NUREG-0776
Supplement No. 6

Safety Evaluation Report
related to the operation of Susquehanna Steam Electric Station, Units 1 and 2

Docket Nos. 50-387 and 50-388

Pennsylvania Power & Light Company
Allegheny Electric Cooperative, Inc.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

March 1984

8404110036

ABSTRACT

In April 1981, the staff of the Nuclear Regulatory Commission issued its Safety Evaluation Report (NUREG-0776) regarding the application of the Pennsylvania Power & Light Company (the applicant and/or licensee) and the Allegheny Electric Cooperative, Inc. (co-applicant) for licenses to operate the Susquehanna Steam Electric Station, Units 1 and 2, located on a site in Luzerne County, Pennsylvania.

Supplement 1 to NUREG-0776 was issued in June 1981 and addressed several outstanding issues. Supplement 2 was issued in September 1981 and addressed additional outstanding issues. Supplement 2 also contains NRC staff responses to the comments made by the Advisory Committee on Reactor Safeguards in its report dated August 11, 1981. Supplement 3 was issued in July 1982 and addressed five items that remained open and closed them out. On July 17, 1982, Operating License NPF-14 was issued to allow Unit 1 operation at power levels not to exceed 5% of rated power. Supplement 4 was issued in November 1982 and discusses the resolution of several license conditions. On November 12, 1982, Operating License NPF-14 was amended to remove the 5% power restriction, thereby permitting full-power operation of Unit 1. Supplement 5 was issued in March 1983 and addressed several issues that required resolution before licensing operation of Unit 2.

This supplement to NUREG-0776 addresses the remaining issues that required resolution before licensing operation of Unit 2 and closes them out.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

1 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

In April 1981, the staff of the Nuclear Regulatory Commission (NRC) (the staff) issued its Safety Evaluation Report (SER) (NUREG-0776) regarding the application of the Pennsylvania Power & Light Company (PP&L) (the applicant and/or licensee) and the Allegheny Electric Cooperative, Inc. (the co-applicant) for licenses to operate Susquehanna Steam Electric Station, Units 1 and 2. In June 1981, the staff issued Supplement 1 to NUREG-0776, which documented the resolution of several outstanding issues in further support of the licensing activities. In September 1981, the staff issued Supplement 2 to NUREG-0776, which addressed the open items identified in the SER and Supplement 1. In July 1982, the staff issued Supplement 3 to NUREG-0776, which addressed all remaining open issues from previous supplements and closed them out. On July 17, 1982, Operating License NPF-14 was issued for Unit 1. Operation was restricted to fuel loading and low-power testing at levels not to exceed 5% rated power. In November 1982, the staff issued Supplement 4 to NUREG-0776, which addressed the resolution of several Unit 1 license conditions that had been met. On November 12, 1982, Amendment 5 to Operating License NPF-14 was issued removing the 5% power restriction, thus allowing Unit 1 operation at power levels not to exceed 100% rated power. In March 1983, the staff issued Supplement 5 to NUREG-0776, which addressed several issues that require resolution before Unit 2 can be licensed for operation.

Each section containing issues addressed in this report, Supplement 6 to NUREG-0776, is numbered and titled to correspond to the sections of NUREG-0776 and its earlier supplements where they were previously discussed. This report addresses the remaining issues that require resolution before Unit 2 can be licensed for operation and closes them out.

Copies of this report are available for public inspection at the Commission's Public Document Room, 1717 H Street, NW, Washington, DC, and at the Osterhout Free Library, 71 South Franklin Street, Wilkes Barre, PA 18701. Copies of this report also are available for purchase from the sources indicated on the inside front cover.

The NRC project manager for Susquehanna is Mr. Robert L. Perch. Mr. Perch may be contacted by writing to the Division of Licensing, U.S. Nuclear Regulatory Commission, Washington, DC 20555.

The following additional NRC staff members contributed to this report, which is a product of the staff.

Name	Position	Branch
Tim Collins	Nuclear Engineer	Reactor Systems
Randall Eberly	Fire Protection Engineer	Chemical Engineering
Barry Elliot	Materials Engineer	Materials Engineering

Name	Position	Branch
Farouk Eltawila	Senior Containment Systems Engineer	Containment Systems
Mike Fleigel	Section Leader	Environmental and Hydrological Engineering
Richard Froelich	Senior Human Factors Engineer	Human Factors Engineering
Hukam Garg	Senior Electrical Engineer	Equipment Qualification
Martin Hum	Senior Materials Engineer	Materials Engineering
Arnold Lee	Senior Mechanical Engineer	Equipment Qualification
William Lefave	Mechanical Engineer	Auxiliary Systems
William Long	Operational Safety Engineer	Procedures and Systems Review
Jerry Mauck	Reactor Engineer	Instrumentation and Control Systems
Eugene McPeek	Project Manager	Standardization and Special Projects
Sang Rhow	Electrical Engineer	Power Systems
Anton Sinisgalli	Site Analyst	Site Analysis
Robert Wright	Mechanical Engineer	Equipment Qualification

1.9 Outstanding Issues

In Section 1.9 of Supplement 5 to NUREG-0776, the staff summarized the status of the identified remaining open items specifically for Unit 2. In this report, the staff discusses the resolution of all of these items previously identified as open, as well as additional information related to other sections of the SER.

The current status and sections in which the staff evaluates the nine remaining items are shown below.

Item	Status	Section
(110) Ultimate heat sink performance test for two-unit operation	Resolved	2.4.4, 9.2.3
(111) Preservice inspection program	Resolved	5.2.4, 6.6
(112) Review of 10 CFR Appendices G and H	Resolved	5.3.1
(113) TMI Action Plan items	License condition	22

Item	Status	Section
(114) Control of heavy loads	License condition	9.1.4
(115) Response to IE Bulletin 79-27	Resolved	7.5.2
(116) Environmental qualification of electrical equipment	License condition	3.11
(117) Seismic Qualification Review Team (SQRT)	License condition	3.10
(118) AC electrical distribution system	Resolved	8.0

1.10 License Conditions

There were several issues for which a condition was included in Operating License NPF-14 for Unit 1 to ensure that NRC requirements would be met during plant operation. The staff considers that the issues listed below also require license conditions for Unit 2 unless satisfactory resolution is reached on these issues before licensing. The current status and sections in which the staff evaluates these issues are shown below.

Issue	Status	Section
(1) Thermal and hydraulic design	Confirmatory	4.4
(2) Qualification of purge valves	Resolved	22(II.E.4.2)
(3) Operation with partial feedwater heating at end of cycle	License condition	
(4) Inservice inspection program	License condition	
(5) Nearby facilities	Resolved	2.2.2
(6) Scram discharge system piping	Confirmatory	4.6
(7) Environmental qualification	License condition	3.11
(8) Assurance of proper design and construction	Resolved	17.6
(9) Seismic and dynamic qualifications	License condition	3.10
(10) Containment purge system	Resolved	6.2.4
(11) Additional instrumentation and control concerns	License condition	
(12) Surveillance of control blade	License condition	

Issue	Status	Section
(13) Emergency diesel engine starting systems	License condition	
(14) Nuclear steam supply system - vendor review of procedures	License condition	
(15) Postaccident sampling	License condition	
(16) Instrumentation for detection of inadequate core cooling	License condition	22(II.F.2)
(17) Modification of automatic depressurization system logic	License condition	22(II.K.3.18)
(18) Effect of loss of power on alternating current pump seals	Resolved	22(II.K.3.25)
(19) Upgrade emergency support facilities	License condition	
(20) Safety relief valve inplant test	Confirmatory	6.2.1.8
(21) Control room design review	License condition	22(I.D.1)
(22) Emergency service water system	License condition	9.2.1

2 SITE CHARACTERISTICS

2.2 Nearby Industrial, Transporation, and Military Facilities

2.2.2 Nearby Facilities

In Section 1.10 of Supplement 5 to the SER, the staff provided a list of issues for which a condition was included in the operating license for Susquehanna Unit 1 for which a similar license condition would be required for Unit 2 unless satisfactory resolution was reached on the issue before the licensing of Unit 2. One such issue regarded the gas pipeline system near the Susquehanna site.

On February 25, 1983, PP&L submitted their response to License Condition 2.C(13) of the operating license for Susquehanna Unit 1. This response described permanent modifications to the 12-in. gas pipeline system that limits the flow to 39 m^3/sec near Susquehanna Steam Electric Station. The staff reviewed the February 25, 1983, submittal and found it to be an acceptable approach in a letter to PP&L dated May 10, 1983.

In a letter dated November 11, 1983, PP&L stated that installation of the permanent modifications that limit flow in the 12-in. gas pipeline to 39 m^3/sec had been completed. This completes all the requirements under License Condition 2.C(13) of the operating license for Susquehanna Unit 1. The staff considers this issue resolved for Susquehanna Unit 2.

2.4 Hydrology

2.4.4 Ultimate Heat Sink

The SER stated that both the applicant's and staff's analysis of the spray pond's thermal performance indicated that it would be capable of providing cooling water below the design temperature of 95°F under the conditions specified in Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants." The staff required, however, that the ability of the as-built spray pond to meet the thermal design basis be confirmed by actual performance tests. The staff stated that staff review and approval of the performance test results and analysis would be required before fuel loading for Unit 2. A description of the test plans and procedures and analysis techniques were to be submitted for staff approval before Unit 1 operation.

