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MAR 20 1979

Docket Nos. 50-387
and 50-388

Mr. Norman W. Curtis
Vice President - Engineering
and Construction
Pennsylvania Power and Light Company
2 North Ninth Street
Allentown, Pennsylvania 18101

Dear Mr. Curtis:

SUBJECT: SUSQUEHANNA STEAM ELECTRIC STATION UNIT NOS. 1 AND 2 - REQUEST FOR ADDITIONAL INFORMATION

As a result of our review of your application for operating licenses for the Susquehanna Steam Electric Plant, we find that we need additional information in the area of Reactor Systems. The specific information required is listed in the Enclosure.

Please inform us of the date when this requested additional information will be available for our review.

Please contact us if you desire any discussion or clarification of the information requested.

Sincerely,

Original Signed by
O. D. Parr

Olan D. Parr, Chief
Light Water Reactors Branch No. 3
Division of Project Management

Enclosure:
As stated

cc w/enclosure
See next page

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ENCLOSURE

REQUEST FOR ADDITIONAL INFORMATION

SUSQUEHANNA STEAM ELECTRIC STATION

DOCKET NOS. 50-387 AND 50-388

211.0 REACTOR SYSTEMS BRANCH

211.68 (5.2.2) The analyses presented to show conformance to the ASME Boiler and Pressure Vessel Code for overpressure protection references NEDO-10802 as the analytical model for plant transient evaluation. General Electric has submitted to the staff an updated analytical model (ODYN) to evaluate plant transients. Reanalyze the overpressure sizing transient using the ODYN code unless assurance can be provided that the NEDO-10802 analysis is bounding with regard to predicting peak pressure. The analysis must include the effects of the high pressure recirculation pump trip (RPT) and the turbine stop valve/control valve closure recirculation pump trip where applicable. Provide analysis to justify that the closure of all main steam isolation valves (MSIV) is the most severe overpressure transient when considering the new code, the second safety-grade scram and the effects of RPT.

211.69 (5.2.2) Sensitivity studies showing the effect of initial operating pressure on the peak transient pressure attained during a limiting overpressure event have not been provided. Therefore, either:

(1) provide a sensitivity study which shows that increasing the initial operating pressure (up to the maximum permitted by the high pressure trip set point) will have negligible effect on the peak transient pressure, or

(2) propose a technical specification which will assure that the reactor operating pressure will not exceed the initial pressure assumed in the overpressure analysis.

211.70 (5.2.2) The performance of essentially all types of safety/relief valves has been less than expected for a safety component. Because of reportable events involving malfunctions of these valves on operating BWRs, the staff is of the opinion that significantly better safety/reflief valve performance should be required of new plants. Provide a detailed description of improvements between your plant and presently operating plants in the areas listed below. In addition, explain why the noted differences will provide the required performance improvement.

(5.2.2) (1) Valve and valve operator type and/or design. Include discussion of improvements in the air actuator, especially materials used for components such as diaphrams and seals. Discuss the safety margins and confidence levels associated with the air accumulator design. Discuss the capability of the operator to detect low pressure in the accumulator(s).

(2) Specifications. What new provisions have been employed to ensure that valve and valve actuator specifications include design requirements for operation under expected environmental conditions (esp. temperature, humidity, and vibration)?

(3) Testing. Prior to installation, safety/relief valves should be proof-tested under environmental conditions and for time periods representative of the most severe operating conditions to which they may be subjected.

(4) Quality Assurance. What new programs have been instituted to assure that valves are manufactured to specifications and will operate to specifications? For example, what tests are performed by the applicant to assure that the blowdown capacity is correct?

(5) Valve Operability. Provide your surveillance program to monitor the performance of the safety/relief valves. Identify the information that will be obtained and how these data will be utilized to improve the operability of the valves. For example, how will this program reduce the malfunctions that have occurred in operating reactors?

