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1 INTRODUCTION AND GENERAL DESCRIPTION OF THE PLANT

1.1 Introduction

In April 1981, the staff of the Nuclear Regulatory Commission issued its Safety Evaluation Report (NUREG-0776) regarding the application for licenses to operate Susquehanna Steam Electric Station, Units Nos. 1 and 2. In June 1981 the staff issued Supplement 1 to NUREG-0776.

Since the preparation of Supplement 1 to the Safety Evaluation Report (SSER-1), the Advisory Committee on Reactor Safeguards considered the Susquehanna operating license application at its 256th meeting and subsequently issued a favorable report, dated August 11, 1981 to the Commission (See Appendix B of this report). In addition, we have received and reviewed Amendment Nos. 36 through 38 to the Final Safety Analysis Report and additional documents associated with the application, and held a number of meetings with the applicants. These events and documents are identified in Appendix A to this supplement.

This supplement, SSER-2, to the Safety Evaluation Report, provides (1) our evaluation of additional information received from the applicants since preparation of SSER-1 regarding previously identified outstanding review items, (2) a listing of additional or revised information related to new issues that have arisen since the preparation of SSER-1, and (3) our response to the comments made by the Advisory Committee on Reactor Safeguards in its report.

Each section of this supplement is numbered and titled to correspond to the sections of the Safety Evaluation Report (SER) that have been affected by our additional evaluation and, except where specifically noted, does not replace the corresponding section of the SER. Appendix A is a continuation of the chronology and lists additional documents used in the supplemental review. Appendix C is a page revision to page C-4.

1.9 Summary of Outstanding Review Items

Items previously identified as outstanding have been resolved since publication of the supplement to the safety Evaluation Report as indicated below.

In Section 1.9 of SSER-1, we identified 14 items related to the overall plant design that were outstanding because additional information was required from the applicants or because the staff had not completed its review of recently submitted information.

Since the preparation of SSER-1 was completed, 9 of the 14 outstanding items described in Section 1.9 have been resolved.

The current status of all review items discussed above and the sections that provide our evaluation of each item are tabulated below.

<u>Open Item #</u>	<u>Item and Section</u>	<u>Status</u>
1.	The nearby transportation of explosive and toxic hazards (2.2)	Resolved
2.	Design bases ground water level (2.4.5)	Resolved
3.	Compaction of rock fill (2.5.1.2)	Resolved
4.	Turbine missiles (3.5.1.3)	Resolved
5.	Equivalence of seismic models (3.7.2)	Resolved
6.	Containment liner anchorage design (3.8.1)	Resolved
7.	Reactor vessel internals loads due to LOCA & SSE (3.9.2)	Resolved pending documentation
8.	Documentation and review of hydrodynamic loads (3.9.3)	Resolved pending documentation
9.	Class 1 fatigue analysis of the SRV lines (3.9.3)	Resolved
10.	Testing of isolation valves in between the high pressure reactor coolant system and the low pressure system (3.9.6)	Resolved via license condition
11.	Seismic qualification review (SQRT) (3.10)	Resolved pending documentation
12.	Environmental qualification of electrical equipment (3.11)	Additional information required
13.	Masonry walls (3.12)	Resolved
14.	Supplemental ECCS calculations (4.2.3)	Resolved
15.	Seismic & LOCA calculations for fuel assembly designs (4.2.3.4)	Resolved pending documentation
16.	ODYN recalculations (4.4) (5.2.2)	Resolved
17.	Responses to staff questions on hydrodynamic stability (4.4)	Resolved via license condition
18.	Description and review of loose parts monitoring system (4.4)	Resolved
19.	Preservice inspection program (5.2.4) (6.6)	Resolved pending documentation

20.	Applicants response to NUREG-0619 (5.2.4)	Resolved pending documentation
21.	Compliance with Appendix G (5.3.1)	Resolved
22.	Compliance with Appendix H (5.3.1)	Resolved
23.	Pressure-temperature limits (5.3.2)	Resolved
24.	Reactor vessel integrity (5.3.3)	Resolved
25.	Steam bypass of the suppression pool (6.2.1.7)	Additional information required
26.	Review of future downcomer lateral load reanalysis (6.2.1.4)	Resolved pending documentation
27.	Review of condensation oscillation loads (6.2.1.1)	Resolved
28.	Additional justification required for T-quencher loads (6.2.1.8)	Resolved
29.	Review of submerged dragloads (6.2.1.1)	Resolved
30.	Pool temperature responses (6.2.1.5)	Resolved
31.	Qualification of purge valves (6.2.4.3) (II.E.4.2)	Resolved via license condition
32.	Compliance to GDC-51 (6.2.7)	Resolved
33.	NPSH for core spray & LPCI pumps (6.3.2.3)	Resolved
34.	Leakage from first isolation valve (6.3.2.3)	Resolved
35.	Review of inservice inspection program (6.6)	Resolved pending Documentation
36.	Leakage from the main steam isolation valve (6.7)	Resolved
37.	LPCI diversion (6.3.4)	Resolved
38.	Residual heat removal system alternate shutdown path (5.4.2)	Resolved
39.	Accident monitoring instrumentation Regulatory Guide 1.97 (7.0)	Resolved
40.	Low pressure coolant injection and core spray interlocks (7.0)	Resolved
41.	Challenges to Class IE circuits from non-Class IE circuits including site visit by reviewer (7.0)	Resolved



42.	ATWS recirculation pump trip (7.0)	Resolved
43.	Refueling interlocks (7.0)	Resolved
44.	IE Bulletin 79-27 & 80-06 (7.0)	Resolved
45.	Control System consequences to high energy line breaks (7.0)	Resolved via license condition
46.	Common electrical sensor or power system malfunctions (7.0)	Resolved via license condition
47.	Diesel generator testing (8.4.4)	Resolved pending documentation
48.	Non-Class IE loads on the Class IE power system (8.4.4)	Resolved pending documentation
49.	Degraded grid voltage (8.4.4)	Resolved
50.	Three-hour fire rating of drywalls (9.5.2.1)	Resolved
51.	Fire damper installation (9.5.2.2)	Resolved
52.	Fire in battery room concern (9.5.1.4)	Resolved
53.	Circuit breaker local fire alarms (9.5.4.5)	Resolved
54.	Fire review of alternate safe shutdown system (9.5.5)	Additional information required
55.	Fracture toughness requirements for steam and feedwater materials (10.3.3)	Resolved
56.	Compliance of offgas system to Regulatory Guide 1.143. (11.2.2)	Resolved
57.	The number of radiation survey meters (12.5)	Resolved
58.	Respirator types (12.5)	Resolved
59.	Qualifications of health physics technicians (12.5)	Resolved pending documentation
60.	Details of the on site components of the Nuclear Safety Assessment group (13.2)	Resolved
61.	Revised licensed operator requalification program and program and replacement training programs (13.2)	Resolved pending documentation
62.	Security Plan revision (13.6)	Resolved
63.	Chapter 14 review	Resolved

64.	Operation with partial feedwater heating at end of cycle (15.1)	Resolved via license condition
65.	Recirculation pump coastdown testing (15.1)	Resolved
66.	Reclassification of transients (15.1)	Resolved
67.	Use of nonsafety-grade equipment in transient analysis (15.1)	Resolved
68.	Use of nonsafety-grade equipment in shaft seizure accident analysis (15.2)	Resolved
69.	ATWS procedure (15.2.1)	Resolved
70.	LOCA doses (15.3.4)	Resolved
71.	Q List (17.5)	Resolved
72.	NUREG-0737 items (open items #72 through 104 and 106) I.A.1.2	Resolved pending documentation
73.	I.C.1	Resolved
74.	I.C.4	Resolved pending documentation
75.	I.C.5	Resolved pending documentation
76.	I.C.6	Resolved
77.	I.C.7	Resolved
78.	I.C.8	Resolved pending documentation
79.	I.G.1	Resolved pending documentation
80.	II.B.2	Resolved
81.	II.B.3	Resolved pending documentation
82.	II.D.1	Resolved
83.	II.D.3	Resolved
84.	II.E.4.2	Resolved pending documentation
85.	II.F.1 Attachment 1	Resolved pending documentation

86.	II.F.1	Attachment 2	Resolved pending documentation
87.	II.F.1	Attachment 3	Resolved
88.	II.K.1	item 5	Resolved via license condition
89.	II.K.1	item 10	Resolved via license condition
90.	II.K.1	item 22	Resolved
91.	II.K.3	item 13	Resolved
92.	II.K.3.	item 15	Resolved
93.	II.K.3	item 16	Resolved
94.	II.K.3	item 17	Resolved
95.	II.K.3	item 18	Additional information required
96.	II.K.3	item 21	Resolved
97.	II.K.3	item 22	Resolved pending documentation
98.	II.K.3	item 24	Resolved
99.	II.K.3	item 27	Resolved
100.	II.K.3	item 44	Resolved
101.	III.A.1.1		Additional information required
102.	III.A.1.2		Resolved
103.	III.A.2		Resolved
104.	II.K.3	item 25	Resolved via license condition
105.		Heavy loads generic letter (9.1.4.1)	Resolved
106.	II.F.2		Resolved pending documentation
107.		Safety relief valve surveillance reports (5.2.2)	Resolved
108.		Scram discharge volume generic letter (4.6)	Resolved pending documentation

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3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS AND COMPONENTS

3.5.1.3 Turbine Missiles

According to General Design Criterion 4, of Appendix A to 10 CFR Part 50, nuclear power plant structures, systems, and components important to safety shall be appropriately protected against dynamic effects including the effects of turbine missiles. Systems important to safety are defined to be those structures, systems, and components necessary to ensure:

1. The integrity of the reactor coolant pressure boundary,
2. The capability to shutdown the reactor and maintain it in a cold shutdown condition, or
3. The capability to prevent accidents that could result in potential offsite exposures that are a significant fraction of the guideline exposures of 10 CFR Part 100, "Reactor Site Criteria."

