QUESTION 005.1

The statement in Section 5.2.1.1 of the FSAR with regard to your compliance with 10 CFR Part 50, Section 50.55a, Codes and Standards Rule, is incorrect as a number of Quality Group A components within the reactor coolant pressure boundary are not in conformance with the applicable ASME Boiler and Pressure Vessel code and addenda as required by the rule.

In Amendment 13 to the Susquehanna Steam Electric Stations' FSAR and in your letter ER 100450, File 040-2, received by the Staff on March 1, 1974, you provided an analysis of anticipated deviations from the codes and standards rule requirements set forth in the provisions of Section 50.55a, 10 CFR Part 50, based on a Construction Permit Date of November 2, 1973, for the Susquehanna reactor pressure vessels, reactor recirculation piping, reactor recirculation system pumps, main steam line isolation valves, and main steam safety/relief valves. Based on this information and on certain additional commitments relative to the reactor pressure vessels, the AEC in a letter dated June 20, 1974, in accordance with paragraph 50.55a (a)(2)(ii), granted approval for relief from the rule for these components and acceptance of the ASME Section III Code and Addenda specified in Amendment 13 to the FSAR and letter ER 100450, File 040-2.

Revise Section 5.2.1.1. of the FSAR to correctly reflect the status of each Quality Group A component within the reactor coolant pressure boundary.

RESPONSE:

For response see Subsection 5.2.1.1 and Table 5.2-10.

QUESTION 005.2

In Table 3.2-1 of the FSAR identify the applicable principal construction codes and standards in those cases where this information is now missing throughout the table.

RESPONSE:

Table 3.2-1 has been revised to provide the requested information.

QUESTION 005.3

The B31.1 component code identified in Table 3.2-1 of the FSAR for the diesel lube oil system piping and valves is inconsistent with the Quality Group C (Safety Class 3) classification for these components. The diesel generator lubrication system piping is also identified in Section 9.5.7.1 of the FSAR as designed in accordance with ASME Section III, Class 3. Resolve this inconsistency and revise the FSAR as appropriate.

RESPONSE:

Section 9.5.7.1 of the FSAR has been revised to resolve this inconsistency.

QUESTION 005.4

The quality group (safety class) classification, seismic classification, component code and quality assurance requirements for the components of the Emergency Service Water System have been omitted from Table 3.2-1. Revise Table 3.2-1 to include this information.

RESPONSE:

Table 3.2-1 of the FSAR has been revised to include this information.

QUESTION 005.5

The quality group (safety class) classification, seismic classification, component code and quality assurance requirements for the spray pond system piping has been omitted from Table 3.2-1. Revise Table 3.2-1 to include this information.

RESPONSE:

Table 3.2-1 of the FSAR has been revised to include this information.

QUESTION 005.6

Verify that all components within the reactor coolant pressure boundary as defined in 10 CFR Part 50.2(v) are classified Quality Group A in compliance with the Codes and Standards Rule, Section 50.55a of 10 CFR Part 50, or as a minimum, are classified Quality Group B if the components meet the exclusion requirements of the rule.

RESPONSE:

Section 3.1.2.2.5 of the FSAR has been revised to resolve this concern.

QUESTION 010.1

The criteria for your high energy and moderate energy line analysis in the FSAR is in accordance with Branch Technical Position APCSB 3-1, "Protection Against Piping Failures in Fluid Systems Outside Containment." However, other than Tables 3.6-2 and 3.6-3, the results of your analyses and the environmental effects regulating from high energy line breaks and leakage cracks have not been provided. Provide these analyses and results for each of the assumed breaks or leakage cracks at their postulated locations.

RESPONSE:

The requested information has been provided in Appendix 3.6A.

QUESTION 010.2

We require that the compartment between the containment and the reactor building which houses the main steam lines and feedwater lines and the isolation valves for those lines, be designed to consider the environmental effects (pressure, temperature, humidity) and potential flooding consequences from an assumed crack, equivalent to the flow area of a single ended pipe rupture in these lines. We require that essential equipment located within the compartment, including the main steam isolation and feedwater valves and their operators be capable of operating in the environment resulting from the above crack. We also will require that if this assumed crack could cause the structural failure of this compartment, then the failure should not jeopardize the safe shutdown of the plant. In addition, we require that the remaining portion of the pipe in the tunnel between the reactor building and the turbine building meet the guidelines of Branch Technical Position APCSB 3-1.

We require that you submit a subcompartment pressure analysis to confirm that the design of both areas conforms to our position as outlined above.

We request that you evaluate the design against this staff position, and advise us as to the outcome of your review, including any design changes which may be required. The evaluation should include a verification that the methods used to calculate the pressure build-up in the subcompartments outside of the containment for postulated breaks are the same as those used for subcompartments inside the containment. Also, the allowance for structural design margins (pressure) should be the same. If different methods are used, justify that your method provides adequate design margins and identify the margins that are available. When you submit the results of your evaluation, identify the computer codes used, the assumptions used for mass and energy release rates, and sufficient design data so that we may perform independent calculations.

RESPONSE:

The requested information is provided in Appendix 3.6A.

QUESTION 010.3

The peak pressures and temperatures resulting from the postulated break of a high energy pipe located in compartments or buildings is dependent on the mass and energy flows during the time of the break. You have not provided the information necessary to determine what terminates the blowdown or to determine the length of time blowdown exists. For each pipe break or leakage crack analyzed, provide the total blowdown time and the mechanism used to terminate or limit the blowdown time of flow so that the environmental effects will not affect safe shutdown of the facility.

RESPONSE:

For those pipe breaks analyzed, termination of blowdown was not a controlling factor in the analysis since the temperature and pressure peaked within the first few seconds after the line break. Short term blowdown in these cases does not result in higher temperatures and pressure. Termination of the blowdown for breaks outside containment is accomplished by an automatic isolation signal from the Leak Detection System described in Subsection 7.6.1a.4.

QUESTION 010.4

The design criteria for the main steam isolation valve leakage control system (MSIVLCS) does not contain provisions to prevent the operation of the MSIVLCS when the inboard MSIV fails to close. We will require that an additional interlock be provided on the main steam isolation valve leakage control system so that the operation of an inboard leakage control system is prevented should an inboard main steam line isolation valve fail to be in its fully closed position.

RESPONSE:

The system design basis considers that there will be appreciable hold up time following the design basis LOCA before fission products from the core are transported down the main steam lines. The leakage control system is designed so that if the inboard system is actuated with one inboard MSIV failed open, the vent line from that steam line will automatically reclose by the time fission products, assuming plug flow, move down the steam line about 1/2 the total pipe run from the reactor vessel to the failed open inboard MSIV. Further, the operator is afforded with information from the control room regarding the status of the MSIV's through the valve position switches. Operating procedure inhibits the operator in activating the system in the event the valve position indicator shows failed open. Therefore, it is concluded that the additional interlock is not warranted.

NOTE:

MSIV-LCS information maintained here for historical purposes. The MSIV-LCS has been deleted. The function is now performed by the Isolated Condenser Treatment Method (Section 6.7).

QUESTION 010.5

You state that the Unit 1 facilities reactor building crane is a single failure proof crane and is designed to handle the spent fuel cask, and that the Unit 2 crane is not single failure-proof and is designed to handle all normal plant operation loads except the spent fuel cask. Provide the following information for these fuel handling systems:

(1) Describe the normal plant operation loads that the Unit 2 reactor building crane is capable of carrying in the fuel building area.

(2) Describe the means used to prevent the Unit 2 reactor building crane from handling the spent fuel cask when stored in the spent fuel shipping cask storage pool.

(3) Describe the mechanical stops and/or electrical interlocks that would restrict the path of the 125-tone crane to those areas identified on Figure 9.1-16A and 9.1-16B.

(4) State whether the Unit 1 reactor building crane has been designed to meet the guidelines of Branch Technical Position ASB 9-1, "Overhead Handling Systems for Nuclear Power Plants."

RESPONSE:

1) Please see revised Subsection 9.1.5 for this information.

2) Please see revised Subsection 9.1.5 for this information.

3) Please see revised Subsection 9.1.5.3 for this information.

4) See response to Question 010.25.

QUESTION 010.6

A single failure of an inboard MSLIV would allow a continuous blowdown of the containment atmosphere to the reactor building standby gas treatment system for a specified period of time when the MSIVLCS is initially actuated. This violates our containment isolation criteria and the consequences of the blowdown are unacceptable. It is our position that an interlock be provided so that the leakage control system actuation valves can be opened only if the associated inboard MSLIV is in a fully closed position. Revise the FSAR to indicate conformance to our position.

RESPONSE:

The system design basis from the outset has been that there will be appreciable hold up time following the design basis LOCA before fission products from the core are transported down the main steam lines. The leakage control system is designed so that if the inboard system is actuated with one inboard MSIV failed open, the vent line from that steam line will automatically reclose by the time fission products, assuming plug flow, move down the steam line about 1/2 the total pipe run from the reactor vessel to the failed open inboard MSIV. Besides, the operator is afforded with information from the control room regarding the status of the MSIV's through the valve position switches. Operating procedures inhibit the operator in activating the system in the event the valve position indicators show failed open. We conclude that the additional interlock is not warranted.

NOTE:

MSIV-LCS information maintained here for historical purposes. The MSIV-LCS has been deleted. The function is now performed by the Isolated Condenser Treatment Method (Section 6.7).

QUESTION 010.7

The design criteria for the main steam isolation valve leakage control system indicates that you propose to allow a main steam isolation valve (MSIV) leakage rate up to 100 SCFH for each MSIV in each steamline. It is our position that the design basis leak rate of 100 SCFH is not an acceptable MSIV leakage rate for normal operation. Therefore, we will still impose a technical specification limit of 11.5 SCFH for the MSIV leak rate and a leak rate verification testing frequency consistent with the plant Technical Specifications used for other operating BWR's. Revise the FSAR to indicate that the MSIV leak rate for normal operation will be limited to 11.5 SCFH.

RESPONSE:

It is stated in Section 6.7.1.3 of the FSAR that the main steam isolation valve leakage control system (MSIV-LCS) is designed to process MSIV leakage rates up to 100 SCFH for each MSIV in each line. This is a design basis for the MSIV-LSC and is not the design basis leakage rate for the MSIV's. The Standard Technical Specification in Chapter 16 of the FSAR specifies the MSIV leakage rate at 11.5 scf per hour.

NOTE:

MSIV-LCS information maintained here for historical purposes. The MSIV-LCS has been deleted. The function is now performed by the Isolated Condenser Treatment Method (Section 6.7).

QUESTION 010.8

Confirm that a Keff of less than 0.98 will be maintained with fuel of the highest anticipated reactivity in place in the new fuel storage racks and assuming optimum moderation.

RESPONSE:

See revised FSAR Subsections 9.1.1.1.1.2, 9.1.1.2 and 9.1.1.3.1.

QUESTION 010.9

The information contained in the Susquehanna FSAR is not of sufficient detail to support a conclusion that the liner plate for the spent fuel pool is designed to seismic category I. Therefore, we require, that you demonstrate compliance with Regulatory Guides 1.13 and 1.29 by showing that a failure of the liner plate as a result of an SSE will not affect any of the following: significant release of radioactive materials due to mechanical damage to the spent fuel; significant loss of water from the pool which could uncover the fuel and lead to release of radioactivity due to heat-up; loss of ability to cool the fuel due to flow blockage caused by a portion or one complete section of the liner plate falling on top of the fuel racks; damage to safety related equipment as a result of pool leakage; or uncontrolled release of significant quantities of radioactive fluids to the environs.

RESPONSE:

See revised Subsections 9.1.2.1 and 9.1.2.2.

QUESTION 010.10

Confirm that all portions of the structure (reactor building) which serve as a low leakage barrier to provide atmospheric isolation of the spent fuel storage pool and associated fuel handling area are designed to seismic Category I criteria.

RESPONSE:

See revised FSAR Subsection 9.1.2.2.

QUESTION 010.11:

The spent fuel pool cooling system is a non-seismic system. This does not meet the guidelines set forth in Regulatory Guide 1.13 and 1.29. Analyze the design of the spent fuel pool cooling system to show that the pumps and piping are supported so that they are capable of withstanding an SSE, or provide the results of an analysis to show that for the complete loss of fuel pool cooling that would result in pool boiling, a release of significant quantities of radioactivity to the environment will not result.

RESPONSE:

A complete analysis showing the amount of radioactive release following a complete loss of fuel pool cooling is provided in Appendix 9-A. As shown in Table 9A-1 the thyroid dose consequences of the boiling pool are well below the guideline values of 10CFR50.67 and the 0.5 REM TEDE thyroid guideline.

Subsection 9.1.2.2 provides the logic which shows that the spent fuel pool will not drain following an SSE.

QUESTION 010.12

Confirm that a spent fuel pool water temperature of 125°F is maintained when the fuel pool cooling system is used to cool the emergency heat load.

RESPONSE:

A spent fuel pool water temperature of 125°F is maintained when the fuel pool cooling and cleanup system (FPCCS) is used in conjunction with the RHR cooling system to cool the emergency heat load. Refer to revised section 9.1.3.1 for FPCCS design basis.

QUESTION 010.13:

Based on information provided in your FSAR, it appears that either the spent fuel pool is capable of storing over 2 1/2 full cores or has a storage capacity for 4 1/2 full cores. State the design bases storage capacity provided for the spent fuel pool.

RESPONSE:

The storage capacity design basis for the spent fuel pool are provided in revised FSAR Section 9.1.2.1.3. Ambiguities upon this matter have been removed from the text.

QUESTION 010.14

The decay heat during normal (1/4 full core load, plus previous refueling loads) storage conditions has not been provided. Assuming that fuel assemblies from 1/4 of a full core load are placed in the pool 7 days after reactor shutdown and the remaining storage spaces are filled with spent fuel from previous refuelings, reevaluate the spent fuel pool cooling system's and the residual heat removal system's capability using the heat loads determined by the methods set forth in Branch Technical Position ASB 9-2, "Residual Decay Energy for Light Water Reactors for Long Term Cooling." Also, reevaluate the systems capability for the emergency (1 full core unloaded from the reactor 7 days after shutdown plus the normal refueling load that has been in the pool for 30 days) storage condition. For both the normal and emergency storage condition stage the maximum decay heat load, the maximum spent fuel pool temperature, and provide the time required to raise the temperature of the pool to boiling assuming the cooling systems are not available.

RESPONSE:

The decay heat during normal storage conditions and the maximum spent fuel pool temperature using the fuel pool cooling system only is given in Subsection 9.1.3.1.

For the normal storage conditions, the maximum decay heat load, maximum spent fuel pool temperature and time to boiling are provided in the dose release calculation of Appendix 9-A.

The emergency storage condition is discussed in Subsection 9.1.3.1.

QUESTION 010.15

Our criteria for safety related cooling systems is that sufficient cooling must be provided for at least 30 days: (1) to permit simultaneous safe shutdown and cooldown of both nuclear reactor units and maintain them is a safe shutdown condition, or (2) to mitigate the consequences of an accident in one unit and a safe shutdown and cooldown in the other unit and maintain it in a safe shutdown condition. Expand table 9.2-5 in the FSAR to cover this 30 days time span.

RESPONSE:

Table 9.2-5 has been revised to cover this 30 day time span.

QUESTION 010.16

The emergency service water system (ESWS) is designed to take water from the spray pond and provide cooling to safety related components during safe shutdown and accident conditions. During safe shutdown or the loss of offsite power non-safety related components are cooled by the ESWS. Demonstrate that the safety function of the system will not be affected assuming a failure in the non-safety related portion of the system coincident with a single failure in the safety related portion of the system. Also, provide an evaluation of the effects of flooding on safety related components.

RESPONSE:

See revised FSAR Section 9.2.

QUESTION 010.17

The reactor building closed cooling water (RBCCW) heat exchanges and turbine building closed cooling water (TBCCW) heat exchanges are not designed to seismic Category I requirements. However, these components are cooled by the safety related emergency service water system and isolated by a single isolation valve. This does not meet the single failure criterion. Revise your design to meet single failure.

RESPONSE:

See revised FSAR Section 9.2.

QUESTION 010.18

In order to permit an assessment of the Ultimate Heat Sink, provide the results of an analysis of the thirty-day period following a design basis accident in one unit and a normal shutdown and cooldown in the remaining unit, that determines the total heat rejected, the sensible heat rejected, the station auxiliary system heat rejected, and the decay heat release from the reactors.

In submitting the results of the analysis requested, include the following information in both tabular and graphical presentations:

(1) The total integrated decay heat.

(2) The heat rejection rate and integrated heat rejected by the station auxiliary systems, including all operating pumps, ventilation equipment, diesels, spent fuel pool makeup, and other heat sources for both units.

(3) The heat rejection rate and integrated heat rejected due to the sensible heat removed from containment and the primary system.

(4) The total integrated heat rejected due to the above.

(5) The maximum allowable inlet water temperature taking into account the rate at which the heat energy must be removed, cooling water flow rate, and the capabilities of the respective heat exchangers.

(6) The required and available NPSH to the Emergency and RHR service water pumps at the minimum Ultimate Heat Sink water level.

The above analysis, including pertinent backup information, is required to demonstrate the capability to provide adequate water inventory and provide sufficient heat dissipation to limit essential cooling water operating temperatures within the design ranges of system components.

Use the methods set forth in Branch Technical Position ASB 9-2, "Residual Decay Energy for Light Water Reactors for Long Term Cooling," to establish the input due to fission produce decay and heavy element decay. Assume an initial cooling water temperature based on the most adverse conditions for normal operation.

RESPONSE:

The results of the analysis requested are presented in graphical form in Figure 9.2-21*.

Part 5. The maximum allowable inlet water temperature is discussed in Subsection 9.2.7.3.1, 9.2.7.3.6, Table 9.2-12, and Figure 9.2-21; and the initial pond temperature is identified in Table 9.2-23 and Figure 9.2-21. The initial cooling water temperature is based on the most adverse meteorological conditions.

Part 6. Vertical pump suction requirements are normally measured in submergence. The bottom of the pond is higher than the minimum submergency required by the pumps (refer to Subsections 9.2.5.1, 9.2.6.1, and 2.4.11.5).

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* Tabular results of the analysis and graphical and tabular heat load data for uprated conditions were not included in FSAR Revision 49 (power uprate).

QUESTION 010.19

Sufficient information is not available for us to evaluate the plant safe shutdown capabilities from internal flooding of the engineered safeguard service water pumphouse. For a moderate energy leakage crack in the residual heat removal service water system piping or emergency service water system piping, determine the effects of flooding on the safety-related pumps located within the pump cubicle, assuming 30 min. for any operator action. Also, describe any communication pathways between service water system pumps cubiels for loops A and B.

RESPONSE:

Subsection 9.2.7.3 has been revised to include this information.

QUESTION 010.20

The Reactor Building chilled water system is designed seismic Category I from the isolation valve outside containment to piping just inside containment. Figure 9.2-13B in the FSAR does not show any safety related valving inside containment for system isolation. The system and components inside containment and outside the containment penetrations are not seismically designed. The rupture of these non-seismic lines, plus a single active failure of the isolation value outside containment would cause a breech of containment. Provide the required isolation valves inside containment.

RESPONSE:

Table 6.2-22 and Dwg. M-187, Sh. 2 of the FSAR have been modified to show the required isolation valves inside containment.

QUESTION 010.21

Your FSAR does not evaluate the effects of an expansion joint failure at the condenser. Expand the information provided to include an evaluation regarding the effects of possible circulating water system failure inside the turbine building. Include the following:

(1) The maximum flow rate through a completely failed expansion joint.

(2) The potential for and the means provided to detect a failure in the circulating water transport system barrier such as the rubber expansion joints. Include the design and operating pressures of the various portions of the transport system barrier and their relation to the pressures which could exist during malfunctions and failures in the system (rapid valve closure).

(3) The time required to stop the circulating water flow (time zero being the instant of failure) including all inherent delays such as operator reaction time, drop out times of the control circuitry and coastdown time.

(4) For each postulated failure in the circulating water transport system barrier give the rate of rise of water in the associated spaces and total height of the water when the circulating water flow has been stopped for overflows to site grade.

(5) For each flooded space provide a discussion, with the aid of drawings if necessary, of the protective barrier provided for all essential systems that could become affected as a result of flooding. Include a discussion of the consideration given to passageways, pipe chases and/or the cableways joining the flooded space to the spaces containing safety related system components. Discuss the effect of the flood water on all submerged essential electrical systems and components.

RESPONSE:

For response see revised Subsection 10.4.1.3.

QUESTION 010.22

The Standard Review Plan, Section 9.1.4, part II provides guidelines for a fuel handling system. The fuel handling platform bridge and its subcomponents such as crane rails, clamps and clips are not excluded from a system's approach. They perform a safety related function, i.e. position fuel and limit the displacement of the fuel handling platform during a seismic event. Your FSAR Volume II, page 9.1-17 identifies the fuel handling platform as a safety Class 2, seismic category 1 piece of equipment and discusses its seismic requirements. There are no departures or exceptions identified in the FSAR.

On the basis of the above, please indicate your intent to upgrade the crane rails, rail clips and clip plates to meet the requirements of 10 CFR Part 50 Appendix B or provide your justification for retaining your present design. Your justification should include the consequences of the failure of these items or show that failure of any of these items will not result in damage to the fuel.

RESPONSE:

The crane rails, rail clips, and clamps have been classified as safety-related (see revised subsection 9.1.4.1).

QUESTION 010.23

Your response to Q010.1 and Q010.2 regarding pressure loadings in compartments within the reactor building does not address differential pressure loadings upon interior walls. While we think it unlikely that the exterior walls of the reactor building will be severely effected we remain concerned with the behavior of the interior walls. The impact of possible structural degradation of interior reactor building walls has implications with regards to safety related equipment. Your response should be expanded to support your conclusions that the differential pressure upon interior walls can be neglected.

RESPONSE:

The interior walls in the reactor building are designed to withstand without structural degradation, differential pressures arising from

1) Water flooding and

2) steam pressures from high energy line breaks as described in our response to Questions 010.1 and 010.2

Table 3.8-8 lists the loading combinational formulas used for Reactor Building interior partitions. The symbol "R" as defined in Table 3.8-2 incorporates the effects of differential pressure loads and is considered an abnormal load.

The room pressures given in the responses to Q010.1 and Q010.2 were incorporated in the interior wall loadings. Hence, interior walls will not fail due to room pressurization.

QUESTION 010.24

We have reviewed your response to Q010.6 and find it unacceptable. We will require an interlock so that the leakage control system actuation valves can be opened only if the associated MSLIV is in a fully closed position. (See Regulatory Guide 1.96.) Please modify your response accordingly.

RESPONSE:

Regulatory Guide 1.96 Rev. 1 has been interpreted to require backfitting only for BWR 6. As such this backfitting does not apply to SSES.

NOTE:

MSIV-LCS information maintained here for historical purposes. The MSIV-LCS has been deleted. The function is now performed by the Isolated Condenser Treatment Method (Section 6.7).

QUESTION 010.25

Your response to Q010.5 for the cranes for Unit 1 and Unit 2 crane is unacceptable. The Unit 1 and 2 cranes do not meet Branch Technical Position APCSB 9-1.

Please reevaluate the design of your cranes in line with APCSB 9-1 and modify your response accordingly.

RESPONSE:

Our response to Q010.5 is now Appendix 9B of the FSAR. Four items are indicated as not complying with APCSB 9-1. These four items have been evaluated against NUREG-0554, "Single Failure Proof Cranes for Nuclear Power Plants," dated May 1979 and issued by the Division of Engineering Standards, Office of Standards Development, and are summarized below.

Further comments on our positions may be found in FSAR Section 3.13 under Regulatory Guide 1.104.

A. Fleet Angles

NUREG-0554 Section 4.1 allows fleet angles up to 3 1/2 . The reactor building crane fleet angle is 3 7'. We agree with the NUREG that this angle has proven to be reliable in service and is an acceptable design.

B. 200% Static Test

NUREG-0554 section 8.2 recommends a 125% load test as does ANSI B.30.2. The RB crane is rated at 125 tons to yield a test weight of 156 tons. The maximum anticipated load is a spent fuel shipping cask weighing 100 tons. This results in a effective 156% static load test.

C. Bridge & Trolley Speeds

NUREG-0554 refers to C.M.A.A. Specification 70, Figure 70-6 for recommended bridge and trolley speeds. As noted above, the maximum lift weight anticipated is 100 tons although the crane's rated capacity is 125 tons.

From the CMAA figure, at 100 tons the suggested trolley slow speed is 50 fpm as is the suggested bridge slow speed. These numbers are identical to our maximum speeds.

D. Two Blocking

We reiterate our position stated in Appendix 9B, item #14; this test is unnecessary due to the protective devices installed, it is hazardous to testing personnel, and it has the potential of causing undetected damage to hoist components. Verification testing of the upper limit switches and the motor overloads will be performed to assure their proper functioning.

Summary

A review of the Branch Technical Position as well as other industry and NRC standards reveals no design feature or test procedure, that in our judgement, requires modification.

QUESTION 010.26

The potential for a partial density moderator (i.e. fire fighting foam) to reach the fresh fuel is a criticality concern. Provide details of the cover that protects the fresh fuel racks which show how effective the seals of the cover plates would be in preventing this unlikely event.

RESPONSE:

Details of the new fuel vault covers are shown in the new Figure 9.1-2. Design features are discussed in the new text added to Subsection 9.1.1.3.2.

Also, no fire fighting foam systems are installed anywhere in the plant.

QUESTION 021.01

Provide the following additional information for the secondary containment:

(1) Show an appropriate plant elevation and section drawings, those structures and areas that will be maintained at negative pressure following a loss-of-coolant accident and that were considered in the dose calculation model;

(2) Provide the Technical Specification limit for leakage which may bypass the Standby Gas Treatment System Filters, (e.g., valve leakage and guard pipe leakage); and,

(3) Discuss the methods of testing that will be used to verify that the systems provided are capable of reducing to and maintaining a negative pressure of 0.25", e.g., within all secondary containment volumes.

RESPONSE:

1) Following a loss-of-coolant-accident, all affected volumes of the secondary containment will be maintained at negative pressure. All these volumes are identified on Figures 6.2-24, 6.2-25, 6.2-26, 6.2-27, 6.2-28, 6.2-29, 6.2-30, 6.2-31, 6.2-32, 6.2-33, 6.2-34, 6.2-35, 6.2-36, 6.2-37, 6.2-38, 6.2-39, 6.2-40, 6.2-41, 6.2-42, and 6.2-43 as ventilation zones I, II and III. Also see Subsection 6.5.3.2 for a discussion of the reactor building recirculation system.

2) See Technical Specifications 3/4.6.5.3 for the limiting conditions for operation and the surveillance requirements for the SGTS. All leakage into the secondary containment is treated by the SGTS. Refer to Subsection 6.2.3.2.3 for a discussion of containment bypass leakage.

3) The Standby Gas Treatment System (See Subsection 6.5.1.1) in conjunction with the reactor building recirculation system (see Subsection 6.5.3.2) and the reactor building isolation system (see Subsection 9.4.2.1.3) is provided to produce and maintain negative pressure within affected volumes of the secondary containment. Actuation and operation of the above systems will be used to verify that the negative pressure is established and maintained.

Each ventilation zone is provided with redundant negative pressure controllers. Low pressure side inputs (low pressure sensing elements) to these controllers are located as follows:

Ventilation Zone I - Access are of El.749'-1"
(See Figure 6.2-28)

Ventilation Zone II - Access area of El.749'-1"

Ventilation Zone III - Refueling Floor, El.818'-1"
(See Figures 6.2-30 and 6.2-40).

The quantity of air exhausted from the secondary containment will be such that in each affected ventilation zone the negative pressure will be maintained. The interconnecting ductwork of the recirculation system will equalize the negative pressure throughout each zone.

QUESTION 021.02

In accordance with the guidelines of SRP 6.2.3., provide the analysis and input assumptions used to determine the depressurization of the secondary containment for our independent review. This analysis should include a pressure time profile.

RESPONSE:

Subsection 6.2.3.2.1 has been revised to include this information.

QUESTION 021.03

For bypass leakage of the secondary containment, provide the following information:

(1) The analytical method by which this bypass leakage was calculated.

(2) Where a closed system is relied on as a barrier, discuss how it meets the requirement specified for a closed system in Branch Technical position CSB 6-3.

RESPONSE:

FSAR Subsection 6.2.3.2.3 and Table 6.2-15 have been corrected to eliminate the discrepancy mentioned in Question 312.10 and to resolve the above question.

QUESTION 021.04

For the post-blowdown depressurization analysis of the drywell, justify the heat transfer and condensation mechanisms assumed in the drywell modeling and the spray effectiveness of the ECCS spillage.

RESPONSE:

Subsection 6.2.1.1.3.3.1.5 has been revised to include this information.

QUESTION 021.05

Provide a schematic diagram showing the geometric configuration of the downcomer and describe the method used to evaluate the head loss coefficient.

RESPONSE:

FSAR Subsection 6.2.1.1.3.2 has been revised to include this information.

QUESTION 021.06

Provide a schematic diagram of a vacuum breaker including the size and describe the bases upon which the loss coefficient and vent flow area were determined.

RESPONSE:

FSAR Subsection 6.2.1.1.3.2 has been revised to include this information.

QUESTION 021.07

Provide the vacuum breaker set point and opening time corresponding to the containment depressurization rate analysis.

RESPONSE:

FSAR Subsection 6.2.1.1.3.2 has been revised to include the requested information.

QUESTION 021.08

Tables 6.2-9 and 6.2-10 present the short term (50 sec) mass and energy release rate for two postulated breaks. Provide the long-term (10^6 sec) mass and energy release rate for both recirculation line and main steam line break similar to that information presented in Tables 6.2-9 and 6.2-10.

RESPONSE:

Subsection 6.2.1.3.1 has been revised to include this information.

TABLE 021.08-1

THIS TABLE WAS DELETED

[Renumbered To 6.2-26 in Revision 39 By LDCN 1505]

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TABLE 021.08-2

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[Renumbered To 6.2-27 in Revision 39 By LDCN 1505]

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QUESTION 021.09

Provide the minimum spray water temperature used for evaluation of an inadvertent spray actuation for containment depressurization.

RESPONSE:

FSAR Subsection 6.2.1.1.4 has been revised to include this information.

QUESTION 021.10

With respect to containment steam bypass for small breaks, indicate your compliance with our proposed Branch Technical Position "Steam Bypass for Mark II Containments," which is enclosed.

RESPONSE:

A comparison of the Susquehanna SES design with your proposed BTP "Steam Bypass for MK II Containments" is presented below. The item numbers correspond with the items in the BTP.

1.a. Bypass Capability, Containment Wetwell Sprays

The wetwell spray system electrical instrumentation and controls supplied by GE meet the same ESF standards of quality, redundancy and testability as the RHR system, of which it is a part. The system is manually controlled and actuated.

The consequences of actuation of the wetwell spray on ECCS function are addressed in the response to Question 211.13.

1.b. Transient Bypass Capability Analyses

The response to this item is covered by PP&L's response to SER Open Item #25, which was resolved as documented in SSER3, Subsection 6.2.1.7.

2.a. FSAR Subsection 6.2.6.5.1.1 addresses this item.

2.b. FSAR Subsection 6.2.6.5.1.2 addresses this item.

2.c. FSAR Subsection 6.2.6.5.1.2 addresses this item.

2.d. Visual inspection will be required every 18 months.

3.a. The Susquehanna design meets the intent of this item.
See Subsection 6.2.1.1.3.2.

3.b. See Technical Specification 3/4.6.4.

With respect to compliance with the proposed Branch Technical Position "Steam Bypass of Mark II Containments," the following Susquehanna SRP position statement is respectfully provided:

Issuance of the Standard Review Plans (SRP) post-dates the Susquehanna construction permit by more than 2 years. Therefore, no attempt was made to design the plant to the requirements of the SRPs. The Susquehanna FSAR was prepared using Revision 2 of Regulatory Guide 1.70 as much as practical for a plant of its vintage, with assurance from NRC management that compliance with this Regulatory Guide assured submittal of all necessary licensing information.

As documented in a letter of August 5, 1977 from G. G. Sherwood to E. G. Case of the NRC, the SRPs constitute a substantial increase in the information required just to describe the degree of compliance of various systems. This increase in turn represents a substantial resource expenditure which is unjustified and which could cause project delays if required of these projects. As stated in the reference letter, General Electric (and PP&L) believes that SRPs should be applied to FSARs only to the extent that they were required in the FSARs.

PP&L and General Electric believe the above position, which is the essence of a directive from Ben C. Rusche, Director of Nuclear Reactor Regulation, to the NRC staff dated January 31, 1977, is the appropriate procedure for review of the Susquehanna FSAR.

QUESTION 021.11

The design and proposed operation of the Containment Purge System is not discussed in sufficient detail for our review. Provide the information per our Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operations."

RESPONSE:

FSAR Subsection 6.2.5.2 has been revised to include this information.

QUESTION 021.12

In the unlikely event of a pipe rupture inside a major component subcompartment (e.g., the annulus and head region) the initial blowdown transient would lead to nonuniform pressure loadings on both the structure and the enclosed component(s). To assure the integrity of these design features, we require that you modify Appendix 6A and 6B to fully present your compartment, multi-node pressure response analysis, and provide the following information:

(1) Provide and justify the pipe break type, area, and location for each analysis. Specify whether the pipe break was postulated for the evaluation of the compartment structural design, component supports design, or both.

(2) For each compartment, provide a table of blowdown mass flow rate and energy release rate as a function of time for the break which results in the maximum structural load, and for the break which was used for the component supports evaluation.

(3) Provide a schematic drawing showing the compartment nodalization for the determination of maximum structural loads, and for the component supports evaluation. Provide sufficiently detailed plan and section drawings for several views, including principal dimensions, showing the arrangement of the compartment structure, major components, piping, and other major obstructions and vent areas to permit verification of the subcompartment nodalization and vent locations.

(4) Provide a tabulation of the nodal net-free volumes and interconnecting flow path areas. For each flow path provide an L/A (ft^{-1}) ratio, where L is the average distance the fluid flows in that flow path and A is the effective cross sectional area. Provide and justify values of vent loss coefficients and/or friction factors used to calculate flow between nodal volumes. When a loss coefficient consists of more than one component, identify each component, its value, and the flow area at which the loss coefficient applies.

(5) Describe the nodalization sensitivity study performed to determine the minimum number of volume nodes required to conservatively predict the maximum pressure load acting on the compartment structure. The nodalization sensitivity study should include consideration of spatial pressure variation; e.g., pressure variation circumferentially, axially, and radially within the compartment. Describe and justify the nodalization sensitivity study performed for the major component supports evaluation, where transient forces and moments acting on the components are of concern.

(6) Discuss the manner in which movable obstructions to vent flow (such as insulation, ducting, plugs, and seals) were treated. Provide analytical and experimental justification that vent areas will not be partially or completely plugged by displaced objects. Discuss how insulation for piping and components was considered in determining volumes and vent areas.

(7) Graphically show the pressure (psia) and differential pressure (psi) responses as functions of time for a selected number of nodes. Discuss the basis establishing the differential pressure on structures and components.

(8) For the compartment structural design pressure evaluation, provide the peak calculated differential pressure and time of peak pressure for each node. Discuss whether the design differential pressure is uniformly applied to the compartment structure or whether it is spatially varied. If the design differential pressure varies depending on the proximity of the pipe break location, discuss how the vent areas and flow coefficients were determined to assure that regions removed from the break location are conservatively designed.

(9) Provide the peak and transient loading on the major components used to establish the adequacy of the supports design. This should include the load forcing functions [e.g., $f_x(t)$, $f_y(t)$, $f_z(t)$] and transients moments [e.g., $M_x(t)$, $M_y(t)$, $M_z(t)$] as resolved about a specific, identified coordinate system.

<u>RESPONSE</u>:

Appendix 6A has been revised to include this information.

QUESTION 021.13

Provide the projected area used to calculate these subcompartment loads and identify the location of the area projections on plan and section drawings in the selected coordinate system. This information should be presented in such a manner that confirmatory evaluations of the loads and moments can be made.

RESPONSE:

Appendix 6A has been revised to include this information.

QUESTION 021.14

With regard to all Class 1E equipment located inside the containment building such as CRD hydraulic system, reactor vessel supports and all incore instrumentation leads, we require that the environment is maintained within the temperature range for which the equipment is qualified to operate.

Indicate if the Reactor Building Ventilation System (RBVS) is required to assist in the maintaining of an acceptable temperature range. If it is, provide the following information on the RBVS:

(1) Justification for not treating this system as an ESF system.

(2) The results of an analysis that the RBVS will not be a potential source for missiles and meets our pipe whip criteria.

(3) A discussion on the operating procedures to be initiated should the RBVS be unavailable.

(4) The location of all temperature sensors associated with the operation of the RBVS.

(5) The requirements imposed on this system in order to perform all Appendix J testing.

RESPONSE:

The environment inside the primary containment is controlled by the Primary Containment Ventilation System which is described in Subsection 9.4.5. The information requested in the subparts of Question 021.14 is contained in the following paragraphs:

Question	FSAR Subsection
021.14(1)	9.4.5.1(d)
021.14(2)	9.4.5.2 & 9.4.5.1(d)
021.14(3)	9.4.5.3
021.14(4)	9.4.5.2 & 7.6.1b.1.2.4
021.14(5)	9.4.5.2

QUESTION 021.15

We note that there is an approved topical report on your recombiners. Provide the proper references on this subject.

RESPONSE:

FSAR Subsection 6.2.5.4 has been revised to include the proper references.

QUESTION 021.16

Provide the seismic class and quality group of the hydrogen monitoring system.

RESPONSE:

See revised Table 3.2-1.

QUESTION 021.17

Section 6.2.5.2, states that all hydrogen mixing will be accomplished by the containment building ventilation system. In order to evaluate this system, we will require detailed layout drawings showing all ventilation ductwork, including intake and exit ports in order to establish circulation paths that will support your mixing assumptions.

RESPONSE:

Subsection 9.4.5.2 has been revised to include this information.

QUESTION 021.18

Identify (1) the location of the hydrogen sample points in the drywell and suppression chamber and (2) location of CGCS suction and discharge points, with respect to local structures and equipment.

RESPONSE:

FSAR Subsection 6.2.5.2 has been revised to include the requested information.

QUESTION 021.19

Discuss and schematically show the design provisions that will permit the personnel airlock door seals and the entire air lock to be tested. Discuss the design capability of the door seals to be leak tested at a pressure of Pa; i.e., the calculated peak containment internal pressure. If it will be necessary to exert a force on the doors to prevent them from being unseated during leak testing, describe the provisions for doing this and discuss whether or not the mechanism can be operated from within the air lock. Also, discuss how the force exerted on the door will be monitored.

RESPONSE:

Subsection 6.2.6.2 and Table 6.2-22 have been revised and Figures 6.2-58-1, 6.2-58-2 and 6.2-59 have been added to supply the requested information.

QUESTION 021.20

Identify the types of insulation used within the containment (e.g., reflective metal insulation, mass insulation, and encapsulated (sheathed) mass insulation) and discuss the methods of attachment to piping and components. Estimate, for a representative break location, the amount of insulation material that would be removed from the pipes by a LOCA. On the basis of the properties and characteristics of this material determine the locations it would accumulate and in what form. Discuss the potential for loose insulation and other debris to clog drains leading to the sump and the sump screening.

RESPONSE:

FSAR Subsection 6.2.2.3 has been revised to include this information.

QUESTION 021.21

We are aware that revision 3 to the DFFR is to be submitted this Summer and that Revision 2 which is now referenced is out-of-date, as it does not adequately reflect the status of current pool dynamic loads. Discuss how the DAR will be updated to reflect this status and discuss any other reports you intend to submit to document your plant design.

RESPONSE:

PP&L is working with the other Mark II owners to develop methodologies, analytical programs and test data which will provide improved definitions of hydrodynamic loads. This effort has resulted in Revision 3 to the DFFR, and is expected to result in further revision to that report.

Future revisions to the DFFR are expected to have no effect on the SSES DAR, since plant specifics as well as generic Mark II methodologies applicable to SSES will be incorporated into the DAR. The DAR has been updated to reflect the current design assessment methodologies used at SSES.

QUESTION 021.22

Based on our review of the information presented in subsection 6.2.1.5 of the FSAR, we find that the discussion of steam bypass from the drywell to the wetwell for a small break is incomplete and does not conform to the enclosed branch technical position (BTP) titled "Steam Bypass for the Mark II Containment." Accordingly, provide the appropriate discussions, justifications, and analyses to demonstrate compliance with the BTP.

RESPONSE:

Compliance with this Branch Technical Position was assessed in the response to Question 021.10. Please refer to this response for the information being requested.

QUESTION 021.23

The response to Item 021.05 is inadequate. Provide a detailed calculation of the friction loss coefficient for the entire vent system. Discuss whether the results of the 4-T tests have been used to confirm the vent loss coefficient calculated. State the margin applied to the friction loss coefficient to account for any difference between the Susquehanna vent design and that of the 4-T facility.

RESPONSE:

The calculation method for the friction loss coefficient is provided in a new FSAR subsection 6.2.1.1.3.2.1. The results of the 4T tests were not used to confirm the vent loss coefficient used for SSES. The vent system used in the 4T test is not prototypical of the SSES design and thus can not be applied directly to analyze the SSES design.

QUESTION 021.24

The response to Items 021.6 and 021.7 regarding the vacuum breaker is incomplete with regard to the vacuum breaker set point and opening time and the bases upon which the loss coefficient and vent flow area were determined. Provide the requested information and in addition:

(1) Describe the preoperational and inservice tests that will be performed to verify proper pressure setpoint and opening time; and

(2) Provide the sensitivity limits and hysteresis characteristics of the switches. Provide a discussion and the results of analysis performed to determine the maximum opening between valve disc and seat from when the position indicator system indicates that the valve is closed.

RESPONSE:

Subsection 6.2.1.1.3.2 has been revised to address this question.

QUESTION 021.25

Section 6.2.1.1.4 of the FSAR states that the containment negative pressure is addressed in the Design Assessment Report. However, the information as provided is insufficient to allow an independent evaluation. Therefore, provide the analysis, including the thermodynamic model assumptions and the parameters used for the drywell cooldown transients that were performed to establish the containment negative pressure.

RESPONSE:

This analysis is provided in revised Subsection 6.2.1.1.4.

QUESTION 021.26

Discuss in detail the design provisions incorporated for periodic inspection and operability testing of the containment heat removal systems' components such as pumps, valves, duct pressure-relieving devices and spray nozzles.

RESPONSE:

The design provisions incorporated for periodic inspection and operability testing of the pumps and valves in the containment heat removal system are discussed in Subsection 6.2.2.4.

Preoperational testing of the containment spray nozzles is discussed in Section 6.2.2.2. The spray nozzles will not be tested periodically.

There are no ducts, and hence no duct pressure-relieving devices, in the containment heat removal system.

QUESTION 021.27

Provide a detailed analysis of the available net positive suction head for the RHR pumps that are used as part of the containment heat removal system to demonstrate compliance with Regulatory Guide 1.1, "NPSH for Emergency Core Cooling and Containment Heat Removal Systems Pumps." Specify the required NPSH of the pumps.

RESPONSE:

The requested information is contained in revised subsection 6.3.2.2.4.1 of the FSAR.

QUESTION 021.28

Describe the sizing analysis performed for the RHR suction screens. Provide a drawing that shows the suction screen assembly.

RESPONSE:

The requested information is given in revised FSAR Subsection 5.4.7.2.2.

QUESTION 021.29

Estimate, for a representative break location, the amount of insulation that would be removed from pipes as a result of a LOCA. On the basis of the properties and characteristics of these materials, determine the locations it would accumulate and in what form and whether or not there is a potential for inhibiting suction flow due to clogging of the strainers.

RESPONSE:

For a complete response to this question see the response to Question 021.20.

QUESTION 021.30

Provide an analysis of the pressure and temperature response in the secondary containment due to a postulated LOCA in the primary containment. Discuss and justify the assumptions made in the analysis and specify the design leakage rate of the reactor building.

RESPONSE:

This question is similar to NRC question 021.02 which requested a post-LOCA pressure profile and design leak rate for the secondary containment. Question 021.02 has been answered in full in FSAR Section 6.2.3.2.1.

In addition, Question 021.30 requests the post LOCA temperature in the secondary-containment. The temperature response is given in Dwgs. C-1815, Sh. 4, C-1815, Sh 5, C-1815, Sh. 6, C-1815, Sh. 7, C-1815, Sh. 8, C-1815, Sh. 9, C-1815, Sh. 10, C-1815, Sh.11 and C-1815, Sh. 12.

QUESTION 021.31:

Identify all openings provided for gaining access to the secondary containment, and discuss the administrative controls that will be exercised over them. Discuss the instrumentation to be provided to monitor the status of the openings and whether or not the position indicators and alarms will have readout and alarm capability in the main control room.

RESPONSE:

1) Secondary Containment Access Openings:

Door Nos	Elev.	Col. Coordinates	Security Monitored
101	670	U/29	Yes
102	670	U/37.4	Yes
103-0	670	U/20.6	Yes
104-0	670	U/29	Yes
119A	676	P/20.6	Yes
120A	676	P/37.4	Yes
571-0	818	P/32	Yes

Roof Hatch @ Elev. 872, coordinates: P/37.4 (Security Monitored)

2) Doors #119A, 120A and 571-O provide access into the secondary containment through the use of card reader/cipher keyboard control. Doors 101, 102, 108-0, 104-0 and the roof hatch (#4001) will not normally be used to gain access into the secondary containment. All transactions will be logged into the Susquehanna Security Computer System. All alarms generated will annunciate at both the Security Control Center (SCC) and Alternate Security Control Center (ASCC). The plant control room will not have a readout or alarm capability. Both the SCC and ASCC are, however, manned continuously 24 hours a day.

Instrumentation to control and monitor the status of secondary containment is described in Chapter 7.0 of the Susquehanna SES Physical Security Plan.

QUESTION 021.32

The following additional information related to potential bypass leakage paths is needed to provide an adequate response to Item 021.03.

(1) Expand Table 6.2-15 to include any branch lines which penetrate the secondary containment and connect to system lines which penetrate primary containment.

(2) For each line in (a), identify each of the potential leakage barriers;

(3) For each air or water seal, perform an analysis that will demonstrate that a sufficient inventory of the fluid is available to maintain the seal for 30 days, and describe the testing program and proposed entries for the Technical Specifications that will verify the assumptions used in the analysis. Provide the basis for the valve fluid leakage used in the analysis;

(4) For each of these paths where water seals eliminate the potential for bypass leakage, provide a sketch to show the location of the water seal relative to system isolation valves;

(5) Table 6.2-15 does indicate that the combustible gas sampling system is eliminated as bypass leakage paths. Show how this system meets each of the requirements specified in Branch Technical Position, CSB 6-3, Section 9a-f, for a closed system;

(6) Table 6.2-15 does not appear to list all potential bypass leakage paths (e.g., steam to RCIC system). Therefore, provide a list of all containment penetrations and seals which do not terminate in the secondary containment and an evaluation of these lines as delineated in the Branch Technical Position, CSB 6-3, "Determination of Bypass Leakage Paths in Dual Containment Plants";

(7) Table 6.2-22 indicates that the feedwater lines and purge exhaust are secondary containment bypass leakage paths; Table 6.2-15 indicates the opposite. Discuss the discrepancy.