(6) Valve Inspection and Overhaul. The FSAR states that one half of the safety/relief valves will be bench checked and visually inspected every refueling outage. However, depending on operating cycle length, this may result in several years between inspections.

Operating experience has shown that safety/relief valve failure may be caused by exceeding the manufacturer's recommended service life for the internals of the safety/relief valve or air actuator. At what frequency do you intend to visually inspect and overhaul the ADS portion of the safety/relief valve? For both safety/relief and ADS modes, what provisions exist to ensure that valve inspection and overhaul are in accordance with the manufacturer's recommendations and that the design service life is not exceeded for any component of the safety/relief valve?

211.71 (5.2.2) The response to Question 211.4 is insufficient to allow an adequate evaluation. Provide all system and core parameter initial values assumed in the overpressure analyses. Include their nominal operating range with uncertainties and technical specification limits.

211.72 (5.2.2) Does your design incorporate a fast scram system? Correct the time scale on figure 15.0-2.

211.73 (5.2.2) Identify the safety/relief valve manufacturer.

211.74 (5.2.2) Provide the calculations to support your relief valve discharge coefficients and flow capacities.

211.75 (5.2.2) Page 5.2-6 states that the spring safety mode in the analysis is assumed to be 1177 to 1217 psig; Table 5.2-2 states 1146 to 1205 psig for spring set pressure. Explain the differences and how these values are used in the overpressure analysis. Define the transient analysis specification of valve groups and how they are used in the analysis.

211.76 (15.0) Provide the power-operated pressure relief set points and capacities used in the transient analyses of Chapter 15.

211.77 (6.3) Confirm that adequate NPSH will exist if operator action is not initiated prior to 20 minutes after a LOCA. Provide your detailed NPSH calculation to demonstrate conformance to Regulatory Guide 1.1 for the ECCS pumps. Provide on Figures 6.3-3 and 6.3-6 the information on pages 6.3-7 and 6.3-14. Provide a discussion of the significance of Figure 6.3-7 with regard to NPSH margin.

211.78 (6.3) Discuss the consequences of not performing operator actions until 20 minutes after a LOCA. Discuss all actions that are required by the operator to place the plant in the long-term cooling mode subsequent to a LOCA.

211.79 (6.3) Item 5 on page 6.3-2 is not clear. Identify the ECCS line break as well as the single failure assumed to yield the available operating ECCS equipment shown.

211.80 (6.3) Page 6.3-9 of your SAR states that the HPCI is automatically shutdown on a RPV high water level signal. What provisions are incorporated in the design to prevent premature termination of the HPCI flow. Are any interlocks provided, such as a LOCA signal, that prevent automatic shutoff?

211.81 (6.3) When the water level in the condensate storage tanks (CST) drops to a predetermined level, the HPCI pump switches automatically to the suppression pool. Provide assurance that adequate NPSH exist up to switchover. In addition, show that the minimum suction piping submergence in the CST will preclude undesirable vortex formation. Describe preoperational testing that will be performed to demonstrate that such vortex formation will not occur.

211.82 (6.3) Figure 6.3-6 shows a core spray head flow curve as used in the LOCA analysis. Credit for core spray heat transfer is not used until rated core spray is achieved (approximately 75 seconds for DBA), even though flow begins to enter the core at approximately 50 seconds. Is this flow included in the inventory calculation for reflood time? How are CCFL effects considered in the calcu-- lation in this earlier time frame?

211.83 (6.3) Provide the Figure 6.3-8c that is discussed in Section 6.3.2.2.4 (page 6.3-15).

211.84 (6.3) A recent CE report, "DC Power Source Failure for BWR 3 and BWR 4," dated 11/1/78, provides a generic response to staff concerns relative to loss of DC power sources on peak cladding temperature (PCT). For smaller break sizes, this failure yields higher PCT's than failure of HPCI. Provide assurance that this failure has been properly taken into account in your single failure analysis. In this regard, Table 6.3-5 should be clarified. For example, a loss of a diesel generator would cause a loss of a core spray pump plus an LPCI pump. Also, it is not clear what is being presented in the column headed, "Effect on Safety Function." Is Table 6.3-5 intended to agree with Table 6.2-7? Is break location considered? Define the asterisk used on DC power failure.