The Susquehanna turbine-generator placement and orientation is tangential with respect to the station reactor buildings; that is, the failure of the turbine could produce missiles which could have trajectories which could impact certain safety areas of the plant. We have reviewed those portions of the reactor buildings within the low trajectory missile (LTM) strike zone and find that the structures, systems, and components important to safety are adequately protected.

The staff has performed an analysis to determine if structural members and non safety-related equipment at Susquehanna serve as adequate barriers protecting safety-related structures, systems, and components from potential turbine missiles.

1. Our analysis indicates that the largest postulated LTM will not advance beyond the radiation shield which surrounds the turbine at the 729 ft. level and above. Below the 729 ft. level the turbine pedestal acts as an adequate turbine missile barrier. Therefore, no LTM will reach the inside of either the reactor building or the control room.
2. With regard to high trajectory missiles (HTMs) our analysis shows:
 - (a) The largest postulated missile descending vertically on the control structure (which houses the control room) will not perforate the floor at the 783 ft. level above the control room. Since there is another floor at the 771 ft. level and the overhead of the control room is at the 753 ft. level, such a missile would not penetrate to the overhead of the control room.
 - (b) The largest postulated HTM descending vertically on the reactor building will not perforate the floor at the 779 ft. level nor perforate the radiation shield over the containment structure. All safety-related targets are at the 749 ft. level and below, except



for the spent fuel pool. The applicants have calculated the strike probability for the spent fuel pool and obtained a value of about 1×10^{-4} per turbine failure.

- (c) Though a HTM could strike the diesel generator building, there are sufficient separation and redundancy which make the probability of unacceptable damage negligible. Furthermore, while a HTM could also strike the Engineered Safeguards and Service Water Pumphouse, the applicants estimate the strike probability to be only about 1×10^{-5} per turbine failure.

On the basis of our review, we conclude that the risk due to potential turbine missiles for Susquehanna Units 1 and 2 is acceptable because of the low probability of turbine failure in conjunction with the even lower probability of damage to safety-related equipment.

3.11 Equipment Qualification for Safety-Related Electrical Equipment

As discussed in Supplement No. 1 the applicants have not submitted their complete qualification program. The applicants forecast a November 1981 submittal. This item, therefore, remains open. Upon receipt of the submittal, the staff will review the program and report its findings in a future supplement to the SER.

4 REACTOR

4.6 Pipe Breaks In The BWR Scram System

In April 1981 the NRC staff sent a letter to each BWR license applicant requesting certain information on this subject. We indicated that this item must be resolved prior to issuance of an operating license. Subsequently, on July 7, 1981 the NRC staff sent a letter to all BWR licensees informing them that the generic review of this issue had been completed. We indicated that a NUREG report describing the results of this review would be issued.

NUREG-0803, "Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping," dated August 1981 has been issued. Section 5 of NUREG-0803 presents the staff's generic conclusions on this issue. Briefly, the staff has concluded that the scram discharge valve (SDV) piping system design is acceptable, provided certain conditions are satisfied on an individual plant basis. The staff further concluded that the safety concerns associated with a postulated failure of the SDV piping system do not represent a dominant contribution to the risk of core melt, provided certain assumptions used in the risk assessment are validated on an individual plant basis.

Table 5.1 of NUREG-0803 provides a summary of the staff's guidance and schedule for implementation. As provided in our April 1981 letter, cited above, plant specific responses should be provided for all plants with Mark I and Mark II containments to support issuance of an operating license. A Susquehanna response conforming to the guidance contained in NUREG-0803 will satisfy the information requested in our April 1981 letter. The applicants must conform to NUREG-0803 or provide an acceptable equivalent resolution. We will require resolution of this item and implementation before fuel load.

5 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.2.3.2 Stainless Steel Pipe Cracking

Leaks and cracks in the heat-affected zones (HAZ) of welds that join austenitic stainless steel piping and associated components in boiling water reactors (BWR) have been observed over the past several years. As a result of the detection of cracks in (BWR) components, two Generic Technical Activities were identified, A-10, "BWR Nozzle Cracking," and A-42, "Pipe Cracks in Boiling Water Reactors," as Unresolved Resolved Safety Issues, and NRR Task Groups were formed to study and recommend resolution of the issue of stainless steel pipe cracking.

NUREG-0619, "BWR Feedwater Nozzle and Control Rod Return Line Nozzle Cracking," was issued in April, 1980, for resolution of Generic Technical Activity A-10. The applicants' responses to the preservice/in-service inspection provisions of NUREG-0619 was evaluated and accepted provisionally by the staff in Section 5.2.4 of SSER-1.

NUREG-0313, Revision 1, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," was issued in October, 1979, for resolution of Generic Technical Activity A-42. The applicants' response to the provisions of NUREG-0313, Revision 1, was contained in a letter dated June 30, 1981.

The Pennsylvania Power and Light Company has undertaken an extension program for Susquehanna Units 1 and 2, which conforms to the requirements of NUREG-0313, Revision 1, to investigate intergranular stress corrosion cracking in austenitic stainless steel.

Regular grade Type 304 stainless steel has been replaced to the extent practical with low carbon grade Type 304 stainless steel in the recirculation system discharge valve bypass line, core spray and head spray, reactor water cleanup system and instrument piping and bottom drain lines. Further replacement of nonconforming material would result in undue hardship because it would involve either the replacement of already installed large diameter piping (20-inch) or flued heads imbedded in concrete. The control rod driven hydraulic return line was eliminated. The applicants will conform to the augmented inspection requirement of NUREG-0313, Revision 1.

Further provisions have been taken by the applicants to reduce the potential for intergranular stress corrosion cracking. For example, dissolved oxygen control, welding parameter control, and ferrite control measures.



6 ENGINEERED SAFETY FEATURES

6.2.1.4 Quencher Arm and Tie-Down Load

Supplement 1 to the Safety Evaluation Report indicated that the applicants had determined that a bending moment of 65.1 kile Newton metal (KNm) instead of the staff recommended value (maximum measured during T-quencher test) on the quencher arm is conservative. The applicants indicated that examination of the frequency distribution of the resultant bending moments measured reveal no trends and, therefore, a statistical average rather than the maximum should be used in the design. The average test data bending moment measured was 35 KNm, however, in only 3 cases out of 99, the test data bending moment exceeded the 65 KNm design specification bending moment with a maximum measured bending moment of 81.7 KNm. In addition, the applicants stated that the resultant bending moment is only one load component (internal temperature, bending moment and pressure gradient), and that the total stress due to the specified loads bound the total stress due to the measured loads. Thus, even if a higher bending moment were to be specified in the design specification calculation (i.e., 81.7 KNm vs. 65 KNm), it is not expected that the primary stress allowable would be exceeded.

The applicants have performed calculations using the rules of ASME Code Section III NC-3200, including Appendix XIII and XIV. The calculations were performed for both the design specification and the maximum test data value.

The fatigue evaluation conservatively assumed that maximum design specification values would occur for 7000 valve actuations. The design specification bending moment used was 65 KNm. However, the governing stress in the fatigue evaluation was the thermal peak stress and not the mechanical bending moment. The thermal peak stress calculated from the design specification exceeded thermal peak stress calculated from test data values (93.37 ksi vs. 81.9 ksi, respectively). The resulting cumulative usage factor for the design specification calculation exceeded the test data usage factor (0.93 vs. 0.7) even though the test data usage factor was calculated assuming 7000 cycles of the maximum measured bending moment (81.7 KNm). Therefore, it is not expected that the larger bending moment from the test data would have a significant effect on the design specification fatigue usage factor and that the relatively few cases where the design specification bending moment is exceeded will not cause fatigue failure.

