April 22, 2002

Mr. Robert G. Byram
Senior Vice President
and Chief Nuclear Officer
PPL Susquehanna, LLC
2 North Ninth Street
Allentown, PA 18101

SUBJECT: SUSQUEHANNA STEAM ELECTRIC STATION, UNITS 1 AND 2 - REQUEST FOR ADDITIONAL INFORMATION RE: HIGH-PRESSURE COOLANT INJECTION (HPCI) PUMP AUTOMATIC SUCTION TRANSFER (TAC NOS. MB2190 AND MB2191)

Dear Mr. Byram:

By letter dated June 8, 2001, as supplemented February 4, 2002, PPL Susquehanna, LLC (PPL), proposed an amendment to modify the Susquehanna Steam Electric Station, Units 1 and 2 (SSES 1 and 2), technical specifications to remove the automatic transfer of the HPCI pump suction source from the condensate storage tank to the suppression pool upon receipt of a high suppression pool level. The automatic HPCI pump suction transfer upon receipt of a low condensate storage tank level would be unaffected. The Nuclear Regulatory Commission staff had reviewed PPL's request and had issued a request for additional information (RAI) by letter dated April 8, 2002. As a result of an April 9, 2002, conference call requested by your staff, we have revised the RAI contained in our April 8, 2002, letter to that enclosed. As discussed with your staff, we request your response by April 30, 2002, in order for our review to remain on schedule.

If you have any questions regarding this correspondence, please contact me at (301) 415-1402.

Sincerely,

/RA/

Timothy G. Colburn, Senior Project Manager, Section 1
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-387 and 50-388

Enclosure: RAI

cc w/encl: See next page

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REQUEST FOR ADDITIONAL INFORMATION

RELATED TO REQUEST TO ELIMINATE THE

HPCI AUTOMATIC PUMP SUCTION TRANSFER ON HIGH SUPPRESSION POOL LEVEL

PPL SUSQUEHANNA, LLC

ALLEGHENY ELECTRIC COOPERATIVE, INC.

SUSQUEHANNA STEAM ELECTRIC STATION (SSES), UNITS 1 AND 2

DOCKET NOS. 50-387 AND 50-388

Requested Information About Calculation EC-ATWS-0505 Revision 8.

1. A lot of SABRE computer code input deck data in Appendix D came from the document, PL-NF-89-005, Revision 0, and another RETRAN computer code calculation. It was indicated that these references have been approved by the Nuclear Regulatory Commission (NRC) through previous licensing submittals. Please provide relevant documents that verify NRC's approvals.

2. On Page 235, the loss coefficient of the fuel spacer is calculated by the correlation for ANF9x9 fuel. Does this correlation still apply to the current cycle? If not, what is the impact? It is found that the entire core is modeled by one 1-D hydraulic component. Please describe the modeling approach about lumping peripheral region bundles with central region bundles, which have different inlet orifice loss coefficients.

3. What kind of post-processing package has been used to extract graphical data from SABRE computer code output? Please provide the package to the NRC staff.

4. It is observed that SABRE computer code uses different time step sizes for thermal-hydraulic calculations and neutronics calculations. Please explain how the core power calculation is synchronized with the fluid and heat transfer calculation. The impact on accuracy needs to be discussed. Please provide a comparison between the unsynchronized and synchronized results.

Requested Information About Calculation EC-052-1018.

5. If the proposed change is made to the plant, will the high pressure coolant injection (HPCI) pump suction auto-swap from the condensate storage tank (CST) to the suppression pool triggered by low CST water level be unaffected? If so, is there a concern that the HPCI system may fail during an anticipated transient without scram (ATWS). Has this been considered or modeled in the risk evaluation? It has been indicated that manual rod insertion (MRI) can be initiated within 10 minutes into the event. Please provide justification for the 10-minute assumption.

6. The proposed new emergency operating procedure (EOP) requires a manual HPCI

pump suction swap from the CST to the suppression pool if the pool level reaches 25 feet and the suppression pool temperature is less than 140 °F. Technical Specifications state a 24-foot maximum suppression pool limit. Please explain the magnitude of the level difference. In addition, please provide the suppression pool water level instrumentation accuracy.

7. Has the containment load-limit curve described in Equation (1) on Page 7 been previously approved by the NRC? If not, what is the justification for using it?

8. What is the elevation difference between the HPCI turbine outlet (not the exhaust line) and the suppression pool normal water level?