(8) The statement is made in Section 6.2.3.2.3 that no bypass leakage will occur following the design basis LOCA. Table 6.2-15 identifies those lines penetrating the primary containment which do not terminate inside the secondary containment and are considered as potential bypass leakage paths. Explain the inconsistency.

RESPONSE:

Each of the eight parts of the question is discussed on the pages indicated below:

(1) Branch lines are discussed in subsection 6.2.3.2.3 and listed in Table 6.2-15.

(2) See Table 6.2-15.

(3) Water inventory for water seals used to prevent bypass leakage is discussed in subsection 6.2.3.2.3.1.

(4) The locations of water seals relative to the containment isolation valves are shown on system P&IDs. Appropriate cross-references are provided in Tables 6.2-15.

(5) The combustible gas sampling system is located entirely within the secondary and primary containments and thus can not lead to bypass leakage.

(6) All potential bypass leakage patches are listed in Tables 6.2-15.

(7) See Subsection 6.2.3.2.3.

(8) Subsection 6.2.3.2.3 has been amended.

QUESTION 021.33

The penetrations taken from Table 6.2-12 and listed below and the corresponding valve arrangement in Figure 6.2-44 are not consistent. Please clarify these inconsistencies. The penetrations are: X - 10, 11, 13A, 19, 23, 24, 36, 53, 54, 55, 56, 85 - A & B, 86 - A & B, and 215.

RESPONSE:

Table 6.2-12 and Figure 6.2-44 have been revised to resolve all of the discrepancies noted.

QUESTION 021.34

Section 6.2.4 of the FSAR, "Containment Isolation System," should be augmented to provide the justification for any penetration including branch lines which do not conform to the requirements of the General Design Criteria. In addition, provide the containment isolation rationale for your design (e.g., RHR pump suction).

RESPONSE:

The "Remarks" column of Table 6.2-12, along with the corresponding notes at the end of the table, discusses non-conformances to the General Design Criteria.

See also the responses to NRC Questions 021.38 and 021.39. The response to Question 021.50 discusses the rationale for non-conformance to the leak rate testing requirements of 10CFR50 with respect to certain penetrations.

QUESTION 021.35

Standard Review Plan 6.2.4, "Containment Isolation Systems," states that provisions should be made to allow the operator in the main control room to know when to isolate systems that require remote-manual isolation. Expand Table 6.2-12 to identify for those systems that rely on remote-manual isolation and the leakage detection provisions for these systems to assure that adequate information is available to the operator for identifying the affected line and for isolating it.

RESPONSE:

FSAR Subsection 6.2.4.2 has been revised to include this information.

QUESTION 021.36

(1) The statement is made in Section 6.2.4.1 of the FSAR that instrumentation lines are designed to the provisions of Regulatory Guide 1.11. Provide the analysis performed which demonstrates that in the event of a rupture of the instrument lines and/or any component in the line outside the primary containment, the integrity and functional performance of secondary containment and its associated filtration systems are maintained.

(2) Revise Table 6.2-12 to include the isolation provisions for instrumentation lines penetrating the primary containment.

RESPONSE:

(1) Instrument lines which penetrate reactor containment incorporate design features provided for complying with Regulatory Guide 1.11, as discussed in subsection 6.2.4.3.5.

FSAR Section 15.6.2 analyzes the consequences of an instrument line break outside primary containment. Barrier performance and radiological consequences are discussed in Subsections 15.6.2.4 and 15.6.2.5, respectively. As mentioned in Subsection 15.6.2.3.1, instrument line breaks are considered to be bounded by the steam line break analyzed in Subsection 15.6-2, the postulated steamline break occurs within secondary containment; consequently, the steam tunnel blowout panels would relieve the pressure to the environs. Therefore, it can be seen that secondary containment is not required for pipe breaks outside containment. Note also that the pressure-temperature analyses in Appendix 3.6A which verify that, with blowout panels, structural integrity is maintained for high energy pipe breaks outside primary containment.

(2) See new Table 6.2-12 (a).

QUESTION 021.37

Revise Table 6.2-12 to include the isolation provisions for the following penetrations X-35B, 36, 37A, 38A, 41, 42, 88 and 93.

RESPONSE:

Table 6.2-12 has been updated to include the requested information.

Penetration X-35B is a capped spare penetration.

The CRD hydraulic system return line has been deleted. Therefore, no containment isolation provisions are required for penetration X-36.

QUESTION 021.38

Table 6.2-12 indicates that the isolation provisions for the containment spray system (X-39A, 205A), the floor drain (X-72A), the equipment drain (X72B), the RHR pump suctions (X-203A,C), the RHR pump test line and containment cooling (X-204A), the core spray pump suction (X-206A), core spray pump test and flush (X-207A), core spray min. recirculation (X-208A), HPCI pump suction (X-209) RCIC pump suction (X-214), RHR min. recirc. (X-226A), suppression pool clean up and drain (X-243) and RHR relief valve discharge (X-246A) conform to the requirement of General Design Criteria 54. It is our position that the isolation provision to these lines should meet the requirement of GDC 56. However, a single isolation valve outside containment is acceptable as discussed in Standard Review Plan 6.2.4, II.3.e. Revise Table 6.2-12 to reflect our position and indicate if the other acceptable alternative for meeting the requirement of the GDC as specified in the SRP could be applied to any of these lines.

RESPONSE:

The isolation provisions for the lines listed in Question 021.38 meet the requirements of GDC56 as modified by Standard Review Plan 6.2.4. Table 6.2-12 has been revised to reflect this position. Subsections 6.2.4.3.3.7, 6.2.4.3.3.8, and 6.2.4.3.6 have been added to discuss the alternative isolation provisions pursuant to SRP 6.2.4, paragraphs II.3.d and II.3.e.

QUESTION 021.39

Table 6.2-12 indicates that a check valve outside the containment is considered as a containment isolation valve for the standby liquid control (X-42), the HPCI pump minimum flow recirculation (X-211), the HPCI turbine exhaust (X-210), RCIC pump recirculation (X-217), the RCIC vacuum pump discharge (X-245). Provide justification for this approach.

RESPONSE:

For the standby liquid control system, the simple check valve is inside, vice outside, containment. See Figure 6.2-44, detail K.

The penetration numbers for the RCIC vacuum breaker (X-245), RCIC pump recirc (X-216), and the RCIC vacuum pump discharge (X-217) were previously given incorrectly in the table but are now correct.

The justification for the approach taken for the RCIC penetrations is given in Subsection 6.2.4.3.3.2. The justification for the approach taken for the HPCI penetrations is given in Subsection 6.2.4.3.3.3.

QUESTION 021.40

The statement is made in Section 6.2.5.2 that nitrogen gas will be used for primary containment atmosphere control. Discuss the reasons which necessitate inerting the primary containment, since the hydrogen concentration does not exceed 3.5 volume percent.

RESPONSE:

FSAR Subsection 6.2.5.2 has been revised to include this information.

QUESTION 021.41

The statement is made in Section 6.2.5.3 of the FSAR that the recombiners and purge systems are activated when the hydrogen concentration reaches 3.5 volume percent. It is our position that the combustible gases resulting from a postulated loss of coolant accident should be controlled without release of radioactive materials to the environment. Therefore, the hydrogen purge system should only be used if, as a result of a post-LOCA event, both recombiner systems fail. Revise your state to indicate conformance with this position.

RESPONSE:

Subsection 6.2.5.2 of the FSAR has been revised to indicate conformance to the above NRC position.

QUESTION 021.42

Section 6.5.3.1 of the FSAR states that the containment purge system is manually operated from the control room at the discretion of the operator. It is our position that the purge system design should satisfy Branch Technical Position, CSB 6-4, "Containment Purging During Normal Plant Operation," if it is used during the reactor operational modes of power operation, startup, hot standby and hot shutdown, or the purge line isolation valve should be locked closed. Therefore, propose a purge system design that complies with the design provisions of the BTP. Also, provide the analysis identified in the BTP if the purge system is used during the operational modes specified above.

RESPONSE:

The information requested in this question was provided in response to NRC question 021.11 in Rev. 1 (8/78) to the FSAR.

QUESTION 021.43

The response to Question 021.14 is incomplete with regard to the requirement imposed on the Reactor Building Ventilation System in order to perform all Appendix J testing. Provide this information.

RESPONSE:

In the response to NRC question 21.14 in Rev. 1 (8/78), it was pointed out that primary containment ventilation is provided by the Primary Containment Ventilation System and not the Reactor Building Ventilation System. Part (5) of the response to 21.14 referenced the FSAR section containing the Appendix J provisions of the Primary Containment Ventilation System. The Reactor Building Ventilation System provides ventilation for the secondary containment which is not subject to Appendix J requirements.

QUESTION 021.44

Table 6.2-22 identifies certain valves for which test pressure is not applied in the same direction as the pressure existing when the valve is required to perform its safety function, as required by Appendix J to 10 CFR 50. Demonstrate that the valve leakage rate is equivalent to or conservative with respect to that which would occur if the test pressure was applied in the direction when the valve is required to perform its safety function.

RESPONSE:

Because of generic BWR valve arrangements, certain isolation valves are tested in the reverse direction as indicated on Table 6.2-22. Other BWR's with similar arrangements have tested their valves in a similar manner. Table 6.2-22 has been amended to provide justification for reverse flow testing.

QUESTION 021.45

Identify those fluid lines penetrating the containment which will be vented and drained to ensure exposure of the system containment isolation valves to the containment atmosphere and the full differential pressure during the containment integrated leakage rate (Type A) test. Discuss the design provisions that will permit this to be done. Those systems that will remain fluid filled for Type A test should be identified and justification provided.

RESPONSE:

Venting and draining of those fluid lines penetrating the containment is done in accordance with the Leak Rate Test Program described in Section 6.2.6

QUESTION 021.46

Provide plan and elevation drawings of the air locks, and identify all mechanical and electrical penetrations. Discuss and schematically show the design provisions that will permit airlock door seals and the entire airlock to be tested.

RESPONSE:

Subsection 6.2.6.2 has been revised to include this information.

QUESTION 021.47

Discuss the design capability of the door seals to be leak tested at a pressure of Pa; i.e., the peak calculated containment internal pressure. If it will be necessary to exert a force on the doors to prevent them from being unseated during leak testing, describe the provisions for doing this and discuss whether or not the mechanism can be operated from within the air lock. Also discuss how the force exerted on the door will be monitored.

RESPONSE:

The information requested by this question was provided in response to NRC question 021.19 in Rev. 1 (8/78) of the FSAR.

QUESTION 021.48

Discuss your plans including the reactor building pressure sensing lines, that will become extensions of the containment boundary following a LOCA, in Type A test.

RESPONSE:

The reactor building pressure sensing lines penetrate the secondary containment boundary only. They are 1/2 inch in diameter and are used to sense the outdoor atmosphere static pressure to provide high pressure side input to differential pressure transmitters. These transmitters control the reactor building ventilation system or the SGTS, in order to maintain the secondary containment at a negative pressure. The reactor building provides the secondary means of containment after the primary containment. Only primary containment (specified by Appendix J) is subject to the requirements of Type A testing.

The subject lines would, however, be tested as part of the secondary containment negative pressure tests.

QUESTION 021.49

Closed systems outside containment having a post accident function, become extensions of the containment boundary following a LOCA. Certain of these systems may also be identified as one of the redundant containment isolation barriers. Since these systems may circulate contaminated water or the containment atmosphere, system components which may leak are relied on to provide containment integrity. Therefore, discuss your plans for specifying a leakage limit for each system that becomes an extension of the containment boundary following a LOCA, and leak testing the systems either hydrostatically or pneumatically. Also discuss how the leakage will be included in the radiological assessment of the site.

RESPONSE:

Closed systems outside containment which become extension of the RCPB post-LOCA are listed in Table 6.2-21. Containment leak rate testing of these systems is discussed in Subsection 6.2.6.1 and Table 6.2-22. Leakage limits are established in the Leak Rate Test Program to ensure that leakage is maintained within that assumed in the DBA LOCA Dose Analysis.

QUESTION 021.50

Table 6.2-22 of the FSAR indicates that exemptions to 10 CFR 50 are required for certain lines. However, the nature and the rationale for the exemption are not given. Provide this information for the following penetrations: X-10, 21, 23, 24, 85, 86A&B, 87, 93 and 218.

RESPONSE:

Table 6.2-22 has been updated to show that no exemptions are required for fluid lines at the following penetrations: X-21, 23, 24, 85 A & B, 86A&B, 87, 93 and 218. See Table 6.2-22 for nature and justification of exemption requested for penetration X-10.

QUESTION 021.51

Based on our review of the information presented in Subsection 6.2.1.1.5 of the FSAR and the responses to Questions 021.10 and 021.22, we find that your discussion of steam bypass from the drywell to the wetwell for a steam line break to be unacceptable. In your response you indicated that the requested information represents a substantial resource expenditure, which is unjustified because the information is required only to describe the degree of compliance of various systems. We find this not to be the case. The staff's position that was attached to Item 021.11 is intended for implementation on all Mark II containments because of its safety significance.

In addition, you stated in your response to 021.10 that Ben C. Rusche's directive to the NRC staff dated January 31, 1977 is the appropriate procedure for review of the Susquehanna FSAR. It should be noted that the referenced letter concerns documentation of departures from the Standard Review Plan. Question 021.10 was forwarded to you specifying our position that the Susquehanna containment should be designed to have a steam bypass capability as characterized in Appendix I to Standard Review Plan 6.2.1.1.c. (It should be noted that Appendix I has been previously forwarded with Question 021.22 as Branch Technical Position CSB 6-X). Accordingly, provide the appropriate discussions, justifications and analyses to demonstrate compliance with the Appendix I to SRP 6.2.1.1.c.

RESPONSE:

See revised response to Question 21.10.

QUESTION 021.52

Section 6.2.1.1.3.2 of the FSAR indicates that the loss coefficient of the vacuum breaker was calculated based on actual flow measurements conducted in the manufacturer's shop. Discuss the applicability of the test performed (e.g., flow regime) considering the conditions that are expected in the containment when the vacuum breaker is required to operate.

Provide a diagram showing the locations of the vacuum breakers relative to the downcomer and the floor slab. Discuss your plan to comply with the requirement (Item 3.b) of Appendix I to SRP 6.2.1.1.C.

RESPONSE:

A. The applicability of the vacuum breaker loss coefficient test is discussed in Subsection 6.2.1.1.3.2.2.

B. Figure 6.2-56 shows the vacuum breaker flange connection to the downcomer. The location of the vacuum breaker relative to the diaphragm slab is also shown in this figure.

C. The degree of compliance with Item 3.b of Appendix I to SRP 6.2.1.1.c was discussed in response to Question 021.10.

QUESTION 021.53

The response to Item 021.32(4) references system P&ID's which do not show the location of the water-seal relative to the system isolation valves; provide a sketch to show these elevations for each path where water seals eliminate the potential for bypass leakage.

RESPONSE:

Figures 6.2-66B, 6.2-66C, 6.2-66D, 6.2-66E, 6.2-66F have been provided to show the location of water-seals relative to the system isolation valves. The elevations, pipe quality group and the seismic classification have been provided in the sketches.

QUESTION 021.54

The statement is made in Subsection 6.2.3.2.3 of the FSAR that closed systems are not relied upon as barriers to eliminate bypass leakage. It was further stated that isolation valves inside or outside the primary containment are considered to limit but not to eliminate bypass leakage. It appears that some of the lines listed in Tables 6.2-15a (e.g., RBCCW) have been eliminated as potential bypass leakage paths because of either or both of the above mentioned statements. Provide clarification for this apparent discrepancy. In addition, provide the quality group and seismic qualification of the closed systems that are relied upon to eliminate bypass leakage.

RESPONSE:

See Subsection 6.2.3.2.3

QUESTION 021.55

Item 2 on page 6.2-36a of the FSAR provides justification for elimination of the RWCU line (DBA-101) as a bypass leakage path. Similarly, provide the justification for line EBC-104.

RESPONSE:

See Subsection 6.2.3.2.3 and Table 6.2-15.

QUESTION 021.56

Note 8 in Table 6.2-12 of the FSAR indicates that the valve isolates two piping penetrations. Provide a sketch to show the typical arrangement and discuss how such an arrangement meets the General Design Criteria.

RESPONSE:

Details have been added to Figure 6.2-44 to show the arrangement of the valves, associated with the penetrations to which Note #8 applies.

The General Design Criteria do not forbid the use of a common isolation valve; the Criterion met by each of the subject penetrations is listed in Table 6.2-12.

QUESTION 021.57

Provide justification for using a check valve outside the containment as a containment isolation valve for the following penetrations; X-210, 211, 214, 215, 216 and 217.

RESPONSE:

As stated in the response to NRC Question 021.39, the justification for using check valves outside containment for the identified penetrations is given in Subsections 6.2.4.3.3.2 and 6.2.4.3.3.3.

Note that the outside containment isolation valve for penetration X-214 is a gate valve, not a check valve.

QUESTION 021.58

Item II.6 of Standard Review Plan 6.2.4, "Containment Isolation Systems," requires diversity in parameters sensed for initiation of containment isolation. Provide justification for not having diversity in the parameters sensed to initiate isolation of the following lines; X-121, 35-B, 208A, 211, 215, 216, 217, 226A and 246A.

RESPONSE:

The requested information has been provided in the appropriate subparagraphs of FSAR Subsection 6.2.4.

QUESTION 021.59

With regard to the control rod drive system provide the following information:

(1) The piping integrity test to detect any leakage from the hydraulic control unit;

(2) The type and number of valves and method of actuation on the charging water, drive water and cooling water;

(3) The type of indicators available to the operator to indicate any leakage;

(4) Whether the CRD system is vented during the performance of the type A test; and

(5) The proposed Technical Specification limit on leakage through the hydraulic control unit.

RESPONSE:

Response to (1)

Prior to shipment, all Hydraulic Control Units (HCU) are hydrostatically tested in accordance with the applicable code(s) of construction (Reference Table 3.2-1).

Appropriate portions of the CRD system are ASME Code Class 2, and piping integrity is demonstrated in accordance with Section XI of the ASME Boiler and Pressure Vessel Code. See the Susquehanna SES Technical Specifications.

Response to (2)

The number and types of valves on the charging water, cooling water and drive water headers are shown on Dwgs. M-146, Sh. 1 and M-147, Sh. 1.

Response to (3)

FSAR Subsection 4.6.1.1.2.4.2 has been revised to include this information.

Response to (4)

This information is provided in FSAR Table 6.2-22 Note 20.

Response to (5)

There are no Technical Specification limits necessary for the possible leakage from the HCU. The design of the CRD system, of which the HCU are a part, is such that a loss of fluid will not prevent or inhibit the execution of the system's safety function (i.e., scram) as long as the scram accumulator operability is under Tech. Spec. control. The operational status of the accumulator is provided by the instrumentation at each hydraulic control unit which monitors the accumulator pressure and the total amount of water which may have collected on the gas side of the accumulator due to internal leakage.

QUESTION 021.60

The statement is made in Subsection 6.2.4.3.2.1 of the FSAR that the feedwater valve is remote manually closed from the control room upon operator determination that continued makeup from the feedwater system is unavailable or unnecessary. We find this approach acceptable, however, discuss the information that will be available to the operator to alert him of the need to isolate the feedwater, the time when this information would become available, and the time it would take the operator to complete this action.

RESPONSE:

For response, refer to Subsection 6.2.4.3.2.1.

QUESTION 021.61

Question 021.42 requests certain information regarding the containment purge system addressed in Section 6.5.3.1 of the FSAR. Your response to that question and to Question 021.11 is related to the containment hydrogen purge system. Provide the information requested in 021.42.

RESPONSE:

Subsection 6.5.3.1 has been revised to provide this information. Refer to this Subsection for response to this question.

QUESTION 021.62

The response to Question 021.44 does not provide enough justification for the testing of certain containment isolation valves in the reverse direction. Therefore provide the following information:

(1) The method by which these penetrations are to be tested and how the leakage will be assigned to that penetration (i.e., if test pressure is between the valves and the total leakage is assigned to that penetration);

(2) Justification that the isolation valves have similar leakage characteristics in both the forward and reverse direction for those penetrations discussed in item a above; and

(3) Justification that these testing methods will yield results at least equivalent to the case when the valve is tested in the forward direction for any other valves that will be tested in the reverse direction.

RESPONSE:

See Subsection 6.2.6.3

QUESTION 021.63

Provide the rationale for not including leakage from valves identified in Table 6.2-22, with notes 14 and/or 26 in the 0.60 La total Type B and C tests.

RESPONSE:

Refer to Subsection 6.2.6.3 for response.

QUESTION 021.64

Discuss the method by which water seals will be maintained for 30 days following LOCA. Specify the quality group and the seismic qualification of all components that are relied upon to perform this function.

RESPONSE:

The method by which water seals will be maintained for 30 days post-LOCA is discussed in Subsection 6.2.3.2.3.1. The quality group and seismic category of piping relied upon to provide a water-seal is shown on the water-seal sketches (Figure 6.2-66 B through F), and the associated P&ID's. Refer to Dwg. M-100, Sh. 2 for a key to pipe line numbers.

QUESTION 021.65

The statement is made in Subsection 6.2.6.3 of the FSAR that a factor will be applied to contaminated liquid to determine the airborne fraction that will be added to Type B and C test totals. Provide the methods by which this factor is determined.

RESPONSE:

The liquid leakage from tests of lines designed to remain filled with liquid following a LOCA will be reported as total liquid leakage. This is consistent with 10 CFR 50, Appendix J (IIIC.3) and the proposed Revision 4 of ANS N274, "Containment Systems Leakage Testing Requirements." A factor to determine the fraction of the leakage which becomes airborne cannot be determined with a large degree of accuracy due to the uncertainty of the leakage location, the water temperatures, the varying activity levels in the leaking water and the dependence on the time after the accident when the leak occurs. The dose effects of liquid leakage from lines designed to be filled with liquid for the duration of the LOCA are bounded by the analysis for ECCS system leakage given in Subsection 15.6.5.

Subsection 6.2.6.3 has been revised to delete the reference to the factor for determining the airborne fraction.

QUESTION 021.66

The statement is made in Subsection 6.2.6.5.1.2 of the FSAR that the low pressure test to determine drywell to suppression chamber atmosphere bypass area will be conducted at each integrated leakage rate test interval. This approach is unacceptable. Our position is stated in Appendix I to SRP 6.2.1.1.C. Revise the FSAR to indicate compliance with our position.

RESPONSE:

See revised Section 6.2.6.5.1.2.

QUESTION 021.67

With regard to the analysis of hydrogen production and accumulation within the containment following a postulated loss-of-coolant accident:

(1) Provide the corrosion rates for the zinc base paint and galvanized steel in this environment. In so doing provide a copy of references 6.2-7 and 6.2-8 for our review and discuss the applicability of these referenced data considering the environmental conditions that are expected following a LOCA.

(2) The staff is currently undertaking additional effort toward better defining the various sources of hydrogen, including zinc-rich paints and organic materials. The attached figure depicts the hydrogen generation rates as a function of temperature that the staff currently uses for confirmatory analysis. Provide a sensitivity study based on this figure that shows that the hydrogen concentration inside the containment will not exceed the acceptance criterion of 4 volume percent. In so doing provide the time the hydrogen recombiner should be turned on and the time needed to heat up the recombiner.

RESPONSE:

Subsection 6.2.5, "Combustible Gas Control in Containment" has been revised to provide the information required by this question. The zinc-based paint and galvanized steel corrosion rates have been provided in Table 6.2-13. The references requested by NRC have been replaced with references to non-proprietary data; thus, they have not been supplied. The heat-up time and the initiation time for the hydrogen recombiners are discussed in Subsection 6.2.5.2. Note the hydrogen recombiners are no longer credited in the accident analysis and do not have a safety related function. The equipment is still maintained safety related.

QUESTION 021.68

With regard to the secondary containment's functional capability:

(1) Discuss if there is any connection between the Unit 1 and Unit 2 secondary containments. If there is a door that separates the two secondary containments, discuss if the SGTS is capable of maintaining a 1/4" water gauge negative pressure in the affected unit's secondary containment assuming the door was open at the time of LOCA.

(2) Discuss the design provision incorporated to prevent such doors from being inadvertently opened.

(3) Discuss the test that will be performed to verify the inleakage assumption and the drawdown time for reestablishing -0.25 inches of water gauge following LOCA.

RESPONSE:

(1),(2) There is one door on elev. 779'-1" between Unit 1 and Unit 2. Since this is in Ventilation Zone III which is common to both units, it has no effect on secondary containment operation.

(3) The test procedure outlined in Subsection 4.6.5.1 of the Technical Specification will be used to verify the inleakage assumption and the drawdown time for reestablishing -0.25 inches of water gauge following a LOCA. The difference between the simulated and actual LOCA is the absence of heat transferred from the drywell head. This heat is insignificant when compared with that generated by operating equipment and lights and can be discounted. (See FSAR Subsection 6.2.3.2.1 for the analysis of the post-LOCA pressure transient in the secondary containment.)

QUESTION 021.69

The LOCA and SRV related pool dynamic loads that are currently acceptable to use are discussed in NUREG-0487. Table IV-1 of NUREG-0487 summarizes these Mark II pool dynamic loads. By letter, dated February 2, 1979, you indicated on Table IV-1 the LOCA related dynamic loads acceptable to the staff that will be adopted for SSES. Revise the DAR to incorporate this information and provide the same information for the SRV related pool dynamic loads. For both the SRV and LOCA loads indicate the alternative criteria that will be used for each item for which an exemption is proposed, and provide references that discuss these alternative criteria.

RESPONSE:

The information requested by this question was provided to the NRC by letter dated November 2, 1979, identified as PLA-417, from Mr. N.W. Curtis to Mr. Olan D. Parr.

QUESTION 021.70

Subsection 4.2.1.1 of the DAR state that the drywell pressure transient used for the pool swell portion of LOCA is based on the methodology described in NEDO-21061. Subsection III.B.3.a.6 of NUREG-0487 requires that a comparison similar to those presented in reference[1] be made if the model used is different from the model described in NEDM-10320. We require the model prior to completion of review of the pool swell calculations.

RESPONSE:

There is no methodology for calculating drywell pressures in the DFFR (NEDO-21061) and the DAR does not say that the pressure transient was based on such methodology.

The Mass and Energy Release Report results were used for calculating the drywell pressure transient using NEDM 10320 methodology.

1 Reference (1) Letter "Response to NRC Request for Additional Information (Round 3 Questions)," to J. F. Stolz (NRC-DPM) from L.J. Sobon (GE) dated June 30, 1978.

QUESTION 021.71

Subsection 4.2.2.2 of the DAR states that the chugging loads on submerged structures and imparted on the downcomers will be evaluated later. Provide the present status of these evaluations and the schedule for your submission of the completed evaluation.

RESPONSE:

The calculation of submerged structure loads due to chugging use the improved chugging load methodology developed under March II Owners Group Task A16. The appropriate design sources are used with the Green's function solution for the SSES annular containment to provide the pressure distribution in the suppression pool. The pressure around a structure is integrated to determine the net pressure load on the structure. A description of this methodology and verification is included in the DAR. The chugging source used are developed from the pressure time histories provided by KWU for the design assessment (see SSES DAR Section 9.5.3).

The downcomer has been assessed for the chugging loads and the results is incorporated into the DAR. The other submerged structures have also been evaluated.

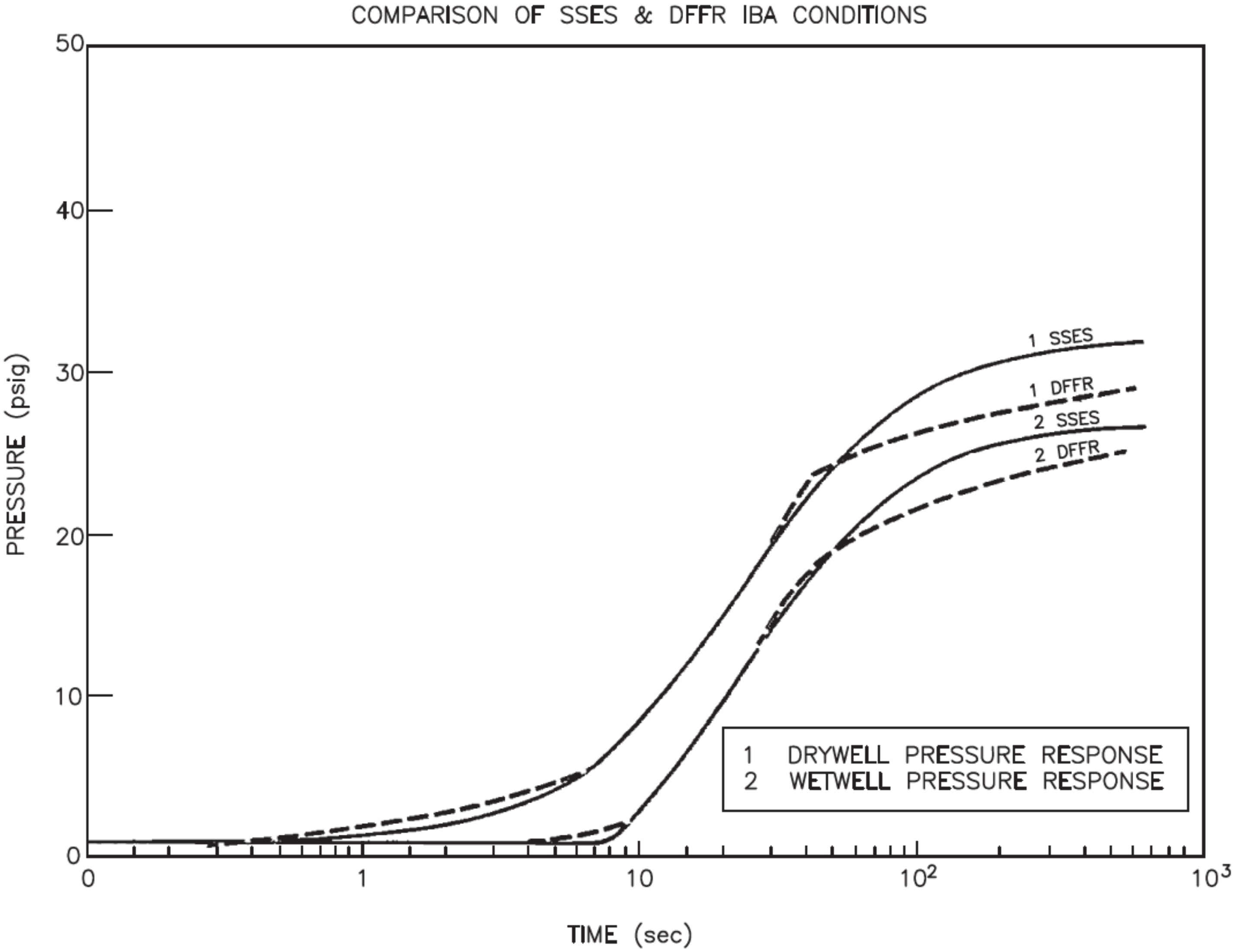
QUESTION 021.72

Statements are made in Subsections 4.2.3.2 and 4.2.3.3 of the DAR that plant unique data of the Susquehanna SES intermediate break accident (IBA) and small break accident (SBA) are estimated from curves for a typical Mark II containment. Discuss the applicability of these analyses (e.g., power level, initial conditions, downcomer configuration, etc.) to Susquehanna SES.

RESPONSE:

The Susquehanna SES FSAR Subsections 6.2.1.1.3.3.4 and 6.2.1.1.3.3.5 give consideration to the SBA and IBA conditions and FSAR figures 6.2-14 and 6.2-15 give the IBA unique curves for Susquehanna SES based on the initial conditions as given in FSAR Tables 6.2-1 thru 6.2-4. In comparing the IBA Susquehanna SES unique FSAR figures with the Susquehanna SES DAR figures 4-50, 4-51 and 4-52, which are generic DFFR, SBA and IBA, it can be seen that basically the generated curves provide similar design basis mass energy data. (See figures 021.72-1 and 021.72-2) Thus we expect the Susquehanna SES SBA conditions to be similar also to the DFFR (or DAR) figures. The parameters for the DFFR and Susquehanna SES are provided in DFFR (NEDO 21061) Table 4-1 and Susquehanna SES FSAR Tables 6.2-1 and 6.2-4 respectively. The differences in parameters are as follows:

	DFFR	SSES
Drywell Free Air Volume ft^3	2.029×10^5	2.396×10^5
Wetwell Free Air Volume ft^3	1.455×10^5	1.4859×10^5
Wetwell Water Volume ft^3	1.2×10^5	1.224×10^5
Drywell Initial Pressure psig.	0.75	1.5
Wetwell Initial Pressure psig.	0.75	1.5
Vent Submergence ft.	11	11.5
Number of vents	108	87



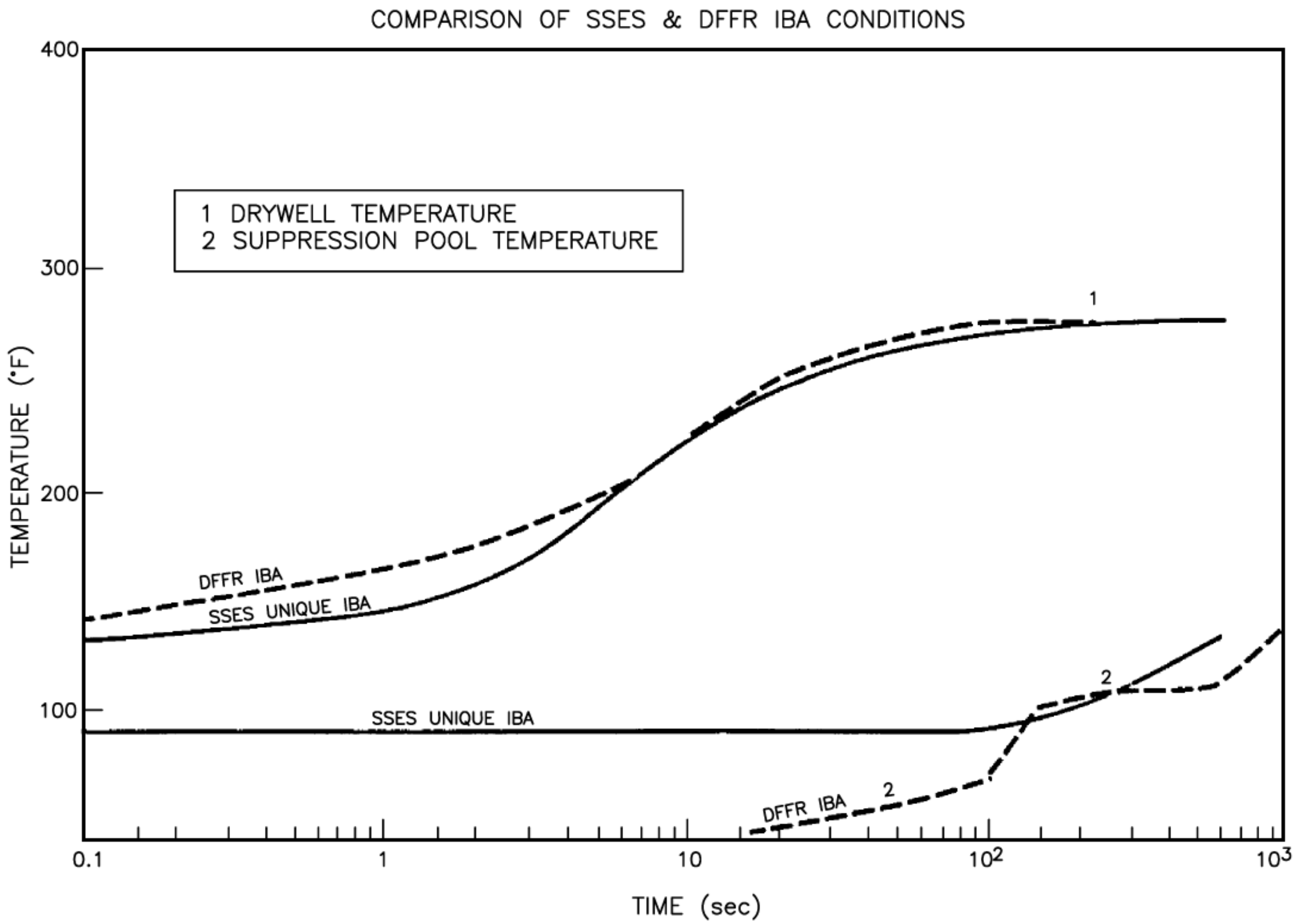
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSE
FOLLOWING AN
IMMEDIATE BREAK ACCIDENT (IBA)

FIGURE 021.72-1, Rev 47

AutoCAD: Figure Fsar_021_72_1.dwg



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SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

TEMPERATURE RESPONSE
FOLLOWING AN
IMMEDIATE BREAK ACCIDENT (IBA)

FIGURE 021.72-2, Rev 49

AutoCAD: Figure Fsar_021_72_2.dwg

QUESTION 021.73

Provide the information previously requested in 020.44 regarding loads resulting from pool swell waves following the pool swell process or seismic slosh. Discuss the analytical model and assumptions used to perform these analyses.

RESPONSE:

The analytical method of calculating the loads resulting from seismic slosh and the assumption used are described in a writeup included in the DAR.

QUESTION 021.74

Provide a list and drawing to identify all piping, equipment instrumentation and structures in containment that may be subjected to pool dynamic loads. In addition, provide drawings to show the location of access galleys in the wetwell, the vent vacuum breaker configuration, wetwell grating, vent bracing configuration, vent configuration in the pedestal region of wetwell and large horizontal structures in the pool swell zone.

RESPONSE:

The drawings requested in 021.74 are listed below. Symbols utilized on these drawings are identified on Dwgs. M-100, Sh. 1, M-100, Sh. 2 and M-100, Sh. 3.

LARGE PIPING

Figure		Title
021.74	- 1	Reactor Building, Unit 1, Primary Containment, M.S.R.V. Discharge in Suppression Pool.
	- 2	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El. 704'-0".
	- 3	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El. 719'-1".
	- 4	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El. 738'-11 1/2".
	- 5	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El. 752'-2 1/2".
	- 6	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El. 779'-1”
	- 7	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Misc. Sections.
	- 8	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Section C-C.
	- 9	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El 761'-1".
	- 10	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Section L-L.
	- 11	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El. 806'-0".
	- 12	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Section M-M.
	- 13	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Misc. Details.

SMALL PIPING

Figure		Title
021.74	- 14	M.S.R.V. Discharge in Suppression Pool, Reactor Building, Unit 1, Primary Containment.
	- 15	M.S.R.V. Discharge in Suppression Pool.
	- 16	Plant Design Drawing, Reactor Building, Unit 1 Area 26, Plan of El. 704'-0".
	- 17	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El. 719'-0".
	- 18	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El. 738'-11 1/2" Sht. 1.
	- 19	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El. 738'-11 1/2", Sht. 2.
	- 20	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El. 752'-2 1/2".
	- 21	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El. 779'-1".
	- 22	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Misc. Plan of El. 719'-1".
	- 23	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Misc. Sections & Details.
	- 24	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El. 761'-1".
	- 25	Plant Design Drawing, Reactor Building, Unit 1, Area 26, Plan of El. 806'-0".

EQUIPMENT LOCATION

Figure		Title
1.2	- 17	Equipment Location, Reactor Building, Plan of Basement, El 645'-0".
	- 18	Equipment Location, Reactor Building, Unit 1, Plan of El. 670'-0".
	- 19	Equipment Location, Reactor Building, Unit 1, Plan of El. 683'-0".
	- 20	Equipment Location, Reactor Building, Unit 1, Plan of El. 719'-1".
	- 21	Equipment Location, Reactor Building, Unit 1, Plan of El. 749'-1".
	- 22	Equipment Location, Reactor Building, Unit 1, Plan of El. 779'-1".
021.74	- 26	Instrument Location Drawing, Reactor Building, Unit 1, Area 26, Plan Below El. 704'-0".

Figure 021.74-27 (Reactor Building 1&2 Primary Containment-Suppression Chamber Platform) shows wetwell grating. Vent bracing configuration is presented in the DAR, Ammend. #1, Figures 1-3 and 4-53. Vent configuration in the pedestal region is not applicable, since Susquehanna SES does not have vents in this region. Also, Susquehanna SES does not have access galleys. There are no large horizontal structures in the pool swell zone.

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

REACTOR BUILDING UNIT 1
PRIMARY CONTAINMENT
M.S.R.V. DISCHARGE
IN SUPPRESSION POOL

FIGURE 021.74-1, Rev 54

AutoCAD: Figure Fsar_021_74_1.dwg
From PPL drawing E106176, sh. 1

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, SECTION L-L

FIGURE 021.74-10, Rev 54

AutoCAD: Figure Fsar 021_74_10.dwg
From PPL drawing E106176, Sh. 13

Security-Related Information Figure
Withheld Under 10 CFR 2.390

FSAR REV.65

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FINAL SAFETY ANALYSIS REPORT

PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF EL. 806'-0"

FIGURE 021.74-11, Rev 54

AutoCAD: Figure Fsar 021_74_11.dwg
From PPL drawing E106176, Sh. 14, Rev. 10

Security-Related Information
Figure Withheld Under 10 CFR 2.390

R R V

2 R
P R

P R
R B
R 2

R 2 7 2 R v

u m P d ng 0 7 h d R 3

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, MISCELLANEOUS DETAILS

FIGURE 021.74-13, Rev 54

AutoCAD: Figure Fsar 021_74_13.dwg
From PPL drawing E106176, Sh. 16

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

REACTOR BUILDING UNIT 1
PRIMARY CONTAINMENT M.S.R.V.
DISCHARGE IN SUPPRESSION POOL

FIGURE 021.74-14, Rev 54

AutoCAD: Figure Fsar 021_74_14.dwg
From PPL drawing E106274, Sh. 1B, Rev. 1

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

REACTOR BUILDING UNIT 1
PRIMARY CONTAINMENT
M.S.R.V. DISCHARGE IN
SUPPRESSION POOL

FIGURE 021.74-15, Rev 54

AutoCAD: Figure Fsar 021_74_15.dwg
From PPL drawing E162274, Sh. 1C

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
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PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF E. 704'-0"

FIGURE 021.74-16, Rev 54

AutoCAD: Figure Fsar 021_74_16.dwg
From PPL drawing E162274, Sh. 2

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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FINAL SAFETY ANALYSIS REPORT

PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF EL. 719'-1"

FIGURE 021.74-17, Rev 54

AutoCAD: Figure Fsar 021_74_17.dwg
From PPL drawing E162274, Sh. 3

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF EL. 738'-11 $\frac{1}{2}$"
SH. 1

FIGURE 021.74-18, Rev 54

AutoCAD: Figure Fsar 021_74_18.dwg
From PPL drawing E162274, Sh. 4A

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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FINAL SAFETY ANALYSIS REPORT

PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF EL. 738'-11 $\frac{1}{2}$"

FIGURE 021.74-19, Rev 54

AutoCAD: Figure Fsar 021_74_19.dwg
From PPL drawing E162274, Sh. 4B, Rev. 3

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF EL. 704'-0"

FIGURE 021.74-2, Rev 54

AutoCAD: Figure Fsar 021_74_2.dwg
From PPL drawing E106176, Sh. 2, Rev. 31

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION
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PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF EL. 752'-2 ½"

FIGURE 021.74-20, Rev 54

AutoCAD: Figure Fsar 021_74_20.dwg
From PPL drawing E162274, Sh. 5, Rev. 20

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
PLANT DESIGN DRAWING REACTOR BUILDING UNIT 1 AREA 26, PLAN OF EL. 779'-1" FIGURE 021.74-21, Rev 54

AutoCAD: Figure Fsar 021_74_21.dwg
From PPL drawing E162274, Sh. 6, Rev. 14

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF EL. 719'-1"

FIGURE 021.74-22, Rev 54

AutoCAD: Figure Fsar 021_74_22.dwg
From PPL drawing E162274, Sh. 7

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, MISCELLANEOUS
SECTIONS & DETAILS

FIGURE 021.74-23, Rev 54

AutoCAD: Figure Fsar 021_74_23.dwg
From PPL drawing E162274, Sh. 8

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF EL. 761'-1"

FIGURE 021.74-24, Rev 54

AutoCAD: Figure Fsar 021_74_24.dwg
From PPL drawing E162274, Sh. 12, Rev. 15

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

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UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF EL. 806'-0"

FIGURE 021.74-25, Rev 54

AutoCAD: Figure Fsar 021_74_25.dwg
From PPL drawing E162274, Sh. 14

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN BELOW 704'-0"

FIGURE 021.74-26, Rev 54

AutoCAD: Figure Fsar 021_74_26.dwg
From PPL drawing E103486, Sh. 8

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

REACTOR BUILDING UNIT 1 & 2
PRIMARY CONTAINMENT
SUPPRESSION POOL CHAMBER
PLATFORM

FIGURE 021.74-27, Rev 54

AutoCAD: Figure Fsar 021_74_27.dwg
From PPL drawing FF170007, Sh. 3182 Rev. 2

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

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PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF EL. 719'-1"

FIGURE 021.74-3, Rev 54

AutoCAD: Figure Fsar 021_74_3.dwg
From PPL drawing E106176, Sh. 3

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
PLANT DESIGN DRAWING REACTOR BUILDING UNIT 1 AREA 26, PLAN OF EL. 738'-11 $\frac{1}{2}$" FIGURE 021.74-4, Rev 54

AutoCAD: Figure Fsar 021_74_4.dwg
From PPL drawing E106176, Sh. 4

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
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PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF EL. 752'-2 $\frac{1}{2}$"

FIGURE 021.74-5, Rev 54

AutoCAD: Figure Fsar 021_74_5.dwg
From PPL drawing E106176, Sh. 5

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
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PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF EL. 779'-1"

FIGURE 021.74-6, Rev 54

AutoCAD: Figure Fsar 021_74_6.dwg
From PPL drawing E106176, Sh. 6, Rev. 9

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, MISC. SECTIONS

FIGURE 021.74-7, Rev 54

AutoCAD: Figure Fsar 021_74_7.dwg
From PPL drawing E106176, Sh. 8, Rev. 12

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
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FINAL SAFETY ANALYSIS REPORT

PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, SECTION C-C

FIGURE 021.74-8, Rev 54

AutoCAD: Figure Fsar 021_74_8.dwg
From PPL drawing E106176, Sh. 11

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

PLANT DESIGN DRAWING
REACTOR BUILDING UNIT 1
AREA 26, PLAN OF EL. 761'-1"

FIGURE 021.74-9, Rev 54

AutoCAD: Figure Fsar 021_74_9.dwg
From PPL drawing E106176, Sh. 12, Rev. 18

QUESTION 021.75

Discuss the applicability of the generic supporting programs, tests and analyses to SSES design (i.e., FSI concerns, downcomer stiffeners, downcomer diameter, etc.)

RESPONSE:

A complete description of the GKM-IIM test program, test results and evaluation of the test data is provided in Chapter 9.0 of the Susquehanna SES DAR. The GKM-IIM tests were structured to be as prototypical of the Susquehanna SES plant configurations as was practical. As such, concerns related to FSI, downcomers stiffness, downcomer diameter, etc., are fully addressed.

QUESTION 021.76

Provide the time history of plant specific loads and assessment of responses of plant structures, piping, equipment and components to pool dynamic loads. Identify any significant plant modifications resulting from pool dynamic loads considerations.