In summary, for the primary stresses, the design specification calculation resulted in stresses higher than the test data stresses. In both cases the primary stresses were less than one-half the stress allowable. For consideration of primary, secondary and peak stresses, the applicants have performed a conservative fatigue evaluation using maximum design specification values. For the few cases where the bending moment does exceed the design specification value, it is not expected that the higher bending moment will result in fatigue failure.

Therefore, based on our review of the applicants' stress report summary and the applicants meeting the special requirements delineated in NC-3211.1 (d),



we find the Susquehanna load specification for the SRV air clearing bending moment acceptable for use in the design of the T-quencher body-to-arm weld.

6.2.1.8 Steam Condensation Drag Load

Submerged structures in the Susquehanna suppression pool were assessed by the applicants for loads due to main vent steam condensation. The pressure sources deduced from the GKM-IIM test data were used to calculate the pressure fields using the IWECS/MARS acoustic model of the suppression pool. To account for the effect of submerged structures on the pressure fields calculated (hydrodynamic mass effect), the applicants performed a series of sensitivity studies and determined that a conservative multiplier of two (2) will be used to calculate the pressure at the submerged structure location to determine the loads due to LOCA steam condensation on submerged structures. We find this approach conservative and acceptable.

6.2.7 Fracture Prevention of Containment Pressure Boundary

We have assessed the ferritic materials in the Susquehanna Unit Nos. 1 & 2 containment system that constitute the containment pressure boundary to determine if the material fracture toughness is in compliance with the requirements of General Design Criterion 51, "Fracture Prevention of Containment Pressure Boundary."

General Design Criterion (GDC) 51 requires that under operating, maintenance, testing and postulated accident conditions, (1) the ferritic materials of the containment pressure boundary behave in a nonbrittle manner, and (2) the probability of rapidly propagating fracture is minimized.

The Susquehanna primary containment is a reinforced concrete structure with a thin steel liner on the inside surface which serves as a leaktight membrane. The ferritic materials of the containment pressure boundary which were considered in our assessment were those applied in the fabrication of the equipment hatch, personnel airlocks, penetrations, drywell head and piping system components, including the isolation valves required to isolate the system. These components are the parts of the containment system which are not backed by concrete and must sustain loads during the performance of the containment function.

The Susquehanna containment pressure boundary is comprised of American Society of Mechanical Engineers (ASME) Code Class 1, 2 and MC components. In late 1979, we reviewed the fracture toughness requirements of the ferritic materials of Class MC, Class 2 and Class 1 components which typically constitute the containment pressure boundary. Based on this review we determined that the fracture toughness requirements contained in ASME Code Editions and Addenda typical of those used in the design of the Susquehanna primary containment may not ensure compliance with GDC-51 for all areas of the containment pressure boundary. We initiated a program to review fracture toughness requirements for containment pressure boundary materials for the purpose of defining those fracture toughness criteria that most appropriately address the requirements of GDC-51. Prior to completion of this study, we have elected to apply in our licensing reviews the criteria identified in the Summer 1977 Addenda of Section III of the ASME Code for Class 2 components. These criteria were selected to ensure that uniform fracture toughness requirements, consistent with the containment safety function, are applied to all components in the containment

pressure boundary. Accordingly, we have reviewed the Class 1, 2, and MC components in the Susquehanna containment pressure boundary according to the fracture toughness requirements of the Summer 1977 Addenda of Section III for Class 2 components.

Our assessment of the fracture toughness of the materials of the Susquehanna containment pressure boundary is based on fracture toughness data provided by the applicants and on correlations of the metallurgical characterization of the materials with fracture toughness data presented in NUREG-0577, "Potential for low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pipe Supports," USNRC, October 1979 and ASME Code Section III, Summer 1977 Addenda, Subsection NC.

The metallurgical characterization of these materials, with respect to their fracture toughness, was developed from a review of how these materials were fabricated and what thermal history they experienced during fabrication.

The metallurgical characterization of these materials, when correlated with the data presented in NUREG-0577 and the Summer 1977 Addenda of the ASME Code Section III, Subsection NC, provided, in part, the technical basis for our evaluation of compliance with Code requirements.

Based on our review of the available fracture toughness data and material fabrication histories, and the use of correlations between metallurgical characteristics and material fracture toughness, we conclude that the ferritic materials in the Susquehanna containment pressure boundary meet the fracture toughness requirements that are specified for Class 2 components by the Summer 1977 Addenda of Section III of the ASME Code. We conclude that compliance with these Code requirements provides reasonable assurance that the materials of the Susquehanna containment pressure boundary will behave in a non-brittle manner, that the probability of rapidly propagating fracture will be minimized, and that the requirements of GDC 51 are met.

7 INSTRUMENTATION AND CONTROL

7.3.2 Loss of Safety Function After Reset

Because of a number of events and concerns related to the overriding and resetting of certain actuation signals, including those addressed in I&E Bulletin 80-06, we required the applicants to address the following positions:

- (1) The overriding^a of one type of safety actuation signal (e.g., particulate radiation) should not cause the blocking of any other type of safety actuation signal (e.g., reactor pressure) for those valves that have no function other than containment isolation.
- (2) Physical features (e.g., key lock switches) should be provided to ensure adequate administrative controls.
- (3) A system level annunciation of the overridden status should be provided for every safety system impacted when any override is active. (See Regulatory Guide 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Safety Systems.")
- (4) The following diverse signals should be provided to initiate isolation of the containment purge/ventilation system: containment high radiation, safety injection actuation, and containment high pressure (where containment high pressure is not a portion of safety injection actuation).
- (5) The instrumentation systems provided to initiate containment purge ventilation isolation should be designed and qualified to Class IE criteria.
- (6) The overriding or resetting^b of the engineered safety features actuation signal should not cause any equipment to change position.

The applicants provide their conformance to this position including a comment to conform item 6 by test. Regarding item 6, they have identified all safety-related equipment which actually will not remain in its emergency configuration on reset of an engineered safety features signal. These exceptions and their justification for the present design is as follows:

The applicants listed the following valves that would not be modified to remain in their emergency mode upon the reset of an Engineered Safety Feature (ESF) actuation signal:

^aOverride: The signal is still present, and it is blocked in order to perform a function contrary to the signal.

^bReset: The signal has come and gone, and the circuit is being cleared in order to return it to the normal condition.



- (a) The reactor core isolation cooling system (RCIC) and high pressure coolant injection (HPCI) turbine steam supply line isolation valves are normally open valves and will close upon a steam line break isolation signal. These valves are essential valves and do not receive a containment isolation signal. Reopening of these valves will occur if the hand switches are not placed in the closed position by the operator prior to actuation of the reset switch and the isolation parameters have cleared.

These valves are equipped with key-locked maintained contact switches to insure that these valves are open during emergency core cooling system (ECCS) initiation. If a pipe break condition were detected, then these valves will be automatically closed. After the pipe break problems are cleared, these valves can be reopened to their normal emergency positions by deliberate operator action using the key-locked reset switches for each system.

These valves require no modifications to prevent automatic reopening after logic reset because the reset switch is a keylock switch with an administratively controlled key. Any operation of the reset switch requires a deliberate operator action. The operator is required to ensure that the valve switches are in the correct position prior to operating the keylock reset switch.

- (b) The inboard HPCI and RCIC isolation valves each have a pressure equalization valve around them. The equalization valves are normally closed and are only used to equalize the pressure around the inboard isolation valve in order to open them. If open, the valves will close upon a steam line break isolation signal. Reopening of these valves will occur if the hand switches are not placed in the closed position by the operator prior to actuation of the reset switch and the isolation parameters have cleared.

As with the HPCI/RCI isolation valves, the equalization valves will reopen upon deliberate manual logic reset using the key-locked reset switches. These valves must open in order to allow the inboard isolation valves to reopen to their normal emergency positions when the pipe break problems have cleared. If the equalization valve switches are not in the open position the operator must manually open them to equalize the pressure around the inboard HPCI/RCIC valves.

These valves require no modifications to prevent automatic reopening after logic reset because the reset switch is a keylock switch with an administratively controlled key. Any operation of the reset switch requires a deliberate operator action. The operator is required to ensure that the valve switches are in the correct position prior to operating the keylock reset switch.

- (c) The residual heat removal (RHR) containment isolation valves associated with the drywell and suppression pool spray lines will reopen if their handswitches are placed in the open position prior to actuation of the reset switch, the low pressure coolant injection (LPCI) injection signals are clear, and the LPCI injection valves are closed. These spray line valves are normally closed and are provided key-locked handswitches. If the valves were open before a LPCI injection event, these valves will automatically close and cannot be reopened if the LPCI injection signals

still exist or the LPCI injection valves are still open. This is to insure that the LPCI injection function will not be inadvertently jeopardized by opening of the spray line isolation valves. If these spray line valves were closed before the LPCI injection event, the valves will remain closed after reset even after all injection signals are clear and the LPCI injection valves are closed.

