this STI assessment, the methodology directs that the assessment continue with Step 14 to perform sensitivity studies.

Step 14: Perform Sensitivity Studies
The first required sensitivity study per the methodology is to re-perform the ΔCDF and ΔLERF determinations assuming that the standby failure rate is three times larger than that used in the base case assessment. The results of this initial sensitivity case lead to a calculated change in CDF from internal events of 9.0E-07 per year and the calculated change in LERF of 6.0E-09 per year. This is still below the RG1.174 limits, but is very close to the CDF threshold value of 1.0E-6 per year. With a similar impact expected from external events, the total change would be above the limits in Step 12-A3. The STI assessment could stop here; however, for this hypothetical example, the remaining quantitative portions of Step 14 are still performed for completeness.

The next item in Step 14 of the methodology is to determine if there is an impact from the STI change on the frequency of event initiators. For the HPCI Pump, Valve, and Flow Test STI assessment, since the impact is limited to the HPCI pump/turbine, no event initiators were identified that would be impacted by the STI change.

The next item in Step 14 is to examine the dominant contributors to the delta assessment and ensure that there is no reliance on recovery of failed components or significant reliance on key assumptions and causes of uncertainty. The results indicated that there was no reliance on recovery of failed components, but there were a few areas of uncertainty identified that led to sensitivity case results of ΔCDF and ΔLERF values below or very near the 9.0E-7 per year and 6.0E-9 per year results from the required initial sensitivity study. Other key areas of uncertainty and gap analysis items to Capability

Category II were noted as being bounded by the initial required sensitivity study that increased the standby failure probability and the associated common cause failure probability by a factor of three. Additionally, it was noted that logical combinations of key sources of uncertainty could increase the change in the calculated CDF to above the acceptance criterion value of 1.0E-6 per year, but even the most pessimistic combination of assumptions does not result in a LERF change above the 1.0E-7 per year criterion value.

The results of these sensitivity studies lead to the HPCI STI change assessment not being within the RG 1.174 limits. Therefore, per the guidance in Step 14 of the draft revised methodology, it is concluded that there is not sufficient margin to the RG 1.174 limits, and the recommendation to the IDP would be to not approve the STI change.

References:

1. Letter from M. P. Gallagher, Exelon Generation Company, LLC, to U. S. Nuclear Regulatory Commission, dated June 11, 2004

2. Letter from T. R. Tjader, U. S. Nuclear Regulatory Commission, to B. Bradley, Nuclear Energy Institute, and M. P. Gallagher, Exelon Nuclear, dated April 12, 2005.

3. Letter from P. B. Cowan, Exelon Generation Company, LLC, to U. S. Nuclear Regulatory Commission, dated December 12, 2005

4. Letter from T. Pietrangelo, Nuclear Energy Institute, to T. R. Tjader, U.S. Nuclear Regulatory Commission, dated December 20, 2005.