211.85 (6.3) Provide assurance that adequate NPSH exists for an ECCS passive failure in a water-tight pump room. Address the possibility of vortex formation at the suction of the remaining ECCS pumps with the lowered pool level. Discuss preoperational tests to be performed to demonstrate that there is not impairment of ECCS function due to lowered suppression pool level.

211.86 (6.3) Confirm that the LPCI system does not perform any other function, such as containment cooling, during the short term portion of the LOCA recovery? If so, this feature must be taken into account in your LOCA analyses. See Question 211.105.

211.87 (6.3) The discussion of the LPCI system is not complete. Discuss the status of valves (open or closed) in the LPCI system and the recirculation system during the LOCA. Provide the initiation signals, interlocks, and time delays associated with each valve movement during the LOCA.

211.88 Provide the assumed values that comprise the total break area for the steam line break; feedwater line break; and core injection spray line break.

211.89 (6.3) Correct Figure 6.3-64 or discuss why the initial PCT for the core spray line break is 1700°F.

211.90 (6.3) What are the differences between steam line breaks inside and outside containment with regard to break area? The analyses suggest that core uncovery could occur if no operator action took place before 20 minutes. Provide the effect on peak clad temperature of no action prior to 20 minutes and discuss all assumptions.

211.91 (6.3) Section 6.3.3.4 (page 6.3-23) states that operator action is not required during the short term cooling mode following a LOCA. Since the short term mode may extend past ten minutes for smaller breaks, discuss in detail what operator actions are required in view of what is stated in Section 6.3.2.8 (page 6.3-19) regarding throttling requirements. In your discussion include the instrumentation that the operator has available, what actions he must perform, and the instructions available to the operator in the emergency procedures. Also include a plot of NPSH margin versus time for the worst case break.

211.92 (6.3) The SSES design uses a swing bus arrangement. In accordance with the staff policy discussed in NUREG-0138, provide an ECCS calculation for the suction line break assuming no LPCI injection.

211.93 (6.3) Identify all ECCS valves that may be potentially submerged or subject to spray impingement following a LOCA. Discuss environmental qualification of these valves for these conditions.

221.94 (6.3) The references provided for the ECCS analysis must include references for the latest model changes and corrections.

211.95 (6.3) Demonstrate that HPCI failure from 1.0 ft^2 to the DBA is not more limiting than the LPCI D/G failure.

211.96 (6.3) There have been damaging water hammer occurrences in the turbine supply or exhaust lines of HPCI systems that were attributed to steam driven slugs of water. Contributing causes included a) water drawn into the exhaust line from the suppression pool, b) inadequate draining of the steam supply line, and c) trapping of water slugs upstream of the supply line isolation valves during maintenance. Also, check valves in the turbine exhaust lines of the HPCI system which serve a containment isolation function have been damaged as the result of intermittent closures which arise from flow oscillations in the exhaust line associated with formation and collapse of steam bubbles in the suppression pool. One type of corrective action involved the use of a sparger to reduce the oscillations. What design features are used at Susquehanna to prevent these types of damage?

211.97 (6.3) Check valves in the discharge side of the HPCI, LPCI/RHR, LPCS systems perform an isolation function in that they protect low pressure systems from full reactor pressure. The staff will require that these check valves be classified ASME IWV-2000 Category AC, with the leak testing for this class of valve being performed to code specifications. It should be noted that a testing program which simply draws a suction on the low pressure side of the outermost check valves will not be acceptable. This only verifies that one of the series check valves is fulfilling an isolation function. The necessary testing frequency will be that specified in the ASME Code, except in cases where only one or two check valves separate high to low pressure systems. In these cases, leak testing will be performed at each refueling after the valves have been exercised.