The performance test plans were submitted to NRC on June 16, 1982. The staff approved those plans on July 22, 1982. The performance tests were conducted from July 23 to July 25, 1983. On December 21, 1983, the applicant submitted a final report to NRC on the results of the tests.

The applicant's report states that the measured spray pond performance was equal or superior to the applicant's model's predictions during periods of wind speeds at or below 4.5 mph. The applicant's analysis of the tests for wind speeds above 4.5 mph could not demonstrate conservatism of the applicant's analytic model. The applicant has therefore reanalyzed the thermal performance of the spray pond using his analytic model but ignoring the effects of wind; that is, the applicant assumed no wind for the entire 30-day period of severe meteorology used in the analysis. This assumption is clearly conservative because the actual meteorological data used, in conformance with Regulatory Guide 1.27, contain wind speeds ranging up to almost 12 mph. Winds increase the efficiency of the heat transfer process even if the formulation used in the applicant's model was optimistic. Thus, ignoring completely the wind's contribution to heat transfer is conservative.

The applicant's reanalysis of the pond's thermal performance, with winds ignored, assumed a starting pond temperature of 81°F and an initial water inventory of 23 million gallons. The maximum pond temperature calculated was 95.26°F. The applicant has requested a modification to the Technical Specifications to require that pond temperature and inventory be within those limits during operation. The applicant recognizes that the temperature limit of 81°F could be exceeded during the summer and is investigating changes that would allow an increase in this temperature limitation.

Although the staff has not performed an independent thermal analysis subsequent to the one discussed in the SER, it can conclude that, subject to the Technical Specification discussed above, the spray pond is capable of providing cooling water below the design temperature. This conclusion is based on the following factors.

The staff's computer evaluation of the spray pond performance cited in the SER used an initial pond temperature of 90.2°F. Results of that analysis indicated a maximum pond temperature below the design level of 95°F. Limiting the initial pond temperature to 81°F (by a Technical Specification) would, therefore, reduce the staff's calculated maximum pond temperature. The applicant's revised analysis completely ignored the effects of wind speed, which is a substantial conservatism, and still showed generally satisfactory performance.

The staff, therefore, concludes that, subject to the Technical Specification discussed above, the ultimate heat sink's thermal performance complies with Regulatory Guide 1.27 and thus meets the requirements of GDC 44.

3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

3.10 Seismic and Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment

The staff has reviewed the applicant's submittal of December 17, 1983, regarding the review of seismic qualification of equipment in Susquehanna Unit 2 and has determined that a plant site audit for Unit 2 is not necessary for the following reasons:

(1) A successful Seismic Qualification Review Team (SQRT) audit was conducted on Unit 1 equipment.

(2) There are very few differences between Unit 1 and Unit 2 equipment, its installation, or the environment in which it operates. For example, a review of balance-of-plant (BOP) SQRT items has shown over 300 items that are similar in Units 1 and 2 and only 13 different items installed in Unit 2. For dynamic qualification, Unit 2 is different from Unit 1 if equipment is unique or modified from the Unit 1 equipment, or if it is the same type but is placed in a different location or orientation in Unit 2 so that new analysis or testing is required.

(3) In most cases the Unit 2 SQRT documentation has been satisfactorily accomplished by referencing the Unit 1 report and analysis, by completing SQRT forms, and by listing the Unit 2 plant identification numbers to which the documentation applies.

(4) For the Unit 2 equipment that differs from that in Unit 1, the SQRT documentation is done in the same manner and to the same criteria as the Unit 1 documentation.

The staff also has reviewed Revision 4 of the Susquehanna Equipment Qualification Summary Report dated September 9, 1983, as well as the applicant's letters of February 16, 1983, June 9, 1983, December 13, 1983, January 10, 1984, and February 1, 1984. Of the equipment items different for Unit 2 that have been identified for both nuclear steam supply system (NSSS) and BOP scope, most have already been qualified or will have been qualified by fuel load with the exception of those for which the justification of interim operation has been provided by the applicant. The system arguments for the justification have been reviewed by the staff and were found acceptable. To complete the Unit 2 review, the qualification status of Unit 1 common equipment items, as well as the evaluation of NSSS equipment fatigue effects resulting from safety/relief valve (SRV) loadings, which are included in the Unit 1 license conditions, is also presented below.

3.10.1 Balance-of-Plant Different Equipment

3.10.1.1 Existing Equipment

The following is a list of existing BOP equipment in Unit 2 that is different from equipment in Unit 1:

(1) Control Rod Drive Platform - The Unit 2 control rod drive platform differs from the Unit 1 platform because of the new as-built conditions of the Unit 2 piping supports that are attached to the platform. A new analysis using a conservative required response spectrum (RRS), which exceeded the Unit 1 and Unit 2 floor envelope spectra, has been conducted to qualify the equipment. This is acceptable to the staff.

(2) Reactor Top Head Insulation Frame - This item differs from the Unit 1 frame because of the many new connections added to support the piping containing Regulatory Guide 1.97 equipment. A new analysis has been completed to account for the dynamic loading on the frame resulting from this new piping and equipment and the different routing of the Unit 2 piping system. This is acceptable to the staff.

(3) Motor Generator Set (E151) - This equipment is located in the center of a floor area in Unit 2, whereas the Unit 1 counterpart is located near the walls. To account for the floor amplification effect, the equipment was finally qualified by showing that the respective Unit 2 nodal point required spectra were less than the test response spectra of the qualification testing. The staff finds this to be acceptable.

(4) Automatic Transfer Switch Unit (E152) - Same status and conclusion as those for the motor generator set (E151) apply.

(5) Cooling Unit for Emergency Switchgear Room - This is equipment unique to Unit 2 and has been completely qualified with completion of documentation.

(6) Reactor Building Crane - The dissimilarity between Unit 1 and Unit 2 cranes is that the crane girders supporting the trolley of the smaller Unit 2 crane are separated by 16 ft instead of 22 ft as for the Unit 1 crane. This produces a lighter trolley, but the crane weight is reduced by less than 10%. In the analysis for the Unit 2 crane, the effect of the above difference in configuration was accounted for, and the result was acceptable as shown in the SQRT documentation.

(7) 1500-lb Motor-Operated Gate Valves - The valves are installed in Unit 2 only and are qualified for seismic and hydrodynamic loads to a level of 10 g. This qualification g level has been verified to exceed that which the valves experience at their respective locations in the Unit 2 piping systems and is acceptable to the staff.

(8) Vacuum Relief Valves - Qualification of the new model Anderson-Greenwood vacuum relief valves for Unit 2 has been completed. Installation of this design in Unit 2 will be completed before Unit 2 fuel loading. Although the Unit 1 vacuum relief valves are dynamically qualified, this design is also scheduled for installation in Unit 1 during the Unit 1 first refueling outage.

(9) Additional Gear-Operated Butterfly Valves - These valves were added to the residual heat removal service water and emergency service water systems. The safety function of these valves is only to maintain pressure boundary. The qualification analyses were performed using higher-than-required acceleration g levels as shown on the piping analysis data sheets attached to the SQRT forms. This is acceptable to the staff.

(10) Diesel Generator Fuel Oil Heat Exchanger - In a recent review of the diesel generator qualification documentation by the applicant, it was found that this equipment was not addressed. Qualification of this equipment will be completed prior to fuel loading, which is acceptable to the staff.

3.10.1.2 New Field-Procured Equipment

The following additional field-procured equipment has been added to BOP panels and will be added to the equipment list in the Equipment Qualification Summary Report.

(1) Reactor Core Isolation Cooling Backup Power Supply and Inverter - This equipment has been installed in the loose parts monitoring panel. Qualification documentation has been procured. The test response spectra (TRS) will be compared with the in-panel RRS and if no exceedances exist, the documentation will be completed by fuel loading. In the meantime, the justification for interim operation up to 5% power level has already been provided and found acceptable to the staff. The staff acceptance is based on the fact that the devices are in operation only for shutdown at the remote shutdown panel (RSP) and that shutdown at the RSP is required only when evacuation on the control room is required.

(2) ITE Overcurrent Relay (E109) - The relay has been relocated to the building wall adjacent to the panel where the corresponding RRS is enveloped by the TRS. Review of the test report and update of the SQRT documentation has been completed. This is acceptable to the staff.

(3) Surge Arrestor - This device has passed dynamic qualification testing. The test report and SQRT form have been added the existing SQRT documentation of the host panels. This is acceptable to the staff.

3.10.2 Nuclear Steam Supply System Equipment

3.10.2.1 Confirmatory Equipment

Confirmatory analysis of the hydraulic control unit (HCU) is being performed to verify that the relatively high TRS achieved in the dynamic testing of the skid assembly resulted in a response at the attachment points that exceeds that of the installed equipment. Response spectra at the two HCU upper-support points will be calculated and compared with those achieved at the same locations during testing of the HCU skid. Verification and final SQRT documentation are to be completed before fuel loading.

3.10.2.2 Unit 2 Different Equipment

The following Unit 2 NSSS equipment is different from that in Unit 1:

(1) Power Range Detector - The power range detector provides safety function only for control rod drop accidents. Should the power range monitors fail to provide a scram signal, the initial power excursion is terminated by the Doppler coefficient, and a backup scram signal is generated by closure of the main steam isolation valves on detection of high radioactivity in

the main steamlines. Therefore, failure of these components will not preclude the ability to accomplish or maintain cold shutdown.

On the basis of the above, the staff finds interim justification to be acceptable for operation until the Unit 1 first refueling outage.