Only the outermost valve is considered a containment isolation valve for these penetrations. The three inboard valves are spring return to "AUTO" switches and will not automatically reopen after logic reset and all signals clear. These inboard valves have not been considered containment isolation valves because they cannot be leak tested in the "forward" direction. Since these valves effectively function as containment isolation valves, a logic reset will not automatically result in a breach of containment integrity for these penetrations.

The RHR containment isolation valves require no modifications to prevent automatic reopening after logic reset and all signals clear because the inboard valves, are already designed so that they do not automatically reopen. The inboard valves will maintain containment integrity when the logic is reset.

It is the staff's opinion that the applicants satisfied the requirements of IE Bulletin 80-06 by identifying the exceptions listed above; describing their operation, justifying that no design change is required, and documented the required test procedures.

We conclude that the applicants' response and commitment are acceptable.

7.4.2 Remote Shutdown System

General Design Criterion (GDC) 19 requires in part that the ability be provided for the safe shutdown of the plant in case the main control room becomes uninhabitable. Plant designs should provide for control stations in locations removed from the main control room. These stations are to be used for manual control and alignment operations needed to achieve and maintain a hot shutdown and subsequently to be able to achieve a cold shutdown. The applicants have provided a remote shutdown panel for each unit located within an enclosure in the reactor building of each unit. Except for reactor scram, which can be initiated from other remote locations, this panel allows the operator to bring the reactor to the cold shutdown condition in an orderly fashion and includes all instrumentation and controls required for operating the following systems:

- (1) Reactor core isolation cooling (RCIC) system
- (2) Residual heat removal (RHR) system (a single pump and its associated RHR loop)
- (3) Relief valves (three)
- (4) Nuclear boiler system instrumentation
- (5) Emergency service water



(6) Containment instrument gas system

(7) Containment and suppression pool instrumentation

We reviewed the applicants' design and found that transferring control to the remote shutdown panel via the transfer switches generates signals to actuate valves that are not controllable from the remote shutdown panel in a direction that will isolate piping that could bypass significant volumes of water away from systems required for remote shutdown. The design assumes that the evacuation occurrence does not occur simultaneously 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. Therefore, the remote shutdown panel provided is a single panel with only the minimum controls and instruments required to bring the reactor to cold shutdown status. The remote shutdown panel itself does not meet single failure criterion. The panel does maintain the separation criteria in that the panel is subdivided with a continuous barrier to physically separate Division I power from Division II power.

The applicants were asked to provide a discussion which would demonstrate the capability of a Hot Shutdown from the Remote Shutdown panel with the worst single failure among the remote shutdown panel systems. The applicants indicated in their response that there is time to accommodate a single failure of a remote shutdown panel system due to automatic level control of the feedwater control system and steam quenching and pressure regulations provided by the condenser via the turbine bypass valves. However their response indicated that several manual actuations and the use of local jumpers would have to be utilized to meet the single failure criterion. It is the staff's opinion that to meet GDC 19, the design should provide redundant safety grade capability to achieve and maintain hot shutdown from a location or locations remote from the control room, assuming no fire damage to any required systems and equipment and assuming no accident has occurred. Credit may be taken for manual actuation (exclusive of continuous control) of systems from locations that are reasonably accessible from the Remote Shutdown Panel. Credit may not be taken for manual actions involving jumpering, rewiring or disconnecting circuits.

The applicants have proposed a preliminary design that would eliminate the use of jumpers and rewiring and instead rely on the use of manually operated keylock switches to meet the single failure criterion as specified above. This proposed design change is acceptable to the staff.

This remote shutdown capability is designed to control the required shutdown systems from outside the control room irrespective of shorts, opens, or grounds in the control circuit in the main control room. The functions needed for remote shutdown control are provided with manual transfer devices which overrides control from the main control room and transfers controls to the remote shutdown panel (RSP). All necessary power supplies are also transferred. The RSP is not operable without actuation of the transfer devices. Operation of the transfer devices causes an alarm in the main control room. When transferring control to the remote shutdown panel, controls for some functions are transferred to maintained contact switches. The applicants indicate the operator uses administrative procedures to determine the proper position of the control switches on the remote shutdown panel before making the transfer.



Transferring control to the remote shutdown panel disables ECCS actuation of both RHR loops i.e., disables LPCI. During this condition, the ECCS is not capable of providing adequate cooling for all design basis accidents (DBAs). We questioned the applicants on this issue and asked for an analysis of the capability of automatic ECCS systems to mitigate the consequences of a LOCA event. The applicant responded by stating that a LOCA event is not part of the design basis of a Main Control Room evacuation occurrence but they did discuss how the remaining automatic ECCS systems would mitigate the consequences of a LOCA.

The staff concluded from this response that the design does not meet 10 CFR 50, Appendix K requirements when control of the plant is transferred to the remote shutdown panel. To meet Appendix K, the design should be such that the manual transfer of control to the remote location should not disable any automatic actuation of ESF functions while the plant is attaining or being maintained in hot shutdown, other than where ESF features are manually placed in service to achieve or maintain hot shutdown. It is permissible to disable automatic LPCI actuation in this manner only when necessary in order to enable control of the RHR system from the remote location and while operating this system to effect cold shutdown from hot shutdown. Therefore, it is the staff's position that disabling LPCI during hot shutdown is not acceptable, and we require that the applicants' design be modified to reflect our position. The applicants have proposed a change in the operating procedures that would delay the transfer of the RHR system to the remote shutdown panel until the RHR system is needed. This would disable automatic LPCI actuation only when necessary in order to enable control of the RHR system from the remote shutdown panel and while operating this system to effect cold shutdown from hot shutdown. This proposal is acceptable to the staff.

We reviewed the design of the remote shutdown panel and we believe it meets the minimum regulatory requirements specified in Criterion 19 of the General Design Criteria subject to a confirmatory review of the final drawings, the acceptance with regard to the fire protection criterion, the acceptance of the final operating procedures and the witnessing by NRC of the procedure verification testing.

7.5.2 Loss of Power to Instruments and Control Systems

As a result of an event involving the loss of a significant amount of control room information at the Oconee Nuclear Station (Docket Nos. 50-269, 50-270, and 50-287) we issued I&E Bulletin 79-27. The applicants have performed an evaluation of the Susquehanna design and have identified the power sources for all instruments in the main control room sorted by panel and power supply. The applicants have also identified these instruments and control devices in the main control room that are required to attain cold shutdown. The applicants have stated that approximately 90% of all instrumentation and control devices have been identified that are required to attain cold shutdown.

The remaining work required (10%) is to identify those power busses required for necessary interfacing instruments and controls outside the control room and to evaluate the data to determine if either equipment changes or procedure changes are required.

The applicants have stated that the expected completion date for determining if equipment changes are required is October 15, 1981 (if required, these are expected to be no more significant than alarm or indication light additions) and expected completion date for determining whether procedure changes are required is December 1, 1981.

Based on the applicants completion of 90% of the identification of the applicable power busses and a definite outline to complete the remaining 10% of the work (power busses outside the control room); we find, subject to review of the completed work as scheduled above, the resolution of this concern to be acceptable.



9 AUXILIARY SYSTEMS

9.1.2.1 Spent Fuel Storage Corrosion Evaluation

Nuclear reactor plants include storage facilities for the wet storage of spent fuel assemblies. The safety function of the spent fuel pool and storage racks is to maintain the spent fuel assemblies in a subcritical array during all credible storage conditions. We have reviewed the compatibility and chemical stability of the materials (except the fuel assemblies) wetted by the pool water.

The spent fuel racks are fabricated of aluminum except for the stainless steel pads attached to the aluminum leveling screws. A ½-inch Acrylonitrile Butadiene Styrene (ABS) plastic material is captured between the stainless steel pad and the aluminum screw. The racks contain a neutron-absorbing medium of natural boron carbide in an aluminum matrix core clad with 1100 series aluminum. The neutron-absorber is marketed under the trade name of "Boral". The spent fuel pool is concrete lined with stainless steel. The pool is filled with demineralized, low-conductivity, oxygen-saturated water.

The Boral is sealed within two concentric square aluminum tubes. The storage modules are assembled so that the aluminum tubes (poison cans) are placed in a checkerboard pattern thus assuring that adjacent storage cavities are separated by a Boral slab. Each module is bolted to another module. The perimeter modules have seismic bracing bolted to embedments in the pool wall.