Identify all ECCS check valves which should be classified Category AC as per the position discussed above. Verify that you will meet the required leak testing schedule, and that you have the necessary test lines to leak test each valve. Provide the leak detection criteria that will be proposed for the Technical Specification.

211.98 (6.3) What provisions are made to protect level instrumentation for the condensate storage tank and the lines from this tank leading to the HPCI systems from the effects of cold weather.

211.99 (6.3) Some relief valve discharge lines on ECCS penetrate primary containment and have outlets below the surface of the suppression pool. Since these lines form part of the primary containment, the concern is that excessive dynamic loads resulting from water hammer during relief valve actuation may cause line cracking or rupture. Identify these lines penetrating containment and provide information concerning measures taken to prevent line damage.

211.100 (6.3) The ECCS contains manual as well as motor-operated valves. Consideration must be given to the possibility that manual valves might be left in the wrong position and remain undetected when an accident occurs. Provide a list of location and type of all manually operated valves in the safety systems and discussion of the methods used for each valve to minimize the possibility of such an occurrence. The staff will require remote indication in the control room for all critical ECCS valves (manual or motor-operated).

211.101 (6.3) Recent operating experience identified a potential common mode flooding of ECCS equipment rooms. The problem involved the equipment drain lines (see IE Circular No. 78-06, May 25, 1978). Verify that the specific design for floor and equipment drains are such that flooding in any one room or location will not result in flooding of redundant ECCS equipment in other rooms. If isolation valves or limit switches are used to prevent common flooding, identify these valves and switches and discuss provisions to be included in the Technical Specifications to assure adequate surveillance.

211.102 (6.3) The discussion in section 6.3.2.2.5 of the fill system used to prevent water hammer due to empty discharge lines in the RHR and ECC systems is inadequate. Since there have been about fifteen damaging water hammer events resulting from empty discharge lines of core spray and RHR systems, the adequacy of fill systems, including instrumentation and alarms is a matter of concern. Please respond to the following:

(1) Provide a detailed description of the fill system including instrumentation and alarms with appropriate references to a P&ID.

(2) Level transmitters apparently are not used to detect trapped air bubbles upstream of injection valves. Pressure read downstream of a pump discharge check valve that is greater than the gravity head corresponding to the highest point in the system does not necessarily indicate the absence of trapped air pockets? What provisions are made to avoid trapping of air pockets? In the discussion include consideration of leaking valves in bypass test lines.

(3) If maintenance is required on a particular loop (e.g., in RHRs) requires draining, how does the fill system protect the other loop and systems (e.g., CS)?

(4) What surveillance testing will be required to demonstrate that the fill system instrumentation is capable of performing the desired function?

(5) How are surveillance tests made to determine if the discharge lines for the RHR and CS systems are full as required in the Standard Technical Specifications?

(6) Assuming the jockey pump system does not maintain full lines, water hammer could occur during surveillance tests of the RHR and CS pumps. If damage occurred, the event would be reported in a LER. However, if special fill and vent procedures were used prior to these tests, water hammer would not occur, but the inadequacies of the jockey pump system might not be evident. Discuss the procedures to be used in surveillance tests involving startup of RHR and CS pumps and the reporting procedures to be used if special filling and venting procedures are used and indicate partially empty lines.

211.103 (6.3) During long-term cooling following a small LOCA, the operator must control primary system pressure to preclude over-pressurizing the pressure vessel after it has been cooled off.

(1) Describe the instructions given the operator to perform long-term cooling.

(2) Indicate and justify the time frame for performing the required action.

(3) List the instrumentation and components needed to perform this action and confirm that these components meet safety grade standards.

(4) Discuss the safety concerns during this period and the design margins available.

(5) Provide temperature, pressure, and RCS inventory graphs that would show the important features during this period.