RESPONSE:

Time history information for LOCA loads can be found in SSES DAR, Section 4.2. Similar information due to SRV actuation can be found in SSES DAR, Section 4.1. In addition, the plant specific LOCA and chugging load definition developed from the GKM II-M test program can be found in Subsection 9.5.3. This load definition will be used to evaluate the conservatism of the DFFR LOCA load definition developed from the GKM II-M test program can be found in Subsection 9.5.3. This load definition was used to evaluate the conservatism of the DFFR LOCA load definition.

Assessment of the piping to pool dynamic loads is completed. PP&L interprets this question as requiring:

a) Response of piping in the wetwell to pool dynamic time history loads.

b) Response of piping in the drywell, wetwell and reactor building to response spectra due to SRV and LOCA loads.

Summary of the results of piping analysis has been provided in the DAR upon completion of piping analysis in May of 1981.

Modification of plant design to date

a) Addition of quenchers
b) Design changes in platform, vacuum breakers, and recombiner Support beams by raising them out of the pool swell zone
c) Redesign of downcomer bracing system
d) Added 60 reinforcing bars in each suppression chamber
e) Added embedments and anchor bolts in suppression chamber walls and diaphragm slab.
f) Diaphragm slab reinforcements changed from 45° to 90° to increase uplift loadings acceptance
g) Significant number of pipe supports added or modified.

QUESTION 021.77

Provide figures showing reactor pressure, quencher mass flux and suppression pool temperature versus time for the following events:

(1) A stuck-open SRV during power operation assuming reactor scram at 10 minutes after pool temperature reaches 110°F and all RHR systems operable;

(2) Same as event (1) above except that only one RHR train available;

(3) A stuck-open SRV during hot standby condition assuming 120°F pool temperature initially and only one RHR train available;

(4) The Automatic Depressurization System (ADS) activated following a small line break assuming an initial pool temperature of 120°F and only one RHR train available; and

(5) The primary system is isolated and depressurizing at a rate of 100°F per hour with an initial pool temperature of 120°F and only one RHR train available.

Provide parameters such as service water temperature, RHR heat exchanger capability, and initial pool mass for the analysis.

RESPONSE:

The Susquehanna unique SRV mass and energy release analysis is presented in Appendix I of the DAR.

QUESTION 021.78

With regard to the pool temperature limit, provide the following additional information:

(1) Definition of the "local" and "bulk" pool temperature and their application to the actual containment and to the scaled test facilities, if any; and

(2) The data base that support any assumed difference between the local and the bulk temperatures.

RESPONSE:

(1) The terms "local" and "bulk" temperature are used as defined in Subsection III.C.1.a of NUREG 0487, "Mark II Containment Lead Plant Program Load Evaluation and Acceptance Criteria," United States Nuclear Regulatory Commission, October, 1978.

Because of the design features of quenchers and their orientation in the suppression pool (as discussed in the SSES DAR, Subsection 8.5.5), the differences between "local" and "bulk" pool temperatures are expected to small. Therefore, the difference should not exceed the value which was previously derived for ramshead discharge devices in Mark I plants (10°F). It is intended to verify the numbers using data from in-plant tests which are presently under preparation for LaSalle and Zimmer.

QUESTION 021.79

For the suppression pool temperature monitoring system, provide the following additional information:

(1) Type, number and location of temperature instrumentation that will be installed in the pool; and

(2) Discussion and justification of the sampling or averaging technique that will be applied to arrive at a definitive pool temperature.

RESPONSE:

(1) Please refer to revised Section 7.6.1b.1.2. Susquehanna SES has completed evaluation of the suppression pool monitoring criteria as defined in NUREG-0487 and has developed a basic system as follows:

- Number and Location of Temperature Instruments: 20 remote temperature detectors (see Figure 021.74-32 in each suppression pool

  -16 remote temperature detectors located just below the min. water level and arranged to provide 2 each on 8 locations around the pool.

  -4 remote temperature detectors (see Figure 021.74-32-TE's 15769, 15761, 15756, 15751) distributed around the pool at "Q" centerline location

- Type: Class 1E Instrument - Divisionalized with one from each location in each division, except for 4 remote temperature detectors at the "Q" centerline. All sensors will be redundant, Seismic Category I and supplied from onsite emergency power.

The technique issued to arrive at an average, or bulk, pool temperature is conservative due to the placement of the 16 pool temperature detectors. These 16 detectors are evenly distributed near the pool surface, where the hottest water will rise.

QUESTION 021.80

The statement is made in response to Question 021.51 that operator action (containment spray, ADS) will limit suppression chamber pressure to 45 psig.

The staff position set forth in Appendix I to Standard Review Plant (SRP) 6.2.1.1.c requires automatic actuation of the spray system. However, if it is demonstrated by analyses that there is sufficient time (minimum of 30 minutes) between the time the operator becomes aware of the leakage path and the time containment design pressure is reached, manual operator action could be accepted as an alternative to automated spray actuation. To complete our review of the Susquehanna Steam Electric Station (SSES), please provide the following information:

a) Graphically show the containment pressure following small steam break assuming a bypass leakage path with a $A/K = .05\ ft^2$ and containment spray actuated 30 minutes from the time the suppression chamber pressure reaches the 30 psig setpoint. The analysis should be based on the assumptions set forth in Appendix I to SRP 6.2.1.1.C.

b) Specify the operator action that will be taken and the time to complete the action, i.e., containment spray or ADS and discuss the consequences of each action. Modify subsection 6.2.1.1.5.2 of the FSAR to address the specific action to be taken.

c) If the analysis stated in item a, above, shows that containment design pressure will be reached, discuss your plan for including automated actuation of the spray system.

RESPONSE:

a) The Susquehanna SES construction permit was issued in 1973. An automatically actuated spray system was not then nor is it now in the plant design. The Standard Review Plans are not a design or construction basis for Susquehanna SES.

Question 021.80 presumes that no effective operator action is performed for thirty (30) minutes after becoming aware of a leakage path. This is not the basis for Susquehanna SES design nor the supporting analysis.

b) This information is provided in FSAR Subsection 6.2.1.1.5.2.

c) There are no plans for including automated actuation of the spray system. The Susquehanna SES configuration is proved reliable and effective in licensed, operating plants.

QUESTION 021.81

Note 6 in Table 6.2-15 indicates that excess flow check valves outside containment eliminates the bypass leakage path. Discuss the advisability of using excess flow check valves to perform satisfactorily during the entire course of transient.

RESPONSE:

See Subsection 6.2.4.3.2.2 for a discussion of the design of these lines.

QUESTION 021.82

The response to question 021.64 is incomplete; discuss whether or not jockey pumps are used to maintain water seal for 30 days. Discuss if the system is single failure (active) proof.

RESPONSE:

This information has been provided in FSAR Subsection 6.2.3.2.3.1.

QUESTION 021.83

The response to Question 021.67 is incomplete; provide the analysis requested in Item 2 of that question.

RESPONSE:

Susquehanna will use an inerted primary containment during power operation. At the maximum oxygen concentration of 4%, any hydrogen concentration forms a non-explosive mixture. Hence the hydrogen generation from zinc is non-consequential.

QUESTION 021.84

Table 6.2-12, a list of the containment isolation valves, references Figure 6.2-44 for valve configuration. Some of the valve arrangements on Figure 6.2-44 do not match those presented in Table 6.2-12; e.g., penetrations 9A, 244, 245, and 246A do not match the referenced arrangement.

In addition, Subsection 6.2.4.3.3.5 does not agree with the arrangement of penetrations 23 and 24. Review Table 6.2-12 for completeness and correctness.

RESPONSE:

The valve arrangements of Figure 6.2-44 have been revised to match those in Table 6.2-12 for penetrations 9A,B, 244, 245, and 246 A, B.

Subsection 6.2.4.3.3.5 and the valve arrangements of penetrations 23 and 24 have been revised to agree with Table 6.2-12.

QUESTION 021.85

Provide justification for having a check valve outside the containment as containment isolation for the seismic pump seal water supply lines.

RESPONSE:

See Subsection 6.2.4.3.2.2.

QUESTION 021.86

Arrangement e in Figure 6.2-44 shows that the 2-inch bypass line relies on the 24-inch purge valve line to perform its intended function. We will require both the 2-inch and the 24-inch valves to meet the requirements set forth in CSBBTP 6-4 or provide another valve arrangement that satisfies GDC 56.

It should be noted that while in modes 1 through 4, purging operations are permitted up to 90 hours per year provided that requirements set forth in BTP 6-4 are met.

RESPONSE:

Dwgs. M-157, Sh. 1, M-157, Sh. 2, and M-157, Sh. 3 for the piping diagram, Subsection 6.2.4.2 for a description of the containment isolation system, and Subsections 6.5.3.1 and revised 6.2.5.2 for a description of containment purging.

During power operation, the purge valves will be controlled as specified in the Technical Specifications.

QUESTION 021.87

With respect to the leakage test program.

a) It is our position that feedwater isolation valves should be Type C tested utilizing air.

b) RHR shutdown supply and return should be Type C tested utilizing air.

c) ECCS injection valves should be tested utilizing air.

d) All containment isolation valves should be Type C tested. Hydrostatic testing is acceptable if it can be demonstrated that the water inventory is sufficient to maintain a water seal for at least 30 days following a LOCA.

e) CRD insert and withdraw line should be vented during Type A test.

RESPONSE:

a) Refer to revised Subsection 6.2.3.2.3.

b) See Table 6.2-22.

c) See Table 6.2-22.

d) Refer to Table 6.2-22 for a description of the testing of containment isolation valves.

e) Refer to Table 6.2-22, Note 20.

QUESTION 021.88

Provide the projected areas used in the calculation of forces on the RPV and supports.

RESPONSE:

This information is contained in the revised Section 6A, specifically the new Table 6A-7.

QUESTION 032.1

Section 1.6 references GE topical report NEDO-10466, "Power Generation Control Complex Design Criteria and Safety Evaluation." This topical report is presently undergoing review. Therefore we require that this topical report be included as a reference in the appropriate section of Chapter 7 and that you provide a commitment to adopt the resolution on this topical report achieved between GE and the staff. In addition, address in the FSAR all the interface requirements of the topical report.

RESPONSE:

The topical report was approved by the NRC on July 13, 1978. The reference in Section 1.6 has been changed to 3.12.3.4.2.1 (f) to which the following was added:

Power Generation Control Complex - (PGCC) Considerations

Detailed design basis, description, and safety evaluation aspects for PGCC System are comprehensively documented and presented in GE-Topical Report: "Power Generation Control Complex; NEDO-10466 and its amendments."

The FSAR does address the system interface requirements that are applicable to FSAR Chapter 7 systems. These system requirements are separation, color coding, and equipment qualification which are addressed in Subsection 3.12.1.

QUESTION 32.2

Section 1.7 states that:

> "Table 1.7-1 contains a list of non-proprietary drawings electrical, instrumentation and control (EI&C) drawings. This table lists those drawings which were considered to be necessary to evaluate the safety-related features in Chapters 7 and 8 of the Susquehanna Unit 1 and 2 FSAR. This table will be updated in future amendments when necessary."

Verify if this list is intended to be a complete list of electrical, instrumentation and control drawings which contain safety-related equipment. In addition, provide all electrical instrumentation and control drawings pertaining to safety systems for staff's review.

RESPONSE:

The list on Table 1.7-1 is a complete list of electrical instrumentation and control drawings which contain safety-related equipment. Copies of these drawings have been provided to NRC under separate cover.

QUESTION 032.3

Section 3.11.2 states, "Instrumentation components have not been qualified to the environmental qualification program delineated in IEEE 323."

Therefore, provide a comparison which delineates each deviation from IEEE Std 323-1974 and the justification for the deviation.

RESPONSE:

Individual devices and assemblies have been seismically qualified.

Compliance with IEEE 323-1971 for Non-NSSS class 1E electrical equipment is discussed in Subsection 3.11.2.1.

General Electric has complied with IEEE-323-1971 for the environmental qualification of Instrumentation Components for the NSSS systems.

QUESTION 032.4

Provide a summary of the temperature qualification of the safety related instrumentation and control equipment in all areas of the plant outside the containment.

This summary should include:

(1) The plant location under consideration (e.g. the room and building)

(2) The type of instrumentation and control equipment located in the area, (e.g. transmitter and controller)

(3) The ventilation provided for the area.

(4) The temperature extremes postulated for the area and equipment (including consideration of loss of forced ventilation, if applicable) and any temperature monitoring instrumentation in such areas.

(5) The equipment temperature qualification limits.

(6) The list of supporting qualification documentation for the equipment (e.g. test reports and industry standards).

RESPONSE:

Parts (1) through (4) are responded to in new table 3.11A-1.

Parts (5) and (6) are responded to in new table 3.11A-2.

QUESTION 032.5

Section 3.10a.4.1 and 3.11.3.1 of the FSAR state that the seismic and environmental qualification tests results for GE safety related equipment are maintained in a permanent file by GE and can be readily audited. Provide a listing of the available subject reports for this equipment.

RESPONSE:

Table 3.10a-1 contains sufficient information upon which to determine acceptable qualification levels. The qualification test results are traceable by equipment and device designation to the permanent files.

QUESTION 032.6

Provide a complete discussion of the instrumentation (pressure switches, manual control switches, and wiring) associated with the nuclear pressure relief system described in Section 5.2.2.4 of the FSAR which actuate the safety/relief valves on an overpressure event or through operator action. Include elementary wiring diagrams as appropriate.

RESPONSE:

The pressure relief instrumentation which controls the electrical operation of each valve is shown on Figure 032.6-1 (typical diagram). Each valve has its own pressure switch which acts to open the valve directly when it senses high vessel pressure unless the control switch (S8 in the diagram) is in the "OFF" position.

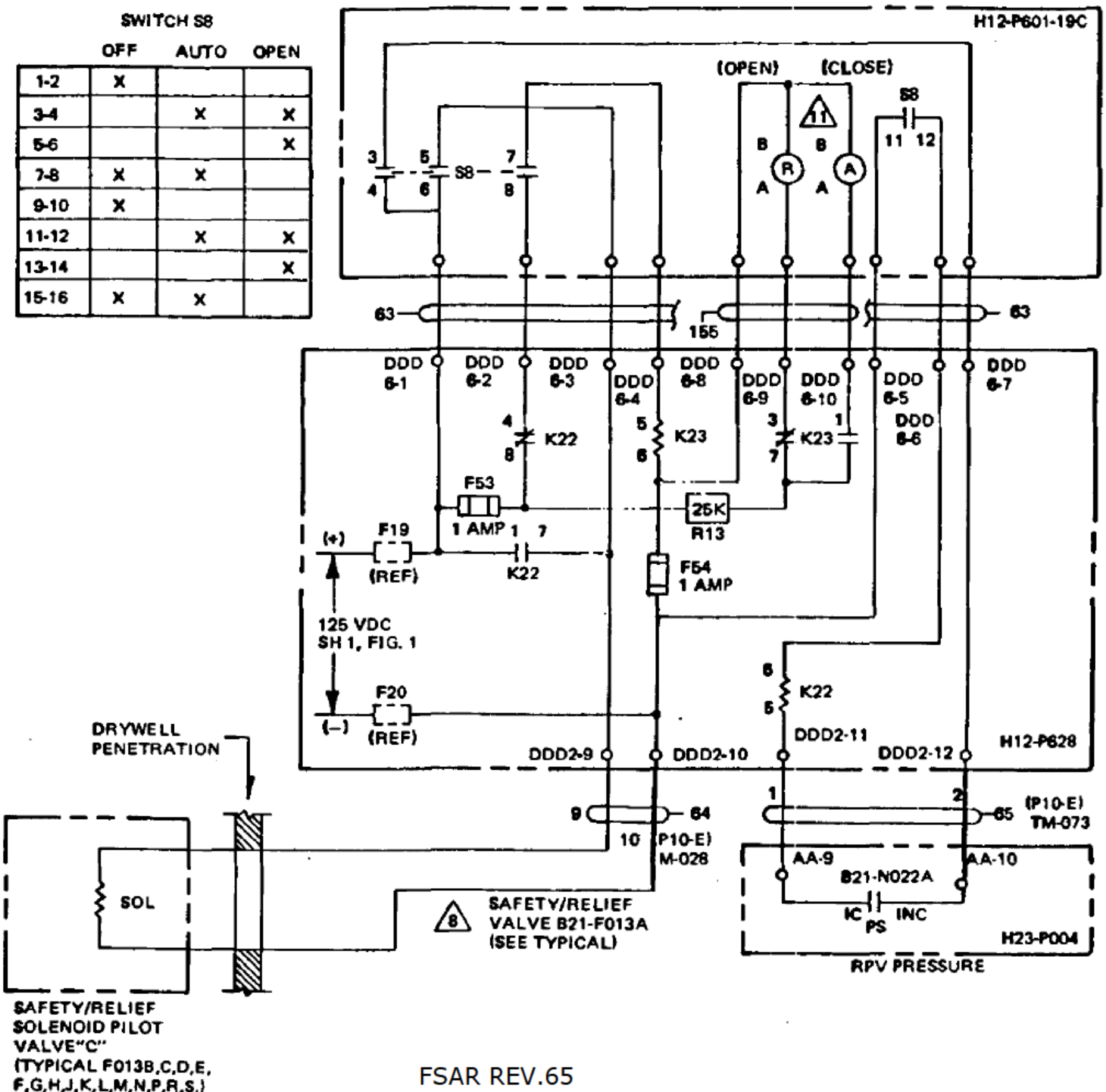
This control switch is a maintained contact switch which may be selected for one of three positions: OFF, AUTO or OPEN. With the switch in "AUTO", pressure at or above the setpoint closes the pressure switch which actuates a relay which opens its respective valve while simultaneously switching indicating lights. When pressure drops to an acceptable level, the pressure switch reopens causing the relay to deenergize and reclose the valve.

Manual control for opening the valve is initiated by simply placing the switch in "OPEN" thereby bypassing the pressure switch relay and opening the valve directly from the switch contact (5-6 in diagram).

The switch may be placed in the "OFF" position for maintenance or pressure switch calibration, etc. However, since this action renders the valve inoperative electrically, an annunciator window is provided to remind the operator of this condition which cannot be cleared until the switch is placed in either "Auto" or "Open". No electrical action will inhibit the valve from opening at its designated mechanical spring pressure relief setpoint. The safety relief valve control scheme is shown in the ADS elementary diagram for all valves, however, only a portion of a valve is wired for ADS action. For this reason, all valves are provided with 3 solenoids. Those designated for ADS utilize solenoids A and B (Div. 1 and 2 respectively). The safety relief logic is wired to solenoid "C" which is piped to separate air accumulators from those of ADS. Only one power division is required for the safety relief electrical control functions because each valve has a diverse back up mechanical spring setpoint capable of non-electrical safety relief action.

SWITCH S8

	OFF	AUTO	OPEN
1-2	X		
3-4		X	X
5-6			X
7-8	X	X	
9-10	X		
11-12		X	X
13-14			X
15-16	X	X	



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

TYPICAL PRESSURE RELIEF
INSTRUMENTATION

FIGURE 032.6-1, Rev 47

AutoCAD: Figure Fsar 032_6_1.dwg

QUESTION 032.7

Section 7.1.2a.1.4.6.3 of the FSAR states that as a power generation design bases for the Rod Block Monitor, it will prevent local fuel damage that may result from a single rod withdrawal error. Provide the justification for classifying this as a power generation design bases and not a safety design bases.

RESPONSE:

A GE/NRC generic meeting was held on January 26, 1981 to discuss the Reactor Manual Control System and to specifically address the appropriateness of utilizing the RBM in transient mitigation.

The new electronic RMCS being utilized at SSES was described in detail with an emphasis upon reliability, redundancy and self-testing features.

The NRC, in the January 26 meeting, indicated approval of the design and use of RBM system in transient analysis.

QUESTION 032.8

Provide the safety design bases for the RHRS Containment Spray Cooling System Instrumentation and Controls in Section 7.1.2a.1.35 of the FSAR.

RESPONSE:

The response may be found in Subsection 7.1.2a.1.35.1.

QUESTION 032.9

Section 7.2.2.1.1.1.2 and Section 7.2.2.1.1.1.4 of the FSAR discuss the Turbine Stop Valve (TSV) position and Turbine Control Valve (TCV) (Fast Closure) trip inputs to the reactor protection system. In both sections, these signals are described as providing greater margin than the reactor vessel high pressure trip. Since these inputs (TSV and TCV) are located in non-seismic Category I areas full credit for these inputs cannot be assumed in the plant protection analyses. Therefore, provide further analyses which demonstrate that upon failure of these inputs, there are other fully qualified safety grade trip inputs which provide adequate plant protection for the corresponding events.

RESPONSE:

The response to Question 211.19 fully analyzes the event conditions surrounding these trip inputs; the response to Question 211.19 will be supplied in September, 1978.

QUESTION 032.10

Section 7.2.2.1.2.4.4 of the FSAR discusses conformance to Branch Technical Position EICSB 24. The concluding remark states that "The method of performing sensor response time verification for neutron monitoring system (APRM) IRM, and main steamline radiation monitoring trip points has not been resolved."

Provide a discussion of the present state of the art in these areas.

RESPONSE:

As stated in Table 3.3.1-2 of the Technical Specifications for Susquehanna SES, neuron detectors are exempt from response time testing. Response time shall be measured from the detector output or from the input of the first electronic component in the channel. This provision is not applicable to Construction Permits docketed after January 1, 1978.

QUESTION 032.11

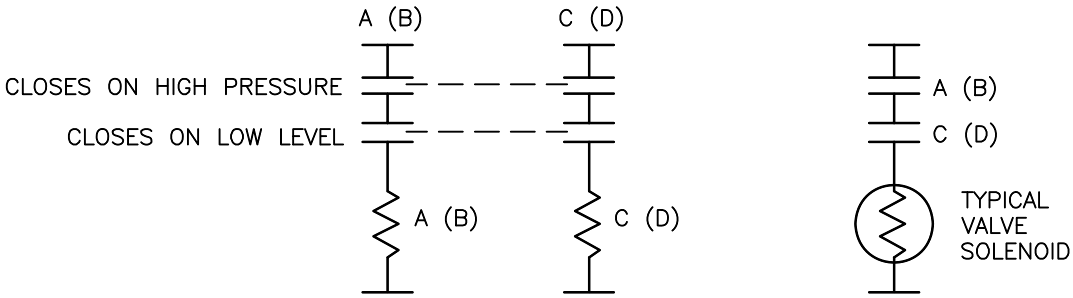
Section 7.3.2.a.1.2.3.1.2 of the FSAR states that for the ADS, at least two failures would have to occur to cause actuation. Describe the design provisions with appropriate logic/schematic diagrams which are included to meet this design basis.

RESPONSE:

Each of the ADS divisions has a two channel permissive which may be expressed by the logic equation (AxC) + (BxD). Therefore, since A and C receive power from Div. 1 and B and D from Div. 2, no single channel failure can cause ADS failure, nor can it cause inadvertent actuation. For example, if channel "A" were to fail in the permissive state, no auto-depressurization could inadvertently occur (>1 valve) unless "C" also were to fail permissive (a double failure). This is likewise true with logic B and D in Division 2. This is accomplished simply by wiring the "A[B]" - final actuator relays within each valve control circuit as shown in the simplified sketch on Figure 032.11-1.

The ADS system, comprised of two independent sets of controls for the two pilot solenoids, meets the single failure criterion. This arrangement utilizes two out of two logic in each of the control channels which prevents the single failure from causing system initiation. Tolerance to the following single failures or events has been incorporated into the control system design and installation:

(1) Single open circuit,
(2) Single short circuit,
(3) Single relay failure to pickup,
(4) Single relay failure to drop out,
(5) Single module failure (including shorts, opens and grounds),
(6) Single control cabinet destruction (including multiple shorts, opens and grounds),
(7) Single instrument rack destruction (including multiple shorts, opens and grounds),
(8) Single raceway destruction (including multiple shorts, opens and grounds),
(9) Single control power supply failure (any mode),
(10) Single motive power supply failure (any mode),
(11) Single control circuit failure,
(12) Single sensing line (pipe) failure,
(13) Single electrical component failure.



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

ADS VALVE CONTROL

FIGURE 032.11-1, Rev 47

AutoCAD: Figure Fsar 032_11_1.dwg

QUESTION 032.12

Section 7.4.1.1.3.1 of the FSAR states that the RCIC system pumps water from either the condensate storage tank or the suppression pool to the reactor vessel. Explain how this selection is made.

RESPONSE:

The suppression pool water is usually of a lower quality compared to that of the CST, therefore, the CST is the prime source of RCIC pump suction. In the standby condition the RCIC pump is lined up to take suction from the condensate storage tank (CST); hence, when the RCIC System is initiated, either due to low reactor water level or operator action, the pump will initially take suction from the CST.

If the CST inventory is satisfactory, no further operator action is required; however, if the water level is low, an alarm sounds in the control room indicating the pump suction must be shifted to the suppression pool for uninterrupted RCIC operation.

FSAR Subsection 7.4.1.1.3.6 discusses this arrangement. The selection is made by the operator.

QUESTION 032.13

Section 7.5.1a.1 of the FSAR states that the elementary diagrams illustrate separation of redundant display instrumentation and electrical isolation of redundant sensors and channels. Provide specific reference drawing numbers containing the above information.

RESPONSE:

The elementary diagrams of the safety related systems are identified in tabular form in FSAR Section 1.7.

No specific reference drawing numbers can be provided since the requested information is not limited to a few drawings, but is contained on most of the elementaries.

QUESTION 032.14

Completely describe the interrelation between the instrumentation and circuitry which provides information to the operator to enable him to perform required safety functions, and the other instrumentation and circuitry of the Advanced Control Room (ACR).

RESPONSE:

The Advanced Control Room (ACR) design is no different than previous control rooms as far as safety functions are concerned. The only difference which exists is the method of presentation of certain non-safety plant data with a redundant video display system. In addition to the hard-wired panel indication, safety related information is also available to the operator via the video display system.

QUESTION 032.15

Provide the functional control diagram and associated elementary wiring diagram for the Recirculation Pump Trip (RPT) System.

RESPONSE:

The Recirculation Pump Trip (RPT) System information is contained on IED729E611AE (Reactor Protection System Figure 7.2-1) and elementary diagram 791E414AE which is listed in Section 1.7.

QUESTION 032.16

The FSAR contains many conflicting or confusing statements which must be resolved in order for the review to proceed. For each of the questions below, provide a FSAR revision which is responsive to the staff's need for information satisfying the requirements of the "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants" Regulatory Guide 1.70.

(1) Clarify the discrepancy between the reference to "three trip logics" in FSAR Section 3.1.2.3.2 and the description of the RPS in FSAR Section 7.2.1.1.4.3.

(2) Clarify the discrepancy between the definition of passive failures in electrical, instrumentation, and control systems in FSAR Sections 1.2.1 and 3.11.4.

(3) Clarify the discrepancy between FSAR Sections 7.1.2a.1.3.5.1 and 7.3.1.1a.4.3 with regard to the parameters which initiate containment spray.

(4) FSAR Section 7.3.1 states that the RHR Suppression Pool Cooling System is an engineered safety feature system. Provide the necessary information in FSAR Section 7.3.1.1a.5 which describes the system in accordance with the requirements of the "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," Regulatory Guide 1.70.

(5) Clarify FSAR Section 7.3.1.1a.2.3 to clearly state where the pressure, temperature, and water level sensors and racks are located.

(6) Provide layout sketches which show the location of all sensors which provide an input to the reactor protection system. The sketch shall have a sufficiently large scale and be of sufficient detail to verify that the separation criteria for RPS and ECCS are met.

(7) Clarify the status of the Main Steamline Isolation Valve design which is presented in Figure 7.3-4. (It is the staff's understanding that this in an outdated design which is no longer being provided by General Electric.)

(8) Resolve the contradiction between FSAR Sections 7.4.1.1.3.6 and 7.4.2.1.2.3.1.4 to provide a clear statement of the conditions under which the RCIC isolation valves will be required to operate and the seismic and environmental conditions for which these valves are qualified.

(9) Clarify the discrepancy between FSAR Section 7.6.1.1.3.1, which states that the refueling interlock-system is single failure proof and the design of the reactor manual control system which has a single rod position input path and a single platform output path.

(10) Clarify the discrepancy between the AIWS trips shown in Figure 7.7-10 and the logic description given in FSAR Section 7.6.1a.8.1.

Question Rev. 48

RESPONSE:

(1) For response refer to revised Subsection 3.1.2.3.2.

(2) For this information see revised Subsection 3.11.4.

(3) There is no discrepancy between the FSAR sections specified in Part 3 of Question 032.16. Containment spray is manually initiated only. However, manual initiation is contingent upon the presence of high drywell pressure.

(4) For response refer to Subsection 7.3.1.1a.5.

(5)(6) For response, see Dwgs:

J-2-4 Sh. 1	J-26-4 Sh. 1	J-28-2 Sh. 1
J-6-3 Sh. 1	J-26-6 Sh. 1	J-28-3 Sh. 1
J-6-4 Sh. 1	J-26-12Sh. 1	J-28-4 Sh. 1
J-10-3 Sh. 1	J-27-1 Sh. 1	J-28-5 Sh. 1
J-11-4 Sh. 1	J-27-2 Sh. 1	J-28-6 Sh. 1
J-25-1 Sh. 1	J-27-3 Sh. 1	J-29-1 Sh. 1
J-25-3 Sh. 1	J-27-4 Sh. 1	J-29-3 Sh. 1
J-25-4 Sh. 1	J-27-5 Sh. 1	J-29-4 Sh. 1
J-26-2 Sh. 1	J-27-6 Sh. 1	J-29-5 Sh. 1
J-26-3 Sh. 1	J-28-1 Sh. 1	

(7) For response, see revised Figure 7.3-4.

(8) RCIC isolation valves receive various signals as shown on Figure 7.4-2. The qualification of these valves is discussed in Subsection 7.4.2.1.2.3.1.4.

There is no contradiction. Both sections state the valves are normally open, and close on the pipe break (RCIC isolation) signal. Equipment qualification is discussed in Section 3.11.

(9) The referenced FSAR statement points out that some of the sensing circuits are provided with equipment that is single-failure proof. This was done to protect against single-failure in these circuits only, and should not be construed to mean that the complete Refueling Interlock System is single-failure proof.

The Refueling Interlocks are not required to meet single-failure criteria. Subsection 7.6.1a.1.3.4 provides the discussion of single-failure criteria and the reason single-failure criteria is not met. The analysis in Subsection 7.6.2a.1 further explains why single-failure criteria need not be met by the Refueling Interlocks.

(10) FSAR Subsection 7.6.1a.8.1 discusses RPT, not ATWS. Figure 7.7-10 is the detector drive system schematic. The logic described for RPT is shown on Figure 7.2-1.

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 25 ELEV. 645'-0"

FIGURE 032.16-1, Rev 54

AutoCAD: Figure Fsar 032_16_1.dwg
From PPL DWG. E103 85 Sh. 1 Rev. 17

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 25 ELEV. 683'-0"

FIGURE 032.16-10, Rev 54

AutoCAD: Figure Fsar 032_16_10.dwg
From PPL DWG. E103485, Sh. 3, Rev. 19

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 26 ELEV. 704'-0"

FIGURE 032.16-11, Rev 54

AutoCAD: Figure Fsar 032_16_11.dwg
From PPL DWG. E103486, Sh. 2, Rev. 16

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 28 ELEV. 719'-1"

FIGURE 032.16-12, Rev 54

AutoCAD: Figure Fsar 032_16_12 dwg
From PPL DWG. E103488, Sh. 4, Rev. 24

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 26 ELEV. 719'-1"

FIGURE 032.16-13, Rev 54

AutoCAD: Figure Fsar 032_16_13.dwg
From PPL DWG. E103486, Sh. 3, Rev. 14

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
INSTRUMENT LOCATION DWG. REACTOR BLDG. UNIT ONE AREA 27 ELEV. 719'-1" FIGURE 032.16-14, Rev 54

AutoCAD: Figure Fsar 032_16_14.dwg
From PPL DWG. E103487, Sh. 4, Rev. 21

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 29 ELEV. 719'-1"

FIGURE 032.16-15, Rev 54

AutoCAD: Figure Fsar 032_16_15.dwg
From PPL DWG. E103489, Sh. 4, Rev. 20

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 25 ELEV. 719'-1"

FIGURE 032.16-16, Rev 54

AutoCAD: Figure Fsar 032_16_16.dwg
From PPL DWG. E103485, Sh. 4, Rev. 25

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 26 ELEV. 738'-11 $\frac{1}{2}$"

FIGURE 032.16-17, Rev 54

AutoCAD: Figure Fsar 032_16_17.dwg
From PPL DWG. E103486, Sh. 4, Rev. 8

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
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INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 28 ELEV. 749'-1"

FIGURE 032.16-18, Rev 54

AutoCAD: Figure Fsar 032_16_18.dwg
From PPL DWG. E103488, Sh. 5, Rev. 13

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 29 ELEV. 749'-1"

FIGURE 032.16-19, Rev 54

AutoCAD: Figure Fsar 032_16_19.dwg
From PPL DWG. E103489, Sh. 5, Rev. 19

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 27 ELEV. 645'-0"

FIGURE 032.16-2, Rev 54

AutoCAD: Figure Fsar 032_16_2.dwg
From PPL DWG. E103487, Sh. 1, Rev. 9

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 27 ELEV. 749'-1"

FIGURE 032.16-20, Rev 54

AutoCAD: Figure Fsar 032_16_20.dwg
From PPL DWG. E103487, Sh. 5, Rev. 14

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 26 ELEV. 761'-1"

FIGURE 032.16-21, Rev 54

AutoCAD: Figure Fsar 032_16_21 dwg
From PPL DWG. E103486, Sh. 12, Rev. 6

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 28 ELEV. 779'-1"

FIGURE 032.16-22, Rev 54

AutoCAD: Figure Fsar 032_16_22.dwg
From PPL DWG. E103488, Sh. 6, Rev. 4

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 26 ELEV. 779'-1"

FIGURE 032.16-23, Rev 54

AutoCAD: Figure Fsar 032_16_23.dwg
From PPL DWG. E103486, Sh. 6, Rev. 6

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 27 ELEV. 779'-1"

FIGURE 032.16-24, Rev 54

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
INSTRUMENT LOCATION DWG. TURBINE BLDG. UNIT ONE AREA 6 ELEV. 689'-0"
FIGURE 032.16-25, Rev 54

AutoCAD: Figure Fsar 032_16_25.dwg
From PPL DWG. E103466, Sh. 3, Rev. 7

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
TURBINE BLDG. UNIT ONE
AREA 10 ELEV. 689'-0"

FIGURE 032.16-26, Rev 54

AutoCAD: Figure Fsar 032_16_26.dwg
From PPL DWG. E103470, Sh. 3, Rev. 10

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
INSTRUMENT LOCATION DWG. TURBINE BLDG. UNIT ONE AREA 6 ELEV. 729'-0"
FIGURE 032.16-27, Rev 54

AutoCAD: Figure Fsar 032_16_27.dwg
From PPL DWG. E103466, Sh. 4, Rev. 13

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
TURBINE BLDG. UNIT ONE
AREA 11 ELEV. 729'-0"

FIGURE 032.16-28, Rev 54

AutoCAD: Figure Fsar 032_16_28.dwg
From PPL DWG. E103471, Sh. 4, Rev. 8

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
TURBINE BLDG. UNIT ONE
AREA 2 ELEV. 729'-0"

FIGURE 032.16-29, Rev 54

AutoCAD: Figure Fsar 032_16_29.dwg
From PPL DWG. E103462, Sh. 4, Rev. 12

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 29 ELEV. 645'-0"

FIGURE 032.16-3, Rev 54

AutoCAD: Figure Fsar 032_16_3.dwg
From PPL DWG. E103489, Sh. 1, Rev. 21

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
INSTRUMENT LOCATION DWG. REACTOR BLDG. UNIT ONE AREA 28 ELEV. 645'-0" FIGURE 032.16-4, Rev 54

AutoCAD: Figure Fsar 032_16_4.dwg
From PPL DWG. E103488, Sh. 1, Rev. 28

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 28 ELEV. 670'-0"

FIGURE 032.16-5, Rev 54

AutoCAD: Figure Fsar 032_16_5.dwg
From PPL DWG. E103488, Sh. 2, Rev. 15

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 27 ELEV. 670'-0"

FIGURE 032.16-6, Rev 54

AutoCAD: Figure Fsar 032_16_6.dwg
From PPL DWG. E103487, Sh. 2, Rev. 12

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 29 ELEV. 683'-0"

FIGURE 032.16-7, Rev 54

AutoCAD: Figure Fsar 032_16_7.dwg
From PPL DWG. E103489, Sh. 3, Rev. 13

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 27 ELEV. 683'-0"

FIGURE 032.16-8, Rev 54

AutoCAD: Figure Fsar 032_16_8.dwg
From PPL DWG. E103487, Sh. 3, Rev. 24

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

INSTRUMENT LOCATION DWG.
REACTOR BLDG. UNIT ONE
AREA 28 ELEV. 683'-0"

FIGURE 032.16-9, Rev 54

QUESTION 032.17

Identify each type of relay in the SSES which must be energized or which must remain energized during a seismic event. For each of these relay types, provide the following information:

(1) The minimum voltage at which it must operate,

(2) The voltage at which it was seismically qualified,

(3) The normal operating voltage, and

(4) The locations and functions of this type of relay.

Where a particular relay was not qualified by test or was not tested in both the energized and deenergized state, justify the seismic qualification of the relay.

RESPONSE:

For the Non-NSSS relays see Subsection 3.10c.2.3.4 and Table 3.10c-17.

Listed below are (ECCS) relays which must be energized or remain energized during a seismic event. Each type may be supplied with AC or DC coils.

MANUFACTURE	TYPE	DRAWING NUMBER
AGASTAT	GP	145C3238
	GP	164C5258
General Electric	HMA	159C4251
	HFA	136B3137
	CR2820	145C3035

(1) The minimum operating voltage for the subject 125VDC relays is 120VDC and 92VAC for the 120VAC relays which is above their pickup and dropout voltages.

(2) These relays are seismically qualified for deenergized and energized modes of operation at nominal operating voltage.

(3) The normal operating voltages (nominal) are 125VDC and 120VAC, respectively, for the subject DC and AC relays

(4) The subject relays are located in their respective ECCS Control Room panels. They energize or remain energized to complete their intended ECSS safety functions. These relays and control room panels are shown on the ECCS related system elementary diagrams which are identified in Section 1.7.

QUESTION 032.18

With regard to FSAR Subsection 3.11.2a.3*, please provide the following additional information and clarifications:

(1) Describe the methods which are used to assure that equipment which is not qualified for all service conditions will not spuriously operate during exposure to service conditions (including excessive exposure times) for which the equipment is not required to function to mitigate the effects of accidents on other events.

(2) Provide a copy of the procedures for the following aging simulations:

(a) Thermal,
(b) Radiation,
(c) Operation, and
(d) Seismic.

(3) Justify the aging temperature which was used in terms of the maximum normal environmental conditions which are listed in FSAR Table 3.11-1.**

(4) Quantify the thermal aging acceleration rate and provide the technical basis for this rate.

(5) Quantify the aging time used for each plant location listed in FSAR Table 3.11-1** which contains a valve which has been qualified in accordance with IEEE Std 382-1972. Identify the valves which are so qualified.

(6) Provide information similar to that requested in Parts 3 through 5 above for radiation aging and, in addition, describe how the neutron fluencies were accounted for.

(7) Provide the criteria for determining the "limits of an actuator family" including:

---

* This subsection has been eliminated since the original response to this question. See Section 3.11.2

** Contents of this Table have been revised since the original response to this question.

(a) Definition of the limits of an actuator family,
(b) The criteria which were used to assure that the sample valve operator is a valid representative of the family, and
(c) A demonstration of how the criteria were applied.

(8) Provide a Table of the following information for all Class 1E valve actuators in the Susquehanna SES design:

(a) The equipment specifications as per Section 3 of IEEE Std 382-1972,
(b) Identification of the family membership,

(c) Identification of the samples.

(9) Quantify the number of operating cycles each test specimen was subjected to.

(10) Specify the frequency range which was used in the seismic qualification and aging of the samples. (Note that the range which is permitted by IEEE Std 382-1972 does not agree with Branch Technical Position EICSB 10 which is presented in Appendix 7A to the Standard Review Plan.)

<u>RESPONSE</u>:

The requested additional information pertaining to the Safety-related instrumentation and electrical equipment supplied with the recirculation system gate, main steam safety/relief and standby liquid control valve assemblies is detailed individually for each valve below.

A. Recirculation System Gate Valve

(1) Equipment qualification is conducted on the safety-related recirculation system gate valve actuators to assure that the equipment will not operate spuriously.

Safety related NSSS recirculation system gate valve actuators are temperature qualified to IEEE 382-1972 by test for the equivalent active 40-year plant life plus LOCA condition.

The referenced conclusion on radiation qualification in the Subsection 3.11.5.3 is made on the basis of integrated radiation doses for LOCA plus 40 years life.

(2) Design control procedures for aging simulations are in accordance with IEEE 382-1972 as follows:

(a) Thermal: Refer to IEEE 382-1972, Part II, Section 2, page 10.

(b) Radiation: Refer to IEEE 382-1972, Part II, Section 1, page 10.

(c) Operation: Refer to IEEE 382-1972, Part II, Section 3, page 10.

(d) Seismic: Refer to IEEE 382-1972, Part I, Section 4, Para. 4.3, Page 8.

These IEEE-382 procedures provided the outline for recirculation valve actuator qualifications. Actual valve test parameters are discussed in the following sections.

(3) The actual thermal aging qualification test parameters which were imposed for the recirculation system gate valve actuator applications at Susquehanna SES were based on the most severe environmental conditions for equipment as described in Section 3.11.

(4) The recirculation system gate valve actuators are qualified for thermal aging in accordance with IEEE 382-1972, with the aging acceleration rate justified by application of the 10 C rule.

(5) The motor stator of the recirculation system gate valve actuator is heat-aged for 100 hours at 180°C (356°F).

(6) i. The actual radiation aging qualification test parameters which are imposed for the recirculation system gate valve actuator applications at Susquehanna SES are based on the most severe radiation environmental conditions for this equipment, as described in Section 3.11.

ii. The radiation aging acceleration rate used for qualifying the recirculation system gate valve actuators is $1X10^6$ RADS/HR. The justification for this rate is the need to complete the test in a reasonable period of time and subject the test actuator to a total radiation dose which envelopes the most severe radiation environmental conditions for the equipment, as described in Section 3.11.

iii. The recirculation system gate valve actuator was qualified by radiation aging for 204 hours with the total radiation dose of 204×10^6 RADS.

iv. For radiation aging, an equivalence of neutron dose to gamma dose was determined so that the actual gamma dose used in aging is the summation of gamma dose and neutron-gamma dose equivalence.

(7) i. All recirculation system valve actuators of the Type SMB, Type SB, Type SBO, ANO and Type SMB/HBC are designed one "family" because all are designed and built with the same design features, standards, and tolerances, and all sizes are constructed of the same material.

ii. The qualification was performed on an SMB-0-25 actuator. Since it is part of the "family" mentioned in (i) above, it qualifies all sizes of Limitorque Actuators for the environmental test conditions in accordance with IEEE 382-1972.

iii. The criteria was applied by testing an SMB-0-25 which falls in the boundaries of the definition as given in (i) above. All recirculation system Limitorque Actuators in GE's scope of supply are within that "family" defined in (i) above.

(8) As required by IEEE 382-1972, a type test demonstrated that the performance characteristics of the actuator adhered to the equipment specifications and met all functional test requirements of IEEE 382-1972. The sample recirculation valve actuator was constructed using normal manufacturing processes and was then subjected to the test program. The test program for the sample valve actuator consisted of subjecting the actuator to the following sequence of conditions to simulate the design-basis service conditions of the actuator: (a) aging (b) seismic, and (c) accident. These test conditions are detailed in subparagraph 2 below. No maintenance was performed during this type test.

All recirculation valve actuators used in the Susquehanna SES NSSS design are in one "family". The designation for this family has been established by the vendor as the "SMB" family. The sample valve actuator which was used to qualify this family was designated as follows:

Manufacturer	Limitorque
Type	SMB
Size	0
Order #	360943A
Serial #	144068

The recirculation system gate valve test specifications for the qualification sample are presented below and encompass the most severe conditions of equipment service.

a. The valve operator was required to operate and remain operable during plant normal, test, design-basis event, and post-design-basis event conditions.

b. The valve operator was required to provide rated mechanical force for the following conditions:

1. Range of voltage - 230 to 460 volts;
2. Range of frequency 1 to 35 hertz @ 1.0g; (including seismic forces) 4 to 34 hertz @ 3.0g; 35 hertz at 5.0g;
3. Thermal conditions - see Figure 0.32.18-1;
4. Mechanical aging - 500 cycles, open and close; and
5. Radiation exposure - see response to part 6.

c. The mounting configuration for the valve and operator was specified as mounted in a nominally horizontal run of pipe with the valve stem nominally vertical.

d. Lubricants, seals and other components have a minimum design life of 5 years.

e. The design life of the valve operator is 40 years.

f. Control and indicating devices contained on the valve operator include a torque switch and a limit switch.

(9) The recirculation valve actuator specimen was subjected to 500 cycles as required by IEEE-382-1972.

(10) With regard to seismic qualification, the following is a description of the testing methods employed which are consistent with Branch Technical Position E1CSB10 for plants with construction permits docketed before October 1972:

A search for resonance was performed by scanning the recirculation valve actuator test specimen in the three major axes. Scanning was done in the range from 1 to 35 hertz at a maximum acceleration of 1g. This testing identified no resonance. Next, the test specimen was vibrated at even-integer frequencies from 4 to 34 hertz for a period of 10 seconds at an excitation of 3g in each of the three major axes. The test specimen was actuated at each dwell for one complete cycle (open and close). The test specimen was then vibrated at 35 hertz for 10 seconds in each of the three major axes at an excitation of 5g and was actuated for one complete cycle.

Specific quantification of actuator qualification is embodied in the qualification test reports which are available for review at GE-NED (San Jose).

B. NSSS MAIN STEAM SAFETY/RELIEF VALVES

(1) The electro-pneumatic actuator assembly for the S/RV has been qualified by tests in accordance with the guidelines specified in IEEE-323-1971. The environmental tests consisted of influences due to radiation, thermal and mechanical aging, seismic conditions, negative pressure and the postulated LOCA steam environment. Test results indicated that the equipment will not operate spuriously.

(2) Design control procedures for qualification of NSSS Safety/Relief valves are in accordance with the guidelines of IEEE-323-1971. Test specifications and/or test parameters are discussed in the following sections.

(3) The thermal aging temperatures used to allow acceleration of time/temperature aging effects artificially by increasing the maximum normal temperature followed the Arrhenius equation identified in Handbook of Engineering Fundamentals, John Wiley and Sons, 1975 and IEEE 101-1972 Guide for the statistical analysis of thermal life test data.

(4) The thermal aging acceleration rate is quantified in part (5) and the technical basis is explained in part (3) above.

(5) Thermal aging was performed at 343° + 9°/-0°F for 96 continuous hours in an air environment with uncontrolled humidity.

(6) i. The actual radiation aging qualification test parameters which are imposed for the NSSS main steam safety/relief valve actuators used at Susquehanna SES are based on the most severe radiation environmental conditions for this equipment, as described in Table 3.11-4.

ii. The radiation aging acceleration rate used for qualifying NSSS main steam safety relief valve actuators is 2.9 X 10^5 RADS/HR. The justification for this rate is the need to complete the test in a reasonable period of time and subject the test actuator to a total radiation dose which envelopes the most severe radiation environmental conditions for this equipment, as described in Table 3-11-4.

iii. The NSSS main steam safety relief valve actuators are radiation-aged for 103.5 hours with a total radiation dose of 30 X 10^6 RADS.

iv. For radiation aging, an equivalent of neutron dose to gamma dose was determined so that the actual gamma dose used in aging is the summation of gamma dose and neutron-gamma dose equivalence.