Evaluation

The seismic restraints from the racks to the wall embedments are entirely of welded stainless steel construction. To reduce the possibility of galvanic corrosion, Inconel pins are used between the wall restraints and the aluminum racks. Galvanic couples between stainless steels, Inconel and aluminum do not appear to give rise to any localized corrosion in BWR spent fuel pool environments since these materials are protected by highly passivating oxide film and are therefore at similar potentials in pure water. The aluminum fuel racks are further protected by an anodized surface. Though the potential for galvanic corrosion is very small, the applicant has elected to further reduce the possibility by the use of ABS plastic to isolate the stainless steel pads from the aluminum leveling screws in the rack leveling legs.

In this environment of oxygen-saturated, high-purity water, the anticipated corrosion of the aluminum alloys located in the pool is negligible in water of this quality at temperatures up to boiling point of water. At 125°C (257°F) a corrosion rate of 1.5×10^{-4} mils/day has been measured for aluminum in water pH 7. This corresponds to a total corrosion of 1.1 mils in 20 years. Since the oxidation rate will continue to decrease slightly over this period, this estimate is conservative. At lower temperatures, as is expected, the rate will be lower.

To provide added assurance that no unexpected corrosion or degradation of the materials will compromise the integrity of the racks, the applicants have

committed to an inservice inspection and surveillance program. The surveillance samples are in the form of shortened production-type cans similar to that in the pool rack. Four sheets of Boral are encapsulated between an outer and inner tube can. The welding and anodizing of the aluminum is similar to that in the racks. These specimens are examined periodically during the life of the spent fuel racks.

Conclusion

From our evaluation as discussed above, we conclude that the corrosion that will occur in the spent fuel storage pool environment should be of little significance during the 40-year life of the plant. Components in the spent fuel storage pool are constructed of alloys which (1) are not in contact, i.e., galvanically isolated, or (2) have a low differential galvanic potential between them, or (3) have a high resistance to general corrosion and localized corrosion.

We further conclude that the environmental compatibility and stability of the materials used in the spent fuel storage pool is adequate based on test data and actual service experience in operating reactors.

We have reviewed the surveillance program and we conclude that the monitoring of the materials in the spent fuel storage pool, as proposed by the licensee, will provide reasonable assurance that the Boral material will continue to perform its function for the design life of the pool. We therefore find that the implementation of a monitoring program and the selection of appropriate materials of construction by the licensee meets the requirements of 10 CFR Part 50, Appendix A, General Design Criterion 61, having a capability to permit appropriate periodic inspection and testing of components, and General Design Criterion 62, preventing criticality by maintaining structural integrity of components and of the boron poison.

9.1.4.1 Heavy Loads

Sections 9.1.2 and 9.1.4 of NUREG-0776 concluded that the spent fuel storage and handling facilities for Susquehanna met the guidelines of Regulatory Guide 1.13 and the requirements of General Design Criteria 61 and 62. We also concluded that the Unit 1 cask handling crane was designed in accordance with Branch Technical Position ASB 9-1 (since issued as NUREG-0554). In Appendix C of the SER we discussed the Commission's unresolved safety issues including Task Number A-36, "Control of Heavy Loads at Nuclear Power Plants." NUREG-0612 presents the resolutions of this matter and provides guidelines for necessary changes to assure the safe handling of heavy loads once a plant becomes operational.

By means of a generic letter dated December 22, 1980, we requested the applicants to review the design of Susquehanna against the guidelines of NUREG-0612 and to provide the results of the study to the NRC staff. Enclosure 2 attached to the December 22, 1980 generic letter identified a number of measures dealing with safe load paths, procedures, operator training and crane inspections, testing, and maintenance. We believe that these interim actions will provide reasonable assurance of safe handling of heavy loads until NUREG-0612 can be fully implemented and are, therefore, acceptable. In a letter dated June 22, 1981, the applicants indicated the implementation of the interim actions.

9.5.5 Alternate Shutdown System

At our request, the applicants performed a fire analysis, which included consideration of the potential effects of a transient exposure fire on equipment and cables (within 20 feet of each other) required for safe shutdown. The licensee is proposing to install an alternate shutdown system for the control room and cable spreading rooms. An alternate shutdown panel is provided, which is located in fire zone 1-2B (access & remote shutdown panel room) in the Reactor Building. A fire in either the control room or cable spreading rooms would not jeopardize operation of the alternate shutdown panels nor would a fire in the panels cause loss of functions in the control room or in the cable spreading room.

The applicants' submittals on the alternate shutdown systems to meet the the safe shutdown requirements specified in Section III.G and III.L of Appendix R are under review. We will report on this item in a subsequent SSER.

13 CONDUCT OF OPERATIONS

13.6 Industrial Security

The revised pages to the Susquehanna Steam Electric Station Safeguards Contingency Plan submitted by the Pennsylvania Power & Light Company letter of June 29, 1981 have been reviewed and found acceptable. A review of the plan against the requirements of Section 73.55(h) and Appendix C of 10 CFR Part 73 has been made. It was found that it adequately contains all the elements of the material required for a plan to be acceptable. It has been determined that the plan:

- (a) sets forth decisions and actions satisfying the stated objectives of the contingency plan.
- (b) identifies data, criteria, procedures, and mechanisms to carry out these decisions and actions, and
- (c) specifies individuals, groups, or organization entities responsible for each such decision and action.



15 SAFETY ANALYSIS

15.1 Abnormal Operational Occurrences

The SER indicated that many abnormal operational transients were analyzed with the methods described in NEDO-10802, "Analytical Methods of Plant Transient Evaluations for the General Electric Boiling Water Reactors" (the REDY Code), which was then under review. In this regard, three turbine trip tests were performed at Peach Bottom Unit 2 plant to provide experimental data for code verification and to improve the understanding of integral plant behavior under transient conditions. Results from this test program raised some questions about the analytical methods then in use since not all the test data were conservatively predicted by the current licensing methods. As a result, the General Electric Company developed a new computer code called ODYN to more adequately model overpressurization transients. The ODYN code has been reviewed by the staff and found acceptable. (Safety Evaluation for the General Electric Topical Report "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," NEDO-24154 and NEDE-24154-P Volumes I, II, III, June 1980.)

The applicants were requested to reanalyze the following transients using ODYN:

(1) For Thermal Limit Evaluation

- (a) Feedwater controller failure - maximum demand,
- (b) Generator load rejection without bypass, and
- (c) Turbine trip without bypass.

The applicants have performed the required analyses. As a consequence of the two options available with ODYN (Option A with straight penalties for uncertainties and option B with statistical convolution of uncertainties and rod scram times), the limiting transient for Susquehanna is dependent upon periodic measurements on site of average scram times. For small average scram items, the operating limit minimum critical power ratio (MCPR) is 1.24, based on ODYN calculations of the feedwater controller failure to maximum demand (FWCF) event. For longer scram times the operating limit MCPR varies from 1.24 to 1.30 as determined by either the FWCF event or generator load rejection without bypass. The largest operating limit MCPR of 1.30 is for generator load rejection without bypass, analyzed with ODYN and using option A.

In summary, the most limiting MCPR events will be determined after each control rod drive scram time test. That event will be used to establish the operating limit minimum critical power ratio, thereby providing assurance that the safety limit will not be violated by any of the abnormal operating transients analyzed.

We have reviewed the submitted ODYN calculations and conclude that they are acceptable.



18 REPORT OF THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

A subcommittee of the Advisory Committee on Reactor Safeguards (Committee) visited the site on July 2, 1981 and considered the application for operating licenses for Susquehanna Steam Electric Station Units 1 and 2 on July 23, 1981. The full Committee completed its review of the applicant at its 256th meeting on August 7, 1981. A copy of the Committee report dated August 11, 1981 is attached as Appendix B. A discussion of the current status of each item on which the Committee commented or made recommendations in the report is included in the following paragraphs.

- (1) The Committee also noted that the NRC staff proposes to require the installation of core thermocouples in the reactor vessel as specified by Regulatory Guide 1.97, Revision 2, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Condition During and Following an Accident"; and the applicants did not agree. The Committee recommended that a study be made to determine the appropriate vertical location for thermocouples. The staff will request that a study be performed by the applicants to determine the appropriate location and the number of thermocouples and we require the applicant to commit to:
 - (a) incorporate thermocouples into the inadequate core cooling monitoring system prior to June 1983 in accordance with Regulatory Guide 1.97; and
 - (b) provide documentation required by Item II.F.2 of NUREG-0737, addressing the inclusion of thermocouples in the final inadequate core cooling monitoring system on a schedule acceptable to the NRC staff.
- (2) The applicants have committed to use a second meteorological tower at the Susquehanna site for the purpose of confirming the accuracy of the meteorological model. This is acceptable to the staff and is discussed in Chapter 22 of this report.
- (3) The applicants have complied with IE Bulletin 79-27 as discussed in Chapter 7 of this report.
- (4) The applicants are developing the station blackout testing procedures. The staff will report later on the actual test results.
- (5) The status of all Outstanding Issues has been revised and is reported in Section 1.9 of this report.