(2) Architect/Engineer (A/E)-Added Devices to NSSS Panels - A dynamic test has been completed to qualify all of these panel devices with the exception of the Agastat ETR and TDPU relays, the TEC-indicating LED, the Simmons display module, the Validyne TMS module, and two HFA relays that are mounted to local racks.

These auxiliary relays provide control functions in their particular circuits, which include providing permissive signals to the control circuits, signal initiation, and contact multiplication for adding duplicate signals to other circuits. The timing relays (ETRs) perform similar functions with load sequence timing. These relays have been qualified for significant levels of seismic and hydrodynamic excitation and are in use in other panels in the control room or relay room. The NSSS panels, to which these relays have been added, are generally of stiffer construction in terms of panel skin thickness and frame members than the other panels for which in-panel response spectra were calculated and later used as RRS for device qualification.

The peak accelerations of the NSSS panels are shown in the addendum to the September 9, 1983 submittal and are compared with the zero period acceleration (ZPA) level of the TRS used to qualify the relays. The actual panel g levels at the relay locations are expected to be significantly lower because the relays are typically installed in the lower two-thirds of the panels and the peak g levels are conservatively based on the product of the floor ZPA and transmissibility of the panel as measured in a low level sine sweep. On the basis of the above reasoning, the staff finds them acceptable for interim operation before 5% power operation is exceeded while the actual NSSS in-panel RRS undergo calculation in a program being implemented by PP&L.

(3) New Local Panel Devices - Qualification of these devices has been completed and has been included with the SQRT forms for NSSS local racks. This is acceptable to the staff.

(4) In-Vessel Rack - Qualification of the rack is to be accomplished by strengthening of the welds at the rack support points. A cable also will be added to prevent the rack from tipping if the rack is in use during a seismic event. The rack is used only during refueling, and there may be an alternative to refueling without using the rack.

On the basis of the above, the staff determines that interim operation until the Unit 2 first refueling outage while the rack is being qualified is acceptable.

(5) Signal Resistive Units - This equipment has been qualified with complete documentation and is acceptable to the staff.

(6) Valcor Control Rod Drive Pilot Solenoid Valves - Valcor model V70900-45 pilot solenoid valves are used in place of the ASCO model 8323 valves in Unit 1. The valve qualification is scheduled for completion by fuel loading.

(7) Standby Liquid Control (SLC) Explosive Valve - The valve has no moving parts, and was found to be rigid by testing to 35 Hz and by analysis to 60 Hz. It has successfully passed multiaxis, single-frequency dynamic testing to input g levels of 6.5 g and 4.5 g in horizontal and vertical directions, respectively, which are much higher than the corresponding required input motion of 1.1 g and 0.8 g, and the explosive charge was fired during the test. In addition, the maintenance and surveillance requirements for this valve are addressed in the plant Technical Specifications, Section 3/4.1.5. Electrical continuity is checked every 31 days, and the valve explosive charge is fired and replaced every 18 months.

On the basis of the above, the staff finds the qualification of this valve to be acceptable.

(8) Main Steam Isolation Valve-Leakage Control System (MSIV-LCS) Heater - This heater has been qualified by comparing the response of the Unit 2 heater in the as-built piping system with the dynamic test environment of 6 g horizontal and 4 g vertical (ZPA) imposed on the heater specimen in the Unit 1 qualification test program. Specifically, the maximum acceleration level required of the Unit 2 heaters was found to be 2.3 g, which is below the above ZPAs.

3.10.2.3 Unit 1 Common Equipment

The following is a list of NSSS equipment that is common for both Units 1 and 2:

(1) Power Range Monitor Panel - On the basis of the same-system-function argument of interim justification of Unit 1 operation, as stated in Supplement 4, the staff concluded that Unit 2 operation without a fully qualified PRM cabinet is acceptable until the Unit 1 first refueling outage.

(2) Level Switches (E41-N014, N002, N003, N015, N018) - These devices have been qualified with complete documentation and are acceptable to the staff.

(3) Condensate Storage Tank - Preliminary structural analysis of the tank indicates that the stresses are within allowable limits. Final qualification will be completed before fuel loading.

(4) High-Pressure Coolant Injection (HPCI) Turbine - Qualification documentation is complete for the turbine. The Unit 1 planned field modification, however, has not been completed. Because a redundant, single-failure-proof equipment path exists, which provides safe shutdown without HPCI (see Supplement 4), the applicant's justification for Unit 2 interim operation until the Unit 1 first refueling outage while the modification is being completed is acceptable to the staff.

(5) Control Rod Drive Vent and Drain Valves - Dynamic testing and in-pipe RRS calculation, together with qualification documentation, have been completed for both Unit 1 and 2 equipment. The staff finds it to be acceptable.

3.10.3 Fatigue Cycling Effects Due to Safety/Relief Valve (SRV) Loading

The applicant's submittal of June 9, 1983, addressed the staff concern regarding the fatigue cycling effects on NSSS equipment resulting from SRV loads. On the basis of an environment of 1,800 and 3,600 significant stress cycles as defined by the applicant for equipment outside and inside containment, respectively, the maximum cumulative usage factor among equipment analyzed was calculated to be 0.33, which occurred on the reactor core isolation cooling pump holddown bolts.

Supporting data were also provided by the applicant for equipment whose fatigue life adequacy was demonstrated using methods of extended duration testing. For the MSIV-LCS blower, the total test time was 40 minutes and was achieved by four upset condition tests for 5 minutes each at 2-g input and four faulted condition tests for 5 minutes each at 3-g input. These g levels are far in excess of the 0.11-g ZPA of the required SRV spectra. A sine sweep test method was performed in the frequency range of interest in which several thousand cycles minimum per each 5-minute test was imposed on the test specimen so that the cumulative number of cycles greatly exceeded the required 3,600 cycles stated previously. Neither structural nor operability failure occurred during this testing.

Similar extended duration tests were performed for a number of other equipment items, using either a biaxial sine sweep input, a multifrequency biaxial input motion, or two biaxial time history input motions. The equipment items covered are 4.16-kV switchgear, 125-Vdc power distribution panel, power range monitoring cabinet, valve motor operators, and MSIV actuator. In all cases, both structural integrity and operability of the equipment were demonstrated during and after the test input motions.

On the basis of the above information provided by the applicant, the staff concludes that all NSSS equipment will perform satisfactorily under the fatigue cycling effects resulting from SRV loads.

3.10.4 Summary

Section 3.10.1 describes the qualification status of Unit 2 BOP equipment that is different from that in Unit 1. Section 3.10.2 describes the qualification status of Unit 2 NSSS equipment that is either different from that of Unit 1, is common with Unit 1, or simply is the one whose qualification needs confirmation. As a result of the above evaluation, the following are actions that must be taken by the applicant.

(1) Before Unit 2 fuel loading, the applicant should ensure full qualification and documentation as well as installation of

- (a) vacuum relief valves
- (b) diesel generator fuel oil heat exchanger
- (c) hydraulic control unit
- (d) Valcor control rod drive pilot solenoid valves
- (e) condensate storage tank

(2) Before Unit 2 exceeds 5% power operation, the applicant should ensure full qualification and documentation as well as installation of

    (a) reactor core isolation cooling backup power supply and inverter
    (b) A/E-added devices to NSSS panels, as identified in Section 3.10.2.2

(3) Before Unit 1 returns to operation after the first refueling outage, the applicant should ensure full qualification and documentation as well as installation of

    (a) power range detector
    (b) power range monitor panel
    (c) high-pressure coolant injection turbine

(4) Before the Unit 2 first refueling outage, the applicant should ensure full qualification and documentation as well as installation of the in-vessel rack.

3.11 Environmental Qualification

3.11.1 Environmental Qualification of Safety-Related Electrical Equipment

Equipment that is used to perform a necessary safety function must be demonstrated to be capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. This requirement, which is embodied in GDC 1 and 4 of Appendix A and Sections III, XI, and XVII of Appendix B to 10 CFR 50, is applicable to equipment located inside as well as outside containment. More detailed requirements and guidance relating to the methods and procedures for demonstrating this capability for electrical equipment have been set forth in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"; NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," which supplements IEEE Std 323; and various NRC regulatory guides and industry standards.

3.11.2 Background

NUREG-0588 was issued in December 1979 to promote a more orderly and systematic implementation of equipment qualification programs by industry and to provide guidance to the NRC staff for its use in ongoing licensing reviews. The positions contained in that report provide guidance on (1) how to establish environmental service conditions, (2) how to select methods that are considered appropriate for qualifying equipment in different areas of the plant, and (3) other areas such as margin, aging, and documentation for each item of safety-related electrical equipment and to identify the degree to which their qualification programs complied with the staff positions discussed in NUREG-0588.

IE Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment," issued January 14, 1980, and its supplements dated February 29, September 30, and October 24, 1980, established environmental qualification requirements for operating reactors. This bulletin and its supplements were provided to operating license applicants for consideration in their review.

A final rule on environmental qualification of electrical equipment important to safety for nuclear power plants became effective February 22, 1983. This rule, 10 CFR 50.49, specifies the requirements to be met for demonstrating the environmental qualification of electrical equipment important to safety located in a harsh environment. In accordance with 10 CFR 50.49, electrical equipment at Susquehanna may be qualified in accordance with the acceptance criteria specified in Category II of NUREG-0588.