9. Are all the safety relief valve (SRV) discharge line vacuum breakers located in the drywell? If they are, do we expect that the water level in the SRV discharge lines is lower than the suppression pool level during a postulated loss-of-cooling accident (LOCA)?

10. It is stated in the calculation that the suppression pool letdown system will be used to lower the suppression pool water level during a small-break LOCA with the assumption of loss-of-offsite power (LOOP). Please provide the letdown system flow path drawings, relevant portions of the applicable EOP and documentation to demonstrate that the letdown pump motor can be powered during a concurrent LOCA and LOOP event.

Questions about Calculation EC-RISK-1083

11. In Section 2.5, two operator actions are identified to prevent water hammer damage to HPCI. Both actions are tied to the 26-foot level of the suppression pool. However, on page 32 in Attachment 1 of the June 8, 2001, submittal, it states that "[b]ecause of the uncertainty associated with restarting the HPCI system under conditions of high suppression pool level, the system would not be restarted if suppression pool level is greater than 25 feet." Based on the submittal, these actions would not be taken and should not be credited in the analysis, as the level would exceed 25 feet. Did the probability risk assessment evaluation include credit for either of these two operator actions? If so, please explain the apparent inconsistency between the submittal and the risk calculation and identify what the impact would be on the results if these two operator actions were not credited?

12. Based on statements contained on page 32 of Attachment 1 of the June 8, 2001, submittal, the exhaust line will begin to fill at 25.1 feet and be completely filled when the suppression pool level reaches 27.2 feet. The potential for failing HPCI on a restart is stated to be of concern if the suppression pool level is greater than the 25.1-foot level. This is why there is the restriction on the HPCI pump restart if the level is above 25 feet. Section 2.8 identifies a credible error in implementing the manual transfer that would cause the HPCI pump to trip, but then states this potential error has no consequences due to its brevity. It is not clear how long after the alarm signal is received that the operators will begin to execute the manual transfer. If there are procedural delays/confirmations or other factors that impact the initiation of the manual transfer, the transfer may occur approximately at the time the suppression pool level is actually reaching the 25-foot level. If the HPCI pump trips during the manual transfer at this

time, then in accordance with the original submittal, a restart of the HPCI pump would not be allowed. Therefore, the identified operator error may have a direct impact on HPCI success and should be modeled as a potential failure mode of the system. Please explain the timing and associated factors leading up to the operator taking the steps to perform this manual transfer. If there is the potential for this operator error to result in a trip of HPCI at about the 25-foot level, please revise the model to reflect this potential failure mode of HPCI during the manual transfer and provide the revised results.

13. Section 4.1.1 indicates that HPCI success is conditioned on standby liquid control (SBLC) operability. However, the event tree reverses these two top events. For the current condition, based on Section 4.1.1, sequences ATWS_8 and ATWS_9 are not possible because SBLC is failed, which should actually guarantee failure of HPCI and thus MRI. The event tree logic resulting in these sequences is not precisely correct. Further, it is not clear from the event tree if different results would be achieved if credit was given for the potential to use reactor core isolation cooling (RCIC), control rod drive (CRD), and SBLC, as identified in this section. Finally, it appears that the licensee has performed the analysis using a “one-top” model quantification process, which could result in the subsumming of valid event tree sequences.

A. Please expand upon the discussion in Section 4.1.1 of using RCIC, CRD, and SBLC specifically identifying the conditions under which these systems can be or cannot be credited, state if these systems were credited in the analysis, and provide the revised results pre- and post-modification if it is appropriate to credit these systems.

B. By switching the event tree top logic so that the SBLC top event comes before the HPCI top event for the current plant conditions, correct sequencing would include cutset results for sequences ATWS_4, ATWS_6, ATWS_9, ATWS_11, ATWS_12, and ATWS_13, but not for sequences ATWS_8 and ATWS_14. However, using the calculation’s ATWS event tree, sequence ATWS_11 could have been inappropriately eliminated if a “one-top” model quantification process was employed. Please provide on a sequence-specific basis the core damage frequency/large early release fraction (CDF/LERF) results pre- and post-modification for the ATWS event.

C. For the current plant, based on the switched event tree top logic, the end state class for Sequence ATWS_9 should be the same as that currently identified in the calculation for Sequence ATWS_14 (i.e., PDS-2), since in both sequences HPCI cannot be successful with SBLC failed for the current plant. Please describe and quantify the impact on LERF from switching the end state class for Sequence ATWS_9 to PDS-2 for the current plant.