(7) i. All of the actuator assemblies are designed and built to the same design features, materials, standards and tolerances.

ii. All actuators are of the same 'family' by virtue of design controls imposed on details of the qualified design which is in accordance with IEEE-323-1971.

iii. The criteria is imposed via GE approval and vendor certification that the actuators were built to the controlled details in (ii).

(8) i. The test specifications for the qualification sample are summarized below and encompass the most severe conditions of equipment service.

a. The valve actuator assembly was required to operate and remain operate and remain operable during plant normal, test, design-basis event, and post-design-basis event conditions.

b. The valve actuator assembly was required to provide mechanical force under the following conditions:

(1) Voltage range - 104 to 138 VDC
(2) Air pressure - 88 to 200 psig
(3) Thermal aging - 343° + 9°/-0°F for 96 continuous hours
(4) Mechanical aging - 500 cycles, open and close
(5) Radiation aging - 30 x 10^6 RADS(Total)
(6) Negative pressure - Ambient pressure at 102°F to 0.7 psia within 5 minutes
(7) LOCA environment - See Figure 032.18-2

c. The mounting orientation of the valve centerline is nominally in the vertical position with a $\pm 5°$ tolerance.

d. Lubricants, seals and other components have a minimum design life of five years under normal operating conditions.

e. Refurbishment or replacement period of the valve actuator is five years.

ii. Design controls assure that actual production units are comparable to the qualification samples.

(9) The actuator assembly was subjected to a minimum of 1000 operating cycles (See Figure 032.18-2).

(10) During seismic qualification testing the S/RV was subjected to a frequency range of 2 to 200 Hz.

C. NSSS STANDBY LIQUID CONTROL SYSTEM EXPLOSIVE VALVE

(1) The qualification tests for the standby liquid control explosive

(2) Valve were performed on a specimen that contained a primer assembly that had been in service for 5 years, the normal replacement interval. Advantage was taken of this opportunity to use the aged replaceable component which had demonstrated ability to survive normal operating conditions. This provided realistic thermal, vibration and radiation aging. Aging per cyclic duty is not applicable.

(3) Maximum normal environmental temperature specified for standby liquid control area in Table 3.11-1 of FSAR is 120°F. Actual aging temperature encountered in service is not available but is expected to have been between 70°F and 120°F. This variance is not considered significant because the maximum temperature specified does not produce rapid degradation of the replaceable components in the primer assembly.

(4) Thermal aging was not accelerated.

(5) A primer chamber that was installed for 5 years in an operating BWR was used for tests that qualified the Conax Corporation explosive valve.

(6) Radiation aging for normal service was not accelerated but obtained under a five year service condition exposure.

(7) i. All valves of similar size, design and materials of construction are judged to belong to the same 'family' for which qualification tests are applicable.

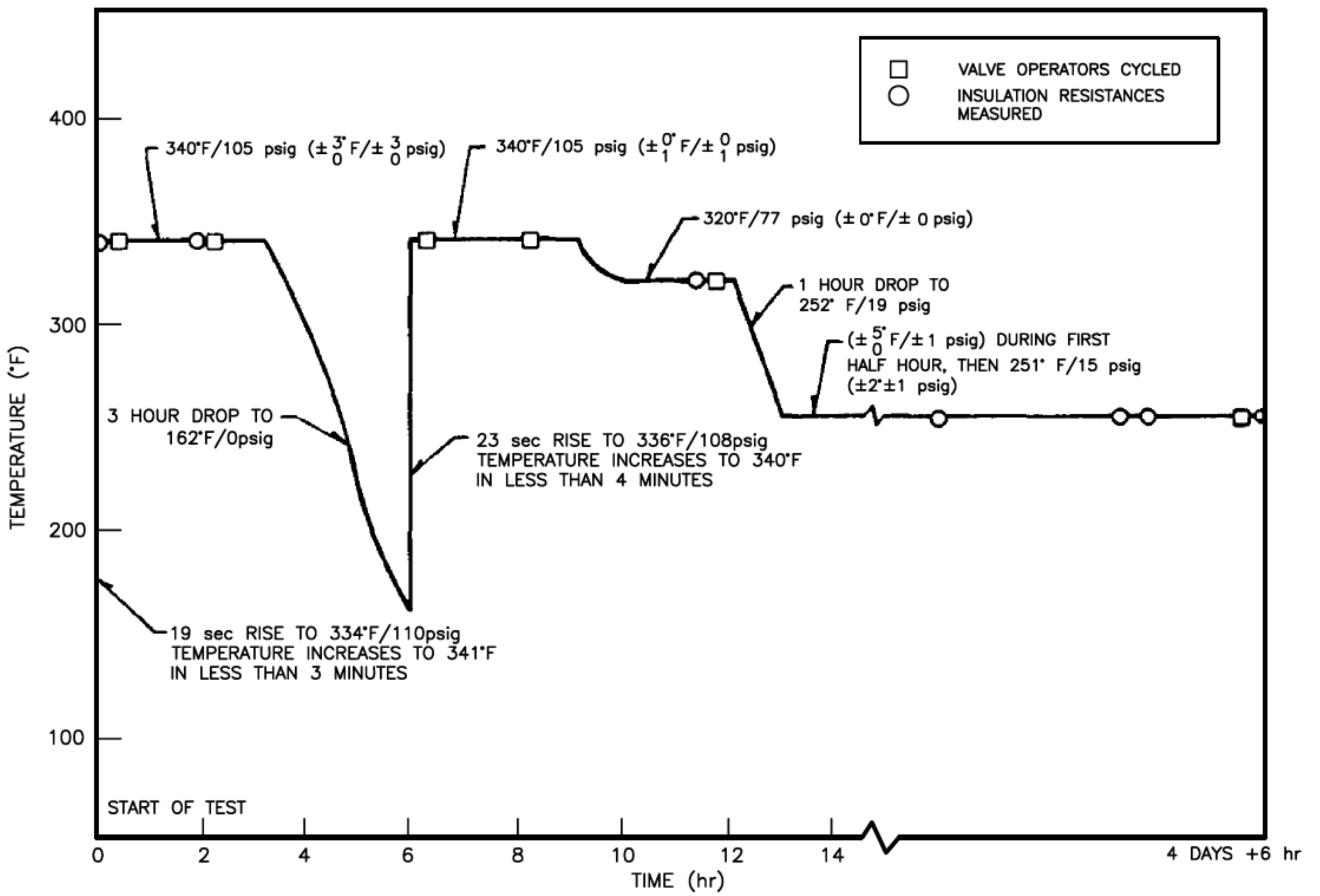
ii. A standard BWR 6 design unit was used for test. The design used for Susquehanna belongs to the same 'family'.

iii. The criterion was applied by extending test results for the BWR 6 design to the design used for Susquehanna.

(8) Identity of the sample tested is Conax Valve P/N 1832-159-01. Design control documentation (equipment specifications per IEEE-382-1972 and drawings demonstrating 'family') are available for audit in San Jose.

(9) The SICS explosive valve was not subjected to any "operating cycles" as such, since it is not required to operate under normal conditions. The non-reuseable primer dial actuates on command at the end of the test sequence.

(10) Frequency scan showed no resonance below 35 Hz and the seismic test input vibration was therefore selected as sine beats at 33 Hz. The aging of the primer was under real life vibration as encountered in the installed position on an operating BWR.



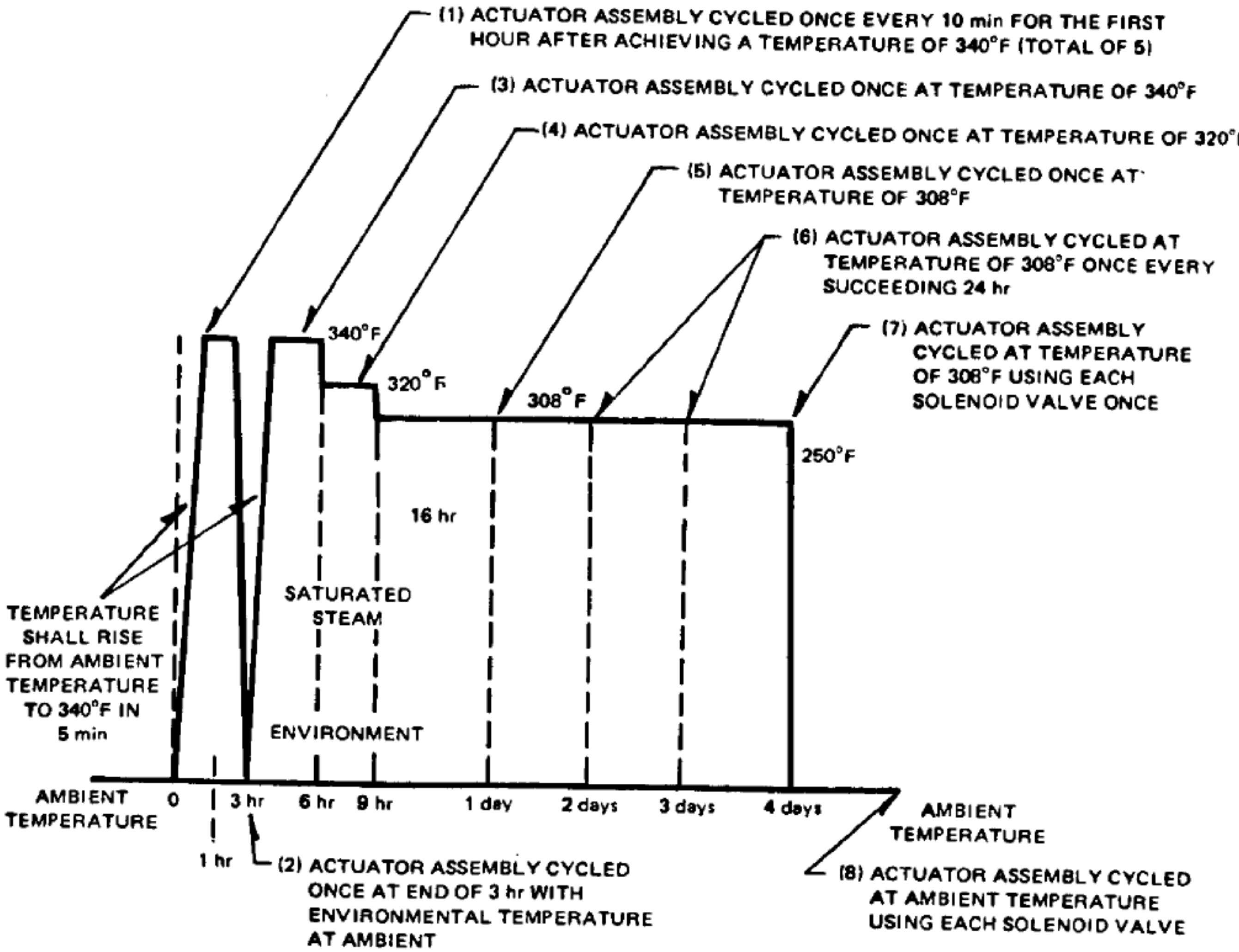
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

ACTUAL STEAM EXPOSURE PROFILE

FIGURE 032.18-1, Rev 47

AutoCAD: Figure Fsar 032_18_1.dwg



SATURATED STEAM ENVIRONMENT	
PRESSURE (psig)	TEMPERATURE (°F)
105	340
75	320
61	308

AIR SUPPLY-200 psig; MINIMUM VOLTAGE-106 OR 212 Vdc, AS APPLICABLE. EXCEPT AS OTHERWISE INDICATED, ACTUATOR TESTS SHALL BE CONDUCTED USING NEAR SOLENOID ONLY

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

ABNORMAL AMBIENT CONDITIONS
FOR QUALIFICATION TEST OF
SRV ACTUATOR ASSEMBLY

FIGURE 032.18-2, Rev 47

AutoCAD: Figure Fsar 032_18_2.dwg

QUESTION 032.19

The requirements for documenting the seismic and environmental qualification of Class 1E equipment are presented in Sections 3.10 and 3.11 of the "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," Regulatory Guide 1.70 and are applicable to all engineered safety features, reactor protection systems and all auxiliary supporting systems and are not limited to those systems which are supplied by General Electric.

It is the staff's position that such documentation, for all Class 1E balance-of-plant supplied systems, required by IEEE Std 323-1971 must be retained by the applicant in an auditable manner. Describe the program which you will implement to satisfy the staff's position.

RESPONSE:

Documentation for the environmental qualification of non-NSSS equipment is retained in an auditable manner as described in Subsection 3.11.3. See response to Question 032.20 for a discussion of compliance with IEEE 323-1971 for non-NSSS equipment.

QUESTION 032.20

The response to Acceptance Review Question 032.3 is incomplete. You state that General Electric has complied with IEEE Std 323-1971 for the environmental qualification of instrumentation components. It is the staff's position that all safety-related equipment, both NSSS and non-NSSS, must be qualified in accordance with IEEE Std 323-1971. Provide a statement in the FSAR which certified compliance to IEEE Std 323-1971 for all safety-related equipment and identify and justify all exceptions.

RESPONSE:

The degree of compliance with IEEE 323-1971 for non-NSSS Class 1E equipment is discussed in Subsection 3.11.2.1. Qualification data for typical equipment is given in response to Question 040.2. Also refer to the response to Question 032.28.

All Susquehanna SES NSSS safety-related equipment is environmentally qualified in accordance with the provision of IEEE 323-1971. See revised Subsection 3.11.1.

QUESTION 032.21

Your discussion of isolation devices, which is presented in FSAR Section 7.2.2.1.2.3.1.7 is incomplete. Provide the following information:

(1) List all parameters and systems that interface between the safety and non-safety systems.

(2) Identify the type of transmission (i.e., analog, digital, electrical, optic, etc.) which is involved with each interface that is identified in response to Item (1) above.

(3) Identify the type of isolation device which defines the Class 1E boundary for each interface which was identified in response to Item (1) above.

(4) Provide the acceptance criteria for each isolation device which is identified in response to Item (3) above.

(5) Describe the type of testing which was conducted on the isolation devices to insure adequate protection against EMI.

(6) Describe the qualification test plans and provide the test results for each isolator which is identified in response to Item (3) above.

RESPONSE:

The system and parameters that interface with the Reactor Protection System (RPS) (system described in Section 7.2) are described in part a to part j in Subsection 7.2.1.1.4.2, entitled Initiating Circuits. The interfaces with RPS are qualified as safety-related. Those instrument trips in non-seismic structures, namely, those associated with turbine stop valve and turbine control valve position sensing, have diversity in high reactor pressure trips to the RPS. Signals to the RPS are of digital type via relay contacts or instrument switch contacts. Annunciators, process computer and Reactor Manual Control System inputs are non-safety related RPS interfaces. These are actuated via RPS relay contacts and isolation is provided through high coil to contact insulation impedance which has been accepted generically on this vintage plant. The testing type and relay qualification data is available for audit by the Commission at General Electric Company in San Jose.

QUESTION 032.22

The standby liquid control system (SLCS) is designated as a special safety system in the SSES design. To assure that availability of the SLCS, you have provided two sets of the components required to actuate the system in parallel redundancy. However, our review indicates that you have not provided redundant heating systems and the heating equipment supplied is not powered from an emergency bus under normal conditions. The staff has concluded, therefore, that the statement in FSAR Section 9.3.5.3 that a "single failure will not prevent system operation" is not true. Provide a modified design of the SLCS which satisfies the single failure criterion or justify the present design.

RESPONSE:

Regulatory Guide 1.70 identifies the SLCS as a safe shutdown system having a safety-related classification. Safety-related systems provide the actions necessary to assure safe shutdown of the reactor, to protect the integrity of radioactive material barriers, and/or to prevent the release of radioactive material in excess of allowable dose limits. However, the system fails to meet all the requirements of a safety-related system in that SLCS is not designed for the single active component failure criteria. A function of the system is to inject boron to the suppression pool via the SLC System to maintain basic pH in the suppression pool in order to minimize re-evolution of iodine from the suppression pool in the event of a Loss of Coolant Accident (LOCA). This function adds additional importance to the system's performance.

The NRC has provided review guidelines for the SLC system that do not meet single failure criteria or that are not of the expected quality (safety related). To demonstrate that the SLC System is able to perform its AST (10 CFR 50.67) function (injection of sodium pentaborate into the suppression pool), the System should satisfy, as a minimum, the recommended guidelines listed below (NRC review guidelines). Meeting these criteria, demonstrates reasonable assurance of the quality of the SBLC System. These guidelines are as follows:

a) The SLC System should be provided with standby AC power supplemented by the emergency diesel generators.

b) The SLC System should be seismically qualified in accordance with Regulatory Guide 1.29 and Appendix A to 10 CFR Part 100.

c) The SCL System should be incorporated into the plant's ASME Code ISI and IST Programs based upon the plant's code or record (10 CFR 50.55a).

d) The SCL System should be incorporated into the plant's Maintenance Rule program consistent with 10 CFR 50.65

e) The SLC System should meet 10 CFR 50.49 and Appendix A (GDC 4) to 10 CFR 50.

An extensive validation of NRC guidelines for the SBLC system of components that do not meet single failure criteria or that are not of the expected quality (safety related) provides reasonable assurance of the System's ability to support its original and the pH controlling functions.

Subsection 9.3.5.3 discusses the consequences of a loss of the tank heaters or suction piping heat tracing. Note that, as stated in Subsection 7.4.1.2.2, the tank heaters receive power from the standby a-c power supply bus C (Division I). The design has been changed to provide Division I standby a-c power to the heat tracing circuit as well.

QUESTION 032.23

The design of the recirculation system as described in FSAR Section 5.4.1.3 appears to be obsolete. It is the staff's understanding that the General Electric design does not include a bypass in the recirculation system piping. Therefore:

(1) Clarify the discrepancies between the cited Sections of the FSAR and FSAR Figure 5.4-2a (which doesn't show a bypass).

(2) Revise the FSAR, as appropriate, to completely describe the actual design of the SSES recirculation system.

RESPONSE:

Subsection 5.4.1.3 of the SSES FSAR describes the actual design of the Susquehanna SES recirculation system. Dwg. M-143, Sh. 1 shows the bypass in the recirculation system piping.

QUESTION 032.24

The accident analysis presented in Chapter 15 is based, in part, on the assumption that the Rod Block Monitor (RBM) acts to mitigate the consequences of a continuous rod withdrawal. The staff's position is that the RBM is a protection system and must be designed, fabricated, installed, tested, and subjected to all of the design criteria which are applicable to a reactor trip system. Revise the FSAR to reflect the importance of the RMB in accordance with the requirements of Section 7.2 of the "Standard Format," Regulatory Guide 1.70. Identify and justify any exceptions.

RESPONSE:

See the response to 32.7.

QUESTION 032.25

Contrary to the statement in FSAR Section 7.2.1.1.2, the staff has noted that the RPS motor generator sets are not Class 1E. Therefore, please:

(1) Clarify the discrepancy between FSAR Sections 7.2.1.1.1 and 7.2.1.1.2 with regard to the qualification of the motor generator sets.

(2) Identify the alternate power source in FSAR Figures 7.2-1, Sheet 1, and Figure 8.3-8.

(3) Describe how the design and implementation of the SSES PPS satisfies the requirements of IEEE Std 379-1972, Section 6.6 (with special emphasis on the last paragraph).

RESPONSE:

(1) FSAR Subsection 7.2.1.1.2 has been revised to state "... Safety Class 1E with the exception of the motor-generator power supplies which are non-Class 1E and the RPS circuits located . . ."

(2) Figure 7.2-1 has been revised to show the alternate power source. The motor-generator sets shown in Figure 8.3-8 are part of the swing bus design and should not be confused with the RPS motor generator sets discussed in Subsection 7.2.1.1.2.

(3) The RPS Motor Generator sets supplied for Susquehanna are the same as those supplied for the Hatch 2 facility. These motor generators will be supplied with Class 1E qualified equipment to monitor and protect the connected loads from unacceptable values of voltage and frequency. The generic design and qualification plan supplied by G.E. has been approved by the NRC as satisfying the requirements of IEEE-379-1972 Section 6.6.

QUESTION 032.26

Provide the design criteria and a description of the scram discharge volume switches and their qualification testing in accordance with the requirements of Section 7.2 of the "Standard Format," Regulatory Guide 1.70. Include the following information:

(1) Manufacturer

(2) Type of float (self-equalizing or sealed)

(3) Float material and magnet material

(4) Qualification Test Conditions

(a) Water Temperature

(b) Pressure

(c) Duration of test conditions

(d) Number of test cycles

(e) Period between test cycles

(f) Extremes of external temperature, pressure, and humidity

(g) Radiation source, strength, and dose.

RESPONSE:

(1) Manufacturer: Magnetrol

(2) Float Type: Sealed

(3) Float Material: 374SS

(4) Qualification Test Conditions:

Qualification information for the scram discharge volume switches is shown on 3.10a-1 of Susquehanna's FSAR. The qualification data requested in 032.26 is available for audit at General Electric in San Jose, under file number 159C4361 (specified in Table 3.10a-1 under column labelled "Item No." and corresponding to item no. C12-N013.

QUESTION 032.27

The staff's position with regards to post accident monitoring and safe shutdown display instrumentation is stated in Branch Technical Position ICSB 23 in Appendix 7A of the NRC Standards Review Plan. State your conformance or justify your alternatives.

The description contained in Section 7.5.1a.4.2 of the FSAR refers to Post Accident Tracking in only general statements. Discuss the extent to which the monitoring devices and safe shutdown equipment will conform to the position set forth above, and revise the FSAR accordingly. Your response should identify the channels that are recorded and their qualification.

RESPONSE:

Post accident monitoring is discussed in PP&L's updated response to TMI related requirements (PLA-659, N.W. Curtis to B.J. Youngblood dated 3/16/81). PP&L has provided its position on Regulatory Guide 1.97, Revision 2 in PLA-965, Curtis to Schwencer, dated 11/13/81.

QUESTION 032.28

Identify the equipment which has been environmentally qualified by inference from tests done on similar equipment or previous operating experience and, for each item, provide the basis for the extrapolation in accordance with the requirements of IEEE Std 323-1971.

RESPONSE:

For the environmental qualification of Class 1E equipment, see the Susquehanna SES Environmental Qualification of Class 1E Equipment Program.

TABLE 032.28-1

NON-NSSS EQUIPMENT ENVIRONMENTALLY QUALIFIED TO IEEE 323-1971 BY INFERENCE FROM TESTS ON SIMILAR EQUIPMENT[1]

M/R	Description
M 307AC	Centrifugal Fans
M 320	Flow Switches for HVAC Systems
M 317	Drywell Unit Coolers
M 327	Chilled Water and Cooling Water Pumps
E 130A	600 V Power and Control Cable
E 131A	Instrument and Special Cable
E 131BC	Instrument and Special Cable
E 135-73	Cable Splices
E 135	Electrical Penetrations
E 109	5 kv Switchgear
E 129	5 kv Single Conductor Cable
E 112	ESW Pump Motor and RHR SW Pump Motor
E 119BC	24 and 250 Vdc Battery and 125 Vdc Battery
E 121	125 and 250 Vdc Load Centers
E 151	M-G Sets
E 152	Automatic Transfer Switches
E 117	480 V Load Center and Load Center Transformer
E 118	480 V MCC
E 136	120 VAC Instrument Transformer
E 118	120 VAC Distribution Panels, AC and DC Motor Actuators for Nuclear Services Valves
J 3A	Electronic Field Mounted Instruments
J 65B	Control Valves
J 70	Process Solenoid Valves

[1] Some of the equipment (but not necessarily all) in the listed purchase orders are qualified by inference from tests on similar equipment.

TABLE 032.28-2

NON-NSSS EQUIPMENT ENVIRONMENTALLY QUALIFIED TO
IEEE 323-1971 BY PREVIOUS OPERATING EXPERIENCE

M/R	Description
M 30	DG and Auxiliaries
M 58	Diesel Fuel Oil Transfer Pump
E 119A	24, 125 and 250 VDC Battery Chargers

QUESTION 032.29

The discussion in FSAR Section 7.2.2.1.2.3.1.20 of compliance with the requirements of IEEE Std 279-1971 Section 4.20 (Information Read-out) is not adequate. Revise the FSAR to describe the equipment and systems which provide "the operator with accurate, complete, and timely information pertinent" to the status of the information channel "and to generating station safety."

RESPONSE:

The requested information is contained in Section 7.5, Safety Related Display Instrumentation.

QUESTION 032.30

List all of the control circuits which receive inputs from the scram trip input circuits.

RESPONSE:

There are no non-NSSS circuit interlocks from any of the RPS input circuits.

The Reactor Manual Control and Nuclear Steam Supply Shut-off Systems receive inputs from the scram trip input circuits.

QUESTION 032.31

Your discussion in FSAR Section 7.2.2.1.2.3.1.10 on the reactor low water level scram trip indicators is incomplete. Describe how the level switches and indicators are calibrated.

RESPONSE:

For response see Subsection 7.2.2.1.2.3.1.10.

QUESTION 032.32

Describe the installation, operation, and removal of the "Startrek" computer system which is used for start-up testing of GE Boiling Water Reactors. Include the following topics:

(1) Specifications of and Qualification testing of electrical isolators.

(2) Separation criteria for permanent and temporary wiring.

RESPONSE:

Subsections 7.7.1.9 and 7.7.2.9 have been included to supply this information.

QUESTION 032.33

Identify and justify all containment isolation valves which are provided with manual override of the isolation logic. Also identify and justify all other aspects of the Susquehanna SES design which do not meet the requirements of IEEE Std 279-1971, Section 4.16. For each manual override which is provided in the Susquehanna SES design, demonstrate compliance with IEEE Std 279-1971, Sections 4.11 through 4.14.

RESPONSE:

For this information, see revised Table 6.12-12 and revised Subsection 7.3.1.1b.1.3.

No non-NSSS circuits are provided with manual override or bypass isolation logic. However, several non-NSSS isolation valves may be manually opened after a LOCA to permit containment atmosphere sampling and as a backup to the hydrogen recombiner system to dilute hydrogen in the containment. Isolation logic for these valves is described in Subsection 7.3.1.1b.1.3.

All non-NSSS protection systems meet the requirements of IEEE 279-1971, Section 4.16.

The valves which are associated with the NSSS isolation logic and can be overridden are identified as part of the following IEEE compliance discussion. Also included are two parts, one is a design justification based on identifying those guidelines (namely IEEE Sections in question) which deem such a design as acceptable; and two is a compliance statement of related valves with IEEE 279-1971 Sections 4.11 through 4.14.

Compliance with IEEE 279, Section 4.16

The NSSS controlled isolation valves and logics are in compliance with IEEE 279-1971, Section 4.16 in that the isolation logics (including the isolation logic provided for AE use) are provided with seal-in circuits that will maintain the logic in a tripped (isolated) condition and cause valve closure even when the initiating signal clears. The operator must manually reset the logic (after the initiating condition clears) to remove the logic seal-in in order to move the valve to any position other than fully closed. The only exception to this logic seal-in is the reactor high pressure trip which is used to interlock the RHR shutdown cooling valves (E11-F008 and F009) and the RHR head spray valves (E11-F022 and F023). However, both shutdown cooling suction valves and the inboard head spray valves have motor control circuit seal-ins which will cause valve full closure even if the high pressure initiating signal clears. The outboard head spray valve (E11-

F023) is a throttling valve and as such has no motor control center seal-in. Therefore, it will stop "as is" should the initiating signal clear and would require manual operator action to cause full closure. It should be noted that the shutdown cooling suction valves and head spray valves are always interlocked closed when the reactor is at pressure and these valves are only opened during shutdown cooling. Additionally, should this unlikely event occur, the inboard head spray valve would perform the isolation function automatically on the spray line.

An assessment of compliance with IEEE 279-1971, Paragraph 4.16, of all systems within NSSS design scope for Susquehanna is provided in applicable analysis sections of Susquehanna's FSAR Chapter 7.

<u>Compliance with IEEE 279-1971, Sections 4.11, 4.12, 4.13, and 4.14</u>

Operational Bypasses

The Main Steamline Isolation Valve Logic has two operational bypasses as follows:

1. Operational bypasses are provided for the main condenser low vacuum trips. The manual bypass switches are in the main control room under operator control and are keylocked. Alarms are provided to indicate when the bypass is in effect. The bypasses are cleared automatically whenever the turbine stop valves reach 90 percent full open or the reactor pressure is above a preset value or whenever the operator places the Reactor Mode Selector Switch in the "Run" position. Thus compliance with IEEE 279, Sections 4.12, 4.13, and 4.14 is achieved by providing automatic removal of the bypass, indication of bypass and keylocked bypass switches.

2. An Operational Bypass is provided for the main steamline low pressure trip whenever the reactor Mode Selector Switch is not in the "Run" with Neutron Flux measuring power above 10 percent of rated power without imposing a SCRAM. Therefore, the bypass is considered to be removed in accordance with the intent of IEEE 279, Section 4.12, although it is removed by manual action rather than automatic action. The bypass of the low pressure isolation signal is not indicated in the control directly except by the position of the switch handle and readout on the Display Control System. This mode switch is keylocked in each position and is centrally located on the operator's main control panel where it is under strict operator control. Its specific

bypass functions are a matter of operator training and as such does not reasonably need to be brought to the operator's attention each time he places the switch in any mode other than "Run." Since the bypass is not removed by any automatic action, it is positively in effect any time the mode switch is not in "Run." Thus compliance with the intent of IEEE 279, Sections 4.13 and 4.14 is met.

These operational bypasses affect the Main Steamline Isolation Valves (B21-3002 A-D and F028 A-D) and the Main Steamline Drain Valves (B21-F016 and F019).

Manual Test Bypasses

The steam leak detection system provides test bypass switches in the isolation logics for the following systems:

1. Residual Heat Removal System (RHR)

2. Reactor Water Cleanup System (RWCU)

3. Reactor Core Isolation Cooling System (RCIC)

4. High Pressure Core Injection System (HPCI)

These bypass switches only override the equipment area high temperature trip portions of the isolation logics and are provided for test purposes so that the temperature trip logics may be tested during plant operations. The Test/Bypass switches are located on panel H12-P614 in the control room where they are under operator control. Additionally, they are keylocked switches which provide an alarm whenever they are removed from the normal position to the Test/Bypass position. Since these switches are provided for channel test, are alarmed when not in Normal, are keylocked and under operator control, compliance with IEEE 279, Section 4.11, 4.13, and 4.14 has been met.

The valves affected by the RHR leak detection bypass switches are the Shutdown Cooling Suction Valves (E11-F008 and F009) and the head spray valve (E11-F022 and F023).

The valves affected by the RWCU leak detection bypass switches are the system suction valves (G33-F001 and F004).

QUESTION 032.34

Provide a discussion in FSAR Section 7.3.1b of testability and how the non-General Electric portions of all engineered safety features systems comply with the requirements of IEEE Std 279-1971, Sections 4.9 and 4.10, and IEEE Std 338-1971.

RESPONSE:

Subsections 7.3.1b and 7.3.2b have been revised to include this information.

QUESTION 032.35

The description of how the ADS satisfies the requirements of IEEE Std 279-1971 Sections 4.19 and 4.20 are insufficient. Provide the following information:

(1) Describe how the operator is made aware of Items a through d under the discussion of compliance with Section 4.19 of IEEE Std 279-1971.

(2) Justify the use of temperature monitors on relief valve discharge pipes and plant annunciators for providing information which forms the basis for operator action to protect public health and safety.

(3) Define "ADS level."

RESPONSE:

(1) As stated in Subsection 7.3.2a.1.2.3.1.19, items a) through d) are indicated by annunciators or lamp indicators via relay contacts, which are operated integrally with its respective actuated device (relay) for a given parameter.

(2) Relief valve discharge temperature is annunciated to inform the operator that steam leakage has exceeded predetermined levels. Temperatures are further recorded and allow the operator to verify and identify the source of leakage. This on-line capability affords additional (beyond temperature annunciator trip point) means upon which to determine temperature/leakage status.

(3) Though the nomenclature "ADS level" could not be found in the sections specified in Question 032.35, it is the reactor water level at which associated ADS logic is initiated. This level is quantitatively defined in Chapter 16.

QUESTION 032.36

Justify your position, presented in FSAR Sections 7.3.2.1 and 7.4.1.1, that only Sections 2.1 and 2.2 of IEEE Std 338-1971 are applicable to the design of the ECCS and RCIC. Identify and justify all exceptions to IEEE Std 338-1971.

RESPONSE:

The ECCS and RCIC systems conform to the scope of IEEE 338-1971 as defined therein by paragraphs 2.1 and 2.2 (see Subsections 7.3.2a.1.2.3.4 and 7.4.2.1.2.3.4).

QUESTION 032.37

The discussion of Environmental Conditions which is typified by material such as that in FSAR Sections 7.3.2.4 and 7.4.2.1 is unacceptable. It is the staff's position that all equipment which is required to protect public health and safety (including cables) must be qualified for operation in the worst case environment. Inside the containment, this environment is typified by accident results. Equipment outside of containment must be qualified to the extremes of expected conditions which could result from the failure of other engineered safety features or equipment required to maintain a controlled environment such as plant heating systems. Revise the FSAR to demonstrate compliance with the staff position. Identify and justify all exceptions.

RESPONSE:

Equipment qualification discussions in Subsections 7.3.2.4 and 7.4.2.1 are appropriate for NSSS equipment supplied. As stated, the equipment is qualified for the normal and abnormal environs in which it is mounted. Sections 3.10 and 3.11 provide further discussions of equipment qualifications.

The qualification of all non-NSSS Class 1E electrical equipment is discussed in Section 3.10 (Seismic) and 3.11 (Environmental). The effects from a loss of HVAC on the qualification of non-NSSS equipment are discussed in Subsection 3.11.4.

QUESTION 032.38

The statement that "All components used in the containment spray system have demonstrated reliable operation in similar nuclear power plant protection system or industrial application," is unacceptable because:

(1) This statement does not satisfy the requirements of IEEE Std 323-1971.

(2) Considerable problems have been experienced with the drift of blind sensors.

Provide an amended discussion of compliance with IEEE Std 279-1971 Section 4.4 which satisfies the requirements of IEEE std 323-1971 and describes the methods which will be used to reduce sensor drift to acceptable levels.

RESPONSE:

The compliance discussion for IEEE 279-1971 Section 4.4 states that the components are capable of accurate operation in both normal and abnormal environments expected. This appears in the discussion directly above the statement cited in this question. Further seismic and environmental qualification discussion to IEEE-323-1971 and IEEE-344-1971 is provided in Sections 3.10 and 3.11, and Subsections 7.3.2a.4.3.1.4 and 7.3.2a.4.3.1.5.

Having recognized the sensor drift problem, the following actions have been initiated:

a) The Technical Specifications Set Points Re-evaluation program has been undertaken to develop set points which take into account drift so that acceptable instrument performance does not cause false out-of-spec. conditions.

b) The periodic testing cycle has been selected so as to detect the occurrence of drift and to keep the instrument within acceptable performance levels.

QUESTION 032.39

Justify the use of a non-seismic Category I condensate storage tank for the RCIC. Include in this justification a discussion of how manual transfer satisfies the assumptions used in the operational analysis of the rod drop accident and how the RCIC satisfies the requirements of Regulatory Guide 1.29.

RESPONSE:

Subsection 7.4.1.1 concerns the Instrumentation and Control systems for the RCIC. All instrumentation and control systems for the RCIC, including the instrumentation and controls for the condensate storage tank (CST), are Class 1E although the CST facility is non-Class 1E. The RCIC is initially aligned to the CST for reactor vessel make-up water but can be manually transferred to the suppression pool at low CST water level. As the RCIC is automatically initiated by reactor vessel low water level and deactivated by reactor vessel high water level, and with the manual transfer of the water source from the CST to the suppression pool (Seismic Category I), the operational analysis is satisfied for the rod drop accident. During a safe shut-down earthquake (SSE), the condensate storage tank and associated non-safety related RCIC valves and circuitry are not required to be seismic Category I qualified to satisfy the requirements of Regulatory Guide 1.29 in the event of a rod drop accident. The accident analysis for rod drop does not rely on RCIC operation.

QUESTION 032.40

It is the staff's position that trip devices such as "86" devices which require manual reset must have the tripped condition indicated on the inoperable and bypassed status indicator. Therefore, provide a revised design for the RCIC turbine over-speed trip, and any other lockout device which is a part of a safety-related system. Identify and justify each such system which does not have all lock-outs indicated on the indicator required by Regulatory Guide 1.47.

RESPONSE:

All non-NSSS lock-out devices (86) in safety related systems are indicated/alarmed directly or indirectly in the control room except the following:

A. 4.16 kV busses and switchgear. The bus lock-out relay (86) in 4.16 kV switchgear is not individually indicated. It trips all closed feeder breakers and prevents closure of any open breakers when actuated on overcurrent of the bus incoming feeders or on a bus differential relay actuation. During the bus lockout, the undervoltage relay will provide an alarm in the Control Room. The bus can not be re-energized and the above alarm can not be cleared without resetting the lockout relay.

B. Engineered Safeguard (ES) Transformer (non-Class 1E; see Dwg. E-1, Sh. 1 and E-1 Sh. 2). A lock-out relay (86), provided in the 13.8 kV S/U switchgear for the ES transformer is not indicated in the Control Room. It trips the ES transformer 13.8 kV feeder breaker and incoming feeder breakers for the ESF busses upon actuation of the ES Transformer differential relay. The trips of these ESF bus feeder breakers and the ES Transformer 13.8 kV feeder breaker are alarmed in the Control Room. These breakers cannot be closed until the ES Transformer lockout relay is reset.

The RCIC meets the requirements of Regulatory Guide 1.47. This is accomplished by providing an indicator light for turbine trip that is actuated by a limit switch when the turbine trip throttle valve is closed. This trip is also connected to annunciate RCIC system out of service.

Although it may be the staff's position that "86" devices which require manual reset must have the tripped condition indicated, Regulatory Guide 1.47 doesn't require this. The design used here, indicates the resultant turbine trip condition and annunciates system level out of service. Component level indication is not required for any system.

QUESTION 032.41

The discussion of compliance with the requirements of IEEE Std 279-1971 Section 4.17 is inadequate because it does not address manual initiation at the system level. Provide a description of manual initiation at the system level for all ECCS. Identify and justify all exceptions.

RESPONSE:

Manual initiation at a system level is addressed on a per system basis under Subsection 7.3.2a.1.2.3.1.17, entitled Manual Initiation (IEEE 279-1971, Paragraph 4.17).

QUESTION 032.42

Amend FSAR Section 7.5 to describe the Advanced Control Room Complex which includes NUCLENET and PGCC in accordance with the requirements of Sections 7.5 and 7.7 of the Standard Format, Regulatory Guide 1.70. This description should include a discussion of the design and qualification testing of all devices which are used to isolate non-Class 1E display systems from Class 1E circuits and the physical separation between Class 1E and non-Class 1E wiring within the Nuclenet system. (e.g. How are the Class 1E circuits protected from the CRT high voltage circuits? How is this isolation system qualified to the requirements of IEEE Std 279-1971?)

RESPONSE:

FSAR Section 7.5 has been revised to contain the information requested on the Advanced Control Room (ACR) implementation in the Susquehanna plant design. Because the Susquehanna SES design predates Regulatory Guide 1.75 and IEEE 384, these requirements are not applicable to this plant (see Subsections 7.1.2.5.8 and 7.1.2.6.16). The separation design used on Susquehanna SES has been found to be acceptable on the Hatch-2, Zimmer, and LaSalle dockets as satisfying the requirements of IEEE-279-1971.

The Susquehanna SES design includes a high degree of design protection between Class 1E safety system signals and non-Class 1E systems as follows: The safety system interfacing signals are either digital or analog. Digital signals are provided from Class 1E qualified components such as relays and switches. The Class 1E qualification testing did not, however, include any requirement to demonstrate isolation capability, since this was a post-design requirement. For BWR IV and V vintage plants the NRC has approved, as acceptable, the inherent protection afforded by contact-to-contact and coil-to-contact isolation. Analog safety signals are being provided from current and voltage limiting circuit designs which provide protection for the safety circuit. The circuit design incorporated good engineering design practices but qualification testing or demonstration of isolation capacity was not required. All of the non-safety signals that come from safety systems originate at the safety device or circuit which is within a safety system enclosure.

The Display Control System (DCS) in a non-safety system and its CRT high voltage circuits are separated from the safety system signals. The CRT high voltage occurs only within the HV section of the CRT chassis; it therefore does not appear in any panel or floor section signal cabling. Separation is provided by routing of safety system cables in floor section divisional ducts that are separated from the non-divisional ducts.

Separation is also provided, as required, by conducting and canning the circuits in the common inner ring operator bench boards. For BWR IV and V vintage plants, the NRC has approved, as acceptable, these mechanical barriers between safety and non-safety circuits.

In summary, the separation design used on this plant has been previously approved by the NRC as satisfying the IEEE-279-1971 requirements and the level of isolation protection afforded by the design has also been approved.

QUESTION 032.43

The discussion of shutdown, isolation and core cooling indication is inadequate. Provide the following additional information:

(1) Identify which instrument bus supplies power to the control rod status lamps.

(2) Identify which instrument bus supplies power to the control rod scram pilot valve status lamps.

(3) Justify the use of the power range channels and recorders downscale indication as a valid indication of reactor subcriticality following a loss of offsite power.

(4) Identify the annunciators which have a safety function.

(5) Describe the qualifications of the annunciators, and plant process computer and demonstrate that they satisfy the requirements of GDC 13, 20(2), 21, 22, 23, and 24 and IEEE Stds 279-1971, 323-1971, 338-1971, and 344-1971. If these criteria are not met, justify the use of this equipment for the protection of public health and safety.

RESPONSE:

(1) Scram position of the control rods are indicated at both panels 1C652 (4 rod group status) and 1C651 (full core display). The rod positions are transmitted to these panels from a multiplexer located in panel 1C615. The power supplies for these panels are as follows (Unit 2 panels are fed from the corresponding Unit 2 power supplies):

1C615, 1C651 -	120 V instrument a-c panel 1Y218 (non Class 1E)
1C652 -	120 V a-c uninterruptable power supply panel 1Y629 (non-Class 1E)

Refer to Section 1.7, Dwg. E-25, Sheets 1, 2, & 3 for panel assignment.

(2) The Division I and Division II scram pilot valve status lamps are powered from the RPS 120 V a-c panels (non-Class 1E) 1Y201A and 1Y201B, respectively. Unit 2 indications are fed from the corresponding Unit 2 RPS panels.

Refer to Section 1.7, Dwg. E-157, for panel assignment.

(3) Although the neutron monitoring power range channels are listed as indication that the reactor is shutdown, this is not to be construed as meaning they are required to verify shutdown. The neutron monitors provide information in addition to the verification that is given by the control rod status lamps and scram pilot status lamps. The neutron monitors would not provide verification following a loss of offsite power.

(4) The annunciators do not perform any safety function.

(5) The annunciator and the process computer are not safety equipment and do not perform any safety functions.

QUESTION 032.44

The seismic qualification of indicators and recorders for post-accident monitoring which is described in FSAR Section 7.5.1a.4.2.3.3 is unacceptable. It is the staff's position that post-accident indicators and recorders must satisfy their minimum performance requirements before and after a seismic event without adjustments or repair. (The staff acknowledges that these electro-mechanical devices may not accurately indicate during severe vibrational excitement.) Provide a modified design to conform to the above position or justify the exception taken.

RESPONSE:

Post-accident monitoring is discussed in PP&L's updated response to TMI related requirements (PLA-659, N. W. Curtis to B. J. Youngblood dated 3/16/81). PP&L has provided its position on Regulatory Guide 1.97, Revision 2 in PLA-965, Curtis to Schwencer, dated 11/13/81.

QUESTION 032.45

It is the staff's position that the use of the Rod Worth Minimizer in unacceptable for the protection of the public health and safety because it does not satisfy the requirements of IEEE Std 279-1971. Therefore, amend the FSAR by deleting this system from those sections specifically designated for systems that are required for safety.

RESPONSE:

The FSAR will be amended, moving Rod Worth Minimizer from Section 7.6 to Section 7.7, under Control System Not Required for Safety.

QUESTION 032.46

The Rod Sequence Control System (RSCS) is assumed to function in FSAR Section 15.4.1.2 to mitigate or prevent several accidents. Therefore, it appears that the Reactor Manual Control System (RMCS), Rod Position Indicating System (RPIS), and RSCS are parts of a reactor protection system. Therefore, provide the design bases and other information in accordance with bases and other information in accordance with the requirements of Section 7.2 of the Standard Format, Regulatory Guide 1.70 for these three subsystems.

RESPONSE:

The Reactor Manual Control System (RMCS) with its Rod Sequence Control (RSCS) and Rod Position Indication (RPIS) portions and the Rod Worth Minimizer (RWM) are not safety systems; however, the safety action required for the continuous control rod withdrawal transient is performed by the qualified Neutron Monitoring System as detailed below.

Continuous control rod withdrawal errors during reactor startup are precluded by the rod sequence control system (RSCS) and the rod worth minimizer (RWM). The RWM prevents the selection and withdrawal of an out-of-sequence control rod. Failure of the RWM to block an out-of-sequence rod will result in a RSCS rod block. Thus, the RSCS and RWM provide redundant protection systems with diverse power supplies.

In the unlikely event that both the RWM and RSCS fail, the IRM system will block rod withdrawal and initiate a scram if the scram setpoint is reached. Furthermore, the ARPM will initiate a scram at 15% of rated power.

The consequences of a rod withdrawal error in the startup range were generically analyzed in NEDO-23842. The analysis shows that the licensing basis criterion for fuel failure is still satisfied even when the RWM and RSCS fail to block rod withdrawal. Thus, a modified design for the RSCS is not required.

QUESTION 032.47

Provide a list of NSSS Class 1E instrumentation and control equipment utilized within the SSES design that have been previously used in BWR plants such as Zimmer, LaSalle, Hatch and Shoreham. Also identify those Class 1E equipment in NSSS scope that are utilized for the first time in SSES design.

RESPONSE:

The following NSSS Class-1E instrumentation and control equipment used on Susquehanna were not previously used on BWR plants such as Zimmer, LaSalle, Hatch, and Shoreham. The other equipment listed in FSAR Tables 3.10-1 and 3.10-2 have previously been used on BWR plants such as Zimmer, LaSalle, Hatch, and Shoreham.

Description	Application	Manufacturer	Identification
Operating Mode Switch	H12P680 C72A-S1	Rundell	163C1487
Push Button Switch	H12P601 e.g. E21A S16A & E11A-S20A	Cutler Hammer	145C3230
Push Button Switch	H12P853	Cutler Hammer	851E392
R.G. 1.47 Bypass Ind. SW	H12P601	J.L. Mark II	851E603
Reactor Core Clinq. BB	H12P601	General Electric	865E102A
Standby Information Panel	H12P678	General Electric	865E129
Unit Operating BB	H12P680	General Electric	865E141
Plant Operting BB	H12P853	General Electric	865E130 AB

QUESTION 032.48

With regard to the seismic and environmental qualification of the Class 1E instrumentation and control equipment in the balance of plant scope, the staff requires the following qualification test program information along with the results of the tests:

(1) Equipment Design specifications

(2) Test Plan

(3) Test set up

(4) Test procedures and

(5) Acceptability goals and requirements.