To document the degree to which the environmental qualification program complies with the NRC's environmental qualification requirements and criteria, the applicant provided equipment qualification information by letters dated June 20, 1983, November 3, 1983, December 21 and 30, 1983, January 5, 1984, and January 11, 1984.

3.11.2.1 Purpose

The purpose of this supplement is to evaluate the adequacy of the Susquehanna environmental qualification program for electrical equipment important to safety as defined in 10 CFR 50.49. The staff position relating to open items, as well as any unresolved issues, is provided in this report.

3.11.2.2 Scope

The scope of this report is limited to an evaluation of the electrical equipment important to safety at Susquehanna Unit 2 that is different from electrical equipment at Unit 1 and that must function to mitigate the consequences of a design-basis accident, inside or outside containment, while subjected to the hostile environments associated with these accidents.

Electrical equipment at Unit 2 that is identical to equipment at Unit 1 was addressed in Supplements 3 and 4.

3.11.3 Staff Evaluation

The staff evaluation of the applicant's Equipment Environmental Qualification (EEQ) submittal dated September 9, 1983, includes a review of the following equipment items that have been identified by the applicant as items installed or to be installed at Unit 2 that are not identical to items installed at Unit 1.

Item description	Manufacturer	Model no.
Cable specialty	Rockbestos	RSS-6-XXX
DX refrigeration system	American Air Filter	
Resistance temperature detector	Conax	7349-10000-01
Transmitter (pressure and level)	ITT Barton	763, 764

Item description	Manufacturer	Model no.
Solenoid valve	Target Rock	75KK209, 211 through 216

In submittals dated September 9, 1983, and January 5 and 11, 1984, the applicant identified items 1, 3, and 4 as being qualified for their application. Item 5 will be qualified by May 1984. The applicant has provided a justification for interim operation for item 5. The staff finds the justification acceptable. Item 2 will be completely qualified after the replacement of the water regulating valve. The applicant has committed to replace the valve with a qualified valve before fuel loading. The applicant should confirm, before the granting of the operating license, that the valve has been replaced with a qualified valve or provide a justification for interim operation. Also in accordance with the latest information available to the staff, the validity of the test report for Rockbestos cable, item 1, is in doubt. However, on the basis of other information available to the staff (results of testing performed on Rockbestos cable by both the Franklin Research Center and Sandia), the staff concludes at this time that no safety problem exists because of the use of this cable. An information notice is being prepared by the NRC Office of Inspection and Enforcement concerning this issue. It will be the applicant's responsibility to evaluate the information in that information notice for applicability to his facility and to take appropriate action to ensure that the documentation relied on to demonstrate environmental qualification of Rockbestos cable supports such a conclusion.

The open item identified in Section 3.11.1 of Supplement 5 involves compliance with 10 CFR 50.49(b). In the submittal of September 9, 1983, the applicant confirmed that all safety-related electrical equipment within the scope of 10 CFR 50.49 has been included in the qualification program. The applicant also stated that there is no nonsafety-related electrical equipment located in a harsh environment whose failure under postulated accident conditions could prevent satisfactory accomplishment of a safety function by safety-related equipment. In a letter dated June 20, 1983, the applicant referenced FSAR Sections 3.12 and 8.1.6, which define his criteria for physical separation and electrical isolation between safety and nonsafety-related equipment. These FSAR sections also discuss compliance with Regulatory Guide 1.75. The staff had previously reviewed these FSAR sections and found them acceptable. The applicant has not, however, provided an evaluation of the effects of high energy line breaks on control systems. Hence, the staff cannot conclude that the failure of nonsafety-related equipment will not prevent safety-related equipment from performing its function. However, in a letter dated December 21, 1983, the applicant committed to provide this information before 5% power is exceeded. The applicant has provided justification for interim operation up to 5% power. This justification is based on the fact that the only activity planned during this period is low power physics testing. The reactor coolant system nuclear fission inventory and residual heat will be sufficiently low so as to preclude any significant effects on the electrical equipment in question should an accident occur. The staff concurs with the applicant's justification and, on the basis of this, issuance of an operating license for up to 5% power is acceptable.

In letters dated June 20, 1983, and December 30, 1983, the applicant also addressed compliance with Regulatory Guide 1.97, Revision 2. The applicant has qualified all equipment considered to be Category I or II in accordance with his position contained in PLA-965, dated November 13, 1981, except for the ex-core neutron monitoring system. For this system, there are two items of equipment, Conax connectors and neutron sensors, for which testing has been successfully completed by the vendors and the qualification reports have been evaluated and approved by the architect/engineer. However, the applicant has not yet completed the review and evaluation in accordance with his equipment qualification program. The applicant expects to approve the qualification of this equipment during the first quarter of 1984. This justification for interim operation is acceptable to the staff. On the basis of this, the staff concludes that the response to 10 CFR 50.49(b)(3) is acceptable.

On the basis of the above, the staff concludes that all open items identified in Section 3.11 of Supplement 5 have been satisfactorily resolved except for the following confirmatory item:

(1) The applicant should confirm, prior to the granting of an operating license, that the water regulating valve on the DX refrigeration unit has been replaced with a qualified valve.

The following license conditions should be incorporated into the Susquehanna Unit 2 license:

(1) The applicant should provide the evaluation of the effects of high energy line breaks on control systems for staff review and approval before 5% power is exceeded.

(2) All electrical equipment within the scope of 10 CFR 50.49 should be environmentally qualified by March 31, 1985.

On the basis of the results of its review and evaluation, and on satisfactory completion of the confirmatory item identified above, the staff concludes that the applicant has demonstrated compliance with the requirements of 10 CFR 50.49, the relevant parts of GDC 1 and 4 of Appendix A and Sections III, XI, and XVII of Appendix B to 10 CFR 50, and the criteria specified in NUREG-0588 for operation up to 5% of full power for Susquehanna Unit 2. The staff concludes that a full-power license can be issued on satisfactory compliance with License Condition (1) above.

4 REACTOR

4.4 Thermal and Hydraulic Design

In Section 1.10 of Supplement 5 to the SER, the staff provided a list of issues for which a condition was included in the operating license for Susquehanna Unit 1 for which a similar license condition would be required for Unit 2 unless satisfactory resolution was reached on the issue for licensing Unit 2. One such issue regarded thermal and hydraulic design, specifically, natural circulation conditions and a new stability analysis at the end of the first fuel cycle indicating the results for appropriate exposure core conditions.

The staff recently became aware of new stability test data that demonstrated the occurrence of limit cycle neutron flux oscillations at natural circulation and several percent above the rated rod line. The oscillations were observable on the average power range monitors (APRMs) and were suppressed with control rod insertion. It was predicted that limit cycle oscillations would occur at the operating conditions tested; however, the characteristics of the observed oscillations were different from those previously observed during other stability tests. Namely, the test data showed that some local power range monitors oscillated out of phase with the APRM signal and at an amplitude as great as six times the core average.

The Unit 1 license condition on thermal and hydraulic design with regard to operation in natural circulation is not required on Unit 2 because the Technical Specifications provide limiting conditions for operation in natural circulation and with only one recirculation loop. However, for the potential thermal-hydraulic instability described above, the Technical Specifications are not sufficiently prescriptive. PP&L in a letter dated March 15, 1984, committed to provide, before exceeding 5% power on Unit 2, either a proposed change to Susquehanna Steam Electric Station Units 1 and 2 Technical Specifications or an alternative resolution that is acceptable to the NRC staff. This commitment is acceptable to the NRC staff because the thermal-hydraulic instability described above is not a safety concern at low power levels.

With regard to providing a new stability analysis at the end of the first fuel cycle indicating the results for appropriate exposure core conditions, the design criteria in Appendix A to 10 CFR 50 address the requirements for new stability analysis. Therefore, a specific license condition to address this issue is not required.

4.6 Safety Concerns Associated With Scram Discharge System Piping

In Section 4.6 of Supplement 4 to the SER, the staff concluded that operation at full power for one fuel cycle with unqualified scram discharge volume (SDV) pipe break detection and mitigation equipment is acceptable. The staff also concluded that if its review of the probabilistic risk assessment (PRA) submitted by the applicant on August 25, 1982, showed that further protection from an SDV pipe break is required, then all equipment qualification had to be implemented before the end of the first refueling outage. The staff's evaluation in

Supplement 4 described the shutdown capability already existing at Susquehanna Unit 2 that formed the basis for allowing interim operation for one fuel cycle. Additional information was submitted in GE Topical Report NEDO-22209. NEDO-22209 updated the probabilistic approach originally presented in the first PRA, NEDO-24342, and presented probabilistic arguments as an alternative to the criteria of NUREG-0803, "Generic Safety Evaluation Report Regarding the Integrity of BWR Scram System Piping."

The staff reviewed NEDO-22209 and concluded that resolution of the concern required more detailed consideration of the applicable pipe break mechanisms than can be obtained by a probabilistic analysis. Further specific information was requested regarding a deterministic fracture mechanics evaluation of the scram system piping and discussions of the associated realistic leak rate, leak detection, and mitigation capability. Since this is a multiplant item, these requests were transmitted to the BWR Owners Group by letter dated July 25, 1983. By letter dated November 18, 1983, the BWR Owners Group provided responses to the additional requests for information except for one item that was plant specific regarding radiation exposure as a result of routine tests and inspections. The staff will review the BWR Owners Group responses and will provide a generic evaluation that identifies any additional design requirements developed as a result of its review. The item regarding radiation exposure will be evaluated on a case-by-case basis following completion of the generic evaluation.