22 TMI REQUIREMENTS

II.K.3.18 Modification of Automatic Depressurization System Logic

Discussion

The applicants are currently preparing their response to this item. This item remains open. The staff will review and report on this letter in a future supplement to this report.

II.K.3.27 Common Reference Level

In its letters of July 21 and August 4, 1981, the applicants have committed to the following modifications prior to issuance of an operating license:

- (1) LR-1R615 and LI-1R610 will be converted to an instrument zero reference point. After this change, all RPV level indication will use the bottom of the steam dryer skirt as the common reference point.
- (2) Technical specifications and procedures will be altered as necessary to reflect the common reference point.
- (3) Operator training on the revised reference level will be completed.
- (4) PP&L will not install the mimics next to the level indicators as previously proposed.

We found that the applicants' proposed modifications and implementation schedule are acceptable and meet the requirement of TMI Task Item II.K.3.27. The changes will be verified by the NRC.

II.A.1.1 Upgraded Emergency Preparedness

See Appendix D of this report.

III.A.1.2 Upgraded Emergency Support Facilities

Appendix I to the Susquehanna Emergency Plan provided a description of the applicants' interim Emergency Response Facilities as well as the proposed final facilities designed to satisfy the criteria of NUREG-0696 "Functional Criteria for Emergency Response Facilities."

The staff has completed its review of the applicants' response facilities and has determined that they satisfy the current criteria for interim facilities. A summary of the interim facilities is included in Appendix D, Section H, of SSER-1.

The staff review of the applicants' proposed design for the final emergency response facilities is continuing.

III.A.2 Long-Term Emergency Preparedness

The applicants have been responsive to the requirements for meteorological capability as given in NUREG-0737, Item III.A:2, and the criteria set forth in NUREG-0654, Appendix 2. The applicants have committed to implementing the three functional requirements of an acceptable program: measurements, assessment, and information transfer.

The applicants are currently upgrading his meteorological measurement system to comply with Regulatory Guide 1.23 criteria. This upgrade includes the installation of a backup capability. The applicants are currently investigating the need for supplemental meteorological measurements that may be needed to characterize plume transport by making field measurements to determine the effects of terrain features in the site terrain environment. The staff will review the findings of the study at the conclusion of this field program.

The applicants will implement a real-time atmospheric transport and diffusion model in the dose calculational methodology. This scheme will incorporate considerations for terrain effects. The results of the field program noted above may lead to adjustments to this scheme to account for terrain induced flow conditions. The applicants will be subject to the same implementation schedule for the Class B model as all operating reactors.

Until the applicants upgrade their meteorological capabilities, they have adopted a series of compensating measures as outlined in NUREG-0737, Item III.A.2. Their meteorological measurements system has been outlined in Section 2.3.3 of the SER. Provisions for an alternate data source have been made with the Avoca-National Weather Service Station. Their atmospheric transport and diffusion capability currently considers source, building, and terrain configuration; as noted above, their field program may indicate refinement is warranted. These actions constitute adequate compensating measures.

The applicants plan to full upgrade their emergency response facilities. The remote access capability will be provided from their ERCS system. Until completely operational, the applicants have committed to provide facsimile products on a rapid basis. This, in conjunction with direct telephone access to the individual responsible for dose projections, forms an adequate compensating measure for the interim period.

APPENDIX A

CHRONOLOGY OF THE RADIOLOGICAL REVIEW
OF THE SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2

Note: Pennsylvania Power & Light Company is authorized to act on behalf of Allegheny Electric Cooperative. In addition, Pennsylvania Power & Light Company has absolute authority for the management, operation and maintenance of the Susquehanna plants. Therefore, most correspondence is between Pennsylvania Power & Light Company and the NRC. As a result, the term "applicant" is used in this appendix and refers to the Pennsylvania Power & Light Company.

APPENDIX A

CHRONOLOGY OF THE RADIOLOGICAL REVIEW OF THE
SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2

June 15, 1981 Letter from applicant concerning NUREG-0737. item

June 15, 1981 Letter from applicant concerning control room habitability system

June 16, 1981 Letter from applicant concerning loose parts monitoring

June 16, 1981 Letter from applicant concerning SER outstanding item #30

June 16, 1981 Letter from applicant concerning upgraded meteorological system

June 16, 1981 Letter from applicant concerning SER outstanding issue #32

June 17, 1981 Letter from applicant concerning shift supervisor responsibilities

June 19, 1981 Letter from applicant concerning SER outstanding issue #71

June 29, 1981 Letter to applicant requesting additional information

June 30, 1981 Letter from applicant responding to generic letter 81-03

June 30, 1981 Letter from applicant forwarding Amendment 37 to FSAR

July 6, 1981 Letter from applicant concerning control room DC indication

July 8, 1981 Letter to applicant transmitting Supplement No. 1 to Safety Evaluation Report, dated June 1981

July 16, 1981 Letter from applicant concerning SER outstanding issue #32

July 20, 1981 Letter from applicant concerning SER outstanding issue #29

July 20, 1981 Letter to applicant concerning prompt notification in the event of an emergency

July 21, 1981 Letter from applicant concerning SER outstanding issue #99

August 4, 1981 Letter from applicant concerning SER outstanding issue #44

August 4, 1981 Letter from applicant concerning SER outstanding issue #99

August 4, 1981 Letter from applicant concerning turbine missile open items



August 6, 1981 Letter from applicant concerning SER outstanding issue #44
August 6, 1981 Letter from applicant concerning SER outstanding issue #54
August 12, 1981 Letter to applicant transmitting ACRS letter dated August 11, 1981
August 18, 1981 Letter to applicant concerning safeguards contingency plan



APPENDIX B
ACRS REPORT

11



12



UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

August 11, 1981.

The Honorable Nunzio J. Palladino
Chairman
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

SUBJECT: REPORT ON SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2

Dear Dr. Palladino:

During its 256th meeting, August 6-8, 1981, the Advisory Committee on Reactor Safeguards completed its review of the application of the Pennsylvania Power and Light Company and Allegheny Electric Cooperative, Inc. (Applicant) for a license to operate the Susquehanna Steam Electric Station Units 1 and 2. The units will be operated by the Pennsylvania Power and Light Company. A Subcommittee meeting was held in Washington, D.C. on July 23, 1981 to consider this project. A tour of the facility was made on July 2, 1981. During its review, the Committee had the benefit of discussions with representatives of the Applicant and the NRC Staff. The Committee also had the benefit of the documents listed. The Committee commented on the construction permit application for this station in its report dated April 13, 1972.

The Susquehanna station is located in Luzerne County, Pennsylvania about 12 miles northwest of Hazleton and 15 miles southwest of Wilkes-Barre, the nearest cities having populations in excess of 25,000.

Each Susquehanna unit is equipped with a General Electric BWR-4 nuclear steam supply system with a rated power level of 3293 MWt and has a Mark II pressure suppression containment with a design pressure of 53 psig.

In connection with our review of the Susquehanna station, the NRC Staff discussed its generic resolution of the safety issues associated with the Mark II containment design and performance. This resolution is given in the Staff report NUREG-0808, "Mark II Containment Program Load Evaluation and Acceptance Criteria." This matter has received detailed review by the ACRS Subcommittee on Fluid Dynamics. We believe that the load definitions given in this report are conservative and acceptable. These load definitions are to be applied to BWR Mark II's on a case-by-case basis. We believe that the Susquehanna containment structures will meet these requirements.

The Applicant described the management organization and the technical personnel available for operation of the Susquehanna plant. Although this is the first nuclear power plant to be operated by this Applicant, both



August 11, 1981

management and plant staff are made up of personnel with considerable background and expertise in commercial nuclear power plant operation. We commend the Applicant's efforts to obtain knowledgeable and experienced personnel.

The Applicant described the program and the philosophy for training of personnel. Training has a high priority as it had even prior to the TMI-2 accident. For example, a training simulator was ordered by the Applicant considerably before the accident at TMI-2 and is currently in use. The training program includes consideration of ATWS. The Applicant's training program appears sound and thorough.

The NRC Staff proposes to require the installation of core thermocouples in the Susquehanna station as specified by Regulatory Guide 1.97, Revision 2, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident." The Applicant has not yet agreed to this requirement. We supported use of core thermocouples in BWRs in our letter of November 10, 1980 to the NRC Executive Director for Operations but called attention to the need for further study to determine the appropriate vertical location of such thermocouples. Since most of the information of interest from thermocouples may be obtainable from a small number of thermocouples placed in a more accessible location, we recommend that this requirement be reevaluated.

The NRC Staff proposes to require a second meteorological tower at the Susquehanna site for the purpose of collecting additional data for use during an emergency. This issue is still being discussed with the NRC Staff. Additionally, there are several other issues concerning emergency planning which are identified by the NRC Staff in its Safety Evaluation Report and Supplement No. 1 as Outstanding Issues. We believe that these issues should be resolved in a manner satisfactory to the NRC Staff. We wish to be kept informed.