The above discussion should account for the following:

(1) Loss of offsite power.

(2) Operator error or single failure.

211.104 (6.3) The answer to 211.10 is not complete. Explain how the leakage detection system meets the requirements of IEEE-279. Provide the minimum time available before operator action is taken after initiation of an alarm. Examine auxiliary system piping in the location of ECCS equipment and address the potential break of a non-safety grade pipe that may cause flooding.

211.105 (6.3) Your response to 211.13 requires supplemental discussion. Demonstrate that for all sizes of breaks in a recirculation loop or in ECCS lines requiring ECCS actuation, the core is covered sufficiently so that LPCI diversion to wetwell spray after 10 minutes is acceptable and the ECCS systems continue to satisfy the requirements of GDC 35 and 10 CFR 50.46. Consideration should be given to the full spectrum of potential single failure and break locations. Confirm that no operator action affecting ECCS performance is required prior to 20 minutes after the initiation of the accident.

Discuss the effects of the following on core cooling and provide the necessary information to show that the requirements of GDC 35 and 10 CFR 50.46 are not violated.

(1) Justify that the system provided for diversion of LPCI flow meets single failure criteria so that diversion before 10 minutes need not be considered.

211.105 (6.3) (Cont'd)

(2) Provide a sensitivity study showing peak clad temperature as a function of break size for small break LOCA's assuming diversion will be initiated at 10 minutes. Perform this study for ECCS and recirculation line breaks. For the most limiting break, provide the following figures:

(a) Water level inside the shroud as a function of time during the LOCA

(b) Reactor vessel pressure vs. time

(c) Convective heat transfer coefficient vs time

(d) Peak clad temperature vs. time

(e) ECCS flow rate vs. time.

(3) Justify that diversion at times greater than 10 minutes will have less severe consequences than diversion at 10 minutes (considering appropriate break size for later diversion).

(4) Provide a discussion which balances the need for LPCI diversion for this limiting break size with the need for abundant core cooling (GDC 35). For example, this discussion could relate to the likelihood of LPCI diversion for this size break.

211.106 (6.3) Your response to Question 211.11 indicates that your ECCS pumps are designed to operate 100 days for any one accident during the 40 year plant lifetime. Provide information that demonstrates that your ECCS pumps will function for that time period as well as any maintenance assumed to occur during that time period.

211.107 (6.3) Your break spectrum analysis is insufficient to allow an adequate evaluation. To confirm that a sufficient number of breaks have been analyzed to generate Figure 6.3-10, provide the tabulated values of peak cladding temperature (PCT) and break area used. Provide small break calculations of approximately 0.02 ft^2 and 1.0 ft^2 with an HPCI failure to verify that these break sizes remain non-limiting (see more complete curve in WPPSS-2 FSAR, Figure 6.3-13). Also, submit a large break model calculation for a 1.0 ft^2 break with HPCI failure to similarly verify that the worst break has been properly identified. Provide a discussion on why the 0.68 discharge DBA yields the limiting PCT for Susquehanna. The discussion should include transition boiling time, hot node uncovery time, rated core spray time, and reflood time. This discussion should also describe the trend in suction line breaks (i.e., does this trend also exist for smaller than the largest suction break area, with perhaps a smaller suction break yielding the highest PCT).

211.108 (6.3) For BWR-4's with the LPCI modification (no loop selection logic) the potential exists for isolating a recirculation break with the core uncovered before the pressure has decreased sufficiently to permit the low pressure ECCS to enter the core. In particular, the single failure considered is an inadvertent closure of the recirculation suction valve with a break between the discharge and suction valves. Analyze the consequences of this failure for the Susquehanna ECCS.

211.109 (6.3) Provide the missing footnote on Table 6.3-3.

211.110 (15.A) Correct Figure 15A.6-31, "Protection Sequences Main Turbine Trip--Without Bypass:"

(1) for the event to occur at <30% power, protection sequences should be the same as for generator trip without bypass as shown in Figure 15A.6-30.