Since this is a multiplant action item, the staff has not made a determination as to what design changes, if any, are necessary for Susquehanna Unit 2 until the review of the BWR Owners Group responses is complete. The staff, therefore, concludes that the requirement for equipment qualification stated in Supplement 4 should be changed because this action is not governed by 10 CFR 50.49.

In a letter dated August 3, 1983, PP&L committed to implement all actions and modifications specified in the generic SER regarding NUREG-0803 within 2 years after the issuance of the generic SER, or before the end of the first refueling outage after the issuance of the generic SER. On the basis of the status of its review, the staff finds PP&L's commitment acceptable.

5 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.2 Integrity of the Reactor Coolant Pressure Boundary

5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing

GDC 32, "Inspection of Reactor Coolant Pressure Boundary," requires, in part, that components of the reactor coolant pressure boundary be designed to permit periodic inspection and testing of important areas and features to assess their structural and leaktight integrity. To ensure that no deleterious defects develop during service, selected welds and weld heat-affected zones will be inspected periodically at the Susquehanna Steam Electric Station. The design of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Class 1 components of the reactor coolant pressure boundary in Susquehanna incorporates provisions for access for inservice examination in accordance with Section XI of the ASME Code. Methods have been developed to facilitate the remote examination of these areas of the reactor vessel not readily accessible to examination personnel.

10 CFR 50.55a(g) defines the detailed requirements for the preservice and inservice inspection programs for light-water-cooled nuclear power facility components. On the basis of the construction permit date of November 2, 1973, this section of the regulations requires that a preservice inspection program be developed and implemented using at least the Edition and Addenda of Section XI of the ASME Code in effect 6 months before the date of issuance of the construction permit, subject to the limitations and modifications listed in 10 CFR 50.55a(b).

Also, the initial inservice inspection program must comply with the requirements of the latest Edition and Addenda of Section XI of the ASME Code in effect 12 months before the date of issuance of the operating license, subject to the limitations and modifications listed in 10 CFR 50.55a(b).

5.2.4.2 Evaluation of Compliance With 10 CFR 50.55a(g) for Unit 2

The staff completed the review of the Preservice Inspection (PSI) Program for Unit 1 and determined that this document was acceptable as described in Section 5.2.4.1 of Supplements 3 and 4. The preservice examination of Unit 2 was performed to the same ASME Code requirements (as modified by specific written relief requests) as the Unit 1 PSI Program with one exception; that is, although the manual ultrasonic data from the Unit 2 reactor vessel were collected before RG 1.150, Revision 1, was issued, the remote automated ultrasonic testing of the Unit 2 reactor vessel did conform to RG 1.150, Revision 1. Therefore, the staff has determined that the PSI Program for Unit 2 is acceptable on the basis of the staff review and acceptance of the corresponding document for Unit 1.

The staff has completed the review of requests for relief from certain requirements that the applicant determined to be impractical in letters dated August 2, 1983, November 1, 1983, and December 21, 1983, in which a supporting technical justification was provided. The staff has determined that certain ASME Code, Section XI, examination requirements defined in 10 CFR 50.55a(g)(2) are impractical. Therefore, pursuant to 10 CFR 50.55a(a)(2), the staff has allowed relief from the requirements that have been determined to be impractical and that if implemented would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. On the basis of the granting of relief from these preservice examination requirements, the staff concludes that the PSI Program for Unit 2 is in compliance with 10 CFR 50.55a(g)(2). A detailed evaluation supporting this conclusion is provided in Appendix H to this report. The initial inservice inspection program for Unit 2 will be evaluated after the applicable ASME Code edition and addenda can be determined based on 10 CFR 50.55a(b) and before the first refueling outage when inservice inspections will be performed.

Periodic inspections and hydrostatic testing of pressure-retaining components of the reactor coolant pressure boundary in accordance with the requirements of Section XI of the ASME Code and 10 CFR 50 will provide reasonable assurance that evidence of structural degradation or loss of leaktight integrity occurring during service will be detected in time to permit corrective action before the safety functions of the components are compromised. Compliance with the inservice inspections required by Section XI of the ASME Code and 10 CFR 50 constitutes an acceptable basis for satisfying the inspection requirements of GDC 32.

5.3 Reactor Vessel

5.3.1 Reactor Vessel Materials

The review requirements and conclusions that were discussed in the staff's safety evaluation of Susquehanna Unit 1 are applicable to Unit 2.

5.3.1.1 Compliance With Appendix G, 10 CFR 50

Appendix G requires that a reference temperature, RT_{NDT}, be determined for each ferritic material of the reactor vessel and that this reference temperature be used as a basis for providing adequate margins of safety for reactor operation. The value of RT_{NDT} is defined in the ASME Code as the higher of either (1) the nil ductility temperature, as determined by the dropweight test, or (2) a temperature of 60F° less than the temperature at which 50 ft-lb of energy and 35 mils of lateral expansion are achieved, as determined by the Charpy V-notch (CVN) impact test. The CVN impact test is to be conducted using specimens oriented in the transverse direction. Unit 2 material tests were performed to meet the requirements of the 1968 Edition, including the Summer 1970 Addenda, Section III of the ASME Code. The applicant stated that to demonstrate compliance with the requirements of Appendix G, 10 CFR 50, RT_{NDT} values have been defined using existing impact test data in conjunction with various data correlations to establish the temperature at which 50 ft-lb of energy is achieved for specimens oriented in the transverse direction. The staff has evaluated the applicant's methods of determining the RT_{NDT} and has concluded that the method used by the applicant will provide a conservative estimate of the RT_{NDT}.

Paragraph IV.A.1 of Appendix G, 10 CFR 50, requires, in part, that the reactor vessel beltline materials have Charpy upper-shelf energy of no less than

75 ft-lb initially and must maintain upper-shelf energy throughout the life of the vessel of no less than 50 ft-lb, unless it is demonstrated in a manner approved by NRC, that lower values of upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of the ASME Code. All beltline materials in Unit 2 meet these requirements except for two weld materials (heat nos. 624263 and 09M057) and four plates (heat nos. 6C1053/1, C2421/3, C2929/1, and C2433/2). These materials were not Charpy tested at high enough temperatures to determine their upper shelf.

The applicant has provided Charpy upper-shelf data from other welds and plates that were fabricated using the same process and heat treated to a microstructure equivalent to that of Unit 2 welds and plates. These data indicate that had the Unit 2 weld and plate materials been tested at higher temperatures, their upper-shelf energies would exceed the requirements of Paragraph IV.A.1 of Appendix G, 10 CFR 50. Hence, the staff considers that all Unit 2 reactor vessel beltline materials will have adequate upper-shelf energies throughout the design life of the vessel.

All Unit 2 ferritic main steam piping and valve materials have been tested to meet the requirements of Appendix G except for the main steam isolation valve (MSIV) body and bonnet materials. Appendix G, 10 CFR 50, requires that these materials be tested to the requirements of the ASME Code. The current ASME Code requirement is that the MSIV body and bonnet materials must be CVN impact tested at the lowest service metal temperature and that the CVN lateral expansion must exceed 25 mils. The applicant has indicated that the lowest service metal temperature is 60°F. This temperature is conservative because significant pressure is not applied to the MSIV during operation until the boiling point of water (212°F) is reached.

The applicant's ferritic reactor coolant pressure boundary materials in the MSIV were not CVN impact tested because they were fabricated to an earlier Code, which did not require CVN impact testing.

The applicant has supplied CVN impact data for MSIV materials from other nuclear facilities that had been fabricated to the same specification and heat treated to an equivalent metallurgical condition as the Unit 2 ferritic valve materials. The data indicate for the ferritic MSIV body and bonnet materials that CVN lateral expansion at 60°F test temperature would exceed 25 mils. Hence, the staff considers that these materials will have adequate toughness.

5.3.1.2 Compliance With Appendix H, 10 CFR 50

The toughness properties of the reactor vessel beltline materials will be monitored throughout the service life of Unit 2 by a materials surveillance program that must meet the requirements of Appendix H, 10 CFR 50, and, therefore, also the requirements of American Society for Testing and Materials (ASTM) Std E 185-73, "Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels." The staff has evaluated the applicant's information for degree of compliance to these requirements and has concluded that the applicant has met all the requirements of Appendix H, 10 CFR 50, except for Paragraph II.B.1. Paragraph II.B.1 requires that the number of Charpy test specimens and the orientation of the test specimens for the Unit 2 reactor vessel surveillance program must comply with the requirements of ASTM Std E 185-73. ASTM Std E 185-73 requires that there be a minimum of 12 Charpy test specimens for each base metal, weld metal, and heat-affected-zone (HAZ) sample in each capsule and that the base metal specimens be removed from the plate with their major axis normal (transversely) to the rolling direction of the plate.

The minimum number of weld metal, base metal, and HAZ specimens contained in a Unit 2 surveillance capsule is eight, and the plate test specimens were removed from the plate with their major axes parallel (longitudinal) to the rolling direction of the plate.

Although the minimum number of specimens is not contained in each capsule and the plate test specimens orientation is in the longitudinal direction, the test data obtained should provide sufficient information to predict the relative shift in RT_{NDT} as a result of neutron irradiation. The staff's conclusion is based on its experience that the relative shift is not greatly sensitive to specimen orientation and that the amount of shift in RT_{NDT} may be estimated from the testing of eight specimens.