Another Outstanding Issue involves IE Bulletin 79-27, "Loss of Non-Class-1-E Instrumentation and Control Power System Bus During Operation." The Applicant has stated that this IE Bulletin will be complied with prior to issuance of an operating license. We recommend that this issue be resolved in a manner satisfactory to the NRC Staff.

The Applicant is currently reviewing the issue of station blackout. Analytical work, development of operating procedures, and actual testing of equipment response to simulated blackout conditions are planned by the Applicant. We believe that the Applicant's proposed program is a satisfactory response to this issue.

The NRC Staff has identified other Outstanding Issues in its Safety Evaluation Report dated April 1981 and in Supplement No. 1 to that report dated June 1981 such as turbine missiles, review of the alternate shutdown system,

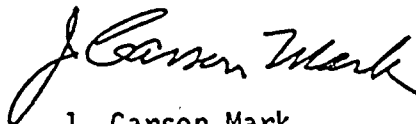


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and modification of depressurization logic. We believe the Outstanding Issues can be resolved, and recommend that this be done in a manner satisfactory to the NRC Staff before operation at full power.

The Committee believes that if due consideration is given to the recommendations above, and subject to satisfactory completion of construction, staffing, and preoperational testing, there is reasonable assurance that Susquehanna Steam Electric Station Units 1 and 2 can be operated at power levels up to 3293 MWt each without undue risk to the health and safety of the public.

Sincerely,



J. Carson Mark
Chairman

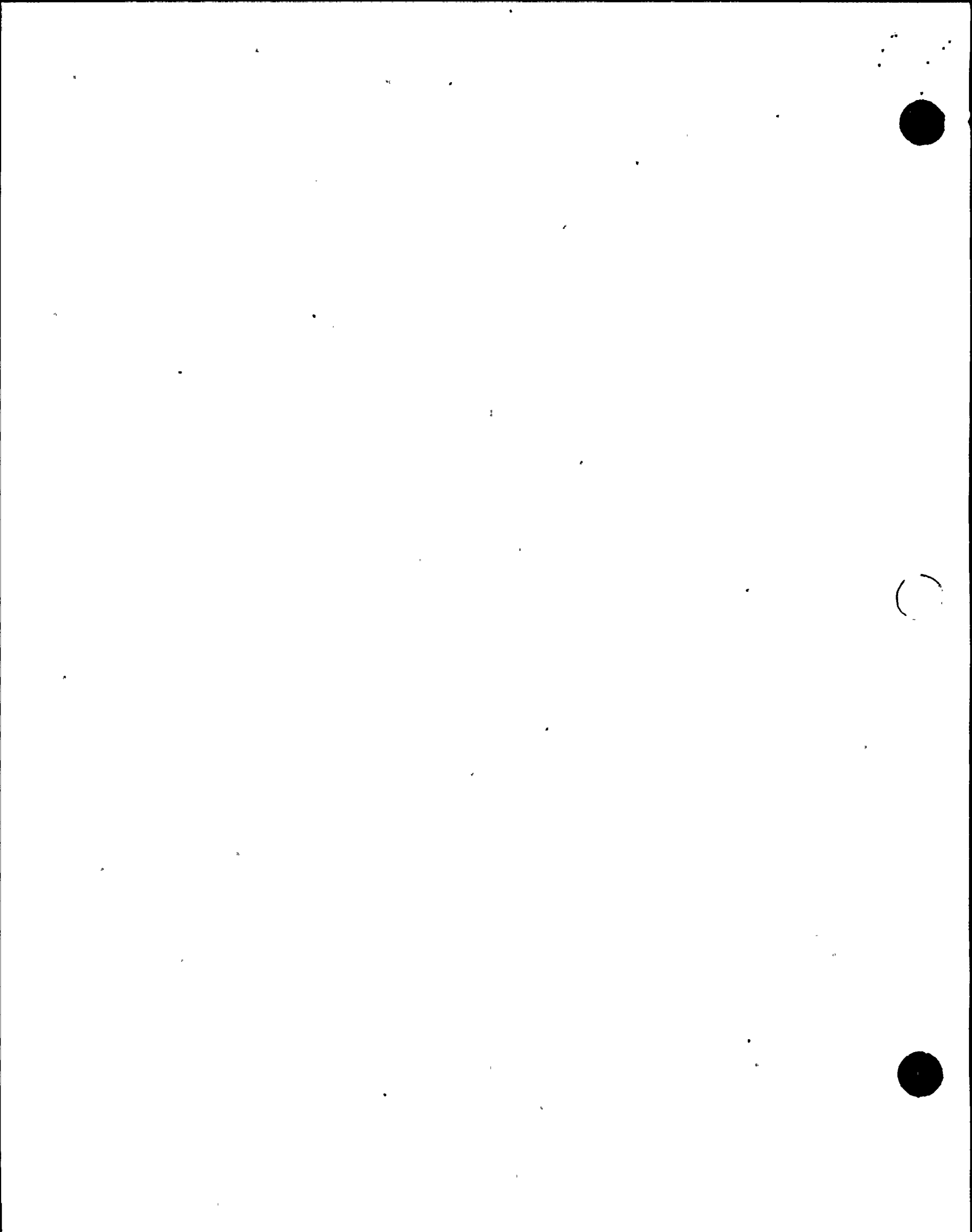
References:

1. Pennsylvania Power and Light Company, "Final Safety Analysis Report, Susquehanna Steam Electric Station, Units 1 and 2," with Amendments 1 through 35.
2. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report Related to the Operation of Susquehanna Steam Electric Station, Units 1 and 2, Docket Nos. 50-387 and 50-388," USNRC Report NUREG-0776, dated April 1981 and Supplement No. 1, dated June 1981.
3. U.S. Nuclear Regulatory Commission IE Bulletin No. 79-27, "Loss of Non-Class-1-E Instrumentation and Control Power System Bus During Operation," dated November 30, 1979.



APPENDIX C
UNRESOLVED SAFETY ISSUES

<u>Task Number</u>	<u>NUREG Report and Title</u>	<u>SER/SER Suppl. Section(s)</u>
A-8	Nureg 0487, "Mark II Containment Lead Plant Program Load Evaluation and Acceptance Criteria," October 1978 Supplement 1 to NUREG-0487, October 1980 Supplement 2 to NUREG-0487, February 1981	6.2.1.3 Suppl. 1 & 2 6.2.4
A-10	NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking"	5.2.4 Suppl. 1
A-24	NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment"	3.11.1
A-31	SRP 5.4.7 and BTP 5-1, "Residual Heat Removal Systems," incorporate requirements of USI A-31.	5.4.2
A-36	NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants"	9.1.4.1 Suppl. 2
A-39	NUREG-0487 and Supplement 1 to NUREG-0487 (See A-8 above)	6.2.1.3 Suppl. 1 6.2.1.4 Suppl. 2
A-42	NUREG-0313, Revision 1, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping"	5.3.4 Suppl. 2



APPENDIX D

EMERGENCY PREPAREDNESS EVALUATION

The staff's evaluation of the applicants' emergency plans is provided in Appendix D of Supplement No. 1 to the Safety Evaluation Report (SER) dated June 1981 (NUREG-0776, Supplement No. 1). Revision 4 to the Susquehanna Steam Electric Station Emergency Plan (the Plan) was reviewed against the requirements of 10 CFR 50.47(b), Appendix E to 10 CFR Part 50, and against the criteria of the 16 Planning Standards in Part II of NUREG-0654/FEMA-REP-1, Rev. 1, dated November 1980. In Supplement No. 1 to the SER, the staff specifically identified 11 items requiring resolution for which additional information and commitments were to be provided by the applicants.

Since the issuance of Supplement No. 1 to the SER, the applicants have provided the staff with additional information and commitments in response to the open items. This information was provided in a letter from PP&L's Mr. N. W. Curtis to NRC's Mr. A. Schwencer dated July 21, 1981 and at a meeting with the staff on August 14, 1981. The applicants' responses to the previously unresolved items have been evaluated and are discussed in this supplement.

With regard to offsite emergency preparedness, in August 1981, Columbia and Luzerne Counties submitted emergency plans (revised in accordance with NUREG-0654) to the Federal Emergency Management Agency (FEMA) for review by the Regional Assistance Committee (RAC). FEMA will review these plans along with the previously submitted State emergency plans in accordance with its Memorandum of Understanding with the NRC and FEMA's proposed emergency planning rule, 44 CFR 350. A joint emergency response exercise, designed to determine the onsite and offsite emergency response capabilities, is scheduled for March 1982.

EVALUATION OF APPLICANTS' EMERGENCY PLAN

The applicants' responses to the 11 items previously identified by the staff as requiring additional information and commitments have been evaluated and are discussed below. (The order of presentation corresponds to listing of unresolved items that appears on pp. D-16 and D-17 of Supplement No. 1 to the SER.)