(2) delete HPCI that is connected with incident detection circuitry.

Also, confirm that subsequent to initial core cooling the sequence of operations to extended core cooling would be the same as shown in Figure 15A.6-26, "Protection Sequences for Loss of Main Condenser Vacuum."

211.111 (15.2) Per your response to Q211.19 regarding the analyses for generator load rejection and turbine trip transient, explain your statement that "...a loss of offsite power would improve the results of the above transient since the only additional effect would be a slow coastdown (in comparison to the RPT function) of the recirculation pumps", particularly since the RPT was intended to improve thermal margin.

211.112 (15.2) Since the reclassification of the generator and turbine trip without bypass transients has not been accepted by the staff and is still under generic review, reanalyze the above events for determination of the operating limit MCPR in which the results would not violate the safety limit MCPR of 1.06. Also, it is our position that the limiting transient be reanalyzed with the ODYN code.

211.113 (15.A) Modify NSOA drawings to include benefits of nonsafety-grade equipment which mitigate transients and accidents. Such equipment includes relief valves, turbine bypass valves, and vessel level (high) trip.

211.114 (15.1.2). During recent meetings with General Electric the staff has discussed the use of nonsafety-grade equipment for anticipated transient analyses. It is our understanding that one of the more limiting events is the feedwater controller failure (maximum flow demand). For this transient, the plant operating equipment that have a significant role in mitigating this event are the turbine bypass system and the reactor vessel high water level (Level 8) trip that closes the turbine stop valves. To assure an acceptable level of performance, it is the staff's position that this equipment be identified in the plant Technical Specifications with regard to availability, set points, and surveillance testing. Submit your plan for implementing this requirement along with any system modifications that may be required to fulfill the requirements.

211.115 (15.3) With regard to your response to Q211.24, you state that the limiting pump trip is assumed in analyzing decrease in reactor coolent system flow rate transients. Identify what trip signal (e.g., RPT on turbine control valve fast closure or stop valve closure; reactor vessel water level L2 set point, motor branch circuit over-current protection, etc.) can be expected to produce the most severe pump coastdown.

211.116 (15.1) It is not evident that the assumed drop of 100°F in feedwater temperature gives a conservative result of this transient with manual recirculation flow control. For example, a feedwater temperature drop of about 150°F occurred at one domestic BWR resulting from a single electrical component failure. The electrical equipment malfunction (circuit break-trip of a motor control center) caused a complete loss of all feedwater heating due to total loss of extraction steam. Accordingly, either (1) submit a sufficiently detailed failure modes and effects analysis (FMEA) to demonstrate the adequacy of a 100°F feedwater temperature reduction relative to single electrical malfunctions or (2) submit calculations using a limiting FW temperature drop which clearly bounds current operating experience.

Also, temperature drops of less than 100°F can occur and involve more realistic slow changes with time. Assuming all combinations result in slow transients with the surface heat flux in equilibrium with the neutron flux at the occurrence of scram, a smaller temperature drop than 100°F that still causes scram could result in a larger ΔCPR. Please evaluate this transient and justify that the assumed values of the magnitude and time rate of change in the feedwater temperature are conservative.

211.117 (15.2) Closure times from partially open to fully closed position are not addressed in the FSAR. For full-stroke closure, the assumed closure time would appear to be conservative in terms of the supplied information. However, for operation in the full arc (full throttling) mode, the closure times may be significantly less than 0.150 second for typical cases where the control valves are only partially open. With respect to this transient, there are two concerns. The first concern is that minimum closure times for part-stroke may be less than those assumed in the analysis. The second concern is that the analysis, which is based on 105% NBR steam flow and valves wide open initial conditions, may give a less conservative result than an initial condition at a somewhat lower power with control valves partially open as expected. Demonstrate that control valve closure times smaller than 0.150 second do not result in unacceptable increases in ΔMCPR and reactor peak pressure or provide either (1) justification that smaller closure times cannot occur or (2) a minimum closure time to be incorporated in the Technical Specifications.