On the basis of its evaluation of the Unit 2 surveillance program, the staff concludes that there is reasonable assurance that the surveillance program will monitor the change in the beltline region to a degree adequate to determine the pressure-temperature limits to preserve the integrity of the vessel. The program will generate sufficient information to permit the determination of conditions under which the reactor vessel will be operated with an adequate margin of safety against rapidly propagating fracture throughout its service lifetime.

5.3.1.3 Conclusions for Compliance With Appendices G and H, 10 CFR 50

The Unit 2 reactor vessel and other reactor coolant pressure boundary components were constructed to an ASME Code that was earlier than the Summer 1972 Addenda of the 1971 Edition. Hence, the materials that were used in the fabrication of these components were not tested to the extent required by Appendices G and H, 10 CFR 50. However, for reactor vessel and other reactor coolant pressure boundary materials that were constructed to an ASME Code earlier than the Summer 1972 Addenda of the 1971 Edition, Appendices G and H, 10 CFR 50, permit the NRC to approve alternative fracture toughness test methods other than those required by the appendices. The staff has evaluated the applicant's alternative fracture toughness test program and methods of demonstrating that the materials comply with the intent of Appendices G and H, 10 CFR 50. The staff considers the applicant's alternative fracture toughness test program acceptable, and that the materials used in the fabrication of the reactor vessel and other reactor coolant pressure boundary components will meet the minimum fracture toughness requirements of Appendices G and H, 10 CFR 50, through the plant's design life of 32 effective full-power years (EFPYs).

Appendix G, "Protection Against Nonductile Failure," Section III of the ASME Code, will be used with fracture toughness test results required by Appendices G and H, 10 CFR 50, to calculate the reactor coolant pressure boundary pressure-temperature limits for Unit 2.

The fracture toughness tests required by the ASME Code and Appendix G, 10 CFR 50, will provide reasonable assurance that adequate safety margins against the possibility of nonductile behavior or rapidly propagating fracture can be established for all pressure-retaining components of the reactor coolant pressure boundary. The use of Appendix G, Section III of the ASME Code, as a guide in establishing safe operating procedures, and the use of the results of the fracture toughness tests performed in accordance with the ASME Code and NRC regulations will provide adequate safety margins during operating, testing, maintenance, and anticipated transient conditions. Compliance with these Code provisions and NRC regulations constitutes an acceptable basis for satisfying the requirements of GDC 31.

The material surveillance program, required by Appendix H, 10 CFR 50, will provide information on material properties and the effects of irradiation on the material properties so that changes in the fracture toughness of material in the Unit 2 reactor vessel beltline region caused by neutron radiation can be properly assessed, and adequate safety margins against the possibility of vessel failure can be provided. Compliance with ASTM Std E 185-73 and Appendix H, 10 CFR 50, satisfies the requirements of GDC 31 and 32.

5.3.2 Pressure-Temperature Limits

Appendix G, "Fracture Toughness Requirements," and Appendix H, "Reactor Vessel Material Surveillance Program Requirements," 10 CFR 50, describe the conditions that require pressure-temperature limits for the reactor coolant pressure boundary and provide the general bases for these limits. These appendices specifically require that pressure-temperature limits must provide safety margins for the reactor coolant pressure boundary at least as great as the safety margins recommended in the ASME Code, Section III, Appendix G. Appendix G, 10 CFR 50, requires additional safety margins for the closure flange region and for the beltline region whenever the reactor core is critical, except for low-level physics tests.

The following pressure-temperature limits imposed on the reactor coolant pressure boundary during operation and tests are reviewed to ensure that they provide adequate safety margins against nonductile behavior or rapidly propagating failure of ferritic components as required by GDC 31:

(1) preservice hydrostatic tests
(2) inservice leak and hydrostatic tests
(3) heatup and cooldown operations
(4) core operation

Appendices G and H, 10 CFR 50, require the applicant to predict the shift in reference temperature resulting from neutron irradiation. The shift in RT_{NDT} resulting from neutron irradiation is then added to the initial RT_{NDT} to establish the adjusted reference temperature. The base plate or weld seam having the highest adjusted reference temperature is considered the most limiting beltline material on which the pressure-temperature operating limits are based. In the case of Unit 2, the limiting beltline material would be plate I.D.21-3.

The applicant in FSAR Figure 5.3-4b has provided pressure-temperature limit curves for Unit 2. The length of time these curves are acceptable depends on the amount of neutron irradiation damage predicted for the limiting Unit 2 beltline material. The staff uses Regulatory Guide 1.99, "Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials," to predict the amount of neutron irradiation damage. The staff's evaluation of the effect of neutron irradiation damage on the limiting beltline material indicates that the curves identified as A, B, and C in FSAR Figure 5.3-4b are acceptable for 15 EFPYs and curves identified as A', B', and C' are acceptable for 32 EFPYs.

Revision to 10 CFR 50, Appendix G, was published in the Federal Register on May 27, 1983, and became effective on July 26, 1983. The amended Appendix G, 10 CFR 50, states that when pressure exceeds 20% of the preservice system hydrostatic test pressure, the temperature of the closure flange regions that are highly stressed by bolt preload must exceed the reference temperature of the materials in those regions by at least 120F° for normal operation and by 90F° for hydrostatic pressure tests and leak tests, unless a lower temperature can be justified by showing that the margins of safety for those regions, when they are controlling, are equivalent to those required for the beltline, when it is controlling.

The applicant's pressure-temperature limit curves do not meet the pressure-temperature margins for the closure flange region defined in the amended Appendix G, 10 CFR 50. The staff will be implementing those requirements in a 10 CFR 50.54(f) letter, which will be sent to all licensees of operating reactors, applicants for operating licenses, and holders of construction permits. The staff will complete its review of the applicant's pressure-temperature limits when it has completed the implementation of the 10 CFR 50.54(f) letter, which will be sent to the applicant.

The pressure-temperature limits to be imposed on the reactor coolant system for all operating and testing conditions to ensure adequate safety margins against nonductile or rapidly propagating failure must be in conformance with established criteria, codes, and standards acceptable to the staff. The use of operating limits based on these criteria, as defined by applicable regulations, codes, and standards, will provide reasonable assurance that nonductile or rapidly propagating failure will not occur and will constitute an acceptable basis for satisfying the applicable requirements of GDC 31.

5.3.3 Reactor Vessel Integrity

The staff has reviewed the FSAR sections related to the reactor vessel integrity of Unit 2. Although most areas are reviewed separately in accordance with other review plans, reactor vessel integrity is of such importance that a special summary review of all factors relating to reactor vessel integrity is warranted.

The staff has reviewed the information in each area to ensure that it is complete and that no inconsistencies exist that would reduce the certainty of vessel integrity. The areas reviewed are:

(1) design (SER Section 5.3.1)
(2) materials of construction (SER Section 5.3.1)
(3) fabrication methods (SER Section 5.3.1)
(4) operating conditions (SER Section 5.3.2)

The staff has reviewed the above factors contributing to the structural integrity of the reactor vessel and concludes that the applicant has complied with Appendices G and H, 10 CFR 50, except for the following items:

(1) All ferritic reactor vessel materials were not sufficiently tested to determine their RT_{NDT}. The applicant has provided alternative methods for determining the RT_{NDT} for each ferritic reactor vessel material. The staff has evaluated the applicant's methods of determining the RT_{NDT} and has concluded that the methods used by the applicant will provide a conservative estimate of the RT_{NDT}.

(2) All beltline materials were not Charpy tested at high enough temperatures to determine whether their upper shelf would meet the requirements of Paragraph IV.A.1 of Appendix G, 10 CFR 50. The applicant has provided Charpy upper-shelf data from other welds and plates to demonstrate that all beltline materials meet the Charpy upper-shelf requirements of Appendix G, 10 CFR 50. The staff has reviewed the Charpy data provided by the applicant and has concluded that all reactor vessel beltline materials will have adequate upper-shelf energies throughout the design life of the vessel.

(3) The MSIV body and bonnet materials were not Charpy tested. However, the applicant has provided alternative Charpy test data that indicate the MSIV body and bonnet materials have adequate toughness.

(4) The applicant's reactor vessel material surveillance program does not contain test specimens that meet the orientation and minimum number requirements of ASTM Std E 185-73. However, the staff has evaluated the applicant's surveillance program and has concluded that it is adequate for determining the amount of change in RT_{NDT} for the Unit 2 beltline materials.

(5) The applicant's pressure-temperature curves do not meet the pressure-temperature margins for the closure-flange region identified in the revised Appendix G, 10 CFR 50, which was published on May 27, 1983. The staff will be implementing those requirements in a 10 CFR 50.54(f) letter, which will be sent to all applicants for operating licenses. The staff will complete its review of the applicant's pressure-temperature limits when it has completed the implementation of the 10 CFR 50.54(f) letter.

The staff has reviewed all factors contributing to the structural integrity of the Unit 2 reactor vessel and concludes that there are no special considerations that make it necessary to consider potential reactor vessel failure.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.1 Containment Functional Design

6.2.1.8 Pool Dynamics

6.2.1.8.g(5) Pool Temperature Limit

In Section 6.2.1.8.g(5) of the SER for the Susquehanna Steam Electric Station, Units 1 and 2, the applicant committed to use data from a comprehensive safety relief valve inplant test that is to be completed before the start of commercial operations at the La Salle facility. The applicant also committed to use the information from these tests to establish the value between local and bulk pool temperatures to demonstrate that a maximum local pool temperature specification of 200°F as specified in NUREG-0487 will not be exceeded.