1. The Plan should be revised to reflect the commitment that the Emergency Operations Facility should be functional, including the stationing of a Senior Manager, within approximately one hour of declaration of a Site or General Emergency.

Discussion and Conclusion

Revision 4 to the applicants' Emergency Plan, dated April 1981, provides that the EOF would be staffed and operational within 4 hours of events classified as a Site Area or General Emergency. In a letter from PP&L's Mr. Norman Curtis to NRC's Mr. Albert Schwencer dated July 21, 1981, PP&L maintained that the emergency functions would be performed in the Plant, either in the TSC or Control Room, during the initial hours of an emergency. The current plans call for PP&L corporate personnel from Allentown, Pennsylvania to staff the EOF.

In a meeting with the staff on August 14, 1981 and in a subsequent letter of August 19, 1981, Pennsylvania Power and Light Company stated its intent to staff the EOF promptly after declaration of a Site or General Emergency, and that vital recovery organization personnel carried pagers from emergency notification. These provisions would enable the personnel from the Allentown office to arrive within 1½ to 2 hours after notification under ideal circumstances. Furthermore, the applicants indicated that their emergency plan would be modified to provide for an interim EOF Coordinator and staff to make the facility operational, perform some communications and radiological functions and to speed the assumption of duties by the augmenting Recovery Organization. Under this proposal, however, the responsibility for making protective action recommendations would remain with the Emergency Director in the TSC until the Recovery Manager arrived in the EOF.

Although the proposed emergency plan commitments for EOF staffing are an improvement over the previous staffing arrangements, the staff position remains that the EOF should be fully functional within about one hour of an emergency declaration as described in NUREG-0696 to allow transfer of responsibility for offsite protective actions recommendations to the EOF so that the TSC and control room personnel can devote their attention to plant safety matters.

2. Expansion and Specific Identification of Certain EALS.

Discussion and Conclusion

Following the issuance of SSER-1, the applicants met with the staff to describe specific areas for improvement of their Emergency Action Level scheme. Subsequently, the applicants initiated a review and comparison



of their Emergency Action Levels with NUREG-0654, Appendix 1, and responded to the staff's request for additional information at a meeting with the staff on August 14, 1981. At that meeting the applicants provided additional Emergency Action Level information. Certain instrument readings or setpoints that relate effluent monitor readings to offsite doses will be established. The applicants will incorporate the revised action levels in Revision 5 to the Susquehanna Emergency Plan in September 1981.

The commitments and information provided by the applicants in response to staff comments will satisfy the criteria in Appendix 1 to NUREG-0654 and are acceptable.

3. Revised procedures to notify State and/or local response agencies within 15 minutes of declaration of an Unusual Event.

Discussion and Conclusion

In the applicants' July 21, 1981 letter, PP&L agreed to modify the Susquehanna Emergency Plan to call for notification of PEMA, Luzerne County and Columbia County within about 15 minutes of a declaration of an Unusual Event. The applicants' Emergency Plan Implementation Procedures will be revised to reflect this commitment.

Based on our review of the applicants' submittal, as summarized above, we find that the applicants have provided a satisfactory response to this item.

4. Develop dose assessment procedures, including methods for estimating total population exposure

Discussion and Conclusion

The applicants' letter of July 21, 1981 provided a general description of the applicants' dose assessment procedures. These procedures, including a Class A dispersion model, are currently under development and will be available in September 1981.

The applicants' dose assessment procedures will incorporate the following primary features. First, dose calculations will be performed by a computerized emergency radiation dose projection system based on a Class A atmospheric dispersion model. This model will utilize fixed terrain correction factors to take into account deviations in plume dispersion caused by the topography of the Susquehanna area.

Secondly, a manual dose projection method will be available in the event of loss of the automatic system. This manual system will utilize a series of whole-body and thyroid dose overlays, which, when applied to area maps, yield factors which can be used to calculate dose rates at any point in the 10-mile EPZ upon determination of source terms and meteorological conditions.

Dose projections by either method will be verified by offsite monitoring teams which will perform surveys at locations in the EPZ as directed by the Radiation Support Manager. As many as five two-man monitoring teams



will be activated at one time following an accident to provide real-time offsite data to update calculational assumptions and update or verify dose projections.

The commitments contained in the applicants' response are acceptable. Final approval will follow the submittal of more detailed dose projection procedures.

5. Describe the procedures and facilities for decontaminating individuals evacuated from the site.

Discussion and Conclusion

The applicants' response to this item was contained in the PP&L letter to the staff dated July 21, 1981, which described decontamination facilities and personnel monitoring equipment that will be in place at the applicants' Emergency Operational Facility (EOF). Individuals evacuated from the site will be monitored with portable instruments to determine if they are contaminated and will be transported to the EOF where decontamination showers, holdup tanks, and additional monitoring facilities will be located. The applicants have committed to provide a detailed description of their decontamination facilities in the next emergency plan revision, currently scheduled for September 1981.

Based on our review of their Plan and submittal as outlined and discussed above, we find that the applicants have provided an acceptable response to this item.

6. Develop procedures and an onsite stockpile of thyroid blocking agent for distribution to onsite emergency workers.

Discussion and Conclusion

In a letter from the applicants dated July 21, 1981, PP&L described its policy for issuance of potassium iodide (KI) to emergency workers. Since issuance of that letter, PP&L informed the staff that it had obtained approximately 1,000 bottles of KI for use in an emergency. The applicants have also forwarded to the staff the implementation procedures which guide the Emergency Director in issuing KI.

The applicants' response to this item, as summarized above, is acceptable, and it satisfactorily resolves this matter.

7. Upgrade the evacuation time estimates to meet the guidance of NUREG-0694, Appendix 4.

Discussion and Conclusion

The applicants' letter to the Staff dated July 21, 1981 included a commitment to provide an evacuation time estimate study which will conform to NUREG-0654, Appendix 4 by September 1, 1981. The staff received a draft copy of that report on August 14, 1981. An initial review indicates that the draft study addresses all of the elements of NUREG-0654, Appendix 4.

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However, the results of the staff's review will be reported following the submittal and full review of a final evacuation time estimate study.

8. The applicants' Emergency Plan should designate the onsite authority to approve doses in excess of 10 CFR 20 limits during emergency conditions onsite.

Discussion and Conclusion

The applicants have designated the Emergency Director as the onsite authority to authorize doses in excess of 10 CFR 20 limits and have committed to modify the Emergency Plan to reflect that authority.

The applicant's response to this item is acceptable and satisfactorily resolves this matter.

9. The applicants should provide emergency response facilities which satisfy the guidance contained in NUREG-0696, "Functional Criteria for Emergency Response Facilities."

Discussion and Conclusion

Appendix I to Revision 4 of the Susquehanna Emergency Plan provided a description of the applicants' interim Emergency Response Facilities as well as the proposed final Emergency Response Facilities which will be required after October 1, 1982. At the time of the issuance of Supplement No. 1 to the SER, both the interim facilities and the final (NUREG-0696) facilities were under review by the staff. The review of the interim facilities resulted in a determination that they are acceptable under the current guidance. Comments on the final design for the long-term facilities have been forwarded to the applicants. A summary of the interim facilities was provided in Appendix D, Section II.H of Supplement No. 1 to the SER.

As outlined and summarized above, the applicants' interim facilities will meet the guidance for interim response facilities and are acceptable. The staff will continue to review the applicants' final response facilities against the criteria of NUREG-0696 as the design is finalized.

10. Install the Alert and Notification System prior to power operation.

Discussion and Conclusion

Pennsylvania Power and Light Company's response dated July 21, 1981 included a commitment to installing the alert and notification system prior to fuel loading. Additionally, PP&L indicated that installation of a system consisting of approximately 105 sirens throughout the plume exposure EPZ is about 90% complete. Installation is scheduled to be complete by early October 1981. Additionally, PP&L has provided the staff with a draft siren evaluation report which concludes that the Susquehanna Alert Notification System will meet the design objectives of Appendix 3 to NUREG-0654.

Based on the system description and schedule for implementation of the Siren Alert System, the staff concludes that the applicants have provided an acceptable response to this item and that the applicants will have the system in place and operational prior to power operation. FEMA will report to the NRC periodically during the plant lifetime relative to any improvements needed to assure effective notification with the plume exposure EPZ.

11. Provide the NRC staff with drafts of Public Education/Information material for review.

Discussion and Conclusion

The applicants have committed to provide the staff with drafts of public education/information material intended for distribution to the population in the plume exposure EPZ by September 15, 1981. The NRC and FEMA staffs will review this material after receipt to determine if the public information and education material to be provided the public by the licensee and State and County governments satisfies the criteria of NUREG-0654.