211.118 (15.1.1) For the loss of feedwater heating transient in the manual flow control mode the thermal power monitor (TPM) is used to scram the reactor. Explain the need for the TPM and provide specific transients for which this trip signal initiates scram. Discuss how surveillance testing of the TPM is incorporated in the station technical specifications.

211.119 (15.4.5) For the recirc flow control failure with increasing flow transient (Section 15.4.5) provide the initial operating MCPR determined at 65% NB rated power and 60% core flow. In addition, provide the K_f factors as a function of core flow for the automatic and manual flow control modes of operation. Furthermore, provide the maximum flow control set point calibration limit (e.g., 100% or 105% of rated flow) for the recirc loop flow control valves used in the transient analysis.

Provide recirculation pump M-G set points for the manual flow control mode assumed in the analysis. Also, you reference the GE topical report NEDO-10802 as the dynamic model to simulate this event. Since NEDO-10802 does not describe the complete event, discuss in greater detail the overall method used to calculate the ΔCPR.

211.120 (15.3.3) For the recirculation pump seizure accident we note in Table 15.3-5 that credit is taken for nonsafety-grade equipment to terminate this event. Section 15.3.3 of the Standard Review Plan, Revision 1, requires use of only safety-grade equipment and that the safety functions be accomplished assuming the worst single failure of an active component. Reevaluate this accident with the above specific criteria, and provide the resulting ΔCPR and percentage of fuel rods in boiling transition.

211.121 (15.1.2) With a sudden increase in feedwater flow, there will be a drop in the feedwater temperature which contributes to the reactivity increase during the first part of the transient. For example, the combination of feedwater temperature drop and a smaller maximum flow rate could lead to a level 8 trip with the surface heat flux close to the flux scram set point. If the feedwater temperature at the reactor vessel has been assumed constant, the transient should be analyzed to include the effect of this temperature variation on MCPR. The basis for determining the time variation in FW temperature at the reactor vessel should be provided. Also show that a smaller increase in feedwater flow rate in conjunction with the change in feedwater temperature does not give a lower MCPR.

211.122 (15.5.1) Figure 15.5-1 (Inadvertent startup of HPCI) is inconsistent with the text described in Section 15.5.1.3.3. For example, the figure shows no change in drive and core inlet flow after 20 seconds when the turbine is tripped nor are there any changes shown for such parameters as steam line pressure rise and bypass flow. Please correct these inconsistencies. Also, based on the text, the sequence of events shown in Table 15.5-1 is incomplete. Finally, the assumption that the HPCI temperature is 40°F does not appear to be conservative if the text description of the course of this transient is correct. A higher HPCI temperature could result in a level 8 trip of the turbine at neutron flux just below scram set point, with a resultant lower MCPR than that obtained using the 40°F value. Provide a reanalysis using more conservative temperatures or justify present results.

211.123 (15.1.4) In the analysis of inadvertent opening of a safety/relief valve, it is stated that a plant shutdown should be initiated if the valve cannot be closed. How much time does the operator have to initiate plant shutdown before exceeding Technical Specification limits for suppression pool temperature?

211.124 (15.2.6) The transient analysis for loss of all grid connections shows main steam line isolation valve (MSIV) closure at 36.8 seconds, due to loss of condenser vacuum. A concern is that the MSIV's may close at an earlier time in the transient and result in higher system pressures. Apparently, credit is taken for MSIV air accumulator operation since the normal air supply to the MSIV's would trip at the start of this transient. Discuss design provisions and verification testing which demonstrate that MSIV performance is qualified to the extent assumed in the analysis.