Since the issuance of the SER, the Mark II Owners Group proposed alternative suppression pool limits. The alternative limits, which are applicable to Susquehanna Steam Electric Station, Units 1 and 2, are contained in NUREG-0783 and supersede the criteria contained in NUREG-0487.

In a letter dated November 21, 1983, the applicant submitted a report entitled "Evaluation of the NUREG-0783 Local Pool Temperature Limits for the Susquehanna Steam Electric Station." The applicant concluded that the local pool temperature limits stipulated in NUREG-0783 for all plant transients involving safety relief valve actuations will not be exceeded. The staff evaluation of this report is ongoing; however, the staff's preliminary assessment has confirmed the applicant's conclusion. Therefore, this issue is now considered a confirmatory item. Upon completion of the staff review, the results and bases of its evaluation will be documented in a future safety evaluation.

6.2.1.8.h Wetwell/Drywell Vacuum Breakers

The Susquehanna Steam Electric Station (SSES) containment is equipped with simple, swing check valves, which serve as vacuum breakers to equalize the pressure between the drywell and wetwell air space regions so that the reverse direction pressure across the diaphragm floor will not exceed the design value. The vacuum relief valves (five assemblies) are mounted on selected downcomers inside the suppression pool air space region.

Following the onset of a loss-of-coolant accident and during the pool swell phase, air flows from the drywell through the vent pipes and the suppression pool into the suppression pool chamber air space resulting in a rise of the suppression pool surface and compression of the air space region above it. This transient wetwell air space pressurization may cause the vacuum breaker valves to experience high opening and closing impact velocities. To estimate the valve disc actuation velocities, the Mark II Owner's Group developed a vacuum breaker valve dynamic model (NEDE-22178-P (General Electric Company)), which was submitted for review by the staff.

The staff has completed its review of NEDE-22178-P, which describes the generic methodology used to calculate the response of the drywell-to-wetwell vacuum breaker to certain transients in the Mark II containment, and found the approach acceptable.

The applicant indicated that use of this model will lead to predictions of very conservative impact velocities during pool swell transients because the hydrodynamic torque generated on the valve disc as a consequence of the pool swell differential pressure upstream and downstream of the valve very conservatively bounds full-scale test data.

Recognizing the above, the SSES applicant along with the applicants for Shoreham and Limerick initiated an effort to predict more realistic yet conservative impact velocities for use in the qualification of the vacuum breaker valves.

During a meeting held on June 7, 1983, in Bethesda, Maryland, between the staff and the applicants for Shoreham, Susquehanna, Limerick, and WNP-2, a presentation was made of the analysis and redesign that produced a reduction in the valve impact velocities during pool swell. The material presented during that meeting is documented in a letter dated June 17, 1983, from Bechtel Power Corporation.

Reduction of the valve impact velocities during pool swell is attributed to the use of more realistic hydrodynamic torque on the valve disc. The applicant stated that the hydrodynamic torque specified in NEDE-22178-P is extremely conservative. Therefore, the applicant proposed a reduction of conservatism in the hydrodynamic torque as a function of valve opening angle and demonstrated that, even with the proposed reduction implemented in the model described in NEDE-22178-P, the predictions of disc impact velocity are conservative when compared with test data.

The staff reviewed the applicant's submittals and concludes that the proposed reduction of the hydrodynamic torque is reasonable and, therefore, acceptable.

Several changes were made to the valve design, which contributed to a reduction of the impact velocities and to the strength of the valve for withstanding these impact velocities. The changes encompass the requirements specified in License Condition 2.C.(16) in Susquehanna Steam Electric Station Unit 1 Operating License No. NPF-14 and include redesign of the spring cylinder linkage (single-bar linkage instead of four-bar linkage); incorporation of an actuating cylinder (double-cylinder modification) for damping; changes for a higher spring constant, thicker dome, and ring flange; use of an internal stop; replacement of the shaft, keys, and pivot arm with higher strength materials; and a change to increase the shaft bearing area.

The predicted pallet impact velocities for the modified valve (using the dynamic model described in NEDE-22178-P, time-dependent differential pressure loading across the vacuum breaker disc derived from the 4TCO test data and adjusted to a peak value of 5.5 psid as recommended in NUREG-0808, and the mean hydrodynamic torque) are an opening impact velocity of less than 1 radian/sec and a closing impact velocity of 5.8 radian/sec.

The modified vacuum breaker was subjected to opening and closing impact velocities higher than the predicted impact velocities. Post-test visual inspection and leakage test show that valve operability and integrity as a pressure boundary are maintained and, therefore, the wetwell-to-drywell vacuum breaker valves will perform their function following the onset of a LOCA.

As analysis was performed for the Shoreham (opening impact velocity of 12.7 radian/sec and closing impact velocity of 10.9 radian/sec) modified vacuum breaker design to verify the valve's structural and pressure integrity. A linear elastic analysis was used for the evaluation of all valve components. An additional plastic analysis was performed to evaluate the structural integrity of the "spiders" for the pool-swell impact loadings. The spiders are spokes that are radially mounted on the valve disc and are designed as energy-absorbing members to absorb the energy associated with the disc impact loads. The loads and load combinations were reviewed and found to be in accordance with the staff's acceptance criteria. The loads were combined using the methodology in NUREG-0484, Revision 1, "Methodology for Combining Dynamic Responses."

The resulting stresses in the primary pressure-retaining boundaries were within the American Society of Mechanical Engineers "Boiler and Pressure Vessel Code" (ASME Code), Class 2 faulted allowable limits (Service Level D). The resulting stresses in the shaft, linkage, and spring cylinder were within the ASME Code, Class 2 emergency allowable limits (Service Level C). The structural integrity of the spiders was verified by comparing the calculated plastic strain with the strain corresponding to the allowable stresses as defined in Paragraph F-134.1.2 of Appendix F of the ASME Code.

On the basis of analyses performed by the Shoreham applicant (Enclosures 6 and 7 of letter dated June 17, 1983, from Bechtel Power Corporation) that verified the valve structural and pressure integrity and test results that demonstrated the valve operability and functionality, the staff finds that the design of the modified vacuum breaker valves for SSES is acceptable and can accommodate the effects of pool swell impact loadings following a design-basis LOCA. The staff's conclusion is based on the analyses performed on the Shoreham valves, which have the same modifications as those at SSES except for the additional actuating cylinder on the SSES valve for damping of the maximum impact velocity. Thus, the SSES valves will experience lower impact velocities and corresponding lower loads than the Shoreham valves.

In a letter dated October 24, 1983, the applicant informed the staff that installation of the modified vacuum breakers described above was completed for Susquehanna Unit 2. Therefore, the staff finds this issue resolved for Susquehanna Unit 2.

6.2.4 Containment Isolation Systems

6.2.4.3 Containment Purge System

In Section 1.10 of Supplement 5 to the SER, the staff provided a list of issues for which a condition was included in the operating license for Susquehanna Unit 1 for which a similar license condition would be required for Unit 2 unless satisfactory resolution was reached on the issue before the licensing of Unit 2. One such issue regarded the containment purge system. The applicant had committed to install debris screens on the drywell containment purge system during the first refueling outage.

In a letter from N. W. Curtis to A. Schwencer dated September 23, 1983, the applicant informed the staff that installation of debris screens on the drywell containment purge system for Unit 2 was complete. The staff finds this issue for Unit 2 resolved.

6.6 Inservice Inspection of Class 2 and 3 Components

GDC 36, "Inspection of Emergency Core Cooling Systems"; 39, "Inspection of Containment Heat Removal Systems"; 42, "Inspection of Containment Atmosphere Cleanup Systems"; and 45, "Inspection of Cooling Water System," require, in part, that the subject systems be designed to permit appropriate periodic inspection of important components to ensure system integrity and capability.

10 CFR 50.55a(g) defines the detailed requirements for the preservice and inservice inspection programs for light-water-cooled nuclear power facility components. On the basis of a construction permit date of November 2, 1973, this section of the regulation requires that a PSI program be developed for Class 2 components and be implemented using at least the Edition and Addenda of Section XI of the ASME Code in effect 6 months before the date of issuance of the construction permit. Also, the initial inservice inspection program must comply with the requirements of the latest Edition and Addenda of Section XI of the ASME Code in effect 12 months before the date of issuance of the operating license, subject to the limitations and modifications listed in 10 CFR 50.55a(b).

6.6.3 Evaluation of Compliance With 10 CFR 50.55a(g) for Unit 2

The staff completed the review of the PSI Program for Unit 1 and determined that this document was acceptable as described in Section 6.6.2 of Supplements 3 and 4. The preservice examination of Unit 2 was performed to the same ASME Code requirements (as modified by specific written relief requests) as the Unit 1 PSI Program. Therefore, the staff has determined that the PSI Program for Unit 2 is acceptable on the basis of the staff review and acceptance of the corresponding document for Unit 1.