D. The “one-top” model quantification process could affect other event tree results, in addition to the ATWS event tree. For this application, impacts are also expected in the small-break LOCA (SBLOCA) analysis. Therefore, the staff will also need to review the SBLOCA event tree and its results on a sequence-specific basis. Please provide the SBLOCA event tree and please provide on a sequence-specific basis the CDF/LERF results pre- and post-modification for the SBLOCA event tree.

14. Section 4.1.2 identifies that two operator errors must fail for HPCI to fail. The first is for the operator control of reactor pressure vessel (RPV) water level, which is described further in Section 4.1.3a. The second operator error involves the failure to actually perform the manual transfer, which is described further in Section 4.1.3b. However, the first error analyzed is only for the operators to gain control of the RPV water level and does not address the potential for the operators to fail to maintain control of RPV water level. The second operator action would be highly dependent on this unanalyzed operator error of not maintaining RPV water level, especially since this error could occur very near the time needed to perform the transfer, which would result in the operators not restarting the HPCI pump and thus failing the system. In addition, the two identified operator actions may also be highly dependent as both actions use the same timing window, especially if performed by the same operator. Also, if the operator fails to gain control of RPV level, the HPCI pump will trip at RPV Level 8 and not restart until RPV Level 2 is reached, but the times associated with reaching RPV Level 8 and then reaching RPV Level 2 have not been provided. Again, this could put the HPCI being in the tripped state at the time the level in the suppression pool reaches the 25-foot level and would make the two identified operator actions essentially fully dependent. Please revise the model to reflect the potential for the operator error to maintain control of RPV water level to result in the direct failure of HPCI, without any other operator errors needed, discuss and revise the model accordingly to address the potential dependency between the identified operator actions, and provide the revised results.

15. Section 4.1.3b indicates that the alarm is actuated by level switches LSHE411(2)N015A or LSHE411(2)N015B. Was the potential for the failure on demand and pre-initiator time-based failure of both switches and associated signal/relay logics modeled in the SSES PRA evaluation, including the potential for common cause failures? If so, please provide the associated demand and time-related failure probabilities used in the model and their bases. If not, please revise the model to reflect the potential for these failures to fail the associated operator action to perform the manual transfer and provide the revised results.

16. The estimated CDF/LERF results indicate no differences between using the mean, the 95 percentile human error probability (HEP), and the no operator error results (i.e., HEP=0). Also, the LERF results don't even change when the operator error is assumed certain (i.e., HEP=1). Please explain why there are no differences in these results, though the HEP value is changed, and please provide the subject HEP value(s) used in each of these quantifications.

17. The results for the post-modification using the mean and 95 percentile HEP actually indicates a relatively large CDF reduction for small LOCAs (both steam and liquid), which is counter-intuitive to what is expected. A relatively large CDF increase is identified for small liquid LOCAs, if the operator error is assumed to occur, which is expected. The evaluation also indicates a relatively large CDF reduction for the reactor building closed cooling water initiator and for the small steam LOCAs, even when assuming the certainty of the operator failure to perform the manual transfer. These events dominate the risk reduction, though they appear to be either unrelated to the proposed modification and/or are counter-intuitive results. Similarly, there are many reductions in LERF that are counter-intuitive and many initiators go from a contribution pre-modification to zero contribution post-modification. Please describe why and how

each of the initiators that change in contribution (by absolute value) are impacted by the proposed modification. In addition, please explain why using the mean and 95 percentile HEP values result in a relatively large CDF reduction (factor of 2) for SBLOCAs, but assuming certain failure results in an even larger relative CDF increase (factor of 15) for small liquid LOCAs. Also, please explain why the modification has an impact on small liquid LOCAs, but not small steam LOCAs when the operator failure is assumed.

18. Given the extremely low CDF/LERF results calculated, what quantification cutoff/truncation CDF/LERF values were used in requantifying the model? Please describe how the selected cutoff values assure that potentially important contributors have not been discarded. If the cutoff value was less than 4 orders of magnitude below the total CDF/LERF, please requantify the model using a cutoff value at least at these values (e.g., 1E-11/year for CDF and 5E-13/year for LERF) and provide the revised results.

April 22, 2002

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