Related to the same potential for faster MSIV closures, is the design such that a loss of all grid connections may result in an isolation signal which would close the MSIV's? What sources of electrical power are used for MSIV isolation logic and isolation actuators? Would these sources of power be available following a loss of all grid connections? Do the logic and actuators fail safe to cause an MSIV isolation signal on loss of electrical power?

211.125 (15.0) Operation of Susquehanna with partial feedwater heating might occur during maintenance or as a result of a decision to operate with lower feedwater temperature near end of cycle. Justify that this mode of operation will not result in (1) greater maximum reactor vessel pressures than those obtained with the assumptions used in Section 5.2.2, or (2) a more limiting ΔMCPR than would be obtained with the assumptions used in Section 15.0. The basis for the maximum reduction in feedwater heating considered in the response should be provided (e.g., specific turbine operational limitations).

211.126 (7.5) Since systems such as the HPCI and RCIC are initially aligned to the condensate storage tank (CST) and switch to the suppression pool on low water level in the CST, the CST water level should be included in Table 7.5-1, entitled "Safety Related Display Instrumentation," Add the above for display in Table 7.5-1 or justify its omission.

211.127 (7.5) For the safety-related display instrumentation shown in Table 7.5-1, identify which parameters serve a post-accident tracking or monitoring function.

211.128 (7.5) In Table 7.5-1 you identify the range of the reactor vessel pressure to be from 0 to 1500 psig. Since the design pressure is 1250 psig, justify the upper bound of the instrumentation range when considering potential accidents that may cause large pressure excursions (i.e., ATWS).

211.129 (7.4.1.14) Display instrumentation for the condensate storage tank level should be provided on the remote shutdown control panel. Secondly, you state that the RHR flow indicator will be located on the remote shutdown panel. Verify that flow indication will be provided for both RHR systems (A and B), and that the flow range will be the same as that shown in Table 7.5-1.

211.130 (7.4) Table 7.4-3 identifies certain valves actuated by the transfer switches. Why are recirculation suction valves F023B and F023A actuated closed? What is the status of the remaining recirculation suction valves? Discuss when the closure of these valves would be initiated and clarify why valve "A" is closed in Unit 2 while valve "B" is closed in Unit 1. Relate the above discussion to the potential for pump cavitation.

211.131 (7.4.1.4) Per Section 7.4.1.4.3, transfer switches on the remote shutdown panel are operated to transfer control to the remote shutdown panel. Provide a list of valves in the nuclear boiler, RHR, and RCIC systems, if any, that would be actuated to the "safe condition" by a signal from the transfer switches.

211.132 (3.11) Add to Table 3.11-3 the Control Rod Hydraulic System (portions of system necessary for scram) and its component operability under abnormal environmental conditions. Clarify whether the RHR steam isolation valves are included in item 4 of Table 3.11-3. Also, provide the basis for selecting an abnormal temperature of 148°F for component operability.

211.133 (3.9.1.1) The following questions pertain to our review of Table 3.9-1 which shows the number of plant cycles (events) considered for reactor assembly design and fatigue analysis.

(1) Explain the events in Item 9 and relate to the transients analyzed in Chapter 15.0. Also, provide the number of cycles for safety or relief valve blowdown.

211.133 (3.9.1.1) (Cont'd)

(2) In Table 3.9-1, item 16b is the indicated automatic blowdown feature related to the ADS function?

(3) Explain event item 15a and relate to Chapter 15.0 or Section 5.2.2 analyses. Justify omission of a reactor overpressure with flux scram and isolation valves stay closed under "Emergency Conditions."

211.134 (15.0) In Table 15.0-2, item 32, provide the correct units (or value) for recirculation pump trip inertia for transient analysis.

211.135 (15.0) In Table 15.0-2, item 28, you show the high flux trip set point of 120% as an input value for transient analysis. Justify for not using the 122% instead of 120% set point which accounts for calibration error, instrument accuracy, and transient overshoot as shown in Table 7.2-4.