This information shall be provided for at least one item in each of the following groups, including the type (functional designation), manufacturer, manufacturer's type number and model number, of Class 1E instrumentation and control equipment.

(1) Transmitter

(2) Logic equipment

(3) Instrument Racks

(4) Control Boards (NUCLENET)

RESPONSE:

The four categories of equipment listed in this question are a subset of the 17 categories listed in NRC Question 042.2. Therefore, for response, refer to question 040.2.

QUESTION 032.49

The SSES control room is different from GE's PGCC concept which we have reviewed. Therefore provide the following information:

(1) Provide the criteria with appropriate layout drawings and concepts for

(a) physical separation and barriers between redundant circuits

(b) physical separation and routing of non-safety circuits

(c) safety channel identification and color coding

(d) seismic qualification

(e) fire detection and protection

(2) Discuss your conformance to GDC-19 and Regulatory Guide 1.78.

(3) Discuss the provisions for satisfying the recommendations of Regulatory Guide 1.75, and the acceptability of large quantities and large concentrations of cables in a small area immediately beneath the elevated control room floor.

(4) Discuss the degree of conformance to Regulatory Guide 1.75 in the vertical cable chase between the upper and lower relay rooms. Justify any exception (i.e. associated circuits) and provide the criteria with appropriate layout drawings depicting

(a) physical separation and barriers between redundant circuits
(b) physical separation and routing of non-safety circuits
(c) safety channel identification and color coding
(d) seismic qualification
(e) fire detection and protection

RESPONSE:

(1) The upper and lower level of the control complex is PGCC, while the center level control room is non-PGCC. Those positions of the control room which are PGCC configured do meet the requirements and exceptions as defined in PGCC NEDO-10466A.

Control Room related electrical layout drawings are identified on Table 1.7-1 and are submitted under separate cover.

(a) Physical separation and barrier's design criterion between redundant circuits in control room raceways is the same as stated in Subsections 3.12.3.4.2.1 and 8.3.1.11.4. See revised Subsection 3.12.3.4.2.6 for a discussion of separation in control room panels. See also Subsection 7.1.2.5.8.

(b) Routing of non-safety circuits is separated from safety related circuits. See Subsections 3.12.3.4.2.1 and 8.3.1.11.4.

(c) Safety channel identification and color coding are shown in Subsections 1.8.6.2, 1.8.6.3, 1.8.6.4, and 8.3.1.11.3.

(d) Refer to Section 3.10 for seismic qualifications.

(e) Fire detection and protection for Susquehanna SES is discussed in detail (including layout drawing) in the Susquehanna Fire Protection Review Report which was submitted on Jan. 18, 1978. For the control room, ionization detectors and manual CO are used under the removable floor. Portable CO extinguishers are deployed in the control room. Hose stations are located outside the control room. All PGCC termination cabinets and floor channeling have smoke and thermal detection coupled with a Halon 1301 file suppressant system as approved by the NRC per Topical Report NEDO-10466-A.

(2) As discussed in Sections 3.1 and 6.4.4.2, the Susquehanna SES control room complies with GDC-19 and Regulatory Guide 1.78. Prompt shutdown of the reactor from outside the control room is described in Subsection 7.4.1.4.

(3) The raceway design beneath the elevated control room floor is in compliance with Regulatory Guide 1.75-1975 as discussed in Subsections 3.12.3.4.2.1 and 7.1.2.6.1.6. In some risers below the control panel where the minimum separation distance between two redundant channel/division or between Class 1E and non-Class 1E circuits cannot be met, cables of one of redundant channel/division or the Class 1E circuits (to be separated from non-class 1E circuits) are either installed in metallic flexible conduits or separated by steel barriers.

(4) Susquehanna SES has fully complied with Regulatory Guide 1.75-1975 in the vertical cable chase design between the upper and lower relay rooms. Layout drawings are listed in Table 1.7-1.

(a) Refer to Subsections 3.12.3.4.2.1 & 8.3.1.11.4.
(b) Refer to Subsections 3.12.3.4.2.1 & 8.3.1.11.4.
(c) Refer to Subsections 1.8.6.2, 1.8.6.3, 1.8.6.4, and 8.3.1.11.3.
(d) Refer to Section 3.10.
(e) Fire detection and protection for vertical cable chases containing safety-related cables:

(i) Ionization detectors and manual total flooding CO_2 are used for chases in the control room.

(ii) Heat detectors and automatic total flooding CO_2 are used for chases above and below the control room into the cable spreading rooms. Also refer to Susquehanna SES Fire Protection Review Report which was submitted on January 18, 1978.

QUESTION 032.50

Regulatory Guide 1.75 and IEEE Standard 384-1974 on Criteria for Separation of Class 1E Equipment and Circuits do not apply to SSES because they were issued after the CP. Separations criteria for safety related mechanical and electrical equipment are described in 3.12. Specific exceptions to RG 1.75 are identified in 3.13 for non-NSSS equipment, but no similar list is supplied for NSSS equipment. A brief, general discussion is contained in 7.1.2.5.8.

Identify all specific exceptions to RG 1.75 and IEEE 384-1977 for NSSS equipment and justify each.

RESPONSE:

The separation design of this plant has the same basis as that already approved by the NRC for Hatch 2.

See revised Sections 3.13 and 7.1.

QUESTION 032.51

Discussion of the APRM system on page 7.2-5 indicates the maximum setpoint is 125% reactor power. Table 7.6-5 lists the nominal APRM setpoint as 120% and the range as 2% of full scale. This setpoint is significant for the accident analysis in 15.0.

Discussion of the APRM system on page 7.2-5 indicates the maximum setpoint is 125% reactor power, but table 7.6-5 lists the nominal setpoint as 120% with a range of 2% of full scale. Clarify this discrepancy and identify the maximum setpoint for accident analysis.

RESPONSE:

The discussion of the APRM in Subsection 7.2.1.1.4.2 has been modified to indicate that the trip setpoint is provided in this plant Technical Specifications. For consistency Table 7.6-5 has also been revised by adding a footnote to the nominal setpoint column referencing the plant Technical Specifications for actual setpoints. These specifications define the analytic or design basis limit value, below that the allowable value, and below that the actual trip setpoint. Each value below the analytic limit (which the safety analysis uses) provides a measure of additional conservatism as well as taking into account instrument accuracy, calibration error and setpoint drift.

QUESTION 032.52

Table 7.2-4, Design Basis Setpoints, was deleted in Revision 11. Several sections still refer to data contained in that table.

Several references are made to design basis setpoints previously listed in Table 7.2-4. This table has been intentionally left blank. Please clarify this discrepancy.

RESPONSE:

Table 7.2-4 was deleted because the information thereon has been incorporated in the plant Technical Specifications. Some information from Table 7.2-1 and all the information from Tables 7.2-5 and 7.2-6 has been deleted from Section 7.2 and is also contained in the Technical Specifications as the appropriate single point of reference for this data. Various discussions in Section 7.2 have been revised by appropriately referencing the Technical Specifications rather than the deleted tables.

QUESTION 032.53

Section 7.2.1.1.4.8 (Testability) states, "During preoperational testing the sensors are tested using an accepted industry method and actual response time data are compared to design requirements for acceptance." Section 7.2.2.1.4.4 (BTP 24) states in part that the sensor response time test method has not been resolved for neutron monitoring system (APRM and IRM) and main steamline radiation monitoring trip points. Question 032.32 asks for a description of the Startrek computer system which is used for startup testing. The question also asks for separation criteria for permanent and temporary wire as well as specifications of qualification testing of electrical isolators. This question, directed at 7.3 only, has not been answered.

The discussion of compliance with BTP 24 is incomplete. Describe methods to be used to perform periodic response time tests of RPS system to verify design specifications are met. Identify all specific exceptions to RG 1.118 and IEEE 338-1977. Describe separation criteria for permanent and temporary wiring and describe the qualification tests for electrical insulators.

RESPONSE:

Subsection 7.2.2.1.2.4.4 has been revised to state that sensor response time testing for the reactor protection system is performed periodically as defined in Table 3.3.1-2 of the Technical Specifications.

Question 32.32 which asked for a description of the Star Trek computer system was submitted in Revision 14 dated February 1980.

With respect to the methods used to perform periodic response time tests of the RPS, the following criteria will be followed:

A precise hydraulic pressure signal will be generated as the input to the individual sensors. The sensor output and the final actuation device or initiation device to all connected loads will be recorded on a high speed recorder. The delay time will be determined along with other channel observations as required. This is consistent with both IEEE-338-1977 and Regulatory Guide 1.118 dated 1978, even though IEEE-338-1977 and Regulatory Guide 1.118 are not design bases for this plant.

QUESTION 032.54

Discussion of the Emergency Core Cooling Systems and the associated tables are incomplete and inconsistent. Correct and clarify the following:

1) The same instruments are used for Reactor Vessel low water level and Primary Containment high pressure for many ESF systems. The specification shown for these instruments in Tables 7.3-1 through 7.3-5 are not consistent. Correct trip settings, ranges, and accuracies shown for these instruments.

2) These tables have allotted columns for instrument response times and margins (of trip setting) to meet requirements of IEEE 279-1971 Section 3, but most data has been omitted. Response times should indicate minimum and/or maximum where applicable.

3) Table 7.3-1 has omitted all specifications for the Turbine overspeed instrument.

4) Figure 7.3-5 has several errors:

   - It does not show two ADS logics as indicated in 7.3.1.1a.1.4.4.

   - Referenced Figure 7.3-16 does not exist.

   - It does not show low pressure interlocks to LPCI and CS required to initiate ADS as indicated in 7.3.1.1a.1.4.4.

5) Table 7.3-2 indicates only one reactor water level setpoint (-149 inches) for the ADS. Section 7.3.1.1a.1.4.4 indicates two level setpoints, a low and a lower water level.

6) Use of level switches with a range of -150"/0/+60" to initiate ADS and CS action with trip settings at -149 does not seem like conservative design. Justify the use of this range for this application. Discuss accuracy of the trip setting and how it is affected by normal and accident environmental conditions and long term drift.

7) Why are two ranges shown for LPCI pump discharge pressure (10-240 psig and 10-260 psig). Range shown for this instrument in Table 7.3-4 is 10-240 psig only.

8) Section 7.3.1.1a.1.4.5 on ADS Bypasses and Interlocks indicates that it is possible for the operator to manually delay the depressurizing action and states "This would reset the timers to zero seconds and prevent depressurization for 105 seconds." Table 7.3-2, Figure 7.3-8-3 and Table 6.3-2 all indicate a time delay of 120 seconds. How is a time delay of 105 seconds achieved?

9) Explain why two ranges (50-1000 psig and 50-1200 psig) are listed for the Reactor Vessel Low Pressure instrument in Table 7.3-3.

10) Instrument ranges for pump discharge flow, Table 7.3-3, and pump minimum flow bypass, Table 7.3-4, are specified in inches of water but trip settings are in gpm. Supply ranges for these flow instruments in gpm.

11) Table 7.3-9 HPCI System Minimum Numbers of Trip Channels Required for Functional Performance does not agree with Table 7.3-1 HPCI Instrument Specifications. Table 7.3-8 does not list HPCI pump high suction pressure or Turbine Overspeed as shown in Table 7.3-1. Table 7.3-8 lists two items, HPCI pump flow and HPCI pump discharge flow, not shown in Table 7.3-1.

12) Table 7.3-4 Low Pressure Coolant Injection - Instrument Specifications does not agree with Table 7.3-10 Low Pressure Coolant Injection System Minimum Number of Trip Channels Required for Functional Performance. Table 7.3-10 does not list Reactor low pressure or Pump discharge pressure as shown in Table 7.3-4. Table 7.3-10 lists several trip channels which are not shown in Table 7.3-4. These include Reactor vessel low water level inside shroud, Reactor vessel low flow, Primary containment high pressure, and Reactor vessel low water level (Recirculation Pumps).

13) Table 7.3-11 Core Spray System Minimum Numbers of Trip Channels Required for Functional Performance is incomplete. It does not list Pump Discharge Flow as shown in Table 7.3-1.

RESPONSE:

1. Tables 7.3-1 through 7.3-4 have been revised to include all appropriate instrument functions and the number of channels provided. The trip settings and response time information has been deleted, and is provided in the Technical Specifications. Tables 7.3-8 thru 7.3-11 are deleted, with appropriate number of channel information incorporated into Tables 7.3-1 thru 7.3-4. Revisions to Table 7.3-5 have been submitted with the response to Question 032.55.

2. The instrument response times and margins (of trip settings) are included in the Technical Specifications. The data in the Technical Specifications is intended to also satisfy the requirements of IEEE 279-1971, Section 3.

3. The HPCI turbine overspeed trip is a mechanical device, which is integral with the turbine. See Section 6.3, for discussion of the HPCI turbine. The overspeed trip setting and accuracy information is provided in the Technical Specifications.

4. Figure 7.3-5 is revised to show a simplified picture of the ADS and LPCI/CS initiation logic. The ADS division I and II Logics, discussed in revised Subsection 7.3.1.1a.1.4.4 and shown in detail by Figure 7.3-8 sheet 3, are identical and energizing either will initiate ADS. Therefore they are shown twice in Figure 7.3-5. Relating the simplified picture in Figure 7.3-5 to the detailed one in Figure 7.3-8, the left branch corresponds to logic A in Div. I (or B in Div. II) and the right to logic C in Division I (or D in Div. II). A note has been added to Figure 7.3-5 to clarify the separate logics for Div. I and Div. II. The reference to Figure 7.3-16 contained on Figure 7.3-5 is erroneous. The correct reference Figure for LPCI logic is Figure 7.3-10, RHR FCD. The low pressure interlocks for pumps (CS and RHR) have been added to Figure 7.3-5.

5. The revised Table 7.3-2 includes an appropriate entry for ADS initiation, with action caused by two signals, one each from the reactor water level L1, and reactor water level L3. Both signals are required before ADS is automatically initiated. The set point for this action is provided in the Technical Specifications.

6. The instrument trip settings have been removed from the tables of Chapter 7 and included in the Technical Specifications. The level switch trip setting of -149 inches for ADS and CS will be changed and will be within the proper accuracy and range of the instrument. The trip setting accuracy related to abnormal operating temperature within the drywell is discussed in the response to Question 032.59. Instrument drift is included in developing the instrument set points.

7. The LPCI pump discharge pressure permissive for the ADS has two redundant channels provided for each LPCI (RHR) pump. However the instruments have identical ranges, so Table 7.3-2 has been revised to agree with Table 7.3-4.

8. The ADS timer setpoint found in Table 6.3-2 is an upper limit. The correct setpoints (including margin) are provided in the Technical Specification. The proper time delay time is by mechanical adjustment of pneumatically operated time delay relay. The text of Subsection 7.3.1.1a.1.4.5 has been revised to delete the actual numerical value. The 105 second time value is nominal, and was used to allow for the margin and tolerance of the device. The proper value is provided in the Technical Specification.

9. The two trip systems for CS have diverse instruments specified for reactor vessel and the same instruments are used in LPCI low pressure. Tables 7.3-3 and 7.3-4, as revised, give the instrument ranges for both trip systems. The trip setting values are provided in the Technical Specifications.

10. The CS and LPCI (RHR) pump minimum flow bypass ranges are converted from differential pressure to flow on the revised Tables 7.3-3 and 7.3-4.

11. Table 7.3-1 has been revised to include HPCI pump minimum flow bypass and the HPCI pump flow controller signaling the HPCI turbine. The turbine overspeed trip is a mechanical device that is integral with the turbine, see Section 6.3. The turbine overspeed instrument range has been added to Table 7.3-1. The number of channels provided is added to Table 7.3-1, and Table 7.3-8 is deleted. The minimum number of trip channels required have been added to the Technical Specifications.

12. The LPCI Table 7.3-4 has been expanded to include the instruments of the actual design and the number of channels provided. The margin and trip setting of Table 7.3-4 as well as Table 7.3-10 have been deleted.

13. The CS Table 7.3-3 has been revised to add the number of instrument channels provided, and margin, response time, and trip settings have been deleted. Table 7.3-11 has been deleted.

QUESTION 032.55

Discussion of the Primary Containment and Reactor Vessel Isolation Control System in Section 7.3.1.1a.2 and associated Tables 7.3-5, 7.3-7 and 7.3-12 are confused, incomplete and inconsistent. Correct or clarify the following:

1) Several instruments listed in 7.3.1.1a.2.1 are not discussed in the text and/or do not appear in the tables. These include RWCS High Flow, RHRS High Flow, RICI High Flow, HPCI High Flow.

2) Several items only appear in Table 7.3-5 with no discussion. These include RCIC Turbine Streamline High Temperature and Low Pressure, HPCI Turbine Steamline High Temperature and Low Pressure, Reactor Building and Drywell Ventilation Exhaust High Radiation.

3) In Table 7.3-5, instrument ranges, setpoints, accuracies, and time responses have been omitted for many sensors. Several sensors discussed in the text are not listed at all. These include Condenser Vacuum, RHR High Temperature and Differential Temperature, RWCS Differential Temperature, Main Steamline Differential Temperature. It is understood that some setpoints will be selected based on operating conditions, but these sensors must be identified.

4) Table 7.3-12 is redundant. It has only one entry, serves no purpose and could be eliminated.

5) Section 7.3.1.1a.4.12, Main Steamline-Leak Detection, appears to serve no purpose since all items are discussed in other parts of this section on the PCRVICS.

6) Table 7.3-7, Trip Channel Required for PCRVICS, is incomplete. Many functions discussed in the text and/or listed in Table 7.3-5 are missing.

7) Section 7.3.1.1a.2.4.2 references Table 7.3-7 for instrument characteristics. These are actually shown in Tables 7.3-5.

RESPONSE:

1) The RWCS High Flow, RCIC High Flow, and HPCI High Flow have been deleted from Subsection 7.3.1.1a.2.1. Please refer to new Subsection 7.3.1.1a.2.4.1.14 for a discussion of the RHR high flow isolation signal on the shut down suction line.

2) RCIC and HPCI systems are not part of the Primary Containment and Reactor Vessel Isolation Control System and have been deleted from Subsection 7.3.1.1a.2 and Table 7.3-5. Both RCIC and HPCI systems have system isolation valves that are initiated closed by HPCI and RCIC isolation signals, not PCRVICS. Refer to Subsections 7.3.1.1a.1.3.7 for HPCI and 7.4.1.1.3.6 for RCIC. The discussion of Reactor Building Ventilation Exhaust High Radiation is found in Subsection 7.3.1.1b.4, 7.3.1.1b.5 and 9.4.2.1.

3) See Revised Table 7.3-5.

4) Table 7.3-12 has been deleted and the main steamline "Upscale Trips per Channel" information has been changed from 1 to 2 on Table 7.3-6. The following notes have been added to Table 7.3-6:

   (a) The Main Steamline Radiation Monitoring System output is part of the Primary Containment and Reactor Vessel Isolation Control System (PCRVICS). See Subsection 7.3.1.1a.2.4.1.2.

   (b) The Reactor Building Ventilation Exhaust High Radiation Monitoring System output is part of the PCRVICS. See Subsections 7.3.1.1b.4, 7.3.1.1b.5, 9.4.2.1 and Table 7.3-5.

5) The purpose of Subsection 7.3.1.1a.2.4.1.12 "Main Steamline Leak Detection" Sub-system Identification discussion is to give a concise interrelation of the three subsystems. Although the same conclusion can be reached by separately referring to Subsections 7.3.1.1a.2.4.1.3 and 4 it would be cumbersome and possibly confusing, therefore this section will not be deleted.

6) Table 7.3-5 has been revised to include the number of trip channels provided information previously shown in Table 7.3-7 and the missing trip channel information. Table 7.3-7 has been deleted. The minimum number of trip channels information of Table 7.3-7 has been incorporated into the Technical Specifications. Table 7.3-5 has been corrected to delete the HPCI and RCIC system information because they are not part of the PCRVICS. See Table 7.3-5 for additional isolation functions and appropriate data.

7) The Subsection 7.3.1.1a.2.4.2 reference to Table 7.3-7 has been changed to reference Table 7.3-5. Section 7.3.1.1a.2.9 reference to Table 7.3-7 has been changed to Chapter 16, Technical Specifications.

QUESTION 032.56

It is the current staff position that Mark II suppression chamber sprays be actuated automatically instead of manually. Similar plants such as Zimmer and Shoreham are making this change. Identify any significant differences between these plants and Susquehanna in this regard and justify the proposed manual system.

RESPONSE:

We believe that manually actuated suppression chamber (wetwell) sprays are acceptable for Susquehanna. The basis for this decision is as follows.

1. Calculated Allowable Bypass Leakage Area ($A/\sqrt{K}$) is Acceptable.

   The NRC has requested in Reference 1 that Mark II Containments be designed with a steam bypass capability for small breaks on the order of 0.05 ft^2 ($A/\sqrt{K}$). A review of the FSAR's for Susquehanna, Shoreham, and Zimmer (References 2, 3 and 4) show the calculated allowable bypass leakage areas to be

Susquehanna;	$A/\sqrt{K}$	= .0535 ft^2
Shoreham;	$A/\sqrt{K}$	= .08 ft^2
Zimmer;	$A/\sqrt{K}$	= .0165 ft^2

   Assumptions for operator action time for the Susquehanna analysis were conservatively chosen and are given in Reference 2.

   Zimmer's area is less than as requested by the NRC and they chose to use automatic wetwell sprays to meet the intent of Reference 1. Shoreham's area is larger than that requested by the NRC and to our knowledge they have not yet made the decision to implement automatic wetwell sprays. Similarly, Susquehanna's area is larger than that requested by the NRC. It therefore meets the steam bypass capability requirement of Reference 1 with manually actuated wetwell sprays.

2. Automatic Spray Diverts Flow From The Vessel.

   Core cooling is the first consideration in the response to a transient or accident. If the automatic wetwell spray is activated, it could potentially degrade required vessel cooling by diverting LPCI flow to the wetwell spray. This diversion would also reduce the operator's flexibility in responding to a transient or accident.

In conclusion, the current design of Susquehanna with the manually initiated wetwell sprays meets the NRC requirements and no automatic wetwell spray is required.

References

1. Appendix I to SRP 6.2.1.1.C, Containment System Branch Steam Bypass for Mark II Containments

2. Susquehanna Final Safety Analysis Report Chapter 6, Section 6.2.1.1.5 (updated per Question 21.51)

3. Shoreham Final Safety Analysis Report Chapter 6, Section 6.2.1.3.6

4. Zimmer Final Safety Analysis Report Chapter 6, Section 6.2.1.3.6

5. Emergency Procedure Guidelines (TMI BWR Owners Group), Draft Revision 6A, March 14, 1980.

QUESTION 032.57

Describe test method to be used to verify closing times for main steamline isolation valves are within limits of technical specifications. identify any special design features to facilitate this test. Table 6.2-12 is referenced for closure times of main steamline isolation valves, but time has been omitted from that table. What is the range of acceptable closure times?

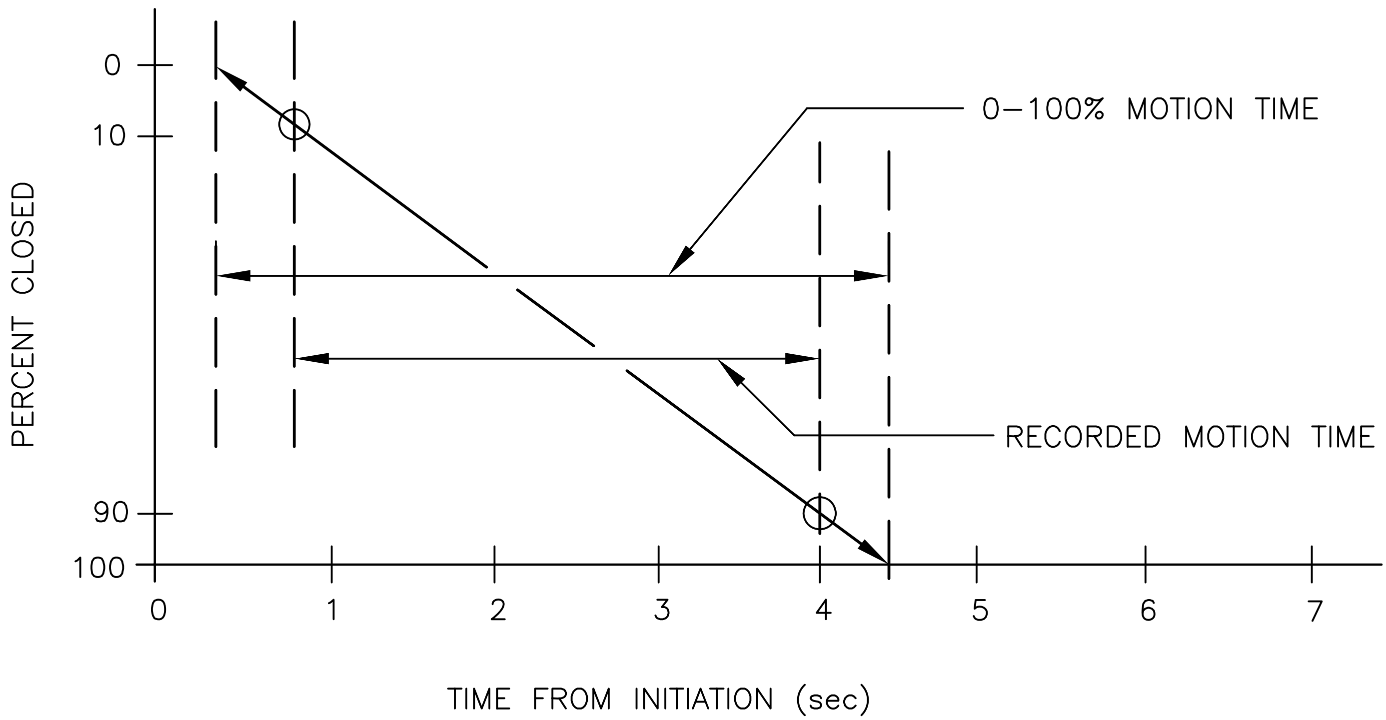
RESPONSE:

The determination of the MSIV closure was an extrapolation from the position lights as illustrated by Figure 032.27. The closure time is the summation of the time between the initiation signal and the 90% closed light plus 1/9 times the time interval between the initiation and the 90% closed lights.

Prior to Startup Testing, data will be taken of actual MSIV stroke length and position limit switch actuation points by direct measurement at each MSIV. From this data, extrapolation factors for closure time have been calculated and included in the Startup Test Procedures. During the startup test these factors, based on actual rather than assumed valve positions, were applied to the closure times obtained by valve limit switch actuation signals to the control room.

The extrapolation factors used assume linear valve motion. However, errors in valve closure time determination due to any non-linearity is small and over-shadowed by the effect of decreasing closure time due to steam line flow (by about one full second from no flow to full steam line flow), and is in the conservative direction. In addition, the extrapolation method is consistent with the method used to satisfy plant technical specification surveillance testing of MSIV closure times. The range of acceptable closure times for the main steamline isolation valves is 3 to 5 seconds.

See revised Table 6.2-12.



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

MSIV PERCENT CLOSURE
VS.
TIME EXTRAPOLATION

FIGURE 032.57-1, Rev 47

AutoCAD: Figure Fsar 032_57_1.dwg

QUESTION 032.58

Review of the Main Steamline Valve Isolation Control System logic at Hatch 2 and similar plants determined that failure of a single relay could cause two redundant isolation valves to open. Has this problem been corrected in the Susquehanna design?

RESPONSE:

The problem of a single relay failure in the MSIV-LSC causing two redundant isolation valves to open has been corrected in the Susquehanna design. The changes to the design were to make to system initiation relays redundant and to separate the isolation valve circuits so that the final actuating relay coils for series valves are not connected directly to common devices. See FSAR Subsection 7.3.2a.3.1 which states that: "The MSIV-LSC has redundant and separate instrumentation and controls to ensure that the system will be able to maintain its functional capability assuming a single failure..."

QUESTION 032.59

General Electric and other NSSS suppliers have reported that post-accident temperature conditions can affect reactor vessel water level instrumentation.

1) Describe the liquid level measuring systems within containment that are used to initiate safety actions or are used to provide post-accident monitoring information. Provide a description of the type of reference leg used, i.e., open column or sealed reference leg.

2) Provide an evaluation of the effect of post-accident ambient temperatures on the indicated water level to determine the change in indicated level relative to actual water level. This evaluation must include other sources of error including the effects of varying fluid pressure and flashing of reference leg to steam on the water level measurements.

3) Provide an analysis of the impact that the level measurement errors in control and protection systems (2 above) have on the assumptions used in the plant transient and accident analysis. This should include a review of all safety and control setpoints derived from level signals to verify that the setpoints will initiate the action required by the plant safety analyses throughout the range of ambient temperatures encountered by the instrumentation, including accident temperatures. If this analysis demonstrates that level measurement errors are greater than assumed in the safety analysis, address the corrective action to be taken. The corrective actions considered should include design changes that could be made to ensure that containment temperature effects are automatically accounted for. These measures may include setpoint changes as an acceptable corrective action for the short term. However, some form of temperature compensation or modification to eliminate or reduce temperature errors should be investigated as a long term solution.

4) Review and indicate the required revisions, as necessary, of emergency procedures to include specific information obtained from the review and evaluation of Items 1, 2 and 3 to ensure that the operators are instructed on the potential for and magnitude of erroneous level signals. Provide a copy of tables, curves, or correction factors that would be applied to post-accident monitoring systems that will be used by plant operators.

RESPONSE:

1) Reactor vessel water level is measured by means of a produced differential pressure between a reference leg and a variable leg. The reference leg is connected to the upper part of the vessel (steam zone) and provides the constant head using an overflow type condensing chamber. The variable leg is connected to the lower part of the vessel. The produced differential pressure is therefore a function of water level.

2),3),4) General Electric has conducted a review on the effects of high drywell temperature on reactor vessel water level instrumentation. Instrument accuracy is not markedly effected by varying drywell temperatures because the vertical drop of the sensing lines within the drywell are similar in length. This ensures equalization of temperature effects between lines, should elevated drywell temperature conditions (as in a LOCA) occur, and thereby ensures continued instrument setpoint accuracy under these conditions.

In summary, with the above instrument routing, there would be little or no impact on the scram or high level trip function, nor would post-accident monitoring be impaired.

QUESTION 032.60

Pressure switches 1N022 A through S are used to actuate the 16 safety relief valves in the overpressure mode of operation as described in section 5.2.2.4.

1) Describe the logic associated with these instruments including those associated with ADS relief valves (Figure 7.3-8 Sht. 3) and non-ADS relief valves.

2) Identify design criteria and requirements met by this system.

3) Justify the use of a single instrument to operate each relief valve and analyze the effects of single failures.

RESPONSE:

Section 7.3.1.1a.1.4 presently includes an overview discussion of the pressure relief function of the safety relief valves.

The ADS is a function of the ECCS and the design criteria for the ADS is found in Section 7.1.2a.1.3 and the analysis and requirements are found in Section 7.3.2a.

The design criteria for the safety relief function of the SRV is discussed in Section 5.2.2. As stated in the FSAR Section 7.3.1.1a.1.4.1, the SRV's are dual function valves, i.e., safety and relief. The safety function includes protection against overpressure of the reactor primary system by mechanical spring actuation. The SRV's open on spring setpoint pressure and close when inlet pressure falls below a predetermined spring setpoint pressure. The safety function is designed according to ASME Boiler and Pressure Vessel Code, Section III.

Each SRV including those designated for ADS are instrumented to open automatically when reactor pressure reaches a specified level. A pressure switch senses reactor pressure, if reactor pressure exceeds the trip setpoint the switch's contacts close and energize a solenoid operated air pilot valve. The pilot valve controls air supply to the SRV. When the pilot valve solenoid is energized, pneumatic energy is supplied to the SRV's air cylinder operator which opens the SRV. There is one pressure switch per SRV. The pressure switch setpoint is established from the overpressurization analysis of Section 5.2.2.

The pressure relief function is not required for accident mitigation, therefore, no safety criteria (e.g., IEEE or regulatory requirements) are applicable. There is no requirement to assume simultaneous pressure switch failures during transient events.

The Pressure Relief System writeup is provided as Subsections 7.7.1.12 and 7.7.2.12.

QUESTION 032.61

The purpose of the Recirculation Pump Trip (RPT) is to aid the Reactor Protection System (RPS) in protecting the integrity of the fuel barrier.

1) Is the RPT designed in accordance with all requirements for the RPS? If not, identify and justify any exceptions.

2) Plants such as Hatch 2 and Zimmer have provided recirculation pump trips for reactor vessel low water level or high reactor pressure. Why have these not been provided for Susquehanna?

RESPONSE:

1) The purpose of the Recirculation Pump (RPT) is to aid the Reactor Protection System (RPS) in protecting the integrity of the fuel barrier at the end of core life, and as such, it has been designed in accordance with all the requirements of the RPS.

   The RPT is initiated on turbine stop valve and turbine control valve closure initiation signals.

2) Reactor vessel low level and high reactor pressure signals are part of the ATWS design change. These signals do exist as part of the Recirculation System and not RPS. They do initiate a separate recirculation pump trip designed to meet the existing ATWS requirements.

QUESTION 032.62

It is the staff's position that the Rod Block Monitor (RBM) is a system important to safety and should be designed, fabricated, installed, tested and subjected to all the design criteria applicable to safety-related systems. Design of the RBM is being reviewed on a generic basis on the Zimmer docket. Identify any differences between the Susquehanna plant and the Zimmer plant in this regard.

RESPONSE:

The Rod Block Monitor system for Susquehanna 1 and 2 identical to that in the Zimmer plant. As in all pre BWR-6 plants (plants where RBM was used), the Rod Block Monitor is designed to prohibit erroneous withdrawal of a control rod so that local fuel damage does not occur. Local fuel damage poses no significant threat relative to radioactive release. The RBM is a power generation system and not utilized for accident mitigation. The RBM's objective is to further fuel life by restricting rod movement to within defined limits, whereby local flux peaking is minimized. The FSAR has been amended to move the RBM from Section 7.6 to Section 7.7.

QUESTION 032.63

The response to Q032.39 states, "The RCIC is initially aligned to the CST for reactor vessel make-up water but automatically switches to the suppression pool at low CST level." This does not agree with the FSAR, Section 7.4.1.1.3.6, or the drawings (791E421AE) submitted for review. Correct this discrepancy.

RESPONSE:

The following general information is provided to clarify assumptions and misunderstandings within questions 032.39, 211.126 and 032.63 which are inter-related. At the Susquehanna SES, the HPCI is initially aligned to the condensate storage tank (CST) and automatically transferred to the suppression pool on low water level in the CST.

When the RCIC system is initiated, the turbine-drive pump supplies makeup water from the condensate storage tank (primary source) or the suppression pool (secondary source) into the reactor vessel. When CST water level is low, the suppression pool suction valve is manually opened, and the CST suction valve automatically closes thus allowing the suppression pool to provide the necessary makeup water.

The response to Q032.39 is partly incorrect in stating that RCIC automatically switches from CST to suppression pool at low CST level. The two pump suction valves provided in the RCIC are interlocked in such a manner that when the suppression pool suction valve is manually opened from the control room, the CST suction valve automatically closes. Subsection 7.4.1.1.3.6 has been amended for clarification. The correct drawing reference is 791E421AE.

See revised responses to Questions 032.39 and 211.126.

QUESTION 032.64

Correct and clarify the following items associated with the Core Spray System:

1) Figure 7.3-8 Sh. 3 indicates a permissive when core spray pump "B" is running. Pump B is not in Division 1. The pressure switch shown (E21-N008A) actually monitors pump C which is in Division 1.

2) Section 7.3.1.1a.1.4.4 states in part that one of the RHR pumps or any pair of the Core Spray pumps is sufficient to give the permissive signal. It appears from Figure 7.3-8 that only two specific pairs of Core Spray pumps can give the permissive. These are the pair in each RHR loop (A & C or B & D). No other pairs can give the permissive.

RESPONSE:

1) Dwg. M1-B21-92, Sh. 3 has been corrected.

2) Section 7.3.1.1a.1.4.4 has been corrected.

QUESTION 032.65

Correct and clarify the following items associated with the Main Steamline Isolation Valve Leakage Control System (MSIV-LCS):

1) Provide instrument specifications and setpoint data. Section 7.3.1.1a.3.12.3 indicates there are no setpoints, but several permissives setpoints on steamline pressure, reactor pressure and leakage flow are indicated in the Functional Control Diagram, Figure 6.7-3.

2) Sections 7.3.2a.3.2.1.4 states in part that the MSIV-LCS does not comply with RG-1.96 with regard to reduction of stem packing leakage or direct leakage to the steam tunnel from MSIV. Section 6.7.1.2 states the system does conform to RG-1.96 and Section 6.7.3.5 indicates the outboard MSIV leakage is piped to the radwaste system.

3) Section 7.3.2a.3.2.1.4 references Section 5.5.5.4 which does not exist.

RESPONSE:

1) Subsection 7.3.1.1a.3.12.3 has been modified and new Table 7.3-27 has been added.

   The MSIV-LCS is a manually actuated system and does not have setpoints as such. There are permissives, however, for reactor pressure, steamline pressure and the inboard MSIV's being fully closed. These permissives are discussed in Subsection 7.3.1.1a.3.4.

2) Subsection 6.7.1.2 is incorrect. The valve stem packing leakoff and direct leakage is not provided by the MSIV-LCS. These leaks are carried off separately. The FSAR has been amended accordingly.

3) The reference in Subsection 7.3.2a.3.2.1.4 to Subsection 5.5.5.4 should instead be to Subsection 5.2.5.4. The FSAR has been amended accordingly.

NOTE:

MSIV-LCS information maintained here for historical purposes. The MSIV-LCS has been deleted. The function is now performed by the Isolated Condenser Treatment Method (Section 6.7).

QUESTION 032.66

The response to Q032.25 is incomplete. Provide a complete description of the design of, and the qualification plan for, the RPS motor generator monitoring and protection equipment to protect the connected loads from unacceptable values of voltage and frequency. Include a functional control diagram and an elementary diagram. Also, revise elementary diagram 115D6002AE and Figure 7.2-1 to show how the protection equipment connects to the RPS and MG sets.

RESPONSE:

There are two Class 1E Electrical Protection Assemblies associated with each of the two RPS Motor Generator Sets. For redundancy, contactors of two EPA's are installed in series between the Motor Generator Set and the RPS power distribution panel. Each EPA provides undervoltage, overvoltage and underfrequency protection for connected loads. In addition, there are two Class 1E EPA's associated with each of the two alternate feeds. The contactors of these EPA's are installed in series between the alternate feed and the RPS panel and provide the protection described above.

The generic design and qualification plan supplied by G.E. for this equipment has been approved by NRC as satisfying the requirements of IEEE-379-1972 Section 6.6 on the Hatch 2, Zimmer and LaSalle plants. The same is planned for Susquehanna. The RPS MG Set Control Elementary Diagram 115D6002AE and the IED have been updated. FSAR changes to text have been completed.

QUESTION 032.67

The description of the backup scram DC power supplies in the FSAR and the elementary diagram (791E414AE) is inadequate. Amend the FSAR to answer the following questions:

1) Does the DC power to the trip system A and B backup scram circuits come from Class 1E sources and, if so, what are the power sources.

2) Assuming the DC power does come from separate Class 1E sources, what methods are used to separate and isolate the two DC sources in the two trip system cabinets since DC sources pass through both the trip system A and trip system B cabinets? Also, what methods are used to separate and isolate the DC power from non-Class 1E power circuits in the cabinets?

RESPONSE:

1) The DC power to the trip system A and B backup scram circuits come from Class 1E sources. The power source for trip system A is control center 1D614, breaker 09. The power source for trip system B is control center 1D624, breaker 11.

2) Divisional separation of the two Class 1E sources within the two RPS trip system cabinets is provided by separated terminal boards, each located in different cabinet bays, and by separated wire routing. Loads separation is further provided by the total enclosure of the source's respective equipment terminations, namely relay contacts in this case.

Class 1E/Non-Class 1E routing separation is provided by routing wiring in separate conduits or by maintaining a minimum of 6 inch separation between wiring. In addition, coil-to-contact and contact-to-contact isolation is used where both Class 1E and non-Class 1E wiring interfaces with common equipment.

The above methods of separation have been approved by the NRC for use in plants of the same vintage as Susquehanna, Hatch 2 being one example.

QUESTION 032.68

The various analyses for Regulatory Guide 1.47, Position C.4, are incomplete since they do not indicate that the individual system level indicators can be actuated manually from the control room by the operators. Describe the provisions incorporated into the Susquehanna design to satisfy Position C.4 of Regulatory Guide 1.47. (Note: This position is not intended to address the testing of annunciators, but is intended to provide manual initiation of system level indication of inoperable and bypassed status.)

RESPONSE:

See response to Question 32.71.

QUESTION 032.69

The description, analyses, figures, and elementary diagram of the HPCI sensors and logic are inconsistent. The text (7.3.1.1a.1.3) begins by describing a system with only two level sensors and then continues describing a system with four level sensors and four pressure sensors. The IEEE 279 analyses appear to be for a system with four each level and pressure sensors arranged in two separate one-out-of-two-taken-twice logics. The information in Table 7.3-8 implies two separate logics. The figures (F5.1-3b, F7.3-6, and F7.3-7) and the elementary diagram (791E420AE) show only two each level and pressure sensors and a single logic.

Amend the appropriate document(s) to describe the HPCI initiation and control system actually installed at Susquehanna. Also, review the RPS, ECCS, and other ESF system descriptions in the FSAR, the FSAR figures, and the elementary diagrams and verify that these documents describe the systems actually installed.

RESPONSE:

The logic required to initiate HPCI consists of four vessel water level switches arranged in a one-out-of-two-twice logic (two level switches from division 11 and two from division 2). This logic is in parallel with four drywell pressure switches (two pressure switches from division 1 and two from division 2) that are also arranged in one-out-of-two-twice logic.

Consistent with the above discussion, Subsection 7.3.1.1a.1.3.3 has been amended.

Figure 7.3-6 has been changed to show 2 parallel sets of one-out-of-two-twice logic for vessel low water level and drywell high pressure.

Dwg. M1-E41-65 Sh.1, M1-E41-65, Sh.2, M1-E41-65, Sh. 3, M1-E41-65, Sh. 4 and M1-E41-65 Sh. 5 have been changed to show the above one-out-of-two-twice logic each for vessel low water level and high drywell pressure. The correct HPCI Elementary Diagram for Susquehanna SES review is 791E420WJ, Rev. 1. This document has been changed to show one-out-of-two-twice logic each for vessel low water level and high drywell pressure.

Per the response to Q032.54, Table 7.3-8 has been deleted. The information pertaining to this discussion has been transferred to Table 7.3-1.

See also revised Subsection 7.3.1.1a.1.6.7, 7.3.1.1a.1.6.8, 7.3.1.1a.2.4.1.1, and 7.3.1.1a.2.4.1.6.

QUESTION 032.70

Describe the actions required to restart HPCI upon again reaching reactor low water level after HPCI has been tripped due to reactor high water level.

RESPONSE:

See revised Subsection 7.3.1.1a.1.3.3 for this information.

QUESTION 032.71

The analysis for compliance with Regulatory Guide 1.47, Positions C.1, C.2, and C.3 appears to address the RPS and PCRVICS and not the ECCS (HPCI, ADS, CS, and LPCI) which is the subject of this section. Provide an analysis showing how the ECCS meets Regulatory Guide 1.47, Positions C.1, C.2, and C.3.

RESPONSE:

The reference to RPS and PCRVICS as examples in the conformance statements for ECCS, under positions C.1, C.2 and C.3 of Subsection 7.3.2a.1.2.1.7 is somewhat misleading and has been deleted from that subsection. Subsection 7.3.2a.2.2.1.5 has also been revised to correct the same problem. See revised Subsections 7.3.2a.1.2.1.7 and 7.3.2a.2.2.1.5.

QUESTION 032.72

The description of LPCI manual initiation is incomplete and is inconsistent with Figure 7.3-10 and elementary diagram 791E418AE. The description of LPCI manual initiation references the HPCI system description which mentions manual initiation but does not describe it. The Regulatory Guide I.62 analysis (7.3.2a.1.2.1.9) indicates a single manual initiation switch for each of the RHR A/RHR C and RHR B/RHR D LPCI systems. Figure 7.3-10 and elementary diagram 791E418AE indicate the LPCI manual initiation switch does not start the RHR pumps. Regulatory Guide 1.62, Position C.2, states that manual initiation of a protective action should perform all actions performed by automatic initiation. LPCI automatic initiation is as follows:

Low level or high drywell pressure coincident with low reactor pressure initiation logic includes coincident reactor pressure due to shared emergency diesel between Units 1&2. Coincident signal used as LOCA confirmation.

Amend the FSAR and/or the figure and elementary diagram to fully describe the LPCI manual initiation system actually installed at Susquehanna. Amend the Regulatory Guide 1.62 analysis to justify having a manual initiation that does not perform all actions performed by automatic initiation, i.e., the manual initiation switch initiates the LPCI valve lineup but does not start the RHR pumps.

RESPONSE:

Per Regulatory Guide 1.62, an LPCI manual initiation performs all actions performed by an automatic initiation, including RHR pump initiation. The correct elementary diagram for Susquehanna SES is 791E418WJ, Revision 2 which shows the starting circuitry for RHR pumps with manual initiation. LPCI automatic initiation is as follows:

Low level or high drywell pressure coincident with low reactor pressure initiation logic includes coincident reactor pressure due to shared emergency diesel between Units 1 & 2. Coincident signal used as LOCA confirmation.

Dwg. M1-E11-51, Sh. 1, M1-E11-51, Sh. 2, M1-E11-51, Sh. 3, M1-E11-51, Sh. 4 and M1-E11-51, Sh. 5 show the proper automatic, as well as manual RHR pump initiation for the LPCI mode of RHR system operation.

See revised Subsections 7.3.1.1a.1.6.3 and 7.3.1.1a.4.4.

QUESTION 032.73

Figure 7.3-10 and elementary diagram 791E418AE show an interlock between the RHR systems in Units 1 and 2 such that when a LOCA signal (Low Reactor Water Level or High Drywell Pressure in coincidence with Low Reactor Pressure) is present in one unit, the RHR pumps in the other unit are prevented from operating either automatically, manually, or remote-manually from the individual pump start/stop switches. This interlock is not mentioned or described in the FSAR text and appears to be a violation of GDC 5.

Amend the FSAR and/or the figure and elementary diagram to fully describe the interlocks between the RHR systems in Unit 1 and Unit 2. Provide a detailed analysis to justify having such an interlock that will prevent the safe and orderly shutdown and cooldown of one unit (by preventing RHR operation) while a LOCA signal is present in the second unit. Include this interlock in your discussion and analysis of compliance with GDC 5 (3.1.2.1.5).

RESPONSE:

The SSES Unit 1 and 2 LPCI interlock fix is described as follows:

Not "all" pumps in one unit are stopped, namely either pumps C and D in Unit 1 (with LOCA in Unit 2) or pumps A and B in Unit 2 (with LOCA in Unit 1). Therefore, one pump in each RHR loop remains operable for use in normal shutdown in the Unit without the LOCA, thereby satisfying the requirement of General Design Criterion 5.

The acceptability of the above scheme is based on Appendix K analysis, using worst case single failure whereby one failure is the false initiation of the LOCA initiation logic in the Unit without the actual LOCA. This and all other credible failures were analyzed to assure that minimum pump capacity for core reflood is always available. The single failure analysis is specifically for Susquehanna Units 1 and 2 on the LPCI fix.

The correct RHR elementary diagram 791E418WJ, Rev. 2, has been reviewed and it shows the LPCI fix logic correctly. Dwg. M1-E11-51, Sh. 1, M1-E11-51, Sh. 2, M1-E11-51 Sh. 3, M1-E11-51, Sh. 4 and M1-E11 Sh. 5 show the appropriate interlock.

See revised Subsections 7.3.1.1a.1.6.3, 7.3.1.1a.1.6.5 and 7.3.2a.1.2.2.

QUESTION 032.74

For the PCRVICS, a large number of inconsistencies, errors, omissions, and conflicts were noted between the descriptions (7.3.1.1a.2), the analyses (7.3.2a.2), the functional control diagram (Figure 7.3-8) and the elementary diagrams (791E401AE, 791E414AE, and 791E425AE). Some examples follow:

1) The FSAR (7.3.1.1a.2.4.1.1.1) indicates four level switches with two sets of contacts each - one set of contacts for low level and one set for low low (lower) level. Also, a single pair of reactor vessel pressure taps for each pair of switches was indicated. Figures 5.1-3b and Figure 7.3-8 and elementary diagrams 791E401AE and 791E414AE show two sets of four each level switches - one for low level and one for low low level. Figure 5.1-3b also shows the low level and low low level switches connected to difference pressure taps.

2) The FSAR (7.3.1.1a.2.4.1.1.1) indicates that the low low water level signal isolates the MSIVs, the steam line drain valves, the sample lines, and "all other NSSS isolation valves." Further review of the FSAR text, figures, and elementary diagrams shows low low water level only isolates the MSIVs, steam line drain valves, and the sample lines. No "other NSSS isolation valves" could be found that were actuated by the low low water level signal.

3) The FSAR indicates the PCRVICS instrumentation and control subsystems include: (10) main steamline - leak detection; (12) reactor water cleanup system - high flow, (14) reactor core isolation cooling system - high flow, and (15) high pressure coolant injection system - high flow. The remaining text does not discuss these items nor were they found in the elementary diagrams or figures.

4) The FSAR (7.3.1.1a.2.4.1.9) indicates that RWCU system high differential flow is sensed with "two differential flow sensing circuits" and the analyses section indicates the PCRVICS complies fully with the single failure criteria. The RWCU P&ID and the elementary diagrams show only one high differential flow instrument consisting of three flow transmitters driving a single summer which, in turn, drives two alarm units (one for each of the two trip channels). This arrangement does not meet the single failure criteria.

5) Elementary diagram 791E401AE shows a device (dPIS G33-NO44A) labeled "High Diff Flow" in addition to the device in 4) above. N044A appears as a differential pressure switch in the RWCU P&ID. No other reference to this device could be found in the text or elementary diagrams.

6) The text states "RWCU system high differential flow trip is bypassed automatically during RWCU system startup." No information on this bypass could be found in the text or elementary diagrams (791E401AE or 791E423AE) or in the various analyses in Section 7.3.2a.2.

7) The text indicates "main condenser low vacuum trip can be bypassed manually when the turbine stop valve is less than 90% open." Elementary diagram 791E401AE and the response to Q032.33 shows that "reactor low pressure" is also required to allow this bypass. No other information on this "reactor low pressure" permissive, including the setpoint, could be found in the FSAR.

8) The FSAR (7.3.1.1a.2.5 and 7.3.1.1a.2.11) mentions a "high differential pressure" signal used for RWCU isolation. No other information could be found on this signal either in the text or the elementary diagrams.

9) The FSAR (7.3.1.1a.2.11) mentions "high temperature downstream of the non-regenerative heat exchanger" as a RWCU isolation signal. Elementary diagram 791E401AE also shows this signal, but only shows a single instrument, which does not meet the single failure criteria. This isolation signal is not discussed, described, or justified in the text or the analyses.

10) Elementary diagram 791E401AE also shows a single SBLC system isolation signal that does not meet single failure criteria. This signal is also not discussed in the text or the analyses.

11) Elementary diagram 791E401AE shows an RHR isolation for "Excess Flow" and "High Reactor Pressure". No information could be found on these signals in the text or analyses.

12) The text indicates that RWCU and RHR systems high area and differential temperature subsystems have "no automatic bypasses." Elementary diagram 791E401AE shows a manual bypass switch for this sybsystem. The text also says that the main steamline low pressure and the condenser low vacuum bypasses are the only bypasses in the PCRVICS.

13) The text indicates that the main steamline high radiation system has bypasses on the individual instruments that are not described in the FSAR or included in the analyses (7.3.2a.2).

Amend the appropriate document(s) to fully and accurately describe the PCRVICS instrumentation and control systems actually installed at Susquehanna. Amend the PCRVICS analyses presented in Section 7.3.2a.2 to agree with the systems discussed in the text and shown in the figures and elementary diagrams.

For the bypasses, fully describe the justify all manual or automatic bypasses associated with any PCRVICS subsystem and include all bypasses in the various Section 7.3.2a.2 analyses. Include a description of how all bypasses are annunciated. Also, review the complete PCRVICS descriptions and analyses given in the FSAR and the figures and elementary diagrams. Verify that these documents accurately describe the systems actually installed at Susquehanna.

RESPONSE:

1) Subsection 7.3.1.1a.2.4.1.1.1 has been amended to indicate one set of four level switches is for low level and a second set is for low low level. There is one common and two variable leg pressure taps for each pair of two water levels.

2) Subsection 7.3.1.1a.2.4.1.1.1 has been modified to read; "the second (and lower)......isolation valves and other selected isolation valves. Isolation valves and their initiating signals are shown in Table 6.2-12." The Nuclear Boiler FCD and NS[4] elementary diagram will be modified to remove drywell pressure as an initiating signal from the RHR isolation valves, except the Radwaste discharge valves and the heat exchanger valves. Drywell pressure as an initiating signal will also be removed as an input to the RWCU valves. In addition, level 3 (low level) isolation will be changed to level 2 (low low level) for all valves except the RHR and TIP. These changes to the PCRVICS initiation signals and set points have no impact on safety. They have been implemented as a plant availability feature i.e. to reduce inadvertent containment isolation during plant transient events. The PCRVICS FCD and elementary diagram has been updated to reflect these changes.

3) Main steamline leak detection is discussed in Subsection 7.3.1.1a.2.4.1.12. RCIC high flow and HPCI high flow are discussed in the response to Question 032.55.

4) The single failure criterion applies at the system (RPS) or function (ECCS) level and not at the signal input or channel level. The RWCU isolation valves will receive a system isolation signal from the space temperature trip channels and high flow signal described in (5) below if a breach occurs in the RWCU system RCPB and the flow summer failed. Single failure of the summer will not preclude RWCU system isolation.

5) G33-NO44A and B provide an RWCU system isolation signal on high flow in the suction line. A revised discussion is contained in Subsection 7.3.1.1a.2.4.1.9.

6) Subsection 7.3.1.1a.2.4.1.9.6 has been modified to stated that the RWCU system high differential flow trip is bypassed during RWCU system startup by a time delay.

   The time delay will not affect RWCU System RCPB isolation. When the RWCU system is initiated a high differential flow will exist between the inlet and outlet flows and initiate system isolation and prevent RWCU operations. The time delay bypasses the flow signal until the system loop flow is established.

7) See revised Subsection 7.3.1.1a.2.4.13.6

8) See revised Subsections 7.3.1.1a.2.5 and 7.3.1.1a.2.11 which use the term "high flow" which is now described per part (5) above.

9) The subject signal is a system trip signal, not a containment isolation signal. See the response to part 4 and see Subsection 7.7.1.8.2.2(1) and 7.7.2.8.1 for coverage of this signal.

10) The signal is required for SLCS operation and is not a containment isolation signal. The RWCU System will be manually shutdown, if standby liquid injection is required, to prevent boron loss to the RWCU system. See response to part 4 and see revised Subsection 7.4.1.2.5.1 to cover the need for manual isolation of RWCU.

11) Excess flow is discussed under the Leak Detection System, in Subsection 7.6.1a.4.3.5.3. High reactor pressure is discussed under High Pressure/Low Pressure System Interlocks, in Subsection 7.6.1a.3.3.1.

12) The text in Subsections 7.3.1.1a.2.4.1.10.6 and 7.3.1.1a.2.4.1.11.6 is referring to operating bypasses, which are the subject of discussion in Subsection 7.3.2a.2.2.3.1.1.2.

    The Manual Bypass Switches are shown on the Leak Detection Elementary Diagram for RWCU and RHR. These switches actuate the system in test annunciator. Test and maintenance bypasses are also discussed in Regulatory Guide 1.47 conformance (see Subsection 7.3.2a.2.2.1.5).

13) Subsection 7.3.1.1a.2.4.1.2.5 discusses bypasses and states that there are no operational bypasses provided with the Main Steamline High Radiation Monitoring Subsystem. The individual log radiation monitors may be bypassed for maintenance or calibration by the use of test switches on each monitor. Bypassing one log radiation monitor will not cause an isolation but will cause a single trip system trip to occur.

QUESTION 032.75

Justify your claim that high drywell pressure provides "diversity of trip initiation for pipe breaks inside primary containment" when high drywell pressure will not close MSIV's, isolate RWCU, or reactor water sample lines. Also, discuss diversity for breaks outside primary containment.

RESPONSE:

See revised Subsection 7.3.1.1a.2.4.1.1.5.

Question Rev. 47

QUESTION 032.76

Justify locating the MSIV-LCS controls, instrumentation, and indicators needed for effective operation on back row panels in the control room. Describe the panels and their location with respect to other safety-related instrumentation and controls required for accidents.

RESPONSE:

Start Historical Section

The MSIV-LCS controls, instrumentation, and indicators, which are located on the MSIV-LCS panels in the control room do not normally require any operator attention either in the shutdown or the operation mode. When required, operator attention is called to the MSIV-LCS controls by an annunciated trip in the system. For example, an MSIV-LCS trip is annunciated in the control room when main steam line pressure drops to predetermined setpoint. The purpose of the annunciation is to signal the control room operator to start up the MSIV-LCS system. Other MSIV-LCS trips are annunciated to alert the operator to all significant operational, and trouble event which require operator action.

There are two MSIV-LCS panels, each located on opposite sides of the main control room floor elevation and situated on back row panels (C644, C645). Both panels are of the single door, totally enclosed, upright type. The panels are readily accessible from the console, although no direct line of vision is available to the operator from the console.

End Historical Section

QUESTION 032.77

For the containment spray cooling system, the following inconsistencies and errors were noted between the FSAR description (7.3.1.1a.4), the analyses (7.3.2a.4), the function control diagram (FCD) (Figure 7.3-10), and the elementary diagram (791E418AE):

1) The description indicates high drywell pressure is the only permissive required for containment spray cooling manual initiation. The analyses, FCD, and elementary diagram show high drywell pressure or reactor low level as the permissive. The FCD and elementary diagram also show LPCI injection valve (F015A) closed as another permissive.

2) The description indicates "containment spray is interlocked with reactor water level." This interlock was not addressed in the analyses and could not be found in the FCD or elementary diagram.

3) The description indicates the "two drywell pressure switches are electrically connected so that no single sensor failure can prevent initiation of containment spray A." This could not be verified in the analyses, FCD, or elementary diagram.

Amend the appropriate document(s) to fully and accurately describe the containment spray cooling instrumentation and control system actually installed at Susquehanna. Amend the analyses presented in Section 7.3.2a.4 to agree with the description. Also review the complete containment spray descriptions, analyses, figures, and elementary diagrams and verify that these documents accurately describe the systems actually installed.

RESPONSE:

1) See revised Subsection 7.3.1.1a.4.4.

2) The FSAR text is incorrect and has been revised to delete the last sentence of FSAR Subsection 7.3.1.1a.4.6.

3) Elementary Diagram 791E418WJ sheet 4 zone B-8, indicates two success paths in each division such that no single sensor failure can prevent initiation of containment spray A.

   See also revised Subsections 7.3.2a.4.3.1.6, 7.3.2a.4.3.1.8 and 7.3.1.1a.4.12.3.

QUESTION 032.78

Discussion of the SGTS, RBRC, HPCI, and RCIC pump rooms unit coolers, and SWGR cooling system indicates the two trains for each system are normally set up in a "lead-lag" fashion and that when the manual control switches for the fans are in the STOP position, this is annunciated on the BIS. What controls are used to ensure the switch for one train is in the LEAD position and the switch for the other train is in the STANDBY position? What are the consequences of having the switches for both trains in either the LEAD or the STANDBY positions when an emergency initiation signal is received and what effect on the safety of the public or the release of radioactivity to the environment would this have?

RESPONSE:

The SWGR air handling units are run during both normal and emergency operations. Their handswitches are stop-auto-start and if the running unit were switched from start to auto it would continue to run. The standby unit being already on auto, would remain on standby. The HPCI and RCIC room unit coolers each have a "Stop-Auto-Start" handswitch and are normally on "auto". A separate two position switch in the main control room for each redundant pair assures that one unit (of each pair) is on LEAD at all times.

The redundant RHR pumps each have their own unit cooler which stops and starts with the pump. Each unit cooler is normally in the "Auto" position on its "stop-auto-start" hand switch.

The SGTS room cooling fan units and heating units are normally in the "auto" position on their individual "stop-auto-start" handswitches. The cooling units start on room temperature high signal and the heating units on a room temperature low signal.

The redundant units of each pair are made lead or lag by the settings of their individual thermostats. If temperature setting were arranged for simultaneous operation of a redundant pair this would have no detrimental effect on equipment in the room.

Hence, as all redundant lagging units are independently actuated and are designed to replace the leading unit in case of failure, no effects to the safety of the public are expected.

The Reactor Building recirculation fans are normally set with the "A" fan in "auto lead" position and "B" fan on "standby". If the "auto lead" fan fails it will alarm on the local control panel and in the control room and the "standby" fan will start automatically. If both switches are on "auto lead" or if both are on "standby" then both fans will run.

QUESTION 032.79

The FSAR section on safety related display instrumentation is incomplete and/or inconsistent as follows:

1. The SRDI as identified in 7.5.1a.1 and Table 7.5-1 is incomplete in comparison to the instrumentation identified in 7.5.1a.4. Specifically, two fuel zone water level channels, control rod information, neutron monitors, all pertinent annunciators and valve position indicators, and relief valve discharge pipe temperature monitors are identified as SRDI in 7.5.1a.4, but are not included in Table 7.5-1. In addition, Table 7.5-1 does not indicate what SRDI is on the remote shutdown panel, what SRDI provides post-accident monitoring, and what SRDI is supplied Class 1E power. In several cases, the discussion indicates that two to four channels of information are displayed on what is identified as a single channel indicator in Table 7.5-1. There is no information listed in Table 7.5-1 for the HPCI turbine steam pressure entry.

2. Sections 7.5.1a.4 and 7.5.2a.5.1 state, or imply, that "indicators and records" will not be qualified for post-seismic performance while 7.5.2a.5.5 states that records and indicators are seismically qualified.

3. The statements on Regulatory Guide 1.97 in Sections 3.13 and 7.5.2a are contradictory or misleading. Section 3.13 states that SRDI was not evaluated against RG 1.97, Rev. 1 while 7.5.2a states that the SRDI complies with paragraphs C.2 through C.16 of RG 1.97 (no revision number is stated and the SRDI does not comply with C.3 of RG 1.97, Rev. 1).

4. Table 7.5-3 indicates that records that provide post-accident monitoring history are not provided with Class 1E power and Section 7.6.1b states that the records are not safety related. It is the staff's position that records providing PAM history are safety related and must be seismically qualified to be operable following an accident.

5. Table 7.5-3 indicates that only the wide range containment and suppression pool pressures are recorded while Section 7.6.1b states that both the narrow range and wide range pressures are recorded.

6. Section 7.5.2b states that cross checking between divisions is the means for checking operability on instrumentation, but does not address how the operable system is determined if the instruments do not compare.

This determination could be crucial if a discrepancy occurs during an accident with only two channels of information displayed.

Amend your FSAR to provide a complete and consistent analysis of the safety-related display instrumentation. Provide a discussion of how the operator will be instructed to resolve discrepancies occurring between two instrument channels during an accident. Revise your design as necessary to assure that all records and indicators used for post-accident monitoring (or history) are qualified to be operable following a seismic event and are powered from Class 1E power.

RESPONSE:

The following modifications to the 7.5 text to correct inaccuracies and deficiencies, and to delete inappropriate discussions are provided:

1. The power source for the main steam line flow indicators described in Subsection 7.5.1a.4.2.3.1 (2)b. is from an instrument AC source only, not from one of the standby AC buses. The FSAR has been amended accordingly.

   The relief valve discharge pipe temperature monitors are powered from an instrument AC source, not from the standby AC buses as described in Item (3)g. The FSAR has been amended accordingly.

   Subsection 7.5.1a.4.2.3.3 has been revised.

   Subsections 7.5.2a.5.1.5, 7.5.2a.5.5, and 7.5.2a.5.6 have been revised. Table 7.5-1 has been modified.

2. Answered in 1. above.

3. Answered in 1. above.

4. Answered in 1. above.

5. Subsection 7.6.1b has been revised to provide this information.

6. Subsection 7.5.2b.4 has been revised to provide this information.

QUESTION 032.80

The description of the refueling interlocks is unacceptable as follows:

1. The statements in 7.6.1a.1.3.4 and 7.6.1a.1.3.6 do not indicate compliance with single failure criteria. (Single failure criteria require that protection from an accident is still provided with any single failure present, not that a single failure will not cause an accident.)

2. Even though refueling operations are the means by which the core reactivity is restored, no mention is made of any interlocks that ensure that the core reactivity is adequately monitored during refueling (nor is there reference to the mechanisms used to ensure refueling with identical or suitable fuel).

Revise your design and/or your analysis to provide compliance with single failure criteria. Justify the exclusion of flux monitoring instruments from the interlocks on the refueling platform and indicate how compliance with GDCs 10, 26, and 27 are maintained and/or re-established following refueling.

RESPONSE:

The refueling interlocks are provided as a backup to administrative procedures which by themselves prevent criticality during refueling operations. For this reason, the refueling interlocks are not safety-related and not required to meet single failure criteria. Therefore, to comply with the requirements of Reg. Guide 1.70 Rev. 2 the refueling interlocks discussion has been moved from FSAR Section 7.6 to Section 7.7 (Table 7.6-1 has been moved to Table 7.7-2). Section 7.7 discusses major plant control systems and (as required by the Standard Review Plan) how their failure affects the plants.

1. Subsection 7.6.1a.1.3.4 has been amended.

2. Multiple failures (in extremely reliable equipment) and operator errors are required in order to cause criticality during refueling. The probabilities of this are remote. Core flux activity monitoring is provided during refueling by the SRM's and/or dunking chambers which are specified and controlled by the technical specifications. The mechanism used to ensure refueling with identical and suitable fuel is procedural and administrative. These mechanisms are sufficient in scope and reliability to ensure compliance with GDC 10, 26, and 27.

QUESTION 032.81

The description of the high pressure/low pressure interlocks is incomplete and/or inconsistent as follows:

1. It is not clear whether the last two sentences of the first paragraph of 7.6.1a.3.3.1 apply to all valves or just to recirculation suction valves.

2. The logic shown on Figure 7.3-10 for RHRS does not show close signals originating from reactor pressure interlocks for any RHRS valves (isolation logic is shown, but is not connected to close circuit).

3. The discussion indicates two motor-operated injection valves for RHR, but only one is listed in the table.

4. The steam condensing mode of RHR is included in the table, but is not discussed. Figure 7.3-10 does not show one of the valves and indicates that the other valve is a pressure regulating valve.

5. It is stated that the core spray valve "must start opening above system design pressure to fulfill the flooding function." The permissive pressure for this valve is the same as for the RHR system.

6. It is stated that the recirculation suction valves have independent and diverse interlocks to prevent valve opening with high primary system pressure, but no diversity is identified.

Revise your FSAR as necessary to correctly describe the high pressure/low pressure interlocks. Include the design basis that justifies a valve permissive pressure that exceeds the "system design pressure," and identify all systems in this category. Identify the "diverse interlocks" claimed for the recirculation valves. (If diversity is provided by utilizing pressure switches from two different manufacturers, identify the diverse principles by which the pressure switches function.)

RESPONSE:

1. Subsection 7.6.1a.3.3 has been revised.
2. Subsections 7.6.1a.3.3 and 7.6.1a.3.3.4 have been revised.
   Dwg. M1-E11-51, Sh. 1, M1-E11, Sh. 2, M1-E11-51, Sh. 3, M1-E11-51, Sh. 4 and M1-E11-51, Sh. 5 were modified.
3. Subsection 7.6.1a.3.3 has been revised.

4&5. Subsection 7.6.1a.3.3 has been revised.
(Note: The steam condensing mode of RHR has been eliminated since the original response to this question.)

6. Diversity is provided by supplying the pressure switches from two different manufacturers as described in Section 7.6.1a.3.3.4. Principles of operation are similar for the diverse pressure switches. Diversity comes from manufacturing techniques, etc.

QUESTION 032.82

The RCIC flow rate monitoring switches are identified as differential switches (measuring pressure drop across an elbow) in the circuit description and as pressure switches (sensing high flow by low pressure) in the logic description. Section 7.6.1a.4 states that there are two channels of (differential) pressure monitoring in each logic, but Figure 7.4-2 only shows one switch in each logic. Revise the appropriate section to provide a correct and consistent description of the RCIC flow rate monitoring circuits. Provide instrument specifications and setpoints.

RESPONSE:

Subsections 7.6.1a.4.3.3.1, 7.6.1a.4.3.3.4.1 and 7.6.1a.4.3.3.4.2 have been revised to correct and clarify the discussion.

QUESTION 032.83

Where is the instrumentation for the "area drain monitoring system" and "area temperature monitoring system" (mentioned in 7.6.1a.4.3.6) for the RWCU discussed? Also, revise 7.6.1a.4.3.6.2.2 to properly describe the RWCU flow comparison logic; the use of two trip units connected to the same flow comparator does not constitute one-out-of-two logic.

RESPONSE:

The two methods of RWCU leak detection which provide containment isolation signals are RWCU high differential flow and RWCU area high temperature. Please refer to revised Subsection 7.6.1a.4.3.6.1.

Also see revised Subsection 7.6.1a.4.3.6.2 and new Subsection 7.6.1a.4.3.6.3.

QUESTION 032.84

Revise your discussion of safety/relief valve discharge line temperature monitoring to correctly identify the monitoring scheme. If the thermocouples are actually all connected in parallel, provide a discussion of how the open relief valve is identified.

RESPONSE:

Subsection 7.6.1a.4.3.7.2.1 has been amended to show the monitoring scheme for the safety/relief valve discharge line temperature.

Positive value position indication monitors are addressed in Subsection 18.1.24.

QUESTION 032.85

Clarify your discussion of HPCI system leakage detection as follows:

1. The circuit description states that some temperature isolation signals are immediate and some must persist continuously for a fixed time before isolation is initiated. The logic description states that all signals are delayed.

2. The logic is said to be one-out-of-two, but it is not clear whether this applies to the ambient and differential temperatures individually or collectively.

3. The three identical statements on bypasses and interlocks and the circuit description imply that HPCI isolation cannot be initiated manually, nor initiated from the high flow/low pressure logic, if a "logic test" is in progress.

4. Instrument specifications are not given, nor referenced, for either the flow or temperature channels.

RESPONSE:

1. The Circuit Description of Subsection 7.6.1a.4.3.9.2.1 is correct. See the amendment to Subsection 7.6.1a.4.3.9.2.2 (Logic and Sequencing) per the response to part two of this question.

2. See revised Subsection 7.6.1a.4.3.9.2.2.

3. The three FSAR statements are correct. When the bypass/test switch is in the test position for one particular division of logic, that division will not allow initiation of HPCI system isolation either manually or automatically. However, the alternate redundant and independent division of HPCI isolation logic will still function in its normal mode.

4. Trip settings will be shown in the Technical Specifications.

QUESTION 032.86

The presentations in Sections 7.6.1a.5 and 7.6.2a.5 provide a questionable explanation of how the SRMs respond to reactivity changes. This in turn makes the analysis for compliance to design requirements questionable. Revise the FSAR to address the following specific points.

1. Justify the claim that the SRMs are designed to meet the single failure criterion in light of your statement that the SRM channels are not redundant.

2. Provide documentation to support the contention that one "section" of the core can independently be on a 20-second period (Section 7.6.2.5.1).

3. Indicate whether the redundancy/single failure relationship of the SRMs is applicable to the IRMs.

4. The APRM response to a full control rod withdrawal is not shown on Figure 7.6-17 in contradiction of the statement in 7.6.2a.5.

5. The parenthetical description contradicts the remainder of the statement in the first paragraph of 7.6.1a.6.3.

6. The LPRM positions are misidentified in Figure 7.6-15. Neither Figure 7.6-15 nor 7.6-16 is clear on whether one or both detectors are failed. Also, verify that a factor of two difference in response (as shown on Figures 7.6-15 and 7.6-16) exists between RBM-A and RBM-B. If this difference is real, identify the cause and address the effect it has on the APRM trips. (Would doing away with the B and/or D inputs improve the APRM response, i.e., cause the APRM signal to increase significantly faster than the average power?)

RESPONSE:

1. The SRM is not a safety-related subsystem of NMS. Therefore, it is not required to meet the single failure criterion of IEEE 279-1971, Paragraph 4.2 (See FSAR Subsections 7.6.1a.5.1 and 7.6.2a.5.1.2). Subsection 7.6.1a.5.3.1.2 has been revised.

2. Chapter 7 is not the proper chapter for a discussion of core performance per core sections or neutron production period of any part of the core. Core performance and neutron production periods are described in Chapter 4. The sensitivity and placement of the SRMS, has been considered in developing the core

performance and detector placement for the SRMS to monitor that performance. Subsection 7.6.2a.5.1.1 has been revised.

3. The IRM is a safety-related subsystem of NMS and has been designed to meet the single failure criterion of IEEE 279-1971, Paragraph 4.2. There is no correlation between SRM and IRM concerning redundancy and applicability of IEEE 279-1971, Paragraph 4.2.

4. The second paragraph of Subsection 7.6.2a.5.4.1 has been revised. FSAR Table 1.6-1, Referenced Reports, under APED 5706, has been amended, adding Subsection 7.6.2a.5 as reference. In addition, Figure 7.6-17 has been deleted.

5. See revised Subsection 7.6.1a.6.3.

6. FSAR Figure 7.6-15 has been amended, changing position 22.23 to 28.29. FSAR Figure 7.6-15 has been changed to Figure 7.7-17.

   As stated in the response to Question 032.62, the RBM is a power generation system and not utilized for accident mitigation. The RBM should not be confused with the Rod Block Trip System, including the APRM rod block trip function. RBM has been appropriately moved from Section 7.6 to 7.7. (See response to Question 032.62).

   The end points will vary according to the following parameters:

   1. Total Rod worth

   2. Rod worth at a specific elevation along the rod.

   3. Detector elevation relative to rod position, and

   4. Since RBM A and RBM B average detectors at different axial heights, the response from RBM B (which averages detectors at B & D locations) is affected slightly more by void formation at top of bundles than RBM A (which averages detectors at A & C locations).

QUESTION 032.87

Revise your description of the recirculation pump trip or the appropriate sections of the FSAR to resolve the following inconsistencies:

1. The FSAR states that the RPT is a Class 1E system. Verify that the sensors and logic are seismically qualified since your analysis merely states that it meets the requirements of a non-existent subsection of IEEE 344-1971.

2. The logic is described as two-out-of-two under "Initiating Circuits," but is correctly identified, in the "Logic" descriptions, as two-out-of-two for the control valves and one-out-of-two-twice for the stop valves.

3. It is stated in the logic paragraph that failure to initiate requires failures in more than two RPS divisions, when obviously failures in A plus C, A plus D, B plus C, or B plus D could prevent initiation for the control valves. (The logic is not sufficiently definitive for the stop valve to determine whether more than two failures would be required.) Similarly, initiation would require two or more channels.

4. The logic shown in Figure 7.2-11 identifies breakers by the numbering scheme used with the two-speed recirculation pumps used in newer (than SSES) BWRs. What breakers are actually tripped?

5. The logic shown in Figure 7.2-1 includes a trip bypass and power level enable (with the enable given in the wrong direction) that are not included in the description or the analysis.

6. The recirculation pump FCDs provided in Section 7.7 do not indicate that the RPT is implemented, even though the ATWS trips are shown.

7. It is stated that paragraphs 4.11, 4.12, and 4.15 of the IEEE 279-1971 are not applicable to the RPT. It is the staff's position that all requirements of the standard are applicable and justification must be provided for deviating from any requirement. Each of these positions is addressed in Section 7.2 when the same circuit is analyzed for the RPS.

RESPONSE:

1. All RPT sensor and logic elements are seismically and environmentally qualified. Subsection 7.6.2a.8.2 has been revised.

2 & 3. A change to the system has been made. The logic for each, Turbine Control Valves and Turbine Stop Valves, is now a two-out-of-two configuration. Subsections 7.6.1a.8.3.1, 7.6.1a.8.3.2 and all applicable documents will reflect this change by the fourth quarter of 1980.

4. The breakers identified (3A, 4A & 3B, 4B) are added specifically for the RPT function and are numbered the same for all plants.

5. The RPT logic shown in Figure 7.2-1 will be revised to be consistent with the permissive for reactor power greater than ~30% rated. Discussion has been added in Subsections 7.6.1a.8.3.2 and 7.6.2a.8.1. The RPS IED will be revised by the end of the fourth quarter of 1980.

6. FSAR Section 7.7 text will be amended to reflect the (ATWS) RPT function. This will be accomplished in the fourth quarter of 1980.

7. The requirements for conformance to Paragraph 4.11 of IEEE 279-1971 are contained in the first two paragraphs of Subsection 7.2.2.1.2.3.1.11. It should be noted that these limit switches cannot be maintained or calibrated during plant operation because they are mounted directly on the stop valve which is located in a high radiation area. Subsection 7.6.2a.8.2 (IEEE 279 Paragraph 4.11) has been amended to refer to Subsection 7.2.2.1.2.3.1.11.

   The requirements for conformance to Paragraph 4.12 of IEEE 279-1971 are contained in Subsection 7.2.2.1.2.1.2.3.1.12. FSAR Subsection 7.6.2a.8.2 (IEEE 279 Paragraph 4.12) has been amended to refer to Subsection 7.2.2.1.2.1.2.3.

QUESTION 032.88

No discussions, descriptions, or analyses of HPCI or RCIC manual isolation systems could be found in Sections 7.3, 7.4, or 7.6. A review of Figures 7.3-7 and 7.4-2 and elementary diagrams 791E420AE and 791E421AE revealed several concerns about the HPCI and RCIC manual isolation systems. Justify having a manual initiation that:

1) Operates only one of the two isolation valves and, therefore, does not meet the requirement of the single failure criteria or Regulatory Guide 1.62.

2) Is interlocked with the system initiation signals such that the manual isolation switch is ineffective unless a system initiation signal is present.

RESPONSE:

The correct elementary diagrams for Susquehanna SES-1 are 791E420WJ, Rev. 1 and 791E421AE, Rev. 7.

1) The HPCI and RCIC systems do comply with the single failure criteria and Regulatory Guide 1.62. Each is a system which operates within one single mechanical/electrical division. HPCI is a Division 2 system while RCIC is a Division 1 system. Each of these systems meets the single failure criteria on a network basis with ADS and LPCI acting as the independent backup for the HPCI system and HPCI acting as the independent backup of the RCIC system. Alone each of these systems is not required to be single failure proof. The manual initiation and isolation capability of each system does satisfy the requirements of Regulatory Guide 1.62 by providing the required system level manual initiation function which is identical to the automatic function. In order to provide some increased availability within each system independent division of automatic initiation logic has been provided. Because these systems are single division systems manual initiation capability was not necessary nor provided in the availability logic division for each system. Isolation capability of each system can be provided by the control switch for each isolation valve. This same isolation valve control capability would exist for each system regardless of the presence or absence of availability logic. Consequently, the operator has at his disposal one system level isolation control switch and one isolation valve control switch for one valve and one isolation valve control switch for the other valve.

2) The interlocking of manual isolation with system initiation was provided to obviate the loss of system availability before the system is even required to function. This objective of maintaining the availability of the system against inadvertent isolations is enhanced with the present logic configuration. This configuration is considered to be consistent with the requirements of Regulatory Guide 1.62.

QUESTION 032.89

The text indicates that RCIC system will not automatically return from the test to the operating mode on system initiation if the flow controller is in the manual mode. Is this annunciated in the control room as a system inoperable/bypassed indication as recommended by Regulatory Guide 1.47?

RESPONSE:

Placing of the flow controller in manual mode occurs at a test frequency of less than once per year. The RCIC inoperable/bypassed system level control room annunciator is administratively actuated by the plant operator when such testing occurs, per the provisions of positions C.3 and C.4 of Regulatory Guide 1.47.

QUESTION 032.90

Describe the actions required to restart RCIC upon again reaching reactor low water level after RCIC has been tripped due to reactor high water level.

RESPONSE:

The RCIC system, once tripped by a reactor vessel high water level, will not automatically restart upon again reaching reactor vessel low water level. The plant operator manually resets the trip and throttle valve. The trip reset is accomplished from the main control room by first closing the turbine trip and throttle valve and then opening it. The system will then restart if vessel water level is below the high level trip point.

An alternate RCIC restart sequence requires the operator to reset the entire RCIC system to the standby condition once the water level is below the high water level trip point. This requires resetting the system valves and logic.

QUESTION 032.91

The analysis for Regulatory Guide 1.47, Position C.4, is incomplete since it does not indicate that the individual system level indicators can be actuated manually from the control room by the operators. Describe the provisions incorporated into the Susquehanna design to satisfy Position C.4 of the Regulatory Guide 1.47. (Note: This position is not intended to address the testing of annunciators, but is intended to provide manual initiation of the system level indication of inoperable and bypassed status.)

RESPONSE:

FSAR Subsection 7.4.2.1.2.7, Position C.4 has been amended.

QUESTION 032.92

Section 7.4.1.3.3.1 states that during the initial phase of cooling the reactor, only a portion of the RHR heat exchanger capacity is required. What is the basis for this statement and is it related to the normal operation of the RHR? Also, the second sentence in Section 7.4.1.3.3.2 does not clarify the first sentence of the section. Two redundant shutdown cooling modes are identified earlier, but what are the "two diverse shutdown cooling means" referred to in Section 7.4.1.3.3.5.

RESPONSE:

Heat exchanger capacity is conservative for all RHR operating modes. The statement in Subsection 7.4.1.3.3.1 is based on the fact that for any single shutdown mode of RHR, the respective heat exchanger capacity utilized is far less than the available system-wide heat exchanger capacity of RHR. This statement is related to normal RHR operation insofar as the RHR System affords alternate loops to one or more heat exchangers plus alternate heat exchanger loops to insure accomplishing its functional objectives. It should be noted that though additional heat exchanger capacity is available for another mode of operation, simultaneous operation of modes is possible only if appropriate interlocks are satisfied.

FSAR Subsection 7.4.1.3.3.1 has been revised.

There is no explicit justification for the statements contained in Subsection 7.4.1.3.3.2, Initiating Circuits, because the reactor shutdown cooling mode is design-based about a controlled shutdown mode, whereby manual operation is acceptable. Furthermore, because of the reactor conditions that are prerequisite to initiating the shutdown cooling mode, as stated in Subsection 7.4.1.3.1.1, Section a, the use of auto-initiation to precisely time such action is neither critical nor necessary.

FSAR Subsection 7.4.1.3.3.2 has been revised.

The two diverse means of shutdown cooling referred to in Subsection 7.4.1.3.3.5 are: (1) the loop consisting of pumping vessel water to the heat exchanger and back to the vessel with relief valves open to the pool; (2) the loop consisting of pumping suppression pool water to the heat exchanger and back to the vessel with relief valves open to the pool.

FSAR Subsection 7.4.1.3.3.5 has been revised.

QUESTION 032.93

A review of the remote shutdown panel description, Drawing E149, and various system drawings indicates several possible concerns.

(1) The remote shutdown panel is a single panel with only the minimum controls and instrumentation required to bring the reactor to cold shutdown status. Other BWR plants (Zimmer and Grand Gulf) have provided separate and independent remote shutdown panels. Justify having a remote shutdown panel that does not meet the single-failure criteria and describe the means used to meet the separations criteria inside the remote shutdown panel.

(2) Transferring control to the remote shutdown panel disables automatic ECCS actuation of both RHR loops. During this condition, the ECCS is no longer capable of providing cooling for all DBAs. Justify.

(3) When transferring control to the remote shutdown panel, controls for some functions are transferred to maintained contact switches. Describe how the operator determines the proper position of the control switches on the remote shutdown panel before making the transfer. Analyze the effects on plant safety of operating any of the transfer switches with its associated control switches in the incorrect position.

RESPONSE:

(1) The remote shutdown panel (RSP) is designed to meet 10CFR50, Appendix A, Criterion 19.

The design assumes that the Evacuation Occurrence does not occur simultaneously or coincident with recovery from another abnormal condition or with any other abnormal operating condition except loss of offsite power. The plant is assumed to remain in an orderly status during the Evacuation Occurrence. The Susquehanna SES remote shutdown system design philosophy is the same as presented in GESSAR-251 and accepted by NUREG 0151, Docket No. 50-531, and the same as presented in Hatch 2, FSAR.

The panel is subdivided with a continuous barrier, top to bottom, back to front, to physically separate Division I power from Division II power.

(2) A DBA is not part of the design criteria for the remote shutdown panel (RSP). The RSP is designed to prevent failure of equipment (controls) in the Control Room or the cable spreading rooms from causing failure of equipment on the Remote Shutdown Panel. Since several RHR Loop A valves are closed to prevent unwanted flow paths and RHR Loop B valves are used for shutdown from the RSP, then the controls for these valves are isolated from the control room to preclude spurious actuations. This includes the automatic ECCS actuation for these valves, which is in the control room panels. Please also refer to the assumed prevailing condition stated in part (1) above.

(3) The operator follows the Susquehanna SES Remote Shutdown Panel C201 normal status procedure, OP-00-001, to transfer control to the RSP or return the RSP switches to standby status.

QUESTION 032.94

A review of the RHR Drawing E153 indicates an interlock between Unit 1 and 2 such that when an RHR pump is operating in one unit, the corresponding RHR pump in the other unit cannot be started. This interlock is in addition to the one questioned in Question SSES 24. This interlock is not mentioned or described in the FSAR text and also appears to be a violation of GDC-5.

Amend the FSAR and/or drawing to fully describe the interlocks between the RHR systems in Units 1 and 2. Provide a detailed analysis to justify having such an interlock that will prevent the safe and orderly shutdown and cooldown of one unit (by preventing RHR operation) while the RHR system in the other unit is operating. Include this interlock in your discussion and analysis of compliance with GDC-5.

RESPONSE:

The interlocks described in Question 032.73 and 032.94 are intended to be the same. The following drawings will be revised in the first quarter of 1981 to show AE's implementation of the GE interlock discussed in 32.73:

E-153-2
E-153-4
E-153-6
E-153-8
E-153-47
E-153-49
E-153-51
E-153-53

QUESTION 032.95

The FSAR text states in Section 7.4.1.2.3.3 that when the SLCS is initiated, both explosive valves fire and also states in Section 7.4.1.2.3.6 that when the SLCS is initiated, one of the two explosive valves is fired. Amend the FSAR to resolve this discrepancy.

RESPONSE:

FSAR Subsection 7.4.1.2.3.6 has been revised to correctly state that both valves are fired when SLCS is initiated.

QUESTION 032.96

The FSAR states the remote shutdown panel transfer switches will generate a signal to actuate valves in a direction that will isolate piping that could bypass significant volumes of water away from systems required for remote shutdown. The valves that are actuated to the "safe-condition" are listed in Table 7.4-3, but Table 7.4-3 does not indicate which condition (either open or closed) is the "safe-condition" for all such valves. Amend Table 7.4-3 to include which condition is the "safe-condition" for all valves so actuated when the transfer switches are operated.

RESPONSE:

Table 7.4-3 has been revised to include this information.

QUESTION 032.97

Apparent inconsistencies and omissions were noted in the analysis for compliance with the following criteria. Amend the FSAR as required.

A. RCIC

1) Regulatory Guide 1.6. Justify your statement that because the single failure criteria are not applicable, RG-1.6 is not applicable to RCIC.
2) General Design Criteria 21. The analysis addresses testability but does not address reliability.
3) General Design Criteria 29. The analysis merely states the function of RCIC; it does not address the probability of the system functioning when needed.
4) General Design Criteria 34. The analysis consists of a reference to a non-existent subsection.
5) IEEE 279. The discussion presented under paragraph 4.12 is pertinent to paragraph 4.13 and is unrelated to paragraph 4.12. The discussion should be modified as needed and relocated to paragraph 4.13. It appears that there are no operating bypasses as defined in IEEE 279 associated with RCIC.

B. SLCS

1) General Design Criteria 20 and IEEE 279, paragraph 4.1. The analysis describes instrumentation that is not a part of the SLCS. Justify the non-compliance of the SLCS with the automatic actuation requirement.
2) General Design Criteria 28. No analysis for GDC-28 is given. Does the SLCS meet GDC-28, assuming that the maximum amount of the SLCS piping that could contain cold water does so at the time the system is activated with the reactor at full power?
3) IEEE 279, paragraphs 4.8 and 4.9. The analysis presented described instruments that are neither system inputs nor system input sensors.

RESPONSE:

A. RCIC

1) Regulatory Guide 1.6 is concerned with independence between redundant standby power sources. RCIC does not have redundant power sources. It should be noted that two divisions of 125VDC power are used to power inboard and outboard isolation valves that are defined as RCIC system valves. These power supplies meet Regulatory Position 3 of Regulatory Guide 1.6. FSAR Subsection 7.4.2.1.2.1.1 has been revised.

2&3) RCIC is periodically tested to ensure operational readiness as part of the reliability and probability of proper functioning. Additional reliability and probability of operation are provided through the use of high functional reliability components and intersystem redundancy. FSAR Subsections 7.4.2.1.2.2.3 and 7.4.2.1.2.2.5 have been revised.

4) Section 7.4.2.1.2.2.6 refers to Section 7.4.1.1.1.1.(3) which does exist in the present text. No change is required.

5) FSAR Subsections 7.4.2.1.2.3.1.12 and 7.4.2.1.2.3.1.13 have been revised.

B. SLCS

1) Subsections 7.4.2.2.2.2.2 and 7.4.2.2.2.3.1.1 have been revised.

The SLCS is not required to comply with the automatic initiation requirements of GDC 20 and IEEE 279, paragraph 4.1. The SLCS is a backup method of manually shutting down the reactor to cold subcritical conditions by independent means other than by the normal method through the control rod drive system. Refer to Subsections 7.4.1.2.1.1, 7.4.1.2.1.2 and 7.4.1.2.3.5 for further clarification.

2) Subsection 7.4.2.2.2.2.6 has been revised. The text material formerly found in Subsection 7.4.2.2.2.2.6 has been renumbered 7.4.2.2.2.7. The maximum amount of cold water that can be contained in the piping between the SLCS sodium pentaborate tank and the reactor vessel is less than 20 gallons. The SLCS piping enters through the bottom of the vessel; therefore, the initial injection of cold water contained in the SLCS piping is insignificant when mixed with the existing reactor coolant. The negative reactivity added to the reactor system by the sodium pentaborate solution counteracts by a very large margin the effect of the initial cold water injection.

3) It is correct that the display instruments described in 7.4.2.2.3.1.8 do not directly provide system inputs or system sensors to the SLCS. However, these instruments display to the operator the status of functions of other systems upon which the operator decides whether or not to manually initiate the SLCS. Therefore, to the extent feasible and practical, system inputs to the SLCS are derived from the operator, based on his judgment from observing displays which are direct measures of desired variables. The SLCS, as an independent system governed by intent and design definition described elsewhere, of necessity requires a man/machine interface as described above. It is in

this sense also, that the annunciated status of sodium pentaborate tank temperature, level, discharge pressure, and explosive valves control circuit continuity, does in fact provide a means for checking, with a high degree of confidence, the operational status of the SLCS system.

Subsections 7.4.2.2.2.3.1.8 and 7.4.2.2.2.3.1.9 have been revised.

QUESTION 032.98

The notes to Table 7.1-2 indicate in several places that Susquehanna has four sets of axial taps on the reactor pressure vessel for water level and vessel pressure sensors and, also indicate that the instrument racks have been located in four distinct quadrants of the plant with the RPS equipment separated from the ECCS and isolation equipment. Figure 5.1-3b, "P&ID Nuclear Boiler Vessel Instrumentation," shows only two sets of axial taps and also shows the RPS and ECCS sharing various sensors. Various other material in Section 7.0 gives conflicting information as to the number of sets of axial taps on the Susquehanna pressure vessel and to the number and arrangement of RPS and ESF sensors. (See also Q032.44, Q032.45, Q032.69, and Q032.74.) These inconsistencies make it difficult to complete the review. Review Sections 5.0, 6.0, and 7.0 and amend the FSAR as necessary to give a clear and consistent description of the pressure vessel axial taps and the number and arrangement of RPS and ESF sensors.

RESPONSE:

Susquehanna 1 and 2 do not have four sets of axial RPV taps, only two. Instrument racks are not located in four distinct quadrants and RPS, NS[4], and ECCS sensors are not separated. Table 7.1-2 has been revised.

QUESTION 032.99

Several inconsistencies and anomalies were noted in the review of the various RHRS drawings:

1) Figure 5.4-2a shows four differential pressure switches measuring the difference in pressure between the risers for System A and System B. These switches are not shown P&ID (M143), are not included in Table 7.3-3, and are not discussed in Section 7; however, F7.3-10 and drawing E11-1040 indicate they are used in the control logic of valves E11-F015 and E11-F017.

2) Figure 7.3-10 appears to indicate that if the recirculating pumps are not operating at the time of LPCI initiation, they will be given a superfluous trip and an additional reactor pressure permissive interlock will have to be satisfied. If the recirculation pumps are running, the trip circuit and the interlock are both bypassed.

3) Figure 7.3-10 shows a number of signal seal-ins with no indication that there is any method for resetting them. In addition, redundant seal-ins are shown following the recirculation pump running/not running logic.

Revise the FSAR as necessary to correctly describe the RHRS and its interlocks and logic, and verify that the FSAR and the drawings describe the instrumentation and controls that are actually being installed at your facility. All FCDs should be reviewed to ensure that all seal-ins are shown correctly.

RESPONSE:

1) The recirculation system riser differential pressure switches no longer provide input to E11-F015 and E11-F017 valve control logics. The RHR System FCD has been corrected.

2) Figure 7.3-10 has been corrected.

3) Figure 7.3-10 has been corrected.

QUESTION 032.100

Section 7.7.1.1 states that the upset water level and the narrow water level range are indicated by recorders in the control room (the wide water level range is described, but the type and location of readout is not stated), and that reactor pressure is indicated on gauges in the containment. Section 7.7.1.4 states that the narrow water level range and the wide water level range are continually recorded in the main control room, and the reactor pressure and upset water level range are "indicated in the main control room." Revise the FSAR to clarify the number of channels and the type of indication provided in the control room for monitoring reactor pressure and water level. Also, identify whether these indications are from the same transmitters that provide safety-related displays in Section 7.5.

RESPONSE:

Subsection 7.7.1.1.3.1.2 and 7.7.1.1.5.2 (Item 4) have been revised. The recorders discussed in Subsection 7.7.1.1 and 7.7.1.4 are the same recorders described in Section 7.5.

QUESTION 032.101

Revise the FSAR to resolve the following discrepancies:

1) Section 7.7.1.2 states that the withdraw and settle commands are applied simultaneously to withdraw a rod and the withdraw command is dropped to enter the settle cycle. Figure 7.7-2 indicates that only the withdraw command is active during withdrawal.

2) Section 7.7.1.2 states in one paragraph that drive commands are transmitted to the selected rod every milli-second and in the next paragraph (and in Figure 7.7-5) states commands are transmitted every 0.2 milliseconds. Figure 7.7-2 indicates that commands are alternated with status monitoring of non-selected rods and that after monitoring the status of all rods, approximately 45 milliseconds, the RMC goes into the self-test loop long enough to test one rod (approximately 60-500 msec based on self-test loop duration). For 185 rods, the 45 millisecond for the monitor loop is a little long for a 0.2 millisecond action loop (37 msec corresponds to the 0.2 msec action loop) and too short for the 1 millisecond action loop. Correct the logic shown in Figure 7.7-5 if it is incorrect; otherwise, explain what happens within the HCU during the 60-500 millisecond the RMC is in the self-test loop.

RESPONSE:

1) The statement in Subsection 7.7.1.2 is correct. During the withdrawal cycle, the settle command and the withdrawal command are applied simultaneously at the end of the withdrawal period (approximately 0.1 sec). This is shown on sheet 1 of Figure 7.7-2, Table I. The references in Subsection 7.7.1.2.3.2.1.3 "Withdraw Cycle" to a "Settle Valve" are correct. The settle valve is so-called because it is held open after all other rod drive directional control valves have been shut, allowing water in the volume under the CRD drive piston to be vented into the exhaust header, thereby allowing the control rod to settle until the collet fingers latch into the next notch on the index tube.

The rod drive directional control valves are traditionally named as follows:

Valve No.	FUNCTION		
	Insert	Withdraw	Settle
120		X	X
121	X		
122		X	
123	X		
Name	Insert Valves	Withdraw Valves	Settle Valves

Note that the 120 "settle" valve also plays a role in withdrawing a rod, so that replacing "settle valve" with "settle function" may not always be accurate. The words "settle function" do not indicate as clearly as the words "settle valve" whether or not the 120 valve is the only valve in action.

2) The "each millisecond" described in paragraph 2 of FSAR Subsection 7.7.1.2.3.2.1.1 defines the periodicity of the generated signal, whereas ".0002 seconds" in the next paragraph defines the duration of the signal. See Subsection 7.7.1.2.3.2.1.1 for a clarification change.

QUESTION 032.102

In Section 7.7.1.4, it is stated that "In event of loss of feedwater, the reactor protection system will cause plant shutdown, thus preventing any further lowering of vessel water level." Identify the interlock in the feedwater system that causes "plant shutdown" instantaneously following the loss of feedwater and discuss the mechanism that prevents a continuing decrease in vessel water purely as a result of the plant being shut down.

RESPONSE:

FSAR Subsection 7.7.1.4 was stated incorrectly and has been revised.

QUESTION 032.103

The response to Q032.16(4) is not acceptable. Specifically, Section 7.3.1.1a.5.6 states that the suppression pool cooling mode is interlocked with reactor water level and drywell pressure functions. No further description, information, or analysis of this interlock is provided. Also, no analyses for conformance to the regulatory criteria are given in Section 7.3.2.

Amend the FSAR to provide a complete description of the suppression pool cooling mode interlocks and to provide analyses for conformance to the regulatory criteria in Section 7.3.2. Also, the inconsistencies and errors raised in Q032.77 for the containment spray cooling system appear to be applicable to the suppression pool cooling system.

RESPONSE:

A. FSAR Subsection 7.3.1.1a.5.6 has been modified to identify the interlock which deals with LPCI mode selection. If additional description of the LPCI interlock is desired see Subsection 7.3.1.1a.1.6.5. Subsection 7.3.1.1a.1.6.7 has been modified showing the ten-minute period after initiation of LPCI during which an open signal is present on the heat exchanger bypass valves.

B. FSAR Section 7.3.2a.5 has been added to provide the required analysis section for suppression pool cooling mode.

   No addition text changes in the discussion or analysis are required due to the concerns identified in Question 32.77.

QUESTION 040.1

With respect to diesel generator alarms in the control room, a review of malfunction reports of diesel generators at operating nuclear plants has uncovered that in some cases the information available to the control room operator to indicate the operational status of the diesel generator may be imprecise and could lead to misinterpretation. This can be caused by the sharing of a single annunciator station to alarm conditions that render a diesel generator unable to respond to an automatic emergency start signal and to also alarm abnormal, but not disabling, conditions. Another cause can be the use of wording of an annunciator window that does not specifically say that a diesel generator is inoperable (i.e., unable at the time to respond to an automatic emergency start signal) when in fact it is inoperable for that purpose. Therefore:

(1) Provide the alarm and control circuitry logic for the diesel generators at your facility to determine how each condition that renders a diesel generator unable to respond to an automatic emergency start signal is alarmed in the control room. These conditions include not only the trips that lock out the diesel generator start and require manual reset, but also control switch or mode switch positions that block automatic start, loss of control voltage, insufficient starting air pressure or battery voltage, etc. This review should consider all aspects of possible diesel generator operational conditions for example test conditions and operation from local control stations. One area of particular concern is the unreset condition following a manual stop at the location station which terminates a diesel generator test and prior to resetting the diesel generator controls for enabling subsequent automatic operation.

(2) Provide the details of your evaluation including the results, conclusions, and a tabulation of the following information:

    (a) all conditions that render the diesel generator incapable of responding to an automatic emergency start signal for each operating mode as discussed above;

    (b) the wording on the annunciator window in the control room that is alarmed for each of the conditions identified in (a);

    (c) any other alarm signals not included in (a) above that also cause the same annunciator to alarm;

    (d) any condition that renders the diesel generator incapable of responding to an automatic emergency start signal which is not alarmed in the control room; and

    (e) any proposed modifications resulting from this evaluation.

RESPONSE:

Subsection 8.3.1.4.12, Table 8.3-16 and Dwg. E-31, Sh. 9 have been added to the FSAR to supply the requested information.

QUESTION 040.2

The staff requires that the following qualification test program information be provided for all Class 1E equipment:

(1) Identification of Equipment including,

(a) Manufacturer
(b) Manufacturer's type number
(c) Manufacturer's model number

(2) Equipment design specification requirements, including,

(a) The system safety function requirements
(b) An environmental envelope which includes all extreme parameters, both maximum and minimum values, expected to occur during plant shutdown, normal operation, abnormal operation, and any design basis event.
(c) Time required to fulfill its safety function when subjected to any of the extremes of the environmental envelope specified above.

(3) Test plan,
(4) Test set-up,
(5) Test procedures,
(6) Acceptability goals and requirements,
(7) Test results,
(8) Identification of the documents which include and describe the above items.
(9) The information requested above shall be provided for at least one item in each of the following groups of Class 1E equipment.

(a) Switchgear
(b) Motor control centers,
(c) Valve operators (in containment)
(d) Motors
(e) Logic equipment
(f) Cable
(g) Diesel generator control equipment
(h) Sensors
(i) Limit switches
(j) Heaters
(k) Fans
(l) Control boards
(m) Instrument racks and panels
(n) Connectors
(o) Penetrations
(p) Splices
(q) Terminal blocks

(10) In accordance with the requirements of Appendix B of 10 CFR 50, the staff requires a statement verifying: (a) that all Class 1E equipment has been qualified to the program described above, and (b) that the qualification information is available for an NRC audit.

RESPONSE:

The qualification test program information for Class 1E equipment is provided in the Susquehanna SES Environmental Qualification Report For Class 1E Equipment submitted under separate cover.

QUESTION 040.3

The Regulatory staff is currently requesting, of all plants in OL review, information on the use of polyethylene type cable in safety systems. These type cables were found to have degraded considerably after many years of installed operation at the Savannah fuel processing plant.

Identify all safety related cable used in your design that has polyethylene in its construction. Provide the following information for each type of cable identified:

(1) The type of cable by name and catalogue number
(2) The manufacturer
(3) The type of polyethylene used
(4) How is the polyethylene used in the cables' construction, i.e., insulation and/or jacket.
(5) The results of environmental qualification tests performed.

RESPONSE:

I. All NSSS Safety Related cables that utilize polyethylene are listed below with the requested information. It is important to note that these cables are all in the Control Structure environment.

A. 1. Coaxial Cable
5021F1031
7521D3339
7523D3339
2. Raychem
3. Cross-linked polyethylene
4. Jacket and insulation
5. Max. temp: 80°C
Radiation Resistance: 200 megarads
Flammability: FED-STD-228

B. 1. Multi Conductor Cable (SI-58779
2. General Electric
3. Vulkene - Cross-linked polyethylene
4. Insulation
5. Max. temp: 90°C
Flammability: Cable qualified to IPCEA S-19-81

C. 1. Multi Conductor
C51-0070
C51-0190
C53-0070
C53-0190

2. Rockbestos Firewall III
3. Cross-linked flame resistant polyethylene
4. Insulation
5. Max. temp: 90°C
   Flammability: Completed cable qualified to IEEE 383 part 2.5. Oxygen index of jacket and insulation material in cable is a minimum of 28%.

II. All non-NSSS supplied safety related cables that utilize polyethylene are listed below. The only polyethylene used is Hypalon. The manufacturer, the use and the test reports are also listed.

A. Instrumentation Cable

1.

Instrumentation Cable Mfrs. Part No.	Thermocouple Extension Cable Mfrs. Part No.
1935-A0536-001	1902-01340-001
1935-A0936-001	1902-02340-001
1935-A4836-001	1902-03340-001
1935-01233-001	1902-65340-001
1935-02733-001	1920-01281-002
1935-50433-001	1924-612A3-001
1935-60733-002	
1935-60933-001	
1935-61233-001	**Communication Cable Mfrs. Part No.**
1935-61433-001	1950-48610-001
1935-63733-001	1950-88310-001
1952-65380-001	1990-90038
1952-68340-002	1990-90039
1962-08340-001	
1962-68340-002	
1974-50233-001	
1974-50333-001	**Rod Position Indication Cable Mfrs. Part No.**
1974-50733-001	1990-90036
1974-50733-001	
1984-50333-001	

2. Samuel Moore & Co.

3. Hypalon (chlorosulfonated polyethylene)

4. Jacket

5. Certified by Isomedix, Inc. (Report dated May 1976) to qualify in accordance with IEEE 323-1974 and IEEE 383-1974, V/P 8856-E131-A-35-2.

B. <u>600 Volt Control Cable</u>

1. 600 volt, single-conductor and multi-conductor copper control cable. No catalog numbers available.

2. American Insulated Wire Co.

3. Hypalon (chlorosulforated polyethylene)

4. Jacket

5. Certified by the Franklin Institute (Report F-C4197-2, dated December 1975) to meet requirements of IEEE 323-1974 and IEEE 383-1974, V/P 8856-E130-A-10-1.

C. <u>600 Volt Power Cable</u>

1. 600 volt, single-conductor Aluminum power cable. No catalog Numbers Available.

2. The Okonite Company

3. Hypalon (Chlorosulfonated polyethylene)

4. Jacket

5. Certified by the Franklin Institute (Report No. F-63694-1, dated November 8, 1974) to meet requirements of IEEE 383-1974, V/P 8856-E130-B-5-2.

III. Safety-related cables used for the multi-pin quick disconnect connectors of motor-operated valves which utilize polyethylene are listed below.

A. 600 Volt Power, Control and Instrumentation Cables

1a. Power Cable: 3-conductor

<u>Mfrs. Product Code</u>

C51-0030
P62-0064
P62-0024

1b. Control Cable: multi-conductor

<u>Mfrs. Product Code</u>

C53-0020
C53-0030
C53-0050
C53-0070
C53-0120

1c. Instrumentation Cable: 1 pair, shielded

<u>Mfrs. Product Code</u>

I46 - 0021

2. Rockbestos

3,4. Chlorosulfonated Polyethylene (Hypalon) - Jacket

Cross-Linked Polyethylene - Insulation

5. Certified by Rockbestos qualification test reports QR-5804 and QR-5805 to meet requirements of IEEE 323-1974 and IEEE 383-1974.

QUESTION 040.4

Qualification of Penetrations

Describe how your design meets the recommendations of Regulatory Guide 1.63, Revision 1.

Identify each type of electrical circuit that penetrates containment. Describe the primary and backup over current protection systems provided for each type of circuit. Describe the fault-current-versus-time for which the primary and backup protection systems and the penetrations are designed and qualified.

Provide coordinated curves which demonstrate, for each circuit identified, that the maximum fault-current-versus-time condition to which the penetration and cable were qualified will not be exceeded.

Describe the provision for periodic testing under simulated fault conditions.

RESPONSE:

The discussion of Regulatory Guide 1.63 in FSAR Section 3.13 has been revised to include this information.

QUESTION 040.5

Potential Problem with Containment Electrical Penetration Assemblies

Recent operating experience at Millstone Unit No. 2 has shown that the deterioration of the epoxy insulation between splices has caused electrical shorts between conductors within a containment electrical penetration assembly. Indicate what tests and/or analysis that have been performed to demonstrate the acceptability of the design in this regard. Provide whatever information is required to perform an independent evaluation of this aspect of the electrical penetration design.

RESPONSE:

Susquehanna SES electrical cable penetrations are not subject to the same problems Millstone has experienced because Millstone's electrical cable penetrations were manufactured by General Electric while those at Susquehanna SES are of a different design and are manufactured by Westinghouse.

Westinghouse Report #75-7B5-BIGAL-R2 demonstrates by test and Arrhenius plotting that the epoxy used in the modular penetrations has an expected life of 40 years. The Westinghouse design has a coat of varnish on the conductor in the monitoring space. The cables have successfully passed the dialectric test as performed in accordance with Westinghouse Report #PEN-TR-76-07.

QUESTION 040.6

Recent operating experience has shown that adverse effects on the safety-related power system and safety related equipment and loads can be caused by sustained low or high grid voltage conditions. We therefore require that your design of the safety related electrical system meet the following staff positions. Supplement the description of your design in the FSAR to show how it meets these positions or provide appropriate analyses to justify non-conformance with these positions.

(1) We require that an additional level of voltage protection for the onsite power system be provided and that this additional level of voltage protection shall satisfy the following criteria:

(a) The selection of voltage and time set points shall be determined from an analysis of the voltage requirements of the safety-related loads at all onsite system distribution levels;

(b) The voltage protection shall include coincidence logic on a per bus basis to preclude spurious trips of the offsite power source;

(c) The time delay selected shall be based on the following conditions:

(i) The allowable time delay, including margin, shall not exceed the maximum time delay that is assumed in the FSAR accident analyses;

(ii) The time delay shall minimize the effect of short-duration disturbances from reducing the availability of the offsite power source(s); and

(iii) The allowable time duration of a degraded voltage condition at all distribution system levels shall not result in failure of safety systems or components;

1) The voltage sensors shall automatically initiate the disconnection of offsite power sources whenever the voltage set point and time delay limits have been exceeded;

2) The voltage sensors shall be designed to satisfy the applicable requirements of IEEE Std. 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations"; and

3) The Technical Specifications shall include limiting condition for operation, surveillance requirements, trip set points with minimum and maximum limits, and allowable values for the second-level voltage protection sensors and associated time delay devices.

(2) We require that the current system designs automatically prevent load shedding of the emergency buses once the onsite sources are supplying power to all sequenced loads on the emergency buses. The design shall also include the capability of the load shedding feature to be automatically reinstated if the onsite source supply breakers are

tripped. The automatic bypass and reinstatement feature shall be verified during the periodic testing identified in Position 3.

In the event an adequate basis can be provided for retaining the load shed feature when loads are energized by the onsite power system, we will require that the setpoint value in the Technical Specifications, which is currently specific as "...equal to or greater than..." be amended to specify a value having maximum and minimum limits. Your bases for the selected setpoints and limits must be documented.

(3) We require that the Technical Specifications include a test requirement to demonstrate the full functional operability and independence of the onsite power sources at least once per 18 months during shutdown. The Technical Specifications shall include a requirement for tests: (1) simulating loss of offsite power; (2) simulating loss of offsite power in conjunction with a safety feature actuation signal; and (3) simulating interruption and subsequent reconnection of onsite power sources to their respective buses. Proper operation shall be determined by:

(a) Verifying that on loss of offsite power the emergency buses have been de-energized and that the loads have been shed from the emergency buses in accordance with design requirements.

(b) Verifying that on loss of offsite power the diesel generators start on the autostart signal, the emergency buses are energized with permanently connected loads, the auto-connected shutdown loads are energized through the load sequencer, and the system operates for five minutes while the generators are loaded with the shutdown loads.

(c) Verifying that on a safety feature's actuation signal (without loss of offsite power), the diesel generators start on the autostart signal and operate on standby for five minutes.

(d) Verifying that on loss of offsite power in conjunction with a safety features actuation signal the diesel generators start on the autostart signal, the emergency buses are energized with permanently connected loads, the auto-connected emergency (accident) loads are energized through the load sequencer, and the system operates for five minutes while the generators are loaded with the emergency loads.

(e) Verifying that on interruption of the onsite sources the loads are shed from the emergency buses in accordance with design requirements and that subsequent loading of the onsite sources is through the load sequencer.

(4) The voltage levels at the safety-related buses should be optimized for the full load and minimum load conditions that are expected throughout the anticipated range of voltage variations of the offsite power source by appropriate adjustment of the voltage tap settings of the intervening transformers. We require that the adequacy of the design in this regard be verified by actual measurement and by correlation of measured values with analysis results. Provide a description of the method for making this verification; before initial reactor power operation, provide the documentation required to establish that this verification has been accomplished.

RESPONSE:

I. Refer to Dwg. E-1, Sh. 1, E-4, Sh. 2, E-5, Sh. 1, and E-31, Sh. 5 for the discussion on undervoltage detection and transfer logic provided below:

The primary bus transfer on loss of offsite power is initiated at the 13.8 kV startup switchgear and at each Class 1E 4.16kV switchgear bus aligned to the lost offsite source. Refer to Subsection 8.3 for discussion on bus arrangement and the interconnection of the offsite power supplies and the on-site distribution system.

1. Each 13.8 kV startup bus is provided with an offsite power supply and the capability of connecting to the second offsite power supply by the closing of the 13.8 kV tie breaker (breaker 52-10502).

   The undervoltage detection system at each 13.8 kV switchgear bus consists of (1) incoming feeder (offsite power supply) undervoltage relays-device 27AI, (2) bus undervoltage relay-device 27A2, and (3) tie bus undervoltage relay-device 27A1.

   (a) Device 27AI-initiates tripping of the incoming feeder

   Device 27AI is a solid state type relay with pickup setting at 76.2 volts (66% of the rated 120 volts). Two independent single phase relays are used to monitor the A-B and B-C phase voltages. The incoming breaker is tripped on coincidence logic of the two undervoltage relays at 74 volts with a 30 cycle time delay.

   (b) Device 27A1 - Provides the permissive for closing of tie breaker

   Device 27A1 is a long time induction disc type undervoltage relay set at 105 volts (91% of rated) and time delay of 15 sec. Two single phase relay are provided for monitoring the availability of the alternate offsite power supply at the 13.8 kV level and provide a coincidence logic for the closing of the tie breaker.

   (c) Device 27A2 - initiates the bus transfer

   Device 27A2 is a 3 phase instantaneous plunger type relay with three full wave bridge rectifiers. The relay is set to drop out at 25 volt (22% of rated). Bus transfer is completed by the closing of the tie breaker (permissive by device 27A1).

2. Each 4.16 kV class 1E switchgear bus is provided with a preferred and an alternate (offsite) power supply and one diesel generator feeder as discussed in Subsection 8.3.1.3.

   The undervoltage detection and backup bus transfer on loss of offsite power or sustained degraded voltage on the bus is provided by (1) incoming feeder undervoltage relay-device 27AI, and (2) bus undervoltage relay-device 27A, and (3) degraded voltage protection relays devices 27B1, 27B2, 27B3, and 27B4.

The devices settings for the Class 1E bus undervoltage protection are summarized in the following Table 40.6-1.

(a) Device 27AI - provides the permissive for closing of the incoming breaker

Device 27AI is two single phase definite time delay relays set at 96.5% dropout voltage. These relays are used to monitor the availability of the offsite power supply at the class 1E 4.16 kV level.

(b) Device 27A - initiates the bus transfer

Device 27A is a 3 phase solid state type relay with three full wave rectifiers. The relay is set to drop out at 24 volts or 20% of rated bus voltage. The 4.16 kV bus transfer is initiated with a time delay of 10 cycles by tripping of the preferred incoming feeder breaker. The transfer is completed if the alternate offsite power supply to this 4.16 kV bus is available (permissive by device 27AI). In case the alternate offsite power is not available, the standby diesel generator is initiated to start with a 0.5 second delay.

(c) Devices 27B1, 27B2, 27B3, and 27B4 - initiate bus transfer and undervoltage alarm. These undervoltage relays are solid-state, single phase with definite time delays

The additional level voltage protection for each 4.16 kV Class 1E bus is provided to assure that voltage levels at all Class 1E distribution buses meet the minimum requirement of all safety-related equipment to the extent practical.

In the event of loss of voltage on the 4.16 kV Class 1E bus, the bus undervoltage relay (27A) initiates bus transfer per paragraph (b) above. In addition, relays 27B1, 27B2, 27B3, and 27B4 provide back up protection for alarms and initiating bus transfer.

If a degraded voltage condition occurs on the 4.16 kV Class 1E bus with no LOCA signal present (see Dwg. E-31, Sh. 5) which is below the setting of relays 27B1 and 27B2, an alarm (coincidence logic) will be initiated after 10 seconds. The relays will initiate the bus transfer after a 5 minute time delay during non-LOCA conditions. A LOCA signal bypasses the 5 minute time delay. The 10 second time delay is provided to preclude spurious alarms and trips for motor start transients. The 5 minute timer is provided so that operators can initiate corrective actions during non-LOCA conditions. Relays 27B1 and 27B2 initiate an alarm when the diesel generator is supplying power but do not trip the diesel generator breaker.

In addition, relays 27B3 and 27B4 trip the offsite supply breakers after a time delay of 3 seconds when the bus voltage falls below their settings. These two relays are also connected in a coincident logic. Their setting is based on coordination with overcurrent relays to prevent false trips due to transient voltage dips from fault currents. These relays have no function when the diesel generator is supplying bus power.

If the alternate offsite power is not available, the emergency diesel generator will be started automatically with a 0.5 second delay and connected to the respective bus within 10 seconds per section 8.3.1.4.1.

II. 1. Selection of all voltage relay settings is based on the onsite distribution system load flow study and is verified by preoperational tests. The continuous operating voltage at each distribution voltage level is maintained at ±10% of the rated voltage level over the entire transmission grid operating range.

Tripping of the offsite power supply at the 13.8 kV level is accomplished by a coincidence logic of two independent single phase undervoltage relays. The backup tripping of the same offsite power supply to the Class 1E 4.16 kV switchgear is provided by a 3 phase full wave rectifier type undervoltage relay for minimizing nuisance tripping such as loss of a single control fuse in the detection circuit. The total time delay allowed by restarting (starting) of class 1E equipment after a DBA is 13 seconds as shown on Table 8.3-1. 10 seconds is reserved for diesel generator starting. Therefore, 3 seconds is allocated for voltage sensing and bus transfer. Pre-operating tests will verify that the time delay on the bus transfer does not exceed the allowable time.

As discussed in (I) of above, offsite power supply is automatically disconnected at the 13.8 kV level. This forces a loss of power to the 4 kV buses connected to the offsite supply and a 4 kV transfer to the alternate offsite supply, if available, or to the diesel generators. The undervoltage detection sensors and circuits are designed in accordance with IEEE Std. 279-1971.

2. All loads on each 4.16 kV Class 1E switchgear bus except the 480 volt load center feeder are shed on loss of power to the bus. Once the bus is re-energized, the 4.16 kV Class 1E loads are loaded in accordance with the pre-set time delay. Load shedding and reloading of 4.16 kV class 1E loads are repeated as discussed above whenever the bus becomes de-energized.

3. Refer to Chapter 16 for Technical Specification.

4. Transformer tap settings are selected for optional operating voltage levels for all loading conditions under the anticipated voltage variation of the offsite power supplies. The continuous operating voltage at each level is maintained within ±10% of rated voltage. Pre-operational tests verify the actual voltage levels.

III. Relay Settings:

The function and settings of undervoltage relays are determined in consideration of the full load, minimum load, and the largest motor starting conditions that are expected throughout the anticipated range of voltage variations for the offsite power sources.

The settings of the degraded voltage protection relays are selected to prevent spurious trips of the offsite power supplies and to provide protection against damaging effects of degraded voltage. The settings are constrained by motor start transients and relay characteristics.

The following design criteria are used:

(1) The maximum allowable voltage at no load or the minimum load conditions is 110% of the motor rated voltage.

(2) The minimum voltage under the maximum running load condition is 90% of the bus rated voltage.

(3) The minimum starting voltage is 80% of motor rated voltage.

See Table 40.6-1.

TABLE 040.6-1

SETTING TABLE (4 KV BUS)

Device No.	Function	Alarm	Voltage Setting	Time Setting
27AI (preferred)	Permissive to close the preferred power incoming Breaker.	Yes	96.5% dropout	1 sec.
27AI (alternate)	Permissive to close the alternate incoming Breaker.	Yes	96.5% dropout	1 sec.
27A	Initiate bus transfer. Trip the incoming closed breaker.	Yes	20%	10 cycles
59/27	Bus over/under voltage (alarm only and located in load center).	Yes	110%/90%	10 sec.
27B1 27B2	Undervoltage alarm and initiate bus transfer with time delay relays.	Yes	93% dropout	10 sec.
27B1X 27B2X	Time delay relays with 27B1 and 27B2 to initiate bus transfer.	No	--	5 min.
27B3 27B4	Initiate bus transfer on LOCA condition.	No	65% dropout	3 sec.

QUESTION 040.7

Provide in Section 9.5.4 the means for indicating, controlling and monitoring the emergency diesel engine fuel oil temperature (SRP 9.5.4, Part III, Item 1).

RESPONSE

This information is contained in revised FSAR Subsection 9.5.4.5.

QUESTION 040.8

Section 9.5.4 of the FSAR does not locate the day tank associated with each diesel generator set. Provide the location of the fuel oil day tank. The day tank should be located at an elevation to assure a positive pressure at the engine fuel pumps. (SRP 9.5.4., Part III, Item 5c.)

RESPONSE:

The requested information is contained in revised FSAR Subsection 9.5.4.2.

QUESTION 040.9

The diesel engine generator sets should be capable of operation at less than full load for extended periods without degradation of performance or reliability. Provide a discussion of your diesel engine operating parameters, including minimum load requirements, and relate this to anticipated minimum loads under accident recover conditions and during accident standby operation when offsite power is available (SRP 9.5.5, Part III, Item 7).

RESPONSE:

Please see revised Subsection 8.3.1.4.

QUESTION 040.10

Provide a discussion of the measures taken in the design of the standby diesel generator air starting system to preclude the fouling of the starting air valve of filter with containment such as oil carry over and rust. (SRP 9.5.6, Part III, Item 1).

RESPONSE:

This discussion is contained in revised FSAR Subsection 9.5.6.2.

QUESTION 040.11

In regard to the diesel engine combustion air intake and exhaust system, discuss the precautionary measures taken to assure that the oxygen content of the incoming combustion air will not under any meteorological and accident conditions be diluted to an extent as to prevent the diesel from developing full rated power or causing engine shutdown. Include in the discussion the potential of fire extinguishing (gaseous) medium, recirculation of diesel combustion products, accidental releases of gases stored in the vicinity of the diesel intakes, restriction of inlet airflow, and air borne dust being drawn into the combustion air system of one or all diesel generators, thereby degrading their performance or possibly result in loss of emergency generator and loss of emergency power supply. (SRP 9.5.8, Part III, Item 3, 4, 5 and 6).

RESPONSE:

The required discussion is contained in revised FSAR Subsection 9.5.8.3.

QUESTION 040.12

Section 9.5.8 of the FSAR states that the diesel generator combustion air intake and exhaust systems are missile protected. Provide further description (with the aid of drawings) explaining how the openings in the diesel generator building for the air intake and exhaust are protected from tornado borne missiles.

RESPONSE:

Missile protection for the diesel generator combustion air intake and exhaust system are described in revised FSAR Subsection 9.5.8.3.

QUESTION 040.13

Provide a general discussion of the criteria and bases of the various steam and condensate instrumentation systems in Section 10.1 of the FSAR. The FSAR should differentiate between normal operation instrumentation and required safety instrumentation.

RESPONSE:

The various steam and condensate instrumentation systems used for normal operation are described in Section 10.4. See Subsections 10.4.1.5, 10.4.2.5, 10.4.3.5, etc. However, Section 7.2 describes specific instrumentation (turbine stop valve and turbine control valve closures) which are inputs to the RPS. These inputs, provided to meet safety related requirements, monitor and initiate protective actions. See Subsections 7.2.1.1.4.2, (d) and (e).

Display instrumentation for steam and power conversion systems is adapted to the ACR Operator Interface configuration described in Section 7.5. Specifically, this means that steam, condensate, feedwater and turbine generator systems display instrumentation each occupy a section of Unit Operating Benchboard (C651) or the Standby Information Panel (C652). Controls, hardwired displays and computer generated displays are located by system on these panels.

As described in Section 7.5, the basis of operation of these displays is that detailed system information is provided to computer displays and hardwired displays in parallel. The exception to this is the Standard General Electric, Mark I EHC instrumentation package which is provided and adapted to the ACR panel arrangement and does not have parallel information on the computer displays.

QUESTION 040.14

Discuss what protection will be provided the turbine overspeed control system equipment and associated electrical wiring and hydraulic lines from the effects of a high or moderate energy pipe failure so that the turbine overspeed protection system will not be damaged to preclude its safety function. (SRP 10.2, Part III, Item 8).

RESPONSE:

The turbine overspeed control system equipment and associated electrical wiring and hydraulic lines are not part of a safety related system and are therefore not subject to the requirements of SRP 10.2, Part III, Item 8. The overspeed equipment on Susquehanna SES does meet the applicable requirements of SRP 10.2. Susquehanna SES has an electro-hydraulic control system, a mechanical overspeed trip device and an independent and redundant backup electrical overspeed trip circuit as described in Subsection 10.2.2.6. In addition, the equipment and components related to the overspeed trip function would fail-safe if damaged by accident as described in Subsection 10.2.2.6. Finally, the equipment and components associated with the overspeed trip function have been so arranged as to minimize damage potential from accidents such as high or moderate energy pipe failures.

QUESTION 040.15

Provide your bases and justification for performing the grid transient stability studies using the 1980 50% of summer peak loads. Also provide a brief description of your operating philosophy with respect to Susquehanna Units 1 and 2 during light grid loading conditions and your projections of generation verses load for as far into the future as you have available and use for planning purposes.

RESPONSE:

The grid transient stability studies were performed on both the 1980 and 1982 systems. The studies were performed using the summer light load level (50% of summer peak loads) for both 1980 and 1982.

Under system light load conditions the electric supply system is characterized by decreased customer loads, lower voltage schedules, and reduced reactive output from generators. These conditions tend to make an electric supply system inherently less stable. Lower voltage levels and reduced generator reactive output are desirable under light load conditions to maintain balanced reactive conditions on the electric supply system.

To verify that light load conditions and not peak load conditions will present the worst case for system stability, a comparison of the relative system stability for summer light load (50% of summer peak) and system peak load (winter peak) conditions was performed. It was determined that the system is less stable under summer light load conditions and that the grid stability evaluation should be performed using the summer light load condition.

It is expected that under light load conditions Susquehanna Unit #1 and Unit #2 will continue to operate at rated continuous output of 1050 MW for each unit. The scheduled voltages on the Susquehanna 230 kV and 500 kV busses, which are regulated by the reactive output of Susquehanna Unit #1 and Unit #2 respectively will be lowered from the peak load voltage schedule values. The specific light load voltage schedules for the Susquehanna 230 kV and 500 kV busses will be set high enough to maintain system transient stability but low enough to aid in maintaining reactive balance on the system under light load conditions. The electric supply system is operated so that generating stations on the bulk power system are not exposed to voltage drops in excess of 10% from the scheduled voltage upon the occurrence of a normal contingency.

PP&L's most recent load projections (through the year 1990) were provided in PP&L's response to the first round of NRC questions on the Environmental Report - Operating License Stage (Question 11). The only post Susquehanna generation addition projected through 1990 is 63 MW of additional capacity at the Safe Harbor Hydroelectric Station. The Safe Harbor expansion (PP&L share 63 C) is projected to be effective in September 1985. This date is dependent on FERC approval of the Safe Harbor Water Power Corporation license application submitted April 1977.

QUESTION 040.16

Provide the approximate loading ($\pm$5 MVA) of the auxiliary and startup transformers at full unit power output assuming normal bus alignments as shown on Figure 8.3-1 of the FSAR. Identify the power sources for the forced cooling provided for these transformers.

RESPONSE:

The maximum loading of the unit auxiliary transformer at full unit power output is estimated at approximately 49 MVA.

The unit auxiliary transformer is provided with forced-oil-forced-air cooling equipment fed by two separate 480 volt, 3ϕ power supplies. One supply is designated as normal supply, and it is fed from a unit auxiliary 480 volt motor control center (MCC) 1B101 (2B101 for Unit 2). The other supply is designated as an alternate supply which is fed from another unit auxiliary motor control center 1B111 (2B111 for Unit 2). Loss of power is alarmed at the local transformer auxiliary cabinet when then retransmits a trouble alarm to the main control room. A local manual transfer switch is provided for transforming to the alternate supply in case the normal supply is lost.

The maximum loading of each startup transformer at full unit power output under the worst climate condition (worst HVAC loading condition) is estimated to be approximately 13 MVA.

Each startup transformer is provided with a forced-oil-forced-air cooling system similar to that of the unit auxiliary transformer. The normal and alternate power supplies for startup transformer 10 (OX103) are fed from MCC 1B101 and 1B111 respectively. Likewise, the normal and alternate power supplies for startup transformer 20 (OX104) are fed from MCC 2B101 and 2B111 respectively.

QUESTION 040.17

Provide note 4 for FSAR Figure 8.3-1 and describe the role of the Unit 1 main transformer circuit breaker.

RESPONSE:

Refer to Subsection 8.2.1.3.2 and Dwg. E-1, Sh. 1 for this information.

QUESTION 040.18

Describe the interlocking circuit that prevents automatic transfer of the startup busses to the alternate startup transformer when the unit auxiliary transformer is the source of power.

RESPONSE:

Subsection 8.3.1.2.1 has been revised to include this information.

QUESTION 040.19

For an offsite power system event that directly or indirectly removes the 500-230 kV switchyard bus tie, describe the provisions of the design of the onsite power system to prevent the typing together of the two offsite grids through the onsite power distribution system.

RESPONSE:

For response refer to revised Subsection 8.3.1.2.1.

QUESTION 040.20

It appears from your description in Section 8.3.1.3.10 that the emergency loads are sequenced with offsite preferred power available.

If this is true, provide your bases and justification. Provide a comparison on a bus by bus basis for all emergency busses of the voltage and motor starting transients associated with sequenced versus instantaneous loading for the condition of grid voltage at the low end of its normal range and maximum plant auxiliary load.

Provide a description of what would be required to remove this nonstandard design feature from your design and the associated safety implications, if any.

RESPONSE:

For information refer to revised Subsection 8.3.1.3.10, revised Table 8.3-1, and Table 8.3-1b.

QUESTION 040.21

FSAR Section 8.3.1.3.2 states that the 4 kV power feeder cables and the larger 480 volt cables are aluminum conductor. Provide a discussion as to how you will deal with any dissimilar metals interface problems.

RESPONSE:

Subsection 8.3.1.3.2 has been revised to include this information.

QUESTION 040.22

Describe the provisions of your design that alerts the Unit 1 and 2 control room operators as to which unit is supplying DC control power to each of the shared diesel generators.

RESPONSE:

Subsection 8.3.1.4 has been revised to include this information.

QUESTION 040.23

With respect to the acceptability of the use of swing busses as part of the LPCI system of BWR-4 plants, the staff has documented its position in NUREG 0138 Issue #3.

The staff position is that for those plants that can meet all Appendix K to 10 CFR Part 50 requirements assuming the total loss of LPCI system, the swing bus is an acceptable concept and the design is scrutinized during the review. For those plants that need some portion of the LPCI system in order to meet Appendix K requirements, the staff has required a redesign of this portion of the system. Please provide a discussion of how Susquehanna meets this position or provide the bases and justification for any noncompliance.

RESPONSE:

The response to this question is provided in revised Subsection 8.3.1.3.5.

QUESTION 040.24

Provide a detailed description of all of the various circuit isolation schemes used in your design and referenced in Section 8.1.6.1 (Regulatory Guide 1.75 (1/75), Part 2).

RESPONSE:

These descriptions are provided in Section 8.1.6.1 (Regulatory Guide 1.75 (1/75), Part 2).

QUESTION 040.25

It appears that diesel generator sequencing capability is based upon the assumption of simultaneous sequencer initiation on both safety busses fed by each generator. The assumption further being that one unit has a LOCA and the other goes to a shutdown condition. It is not clear from the limited description provided in the FSAR that this is truly the design basis nor that this is a conservative assumption. Provide a detailed description of this aspect of your design. This description should also address the following contingencies:

(1) The two safety busses for a given diesel might not be fed from the same startup transformers. This greatly increases the probability of a single failure causing the diesel generator to initially energize only one safety bus. Subsequent loss of offsite power would cause the second safety bus to initiate sequencing out of time phase with the first sequencer.

(2) A spurious accident signal in the second unit.

RESPONSE:

For information refer to revised Subsection 8.3.1.3.10, revised Table 8.3-1, and Table 8.3-1b.

QUESTION 040.26

Provide a listing of all motor operated valves within your design that require power lock out in order to meet the single failure criterion and provide the details of your design that accomplish this requirement.

RESPONSE:

There are no MOV's in Susquehanna SES which require electric power lockout in order to meet the single failure criterion as described in BTP EICSB 18.

QUESTION 040.27

Provide a description of the capability of the emergency power system battery chargers to properly function and remain stable upon the disconnection of the battery. Include in the description any foreseen modes of operation that would require battery disconnection such as when applying an equalizing charge.

RESPONSE:

See revised Subsection 8.3.2.1.1.4 for the requested discussion.

QUESTION 040.28

Provide the details of your design of the DC power system that assures equipment will be protected from damaging overvoltages from the battery chargers that may occur due to faulty regulation or operator error.

RESPONSE:

For this information see revised Subsection 8.3.2.

QUESTION 040.29

Provide the results of a review of your operating, maintenance, and testing procedures to determine the extent of usage of jumpers or other temporary forms of bypassing functions for operating, testing, or maintaining of safety related systems. Identify and justify any cases where the use of the above methods cannot be avoided. Provide the criteria for any use of jumpers for testing.

RESPONSE:

Commencing with the start of fuel load in the reactor, proceeding through power level testing and encompassing normal operations throughout the plant life, plant operations will be controlled under the plant administrative program. At the present time essentially all plant procedures are in preparation or in draft form. Their being incomplete means it is not currently possible to identify specific instances where use of temporary bypass measures would be required by operating, maintenance, or testing procedures. As currently envisioned, required usage of such bypasses will be limited to a small number of testing procedures for actions such as defeating interlock functions not being tested (to limit scope of testing) and providing simulated actuation signals.

Procedures requiring such a temporary modification to a safety-related system shall be prepared in accordance with AD-00-001, "Procedure Program," which stipulates PORC review prior to implementation. Control of placement and removal of these bypasses will either be provided directly by the procedure (requiring positive control of installation and removal) or will be controlled by shift supervision through adherence to AD-00-042, "Control of Temporary Modifications." The only exceptions to the above methods of control will be tests in the Start-up Test Program during the initial power ascension. Procedures in this program which would require a temporary modification to a safety-related system will also receive PORC review as stated in FSAR section 14.2.2.3. Such modifications will only be utilized to permit testing described in the FSAR test abstracts and they will have positive control of both installation and removal, either in the test procedure body or through adherence to AD-00-042.

QUESTION 040.30

We request that you perform a review of the electrical control circuits for all safety related equipment, so as to assure that disabling of one component does not, through incorporation in other inter locking or sequencing controls, render other components inoperable. All modes of test, operation, and failure should be considered. Describe and state the results of your review.

RESPONSE:

The class 1E electrical power distribution systems as well as non-NSSS control systems have been reviewed for interlocks which could provide a mechanism for disabling engineered safeguard equipment of more than one redundant load group due to a single failure, misoperation, component test, bypass or lockout. The review was made in view of determining satisfactory compliance of the safeguard systems and components to the single failure criterion. The review proved that we have no such disabling interlocks and that where interlocks do exist between redundant load groups, they are designed with separation and isolation devices so as to prevent a common mode failure.

There are a few schemes that require interlocking between redundant load groups. One is the emergency service water (ESW) diesel cooler valves automatic loop transfer, Ref. drawing E-146 Sh. 11 (Sect. 1.7). The ESW system has two loops, A&B, corresponding to Divisions I & II. Each of the four standby diesel generations are normally cooled from ESW loop A and on failure of this loop, an auto transfer is made to loop B. The transfer is made by opening the inlet and outlet valves associated with loop B. Check valves prevent flow from one water loop to the other. The valves are powered separately from the four redundant channels, but a common control circuit for the transfer operation exists and is powered from channel "A" battery. The control relays are in a fail safe mode so that loss of power supply results in an auto transfer. This control circuit receives inputs from redundant channels A, B, C & D to sense the condition of the channelized ESW pumps. To isolate the control circuit from the starter circuits of the channelized transfer valves and, in addition, to isolate it from the channelized inputs, isolation relays of the type described in our response to Question 040.24 (see Subsection 8.1.6.1.n) are utilized. No single power supply or component failure would prevent the safe operation of the above transfer scheme.

The remaining schemes involving interlocks between redundant channels may by grouped into one. These schemes are associated with the fault protection of the ESF transformers. A current differential relay located in each of the start-up switchgears take inputs from each of four current transformers located in the four class 1E switchgears sensing the current flow into each switchgear (Ref. Dwg. E-23 Sh. 1 & E-22 Sh. 2 Subsection 1.7). The transformer primary current is sensed by a current transformer at the startup bus. Each CT is mounted at the bus side of the circuit breaker connecting each bus to the ES transformer. The CT secondary circuits connect to the differential relay restraint coils by means of non-class 1E cabling. These non-class 1E cables are separated at the class 1E switchgear from class 1E cables by an isolating barrier. Similarly the wiring from the terminal block to the current transformer is isolated from wires having a safety related function. The CT itself is located in the power cubicle isolated from the control cubicle by fire barriers.

The differential relay mentioned above trips the transformer high-side breaker as well as all the incoming breakers of the class 1E switchgears (Ref. Dwg. E-102 Sh. 30). In order to provide isolation between the class 1E control circuitry of the class 1E breakers from the non-1E differential relay trip circuit, an isolating relay is employed at the class 1E switchgear. Switchgear wiring to the relay coil and the non-class 1E control cable is separated from all other wiring and cables in the switchgear by an isolating barrier.

QUESTION 040.31

The information regarding the onsite communications system (Section 9.5.2) does not adequately cover the system capabilities during transients and accidents. Provide the following information:

(1) Identify all working stations on the plant site where it may be necessary for plant personnel to communicate with the control room or the emergency shutdown panel during and/or following transients and/or accidents (including fires) in order to mitigate the consequences of the event and to attain a safe cold plant shutdown.

(2) Indicate the maximum sound levels that could exist at each of the above identified working stations for all transients and accident conditions.

(3) Indicate the types of communication systems available at each of the above identified working stations.

(4) Indicate the maximum background noise level that could exist at each working station and yet reliably expect effective communication with the control room using:

(a) the public address communications system, and

(b) any other additional communication system provided at that working station.

(5) Describe the performance requirements and tests that the above onsite working stations communication systems will be required to pass in order to be assured that effective communication with the control room or emergency shutdown panel is possible under all conditions.

(6) Identify and describe the power source(s) provided for each of the communications systems.

(7) Discuss the protective measures taken to assure a functionally operable onsite communication system. The discussion should include the considerations given to component failures, loss of power, and the severing of a communication line or trunk as a result of an accident or fire.

RESPONSE:

For this information see revised Subsections 9.5.2.2.1, 9.5.2.2.3, 9.5.2.2.4, 9.5.2.1, and 9.5.2.2.

QUESTION 040.32

In section 9.5.2.2 you describe the plant communications system provided. It is noted that use of radio (portable and fixed) communications has been excluded. As part of the plant defense-in-depth concept, in the event of an accident or fire in an area where fixed communications systems cannot be used, we require (as a minimum) that portable communications equipment be provided at strategic work stations in the plant for use by personnel under such conditions.

RESPONSE:

Refer to revised Subsection 9.5.2 and the response provided to Question 281.13.

QUESTION 040.33

Identify the vital areas and hazardous areas where emergency lighting is needed for safe shutdown of the reactor and the evacuation of personnel in the event of an accident (including fire). Tabulate the lighting systems provided in your design to accommodate those areas so identified.

RESPONSE:

For information refer to revised Subsection 9.5.3.

QUESTION 040.34

In section 9.5.3.2.3 you state that emergency lighting in remote buildings are areas where emergency dc lighting service is not available you are providing battery powered self-contained units. Identify the remote buildings and areas where this type of lighting is used.

As part of the plant defense-in-depth concept in addition to normal and emergency lighting systems we require emergency self-contained (including charger) sealed beam battery powered units with individual 8 hour minimum capacity. These units should be installed in the control room, all locations required to safely shutdown the plant, in stairways, and along exit routes from each floor throughout the plant. Provide a detailed description of the self contained battery power units, how they will be powered under normal plant conditions, and how they will be controlled under accident conditions in the absence of both the normal and emergency lighting systems.

RESPONSE:

For information refer to revised Subsection 9.5.3.

QUESTION 040.35

Section 9.5.4.1, Emergency Diesel Engine Fuel Oil Storage and Transfer System (EDEFSS), does not specifically reference ANSI Standard N195 "Fuel Oil Systems for Standby Diesel Generators". Indicate if you intend to comply with this standard in your design of the EDEFSS; otherwise provide justification for non-compliance. (SRP 9.5.4, Rev. 1, Part II, Item 12).

RESPONSE:

Subsection 9.5.4.1 has been revised to include this information.

QUESTION 040.36

In section 9.5.4.2 you state the diesel generator fuel oil storage tank has a 50,000 gallon capacity which is sufficient to operate the diesel generator for 7 days at full rated load, the fuel oil transfer pump has a suction strainer which is located 2 ft. above the bottom of the tank, and the transfer pump requires 1 ft. 6 inch NPSH. You also state the fuel oil storage tanks are designed to include the NPSH required by the pump. Clarify this statement.

Using the above stated data demonstrate by analysis that the volume of usable fuel oil (tank volume above pump NPSH level) in the fuel oil storage tank is sufficient to operate its diesel generator for a period of 7 days at full rated load.

RESPONSE:

Subsection 9.5.4.2 has been revised to include this information.

QUESTION 040.37

In Section 9.5.4.2 you state the diesel generator fuel oil storage tanks are filled and replenished from trucks through the fill connection which branches to each of the four tanks. Provide a drawing (plan and elevation) showing the location of the truck fill and tank vent connection and location of the fuel oil storage tanks with respect to the diesel generator building. Also provide a description of how the tank fill and vent connections are protected against tornado missiles and the precautions taken in your design of the emergency diesel engine fuel oil storage and transfer system to minimize the entrance of deleterious material into the system during recharging, by operator error or natural phenomena (SRP 9.5.4, Part III, item 1, 2 and 4).

RESPONSE:

Refer to revised Subsection 9.5.4.2 and Dwg. C-1006, Sh. 1 C-1007, Sh. 1, C-1032, Sh. 1 for this information.

QUESTION 040.38

Figure 9.5-19 shows the tank fill connection and branch fill lines to each fuel oil storage tank as non-seismic, Class D construction. Also figure 9.5-19 does not identify the piping classification of the tank vent line and other connections. It is our position that the fuel oil storage tank fill line from the tank interface up to and including the truck fill interface and all other tank connections should be seismic Category I, Class C construction. Revise your system design accordingly.

RESPONSE:

Refer to revised Subsection 9.5.4.2 and Dwgs. C-1006, Sh. 1, C-1007, Sh. 1, C-1032, Sh. 1 for this information.

QUESTION 040.39

In section 9.5.4.3 you state fuel oil for the diesel generators is delivered onsite for trucks and rail. Identify the sources where diesel quality fuel oil will be available and the distances required to be travelled from the sources to the plant. Also discuss how fuel oil will be delivered onsite under extremely unfavorable environmental conditions.

RESPONSE:

Subsection 9.5.4.3.a mentions that additional supplies of fuel oil for the diesel generators could be delivered to the site during the 7 day operation period provided by onsite supplies. Currently, no contractual arrangements have been made for supply of diesel fuel oil. However, a preliminary survey indicates that several fuel oil suppliers are located in proximity to the plant which might be utilized in an emergency situation. The survey showed five vendors located in an emergency situation. The survey showed five vendors located in the Berwick/Nescopeck area (5 miles southwest of the plant), two located in the Bloomsburg area (15 miles southwest of the plant) and six located in the Wilkes-Barre/Scranton area (30 miles northeast of the plant). It is not intended that this be a comprehensive listing of local suppliers, nor does it indicate any agreements with these suppliers.

The plant is located directly on US Rte. 11, a major highway which connects with Interstate Routes 80 and 81. These arteries should be available under extremely unfavorable environmental conditions, providing access to the site from surrounding population centers. Truck delivery via these routes would be the preferred method for emergency supply of fuel under extreme conditions.

QUESTION 040.40

Assume an unlikely event has occurred requiring operation of a diesel generator for a prolonged period that would require replenishment of fuel oil without interrupting operating of the diesel generator. What provision will be made in the design of the fuel oil storage fill system to minimize the creation of turbulence of the sediment in the bottom of the storage tank. Stirring of this sediment during addition of new fuel has the potential of causing the overall quality of the fuel to become unacceptable and could potentially lead to the degradation or failure of the diesel generator.

RESPONSE:

See revised Subsection 9.5.4.3 for this information.

QUESTION 040.41

Discuss the precautionary measures that will be taken to assure the quality and reliability of the fuel oil supply for emergency diesel generator operation. Include the type of fuel oil, impurity and quality limitations as well as diesel index number of its equivalent, cloud point, entrained moisture, sulfur, particulates and other deleterious insoluble substances; procedure for testing newly delivered fuel, periodic sampling and testing of on-site fuel oil (including interval between tests), interval of time between periodic removal of condensate from fuel tanks and periodic system inspection. In your discussion include reference to specific industry (or other standards which will be followed to assure a reliable fuel oil supply to the emergency generators.

RESPONSE:

Discussion included in Section 9.5.4.4 of the FSAR.

QUESTION 040.42

Discuss the means for detecting or preventing growth of algae in the diesel fuel storage tank. If it were detected, describe the method to be provided for cleaning the affected storage tank. (SRP 9.5.4, Part III, Item 4).

RESPONSE:

See revised Subsection 9.5.4.2 for this information.

QUESTION 040.43

Discuss what precautions have been taken in the design of the fuel oil system in locating the fuel oil piping with regard to possible exposure to ignition sources such as open flame and hot surfaces (SRP 9.5.4, Part III, Item 6).

RESPONSE:

These precautions are discussed in revised Subsection 9.5.4.3.

QUESTION 040.44

Identify all high and moderate energy lines and systems that will be installed in the diesel generator room. Discuss the measures that will be taken in the design of the diesel generator facility to protect the safety related systems, piping and components from the effects of high and moderate energy line failure to assure availability of the diesel generators when needed. (SRP 9.5.4, Part III, Item 8 SRP 9.5.5, Part III, Item 4, SRP 9.5.6, Part III, item 5, SRP 9.5.7, Part III, item 3, SRP 9.5.8, Part III, item 6c).

RESPONSE:

During normal plant conditions, the following piping systems in the diesel rooms are classified as moderate energy: diesel starting air, emergency service water (during reactor cooldown), service air, and sump pump discharge (intermittent). The other piping in the rooms is not pressurized under normal plant conditions (e.g., fire protection system) and there are no high energy lines in the rooms. Flood detectors are located in the rooms (See Dwg. M-111, Sh. 1) Figure 9.2-5A) to detect any leakage.

With a piping failure postulated in one of the emergency diesel generator rooms, capability to safely shutdown the reactor would still exist. This is because failure of the moderate energy piping existing in any diesel generator room would not directly result in turbine generator or reactor protection system trip. Hence, offsite power would be assumed to be available. This is in accordance with Branch Technical Position APCSB 3-1.

QUESTION 040.45

In section 9.5.5.2 you state that the diesel generator cooling water system includes a standpipe that serves as a reservoir, decorator and an expansion tank. Makeup water to the standpipe is from the non-seismically designed demineralized water system.

In addition to the items monitored, the standpipe is to provide for venting of air from the system, minor leaks at pump shaft seals, valve stems and other components and to maintain required NPSH on the system circulating pump. Provide the size of the standpipe, location and elevation relative to the diesel engine cooling system. Demonstrate by analysis that the standpipe size will be adequate to maintain required circulating pump NPSH and include a sufficient volume of water for system leaks for seven days continuous operation of the diesel engine at full rated load without makeup, or provide a seismic Category I, safety Class C makeup water supply to the standpipe.

RESPONSE:

For response see Subsection 9.5.5.

QUESTION 040.46

Describe the provisions made in the design of the diesel generator cooling water system to assure all components and piping are filled with water. (SRP 9.5.5, Part III, item 2).

RESPONSE:

For response see revised Subsection 9.5.5.5.

QUESTION 040.47

In section 8.3.4.1 you state the diesel generators are capable of continuous operation with no load. This statement should be expanded and clarified. In the event of a LOCA it may be necessary to operate diesel generator(s) for a period of 30 days or more. The diesel generators are automatically started and run unloaded during a LOCA condition when offsite power is available to the Class 1E buses. Should a LOCA occur with availability of offsite power, provide a detailed discussion on how long the diesel generator(s) are capable of operating unloaded without degradation of engine performance or reliability. (SRP 9.5.5, Part III, Item 7).

RESPONSE:

See revised Subsection 8.3.1.4 for this information.

QUESTION 040.48

What protective measures have been incorporated in the design of the lubrication oil system to maintain the required quality of lubricating oil during diesel engine operation, and during standby conditions. (SRP 9.5.7, Part III, item 1).

RESPONSE:

Refer to revised Subsection 9.5.7.2 for this information.

QUESTION 040.49

What system design precautions have been taken to prevent entry of deleterious materials into the diesel engine lubrication oil system due to operator error during recharging of lubrication oil or normal operation (SRP 9.5.7, Part III, item 1c).

RESPONSE:

See Subsection 9.5.7.2 for this information.

QUESTION 040.50

What protective measures have been taken to prevent unacceptable crankcase explosions and to mitigate the consequences of such an event. Identify and discuss the protective measures and describe how the protective measures will mitigate the consequences of a crankcase explosion.

RESPONSE:

See revised Subsection 9.5.7.3 for this information.

QUESTION 040.51

Describe the instrumentation, controls, sensors, and alarms provided in the design of the diesel engine combustion air intake and exhaust system to warn the operators when design parameters are exceeded. (SRP 9.5.8, Part III, item 1 and 4).

RESPONSE:

Refer to Subsection 9.5.8 for this response.

QUESTION 040.52

Indicate which system components in the diesel generator air intake and exhaust system are exposed to inclement weather conditions (heavy rain, freezing rain, ice or snow). Discuss how these components are protected from possible clogging to assure availability of the emergency diesel generators when needed (SRP 9.5.8, Part III, item 5).

RESPONSE:

See revised Subsection 9.5.8.3 for this information.

QUESTION 040.53

Provide a general discussion of the design criteria and bases of the various steam and condensate instrumentation systems in section 10.1 of the FSAR. The FSAR should differentiate between normal operation instrumentation and required safety instrumentation.

RESPONSE:

Section 10.1 has been revised to include this information.

QUESTION 040.54

For the turbine speed control system, provide with the aid of system schematics (including turbine control and extraction steam valves to the heaters), a detailed explanation of the turbine and generator electrical load following capability. Tabulate the individual overspeed protection devices (normal, emergency and backup), the design speed (or percent of rated speed) at which it performs its safeguards function and specify the valve or other component which is subsequently activated to complete the turbine trip. In order to evaluate the adequacy of the control and overspeed protection system include identifying numbers to valves and mechanisms (mechanical and electrical) on the schematics and provide a discussion to describe in detail with references to the identifying numbers, the sequence of events in a trip, including response times. Show that stable turbine operation will result after a trip. Provide the results of a failure mode and effects analysis for each of the overspeed protection systems. Show that a single valve failure cannot disable the turbine overspeed trip functions. (SRP 10.2, Part III, Items 1, 2, 3 and 4).

RESPONSE:

For the response to the question see revised FSAR Subsections 10.2.2.6 and 10.2.2.8.

QUESTION 040.55

In sections 10.2.1 and 10.2.2.2 you state that the generator is cooled by hydrogen at 75 psig pressure. Describe, with the aid of drawings, your design of the bulk hydrogen storage facility including controls, its location and distribution system. Include the protection measures and system design features considered to prevent fires and explosions during normal plant operations.

RESPONSE:

Refer to Subsection 10.2.2.2 for this information.

QUESTION 040.56

Discuss the measures taken to prevent galvanic corrosion of condenser tubes and components (SRP 10.4.1, Part III, Item 1).

RESPONSE:

Subsection 10.4.1.3.2 has been revised to include this information.

QUESTION 040.57

Indicate what design provisions have been made to preclude failures of condenser tubes or components from turbine by-pass blowdown. (SRP 10.4.1, Part III, item 1).

RESPONSE:

Subsection 10.4.1.3.2 has been revised to include this information.

QUESTION 040.58

Provide the following additional information (with the aid of drawings) for the turbine by-pass valves and associated instruments and controls: (1) number, size, principle of operations, construction, set points; (2) the capacity of each valve; (3) the malfunctions and/or modes of failure considered in the design; (4) the maximum reactor power step change the system is designed to accommodate without reactor or turbine trip and (5) the maximum electric load step change the reactor is designed to accommodate without reactor control rod motion or steam bypassing. (SRP 10.4.4, Part III, Items 1 and 2).

RESPONSE:

1) Number: There are 5 valves in one common valve chest. (refer to Subsection 10.4.4.2)

   Size: The valve chest is fed through two 18" headers from the main steam (refer to Subsection 10.4.4.2). The discharge of each valve is piped individually in 10" lines to the condenser (refer to Subsection 10.4.4.2 and Figure 10.4-1).

   Principle of Operation and Set Points:

   The bypass valve is biased from 5 to 15% above the difference of the desired control valve flow signal and the total steam flow (refer to Subsections 10.4.4.30, 7.7.1.5.3, 7.7.1.5.3.3 and Figure 7.7-15.

   Construction: All turbine-generator and associated auxiliaries supplied by GE are manufactured to GE standards (refer to Subsection 10.2.1).

2) The five bypass valves have the ability to bypass a total of 25% of the nuclear boiler rated steam flow. (refer to Subsections 10.2.1 & 10.4.4.2)

3) The malfunction or failure mode considered is discussed in Subsection 10.4.4.3. If the valves fail to operate (open), ultimately it would cause the main steam safety relief valves to open.

4) The turbine controls can follow a reactor power change of ±10% rated power per second which is discussed in Subsection 10.2.1. The bypass controls follow the control valve. (Refer to Subsections 10.4.4.1, 7.7.1.5.3.3 and the applicable failure analysis in Subsections 15.1 and 15.2).

5) The maximum electric load step change the reactor is designed to accommodate without reactor control rod motion or steam bypassing is discussed in Subsection 10.2.1.

QUESTION 040.59

Demonstrate that a high energy line failure of the turbine bypass system (TBS) will not have an adverse effect or preclude operation of turbine speed controls or any safety related components or systems located close to the TBS. (SRP 10.4.4, Part III, Item 4).

RESPONSE:

See revised Subsections 10.4.4.2 and 10.4.4.3.

QUESTION 040.60

Provide the results of a failure mode and effects analysis to determine the effect of malfunctions of the turbine by-pass system on the operation of the reactor and main turbine generator unit. (SRP 10.4.4, Part III, Item 4).

RESPONSE:

See revised Subsections 10.4.4.2 and 10.4.4.3.

QUESTION 040.61

Discuss the affect of the maximum turbine by-pass flow on condenser back pressure and turbine exhaust temperature in reference to allowable values.

RESPONSE:

See revised Subsections 10.4.4.2 and 10.4.4.3.

QUESTION 040.62-X10

The RBCCW and TBCCW are sequenced in the D. G. buses after a loss of off-site power (LOOSP) (Table 8.3-1). In Section 9.2.2 in the FSAR these are both listed as non-ESF loads but in Tables 8.3-1 and 1a the RBCCW is listed as an ESF load, sequenced at 60 sec onto Unit 2 for safe shutdown. Explain the power supply rationale for these two systems, state whether they both can be isolated from their power supplies by a derivative of an accident signal in order to meet isolation requirements in accordance with Reg. Guide 1.75, and correct any inconsistences in the FSAR text.

RESPONSE:

Tables 8.3-1 through 8.3-5 have been revised to show RBCCW pumps as non-ESF loads. The RBCCW pumps are tripped by the opening of the motor starter contractors on LOCA conditions. The RBCCW system is not required to support post-LOCA recovery operations. The RBCCW pumps are powered from the emergency diesel generators on loss of off site power without occurrence of LOCA as described in FSAR section 9.22 in order to support non-essential loads.

The TBCCW pumps are not tripped by a LOCA signal. They are fed by a non-Class 1E 480 Vac motor control center connected too a Class 1E 480 V load center through an isolation system. Isolation Systems are described in Subsection 8.1.6.1-n. The TBCCW system is not required to support post-LOCA recovery operations. The BTCCW pumps are tripped on loss of off site power. The TBCCW pumps may be powered from the emergency diesel generators on loss of off site power as described in FSAR Section 9.2.3 in order to support non-essential loads.

QUESTION 040.63-X10

Provide a failure mode and effects analysis of the dc system of the plant. Describe the operation of the Unit 1 dc system and the "uninterruptable ac power supply" of Unit 1 during the period that Unit 1 is operating and Unit 2 is under construction.

During this phase of operation there is, apparently, some switching of loads (lighting and communication) from a Unit 1 vital ac bus to a Unit 2 vital ac bus under some conditions (Sec. 9.5). Provide further details of this aspect of your design.

The indicated load on the 125v dc system (Table 8.3-6) is 106A or greater over a four hour period, while the battery charger is rated at 100A. Discuss the time span and conditions or actions that will be necessary to establish charge equilibrium in the batteries.

In addition, with regard to the dc systems, provide note 5 for Figure 8.3-6 and for the 24v dc system shown in this figure. Review the battery capacity which should, by your own criteria, be 125% of four hour demand but seems to be actually only 100% of 4 hour demand by Table 8.3-8 and report your findings.

RESPONSE:

1) The failure-mode-and-effect analysis for the plant dc systems is presented in FSAR Tables 8.3-21, 8.3-22 and 8.3-23, corresponding to the 125 V dc, 250 V dc and + 24 V dc subsystems.

2) There are two uninterruptable ac power supplies (UPS) of each generating unit, the computer UPS and the vital ac UPS. The inverter of each UPS is fed from one of two 250 V dc load centers. The vital ac UPS bus supplies power to the intra-plant public address (PA) system and the emergency evacuation (EVAC) system. These systems require an alternate power supply which is the vital ac bus of Unit 2. During Unit 1 operation while Unit 2 is in construction stage, the alternate power to the PA and EVAC systems is taken from the Unit 1 computer UPS bus. Transfer from the normal supply to the alternate supply is done automatically. Subsections 9.5.2.2.1 and 9.5.2.2.4 of the FSAR have been revised to reflect the above arrangement.

   Another load which requires switching between Units 1 and 2 is the roof siren. The preferred source is a Unit 1 125 V dc lens and the alternate source is a Unit 2 125 V dc lens.

   During Unit 1 operation while Unit 2 is under construction, the alternate source is a separate 125 V dc bus of Unit 1.. Transfer from the normal supply to the alternate supply is done automatically. Subsection 9.5.2.2.4 of the FSAR has been revised to reflect the above arrangement.

3) During normal plant operation the batteries are maintained at fully charged state and the continuous current load of 44 Amperes is supplied by the charger which has ample capacity, if required, to recharge the battery.

The nominal rating of the 125 V dc battery charger is 100A. It has a 25% overload capacity. The charger is a constant voltage source until the overload limit (set point) is reached above which the unit shifts into a constant current source at a current equal to the set point value.

The current of 106A, as indicated in Table 8.3-6, can be supplied by the battery charger while the battery is fully charged.

4) Dwg. E-13, Sh. 1 of the FSAR has been revised to show Note 5 which will read: "Bechtel field shall disconnect fuses for transducer circuits unless otherwise noted."

5) The 18.74A dc load current shown in Table 8.3-8 is actually the arithmetic sum of the +24 V dc and -24V dc banks which are in series. At the distribution panel, + 9.37A and - 9.37A are distributed by the positive and the negative buses. The four-hour demand per bank is 9.37 x 4 or 37.48 AH. The 4 hour rating for the C&D type DCU-7 cells is 63 AH or 168% of the 4-hour demand.

QUESTION 040.64-X10

In the event of failure of preferred power, then the alternate power, please discuss the operational sequence for restoration of the Class 1E power channels.

a) from standby power to alternate power,

b) from standby power to preferred power.

RESPONSE:

See revised Subsection 8.3.1.3.6.

QUESTION 040.65-X10

Branch Technical Position ICSB (PSB) 2 Diesel Generator Reliability Qualification Testing (SRP Appendix 8A) requires a prototype qualification program to demonstrate the capability of new and/or unique designs for use in nuclear service. Provide the results of the prototype qualification for the Susquehanna SES units.

Cooper Bessemer has made recent changes in its design of cylinder heads and induction systems. State in light of these changes whether the Susquehanna SES diesel generators have these new design features and if so whether they have been qualified in accordance with BTP ICSB (PSB) 2, or offer an alternative on some other defined basis.

RESPONSE:

The prototype engine qualification testing was performed by the supplier in accordance with IEEE 387-1972 and IEEE 323-1971 editions as required by FSAR, Volume 7, Section 3.13.1, Regulatory Guide 1.9.

The results of the prototype qualification testing are available for NRC's review when required.

The following tests were performed:

1. High potential testing of control wiring
2. Measurement of engine vibration
3. Fast start capability
4. Transient performance evaluation
5. Steady state load capability
6. Load rejection
7. Number of starts from a single air receiver
8. Performance evaluation of power factor discrimination and standby voltage regulator.

The modifications made on the engines consisted of replacement of certain existing components with similar, improved components. The reason for replacing these components was to eliminate long term wear problems with the rocker arm assembly and cracking problems of the air intake valve spring. These changes have increased the engine's reliability.

Since major engine modifications were not made, retesting the engines for prototype qualifications is not required, and the original testing is still valid.

The engines, however, with the new components installed, will be subjected to site acceptance testing per Paragraph 6.3 of IEEE 387-1972 edition, which requires, that after startup testing "... each diesel generator unit shall be tested at the site to demonstrate that the capability of the unit to perform its intended function is acceptable."

QUESTION 040.66-X10

In FSAR Section 7.4.1.2.2 it is stated that both divisions of the SLCS are powered from Division I. Yet in Table 3.12-1 the SLCS is listed in two separate divisions, I and II. Provide a discussion which resolves these apparent inconsistencies.

RESPONSE:

Table 3.12-1 has been revised and is now consistent with Subsection 7.4.1.2.2.

QUESTION 040.67-X10

A "480v Swing Bus" is listed in Division I and another in Division II (table 3.12-1) and described in Section 8.3.1.3.5. Although these swings are not between redundant divisions they are between redundant separation channels as three channels out of four are required in your plant to successfully meet the on-site power requirements of a LOCA in one unit and safe shutdown of the other unit. This configuration requires independence and separation between Class 1E channels as well as ESF divisions in each of the two units of your plant. In order to facilitate our review of this aspect of your design, provide a common mode-common cause failure analysis for the Russell Electric Company transfer switches that you use to transfer from one power supply channel to the other in each division. Also describe the testing program for the entire isolation arrangement (motor-generator set) protective switchgear, and transfer scheme of the swing bus arrangement to satisfy the requirements of GDC 18.

RESPONSE:

See revised Subsection 8.3.1.3.5, Table 8.3-24 and Figures 8.3-13 and 8-3-14.

QUESTION 040.68-X10

Various metallic vapor lamps have "delayed" re-ignition time characteristics.

Postulate a condition such as a temporary loss of power, which would produce a delayed re-ignition condition. Are there any SSES plant areas in which this postulated condition could interfere with plant operations? If so, provide modified design to correct this situation.

RESPONSE:

High pressure sodium and mercury vapor lamps are provided at selected plant operating areas as described in Subsection 9.5.3.2. These lamps provide 80-90% of the total lighting. The remaining 10-20% is provided by the essential lighting system (fluorescent) as described in Subsection 9.5.3.2.2. The essential lighting system provides minimum lighting level during the delayed re-ignition of the high pressure sodium and mercury vapor lamps, assuming a temporary loss of power. Therefore, plant operation is not affected.

QUESTION 040.69-X10

In Section 7.4 the statement "heat tracing of pump suction piping receives power from a bus that is connectable to the standby A-C power supply." Identify this "connectable bus" and describe the loads (by name and rating), method of connection, and isolation (if non-1E).

RESPONSE:

See revised Subsection 7.4.1.2.2.

QUESTION 040.70-X10

Reg. Guide 1.70 recommends "in particular, the circuits that supply power for the safety loads from the transmission network should be identified and shown to meet GDC 17 and 18," and "describe and provide layout drawings of the circuits that connect the onsite distribution system to the preferred power supply including transmission lines, switchyard arrangement, right of way, etc."

GDC 18 states "electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features ---."

You state that for pre-Unit 2 operation the preferred power sources for the SSES are the Montour-Mountain and the Wescosville-Susquehanna tie lines. Discuss these two tie line systems and their associated switchyards with regard to the above stated references and reaffirm that PC protective relay testing, maintenance and calibration apply to these switchyards and can be performed during unit operation.

RESPONSE:

See revised Section 8.2

QUESTION 040.71-X10

In the event that the control room must be vacated, what means and methods of communication are available from the remote shutdown panel of Unit 2 to the various out-buildings such as diesel generator building, emergency service water pump house, make-up water pump house, circulating water pump house, and radwaste building.

RESPONSE:

See revised Subsection 9.5.2.2.1.

QUESTION 040.72-X10

General Design Criterion 18 requires the ability to periodically inspect and test important safety features of electric power systems. State whether periodic inspection of the penetration assemblies is possible and whether the requirement of GDC-18 have been satisfied in this regard.

Figure 3.13-4. Is there a program for testing and inspecting the 120V ac control circuit 6A fuses? Also, provide the type (e.g. molded case) and source of actuation power for the 20A Cutler mm Hammer Type CHB breakers, the HFB-TM 50A breakers at the 480V MCC, and the 225A supply breaker at each instrument ac panel.

Periodic testing of containment circuit protection schemes is a requirement. Provide the details of your periodic testing program.

RESPONSE:

See Section 3.13, revised response to Regulatory Guide 1.63.

QUESTION 040.73-X10

State whether the essential lighting system is sequenced onto the Class 1E 480 buses or remains connected to the bus throughout transfer to the diesels in the event of a LOOSP. Is the total of essential lighting 169kw as in Table 8.3-3, or 188kw and in 8.3-2 or 222kw as in 8.3-4, or 258kw in 8.3-5? Why these differences?

RESPONSE

See revised Subsection 9.5.3.2.2.

QUESTION 040.74-X10

On the topic of non-Class 1E instrument circuits: In paragraph 8.1.6.1.n-7 you state as an "analysis" that "non-Class 1E instrument circuits are considered low energy and the probability of these non-Class 1E circuits providing a mechanism of failure to the Class 1E circuit is extremely low."

This is not acceptable as an analysis of your design. Provide the necessary justification and supporting bases to demonstrate your conclusions.

In this same context review your use of Class 1E devices as information sources for digital/analog information, as described in paragraph 9 of Section 3.12.3.4.1 of the FSAR (Page 3.12-9 of FSAR) and report your findings. Verify that acceptable isolation is provided in accordance with IEEE Standard 279-1971 Sections 4.1 and 4.7.

RESPONSE

See revised Subsection 8.1.6.1.n.

QUESTION 040.75-X10

On the same topic as Item 040.82, above, but in its application to containment electrical penetrations, (your paragraph 8.1.6.1.n-13) you state that cable penetrations into the suppression pool contain Class 1E and non-Class 1E circuits.

These non-Class 1E circuits include instrumentation annunciation, circuits, and computer circuits. Provide further justification for the classification of these as non-Class 1E circuits in containment penetrations, or describe a testing program to demonstrate the acceptability of your design approach.

RESPONSE

See revised Subsection 8.1.6.1.n-13.

QUESTION 040.76-X10

Your placement of electrical separation descriptions in section 3.12.3.4 has made it difficult to follow the continuity of subject matter in the FSAR. In 3.12.3.4.1-fourth subsection, "Raceway sharing of Class 1E and non-Class 1E Circuits" it is stated that, "480v and 125/250v dc non-Class 1E load groups connected to Class 1E buses are supplied through two circuit breakers physically separated from each other and connected in series. The cables from the Class 1E bus up to the second breaker remain with and follow the same rules as the Class 1E circuits of the respective separation divisions and are uniquely identified. The second breaker and its circuits are not subject ---."

State whether the second breaker of such an arrangement is Class 1E, and list the circuits that use this double breaker isolation scheme. Further, provide the bases for acceptance for the use of this fault-actuated isolation scheme.

RESPONSE

See revised Subsection 8.1.6.

QUESTION 040.77-X10

Section 8.1.6.1.n, "Compliance with Regulatory Guide 1.75 (1/75)".

1) The statement at the end of the first paragraph of this section, referring to Section 7.1, is not understandable, nor is the next paragraph correct in its description of redundancy and independence.

   It is still not clear what forms of electrical isolation are used in the design of SSES.

   Therefore, provide a listing of all the associated and non-1E circuits that require isolation from the Class 1E systems and the method if isolation (method 1, 2, 3, or 4 as described in your paragraph 8.1.6.1.n-5) used for each circuit.

2) Your description of "isolation systems" in paragraph 8.1.6.1.n-5 defines something that is not in accordance with Regulatory Guide 1.75 for assuring independence of Class 1E power sources from an intermediate non-Class 1E bus (method 3 of the paragraph). Therefore, state whether there are indeed some non-Class 1E loads in the SSES design that are supplied from a Class 1E source through an intermediate bus, and describe that isolation system for that bus.

RESPONSE

See revised Subsection 8.1.6.1 and Table 8.1-2.

QUESTION 040.78-X10

Paragraph 8.3.1.3.14 of the FSAR indicates that some " ... electrical equipment associated with Class 1E loads identified in Chapter 16.0" is not testable during reactor operation. List or reference this equipment. Demonstrate that all of the above equipment so identified is in conformance with Regulatory Guide 1.22 Section D.4.

RESPONSE

See Section 8.3.1.3.15.

QUESTION 040.79-X10

Figure 8.3-5, "125v dc and 250v dc Systems" indicates that loads 1D666, 1D165, 1D656, and 1D155 and 1D615, 1D635, 1D625 and 1D645, are "Non-Q-Listed" Panels. Yet on drawings E11, Sheets 3 and 4, there are notes that all loads are "Q-listed". On drawing E11 Sheets 1 and 2 the note also says that all equipment is "Q listed". Provide further details to facilitate our understanding of this aspect of your design.

We do not have drawing E26-Sh. 3, and therefore, cannot tell just what loads are on the 125v dc distribution panels in question. Provide this drawing. In the 250v dc case (Fig. E-11 Sh. 3 and Sh. 4) the loads seem to be entirely emergency lube oil pumps that are not Class 1E by function. State how such load centers are handled and whether an accident signal derivative trips off the entire bus or individual loads.

We note that in Table 3.10c-13 panels 1D155, 1D165, as well as 2D155 and 2D165 (for Unit 2) are listed as seismically qualified while all the others are not. Explain the rationale for these differences.

Also, in Fig. 8.3-5 the 250v dc Class 1E battery supplies a 1600A distribution panel through a 2000A fuse. State the design bases for this aspect of your design.

RESPONSE

See revised Subsection 8.3.2.1.1.2, Table 1.7-1 (pages 2 and 3), and Table 3.10c-13.

QUESTION 040.80-X10

Provide a listing of all switchgear that is not self-activated (both safety and non-safety) and specifically identify the source of control power to each one. This is needed in order to assist our independent review of how your emergency power system design meets the single failure criterion.

RESPONSE:

See revised subsections 8.3.1.3 and 8.3.1.2, and Tables 8.3-17, 18, 19, and 20.

QUESTION 040.81

The availability on demand of an emergency diesel generator is dependent upon, among other things, the proper functioning of its controls and monitoring instrumentation. This equipment is generally panel-mounted and in some instances the panels are mounted directly on the diesel generator skid. Major diesel engine damage has occurred at some operating plants from vibration-induced wear on skid-mounted control and monitoring instrumentation. This sensitive instrumentation is not made to withstand and function accurately for prolonged periods under continuous vibrational stresses normally encountered with internal combustion engines. Operation of sensitive instrumentation under this environment rapidly deteriorates calibration, accuracy, and control signal output.

Therefore, except for sensor and other equipment that must be directly mounted on the engine or associated piping, the controls and monitoring instrumentation should be installed on a free-standing floor-mounted panel separate from the engine skids, and located on a vibration-free floor area or equipped with vibration mounts.

Confirm your compliance with the above requirement or provide justification for noncompliance.

RESPONSE:

See revised Subsection 8.3.1.4a.

QUESTION 040.82

Periodic testing and test loading of an emergency diesel generator in a nuclear power plant is a necessary function to demonstrate the operability, capability, and availability of the unit on demand. Periodic testing coupled with good preventive maintenance practices will assure optimum equipment readiness and availability on demand. This is the desired goal.

To achieve this optimum equipment readiness status, the following requirements should be met:

1. The equipment should be tested with a minimum loading of 25 percent of rated load. No load or light load operation will cause incomplete combustion of fuel resulting in the formation of gum and varnish deposits on the cylinder walls, intake and exhaust valves, pistons, and piston rings, etc., and accumulation of unburned fuel in the turbocharger and exhaust system. The consequences of no load or light load operation are potential equipment failure due to the gum and varnish deposits and fire in the engine exhaust system.

2. Periodic surveillance testing should be performed in accordance with the applicable NRC guidelines (Regulatory Guide 1.108), and with the recommendations of the engine manufacturer. Conflicts between any such recommendation and the NRC guidelines, particularly with respect to test frequency, loading, and duration, should be identified and justified.

3. Preventive maintenance should go beyond the normal routine adjustments, servicing and repair of components when a malfunction occurs. Preventive maintenance should encompass investigative testing of components which have a history of repeated malfunctioning and require constant attention and repair. In such cases, consideration should be given to replacement of those components with other products which have a record of demonstrated reliability, rather than repetitive repair and maintenance of the existing components. Testing of the unit after adjustments or repairs have been made only confirms that the equipment is operable and does not necessarily mean that the root cause of the problem has been eliminated or alleviated.

4. Upon completion of repairs or maintenance and prior to an actual start, run, and load test, a final equipment check should be made to assure that all electrical circuits are functional, i.e. fuses are in place,

switches and circuit breakers are in their proper position, no loose wires, all test leads have been removed, and all valves are in the proper position to permit a manual start of the equipment, after the unit to ready automatic standby service and under the control of the control room operator.

Provide a discussion of how the above requirements have been implemented in the emergency diesel generator system design and how they will be considered when the plant is in commercial operation, i.e., by what means will the above requirements be enforced.

RESPONSE:

1. Minimum Loading

   The diesel generator surveillance test procedure provides for testing at 100% load on a monthly basis. The diesel generator operating procedure provides guidance on increasing the load prior to shutdown, if the diesel generator had been operating at less than 80% load. FSAR Subsection 8.3.1.4 shows the commitment to follow the manufacturers' recommendations for maintaining load at 50-100% for normal, continuous operation.

2. Periodic Surveillance Testing

   Surveillance testing of the diesel generators will be in accordance with requirements contained in Technical Specifications to be issued for Susquehanna SES. The current draft of these Technical Specifications (being prepared for submittal one year prior to fuel load) closely follows the recommendations for diesel generator testing contained in NUREG-0123, Rev. 2, "Standard Technical Specifications for General Electric Boiling Water Reactors."

3. Investigative Testing

   As Susquehanna SES, Technical Section engineers are assigned responsibility for various systems in the plant. The engineer assigned responsibility for the emergency diesel generators will provide the investigative testing and evaluation function described. System engineer responsibilities typically include review and revision of operating procedures, review of test results, evaluation of proposed modifications, evaluation of 1E bulletins, circulars, and information notices and other related duties. It is a responsibility of the system engineer to suggest investigative testing when situations warrant. This technical support engineering function, combined with normal maintenance activities will enhance the reliability of the diesel generators.

4. Post-Maintenance Testing

Specific maintenance procedures will specify steps necessary to return the system to operational status. Testing for operability is the responsibility of Shift Supervision and is controlled through the Work Authorization program.

QUESTION 040.83

Provide a detailed discussion (or plan) of the level of training proposed for your operators, maintenance crew, quality assurance, and supervisory personnel responsible for the operation and maintenance of the emergency generators. Identify the number and type of personnel that will be dedicated to the operations and maintenance of the emergency diesel generators and the number and type that will be assigned from your general plant operations and maintenance groups to assist when needed.

In your discussion, identify the amount of kind of training that will be received by each of the above categories and the type of ongoing training program planned to assure optimum availability of the emergency generators. Also discuss the level of education and minimum experience requirements for the various categories of operations and maintenance personnel associated with the emergency diesel generators.

RESPONSE:

At Susquehanna SES, no specific group of operators, maintenance personnel, supervisors, etc. will be assigned exclusive responsibility for the emergency diesel generators.

On each operation shift, one of the three Nuclear Plant Operators, (NPO) will handle diesel generator operations on a rotating basis. Control room operation of the diesel generators is assigned to one or more of the three Plant Control Operators (PCO) on shift. The PCO, who holds a reactor operator license, normally directs the activities of the NPO.

The initial training program for the Operations Section is described in Subsection 13.2.1.1.2. The program provides Susquehanna SES specific systems training for licensed and non-licensed operators, which encompasses emergency diesel generator training provided by the manufacturer or equivalent. The basic retraining program for operators is described in Subsection 13.2.2. To supplement this basic retraining, additional operations personnel may be selected to receive the detailed diesel generator training provided by the manufacturer or equivalent. The basic retraining program for operators is described in Subsection 13.2.2. To supplement this basic retraining, additional operations personnel may be selected to receive the detailed vendor training or a detailed retraining program.

The responsibility for maintenance of the diesel generators is shared by electrical maintenance, mechanical maintenance, instrumentation and control, and electrical test group for appropriate components and subsystems. As with the Operations

Section, no specific personnel will be dedicated to the diesel generators. However, selected personnel will receive detailed training offered by the manufacturer or equivalent as appropriate. Retraining/replacement training will be provided on an as-needed basis. This supplements the basic training program described in Subsections 13.2.1 and 13.2.2.

Qualifications of all plant personnel are discussed in Subsection 13.1.3.

QUESTION 040.84

Your response to request 040.36 is not complete. You state in Subsection 9.5.4.2 the available net positive suction head (NPSH), with the impeller flooded, is much greater than the 1 foot, 6 inch required NPSH for the pump. Therefore, the entire volume above the pump centerline, 10 3/4 inches from the bottom, is available for the diesel generator.

The fuel oil storage tank transfer pump selected requires a minimum NPSH of 1 foot, 6 inches to deliver its rated capacity of 25 gpm at 30 psi differential head. Operation of this pump with less than the required NPSH will affect pump performance and reliability. At some point, if the pump is permitted to operate with diminishing NPSH, the pump will cease to deliver fuel and severe cavitation will occur.

Your above statements need further clarification.

RESPONSE:

See revised Subsection 9.5.4.2.

QUESTION 040.85

Your answer to request 040.37 is not complete. The new Figures 9.5-28, 9.5-29, and 9.5-30 do not provide the needed information to evaluate the adequacy of the diesel generator fuel oil storage and transfer system.

Provide additional information and drawing (plans and sections).

1. The piping in the truck fill pit.

2. The location of the fuel oil storage tanks with respect to the diesel generator building including all fuel piping from the storage tank to its associated day tank and from the day tank to the storage tank.

3. The relation of the fuel oil storage tanks to buried yard piping that may be in the vicinity or cross under the fuel storage tank concrete support mat (see Figure 9.5-28). Identify the line size, carrying capacity in gpm, pressure and fluid. Provide assurance that a pipe line break under the fuel oil storage tanks support structure will not prevent the diesel generator fuel oil storage and transfer system from performing its safety function.

4. Plans of diesel generator building at elevations 660'-0", 710'-0", and 723'-0".

RESPONSE:

See revised Subsection 9.5.4.2. Dwgs. C-46, Sh. 1, C-5012, Sh. 1, C-904, Sh. 1, C-5013, Sh. 1, C-905, Sh. 1, C-5014, Sh. 1, C-5015, Sh. 1, C-1029, Sh. 1, C-1029, Sh. 2, E-412, Sh. 1, have been added.

QUESTION 040.86

Your answer to request 040.38 is not complete. Figures 9.5-19, 9.5-28, 9.5-29, and 9.5-30 show the tank fill connection and branch fill lines to each fuel oil storage tank as non-seismic, Class D construction. Also, the above figures do not identify the piping classification of the fuel oil storage tank vent line and other connections.

RESPONSE:

See revised Subsection 9.5.4.2

QUESTION 040.87

It is our position that the fuel oil storage tank fill line from the tank interface up to and including the truck fill interface and all other tank connections should be seismic Category I, Class C construction. Revise your design accordingly.

You state in Subsection 9.5.4.2 (Revision 9) that the fuel oil storage tank vents are goose-necked and provided with screens to keep out potential above-grade fuel contamination. This is not acceptable. It is our position that fuel tank vents should be provided with flame arrestors. Revise your design accordingly.

RESPONSE:

See revised Subsection 9.5.4.2

QUESTION 040.88

Section B on Figure 9.5-29 shows that the four diesel generator fuel oil storage tanks, concrete support mat and structures are located between and abutting existing crane foundations.

Provide the result of an analysis which demonstrates that in the event of a design basis earthquake seismic interaction between the existing crane foundations and diesel generator fuel oil system support structures will not prevent the diesel generator fuel oil storage and transfer system from performing its safety function.

RESPONSE:

The existing crane foundations were used to support cranes only during construction activity. A one-inch layer of rodofoam was placed between the crane foundation and the structure surrounding the diesel tanks, in order to dampen crane vibrations.

The crane foundations are continuous beyond both ends of the diesel structure and are supported directly on the bedrock in their entirety. Further, sand-cement-flyash backfill is placed between the east and west foundations from El. 646'-0" to El.670'-0", thus preventing movement in an inner direction. The foundations are abandoned in place since they do not support any permanent structure.

The presence of the foundations does not hinder the diesel tanks from performing safety functions. No special analysis is required.

QUESTION 040.89

You state in Subsection 9.5.4.3 (Revision 7) that excessive splashing and sediment turbulence is prevented by the fuel fill line discharging near the bottom of the storage tank. If minor sediment turbulence occurs, fuel filters will keep the overall quality of the fuel oil acceptable during replenishment.

Location of the fill line near the bottom of the storage tank does not necessarily mean that turbulence is minimized. to the contrary, the magnitude of turbulence generated with a vertical fuel fill line is dependent upon exit pipe velocity and the distance the end of the fuel fill pipe is from the bottom of the storage tank. The turbulence generated within the storage tank with your design is dependent upon the fill line location and exit velocity.

Provide a drawing showing the size and arrangement of the fuel fill line in the storage tank, expected maximum refueling rate (gpm), and maximum fill line exist velocity. Also provide assurance that the turbulence generated at the maximum existing velocity will not degrade the fuel and prevent availability of the diesel generator on demand.

A method of alleviating or minimizing excessive turbulence in storage tank would be by a perforated fuel fill distribution header. The perforations or orifices should be designed for low exist velocities.

RESPONSE:

See revised Subsection 9.5.4.3.

QUESTION 040.90

Operating experience has shown that accumulation of water in the starting air system has been one of the most frequent causes of diesel engine failure to start on demand. Condensation of entrained moisture in compressed air lines leading to control and starting air valves, air start motors, and condensation of moisture on the working surfaces of these components has caused rust, scale and water itself to build up and score and jam the internal working parts of these vital components thereby preventing starting of the diesel generators.

In the event of loss of offsite power the diesel generators must function since they are vital to the safe shutdown of the reactor(s). Failure of the diesel engines to start from the effects of moisture condensation in air starting systems and from other causes have lowered their operational reliability to substantially less than the desired reliability to substantially less than the desired reliability of 0.99 as specified in Branch Technical Position ICSB (PSB) 2" Diesel Generator Reliability Testing" and Regulatory Guide 1.108 "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants."

In an effort toward improving diesel engine starting reliability we require that compressed air starting system designs include air dryers for the removal of entrained moisture. The two air dryers most commonly used are the desiccant and refrigerant types. Of these two types, the refrigerant type is the one most suited for this application and therefore is preferred. Starting air should be dried to a dew point of not more than 50°F when installed in a normally controlled 70°F environment, otherwise the starting air dew point should be controlled to at least 10°F less than the lowest expected ambient temperature.

Revise your design of the diesel engine air starting system accordingly, describe this feature of your design.

RESPONSE:

We concur that air dryers will minimize the potential for rust accumulation in the air start and pneumatic control systems of the diesel generators. Since all system low points are drained and the operating pressure is over 200 psig, there will be very little moisture in the air, even when saturated. Thus, we believe there is little risk of air start or control air blockage from moisture.

To prevent rust accumulation in the air start and control air systems, and thus improve the long-term reliability of the diesel generator sets, we will provide air dryers in the air start systems prior to plant startup following the first refueling outage. The air dryer units will be non-seismic components and will be standard commercial products of proven quality and reliability. These units are not available with ASME Section III components and will be provided with ASME Section VIII, ANSI B31.1 and commercial grade components. Each of the eight air dryer units will be independent and will be provided with power from the diesel generator they serve. The dryers will be located in the system between the air compressor and air receiver.

QUESTION 040.91

You state response to our request 040.49 is covered in section 9.5.7.2 revision 7. We have reviewed revision 7 and do not find that you have addressed our request. Provide your response to request 040.49.

Response:

See revised Subsection 9.5.7.2.

QUESTION 040.92

Several fires have occurred at some operating plants in the area of the diesel engine exhaust manifold and inside the turbocharger housing which have resulted in equipment unavailability. The fires were started from lube oil leaking and accumulating on the engine exhaust manifold and accumulating and igniting inside the turbocharger housing. Accumulation of lube oil in these areas, on some engines, is apparently caused from an excessively long prelube period, generally longer than five minutes, prior to manual starting of a diesel generator. This condition does not occur on an emergency start since the prelube period is minimal.

When manually starting the diesel generators for any reason, to minimize the potential fire hazard and to improve equipment availability, the prelube period should be limited to a maximum of three to five minutes unless otherwise recommended by the diesel engine manufacturer. Confirm your compliance with this requirement or provide your justification for requiring a longer prelube time interval period to manual starting of the diesel generators. Provide the prelube time interval your diesel engine will be exposed to prior to manual start.

RESPONSE:

See revised Subsection 9.5.7.1

QUESTION 040.93

An emergency diesel generator unit in a nuclear power plant is normally in the ready standby mode unless there is a loss of offsite power, an accident, or the diesel generator is under test. Long periods on standby have a tendency to drain or nearly empty the engine lube oil piping system. On an emergency start of the engine as much as 5 to 14 or more seconds may elapse from the start of cranking until full lube oil pressure is attained even though full engine speed is generally reached in about five seconds. With an essentially dry engine, the momentary lack of lubrication or the various moving parts may damage bearing surfaces producing incipient or actual component failure with resultant equipment unavailability.

The emergency condition of readiness requires this equipment to attain full rated speed and enable automatic sequencing of electric load within ten seconds. For this reason, and to improve upon the availability of this equipment on demand, it is necessary to establish as quickly as possible an oil film in the wearing parts of the diesel engine. Lubricating oil is normally delivered to the engine wearing parts by one or more engine driven pump(s). During the starting cycle the pump(s) accelerates slowly with the engine and may not supply the required quantity of lubricating oil where needed fast enough. To remedy this condition, as a minimum, an electrically driven lubricating oil pump, powered from a reliable DC power supply, should be installed in the lube oil system to operate in parallel with the engine driven main lube pump. The electric driven prelube pump should operate only during the engine cranking cycle or until satisfactory lube oil pressure is established in the engine main lube distribution header. The installation of this prelube pump should be coordinated with the respective engine manufacturer. Some diesel engines include a lube oil circulating pump as an integral part of the lube oil preheating system which is in use while the diesel engine is in the standby mode. In this case an additional prelube oil pump may not be needed.

Confirm your compliance with the above requirement or provide your justification for not installing an electric prelube oil pump.

RESPONSE:

See revised Subsection 9.5.7.1.

QUESTION 040.94

Experience at some operating plants has shown that diesel engines have failed to start due to accumulation of dust and other deleterious material on electrical equipment associated with starting of the diesel generators (e.g., auxiliary relay contacts, control switches - etc.). Describe the provisions that have been made in your diesel generator building design, electrical starting system, and combustion air and ventilation air intake design(s) to preclude this condition to assure availability of the diesel generator on demand.

Also describe under normal plant operation what procedure(s) will be used to minimize accumulation of dust in the diesel generator room. In your response also consider the condition when Unit 1 is in operation and Unit 2 is under construction (abnormal generation of dust).

RESPONSE:

See revised Subsection 9.4.7.2.

QUESTION 40.95

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TABLE 40.95-1

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TABLE 40.95-2

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QUESTION 40.96

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