The staff has completed the review of requests for relief from certain requirements that the applicant determined to be impractical in letters dated August 2, 1983, November 1, 1983, and December 21, 1983, in which a supporting technical justification was provided. The staff has determined that certain ASME Code, Section XI, examination requirements defined in 10 CFR 50.55a(g)(2) are impractical. Therefore, pursuant to 10 CFR 50.55a(a)(2), the staff has allowed relief from the requirements that have been determined to be impractical and that if implemented would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. On the basis of the granting of relief from these preservice examination requirements, the staff concludes that the PSI Program for Unit 2 is in compliance with 10 CFR 50.55a(g)(2). A detailed evaluation supporting this conclusion is provided in Appendix H to this report. The initial inservice inspection program for Unit 2 will be evaluated after the applicable ASME Code edition and addenda can be determined on the basis of 10 CFR 50.55a(b) and before the first refueling outage when inservice inspections will be performed.

Compliance with the inservice inspections required by Section XI of the ASME Code and 10 CFR 50 constitutes an acceptable basis for satisfying applicable inspection requirements of GDC 36, 39, 42, and 45.

7 INSTRUMENTATION AND CONTROL

7.5 Safety-Related Display Instrumentation

7.5.2 Specific Findings

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 plant, the staff issued IE Bulletin (IEB) 79-27. The applicant was asked to review Susquehanna Unit 2 with respect to this bulletin. In response to this concern, the applicant initiated a detailed review and analysis of the Susquehanna Unit 2 power sources and submitted a response (letter from N. W. Curtis to Director of Nuclear Reactor Regulation dated October 10, 1983). In this response, the applicant stated that

(1) The power system distribution buses for all instrumentation and controls required to operate those systems used to achieve cold shutdown from full-power operation and the control room alarms and indications used by the operators to detect and diagnose the failure of these critical power supplies were identified. Sufficient main control room alarms and indications are available to (a) alert the operators to the loss of any critical instrument and control power supply and (b) allow for ready identification of the failed power bus. Therefore, no design changes to instrument and control power supply availability displays were necessary.

(2) The effect of the loss of individual instrument and control power supplies on shutdown system operator control and indication circuits have been identified. A tabulation of these effects will be used in preparing emergency procedures in accordance with the bulletin. These procedures will be completed by fuel loading.

(3) Susquehanna does not have Class 1E inverters, and on the basis of review of IE Circular 79-02 and the non-Class 1E inverter, design modifications and administrative controls are not required.

7.5.3 Summary

On the basis of its review of the applicant's design as discussed in the Final Safety Analysis Report (FSAR), the response to IEB 79-27, and the applicant's commitment to include in the Susquehanna Unit 2 emergency procedures the appropriate operator actions requested by IEB 79-27, the staff considers this concern resolved.

8 ELECTRIC POWER SYSTEMS

PP&L proposed to modify the onsite distribution systems for Susquehanna Units 1 and 2 by letter dated September 26, 1983. These modifications of the onsite distribution systems involve the installation of the two new engineered safeguard transformers in addition to the two installed engineered safety features (ESF) transformers and retention of the construction substation off site after start of operation of Unit 2.

8.2 Offsite Power Systems

The construction substation provided power for the initial plant construction and provides power for various auxiliary buildings around the plant during operation. It is not interconnected with the plant auxiliary power system and the onsite distribution system. The Susquehanna 230-kV yard tie line supplies power to the construction transformer through a motor-operated air break switch. The construction transformer is protected by high-speed percentage differential, sudden pressure, and overcurrent relaying. Direct tranfer trip facilities are used as the primary relaying scheme to open the circuit breakers at the remote terminals of the transmission line in the event of a transformer fault. Backup protection is provided by a high-speed ground switch on the 230-kV side of the construction transformer. The motor-operated air switch automatically opens after the 230-kV system is deenergized to isolate the construction transformer from the offsite transmission system and permit the reclosing of the transmission line terminal circuit breakers to continue the supply of offsite power. The staff has reviewed the construction substation system and concludes that the fault of the construction substation, including the transformer, will be isolated by the primary and backup protective relaying fast enough to supply offsite power to the onsite distribution systems without disruption. Therefore, the construction substation connected to the offsite system is acceptable.

8.3 Onsite Emergency Power Systems

The ac onsite power system consists of four redundant and independent 4.16-kV ESF distribution systems with their 480-V load centers and motor control centers, 120-V vital ac power systems, and the standby power supplies (diesel generator units). Each 4.16-kV ESF bus is normally connected to a preferred source that is one of four engineered safeguard transformers connected respectively to the two 13.8-kV startup buses, two ESF transformers for each 13.8-kV bus. The staff had previously approved the onsite distribution system configuration in which one of the two ESF transformers supplied power to the two 4.16-kV ESF buses for Unit 1 operation. The modification (adding two ESF transformers) doubles the capacity of the ESF transformers for the Susquehanna plant. The capacity of the ESF transformers connected to the preferred source is sufficient to power the ESF loads of one unit and those loads required for concurrent safe shutdown of the second unit. An analysis has shown that during load sequencing and operation, frequency and voltage are maintained at a level that would not degrade the performance of any load below minimum design requirements. Therefore, this design modification of the onsite distribution systems is acceptable.

9 AUXILIARY SYSTEMS

9.1 Fuel Storage and Handling

9.1.4 Fuel Handling System

9.1.4.1 Heavy Loads

As a result of Generic Task A-36, "Control of Heavy Loads Near Spent Fuel," NUREG-0612, "Control of Heavy Loads at Nuclear Plants," was developed. Following the issuance of NUREG-0612, a generic letter dated December 22, 1980, was sent to all operating plants, applicants for operating licenses, and holders of construction permits requesting that responses be prepared to indicate the degree of compliance with the guidelines of NUREG-0612. The responses were to be made in two stages. The first response (Phase I) was to identify the load-handling equipment within the scope of NUREG-0612 and to describe the associated general load-handling operations such as safe load paths, procedures, operator training, special and general purpose lifting devices, the maintenance, testing, and repair of equipment, and the specifications for handling equipment. The second response (Phase II) was intended to show that either single-failure-proof handling equipment was not needed or that single-failure-proof equipment had been provided. This supplement contains the staff's evaluation of Phase I. An evaluation of Phase II will be the subject of future correspondence.

By letter dated December 22, 1980, PP&L was requested to review their provisions for handling and control of heavy loads at Susquehanna Unit 2 to determine the extent to which the guidelines of NUREG-0612 are currently satisfied and to discuss and commit to mutually agreeable changes and modifications that would be required in order to fully satisfy these guidelines.

The staff and its consultant, EG&G Idaho, Inc., have reviewed the PP&L submittal dated July 22, 1983, for Susquehanna Unit 2. As a result of its review, EG&G has issued a Technical Evaluation Report (TER). The staff has reviewed the TER and concurs with its findings that the guidelines in NUREG-0612, Section 5.1.1, have been satisfied. The TER and the results of the NRC evaluation were provided to the applicant in a letter from A. Schwencer to N. Curtis dated October 31, 1983. The staff concludes that Phase I for Susquehanna Unit 2 is acceptable.

9.2 Water Systems

9.2.1 Emergency Service Water System

In Section 1.10 of Supplement 5 to the SER, the staff provided a list of issues for which a condition was included in the operating license for Susquehanna Unit 1 for which a similar license condition would be required for Unit 2 unless satisfactory resolution was reached on the issue before licensing of Unit 2. One such issue regarded single failure in the emergency service water system.

By letter dated November 8, 1982, PP&L described a single failure in the emergency service water (ESW) system that resulted in less than 100% heat removal capability from one ESW loop for a specific large-break loss-of-coolant accident (LOCA). The scenario, described in detail below, results in two low-pressure core spray (LPCS) pumps being cooled by the operable ESW loop plus one low-pressure coolant injection (LPCI) pump (without cooling to the room, oil coolers, or seal cooler) to cool the core following the postulated LOCA. General Electric performed analyses (reviewed and evaluated in Supplement 4 to the SER) to show that acceptable core cooling is maintained under these conditions if the single LPCI pump is operated for at least 10 min. In that supplement, the staff also evaluated manufacturer's data for the LPCI pumps, backed up by test data that showed the LPCI pumps could operate for 10 min following loss of ESW. As reported in Supplement 4, the staff concluded that the analyses and pump tests were acceptable, and therefore, the design was acceptable.

In the November 8, 1982, letter, PP&L also identified several modifications that would eliminate a single active failure in the ESW system resulting from the above concern. PP&L indicated that modifications would be made in the long term so that ESW cooling water would be available to the necessary emergency core cooling systems for all postulated single failures in the ESW system.

By letter dated May 16, 1983, PP&L proposed a modification to the ESW system piping as a long-term resolution to the single-failure concern. In the existing design the division 1 ESW loop (ESW pumps powered by diesel generators A and C) supplies water to LPCI pumps A and C; the division 2 ESW loop (powered by diesel generators B and D) supplies cooling water to LPCI pumps B and D. A loss of flow in the division 1 loop (same basic failure mode for division 2) causes loss of cooling to LPCI pumps A and C, and the postulated LOCA can cause LPCI pumps B and D to be ineffective. The most limiting single failure for the division 1 loop is the loss of diesel generator A, which causes loss of division 1 ESW loop flow (resulting from the failure to open of the bypass valve to the spray pond) and loss of LPCI pump A. LPCI pump C would be available without cooling water. The proposed modification is to repipe cooling water to LPCI pumps C and D so that cooling water will be provided by the opposite ESW loop. Hence, the division 1 ESW loop would provide cooling water to LPCI pumps A and D, and the division 2 ESW loop would supply cooling water to LPCI pumps B and C. With the proposed modifications at least one LPCI pump with cooling water would be available for any postulated LOCA plus single active failure, including failure of a diesel generator to start. It should be noted that the failure of either diesel generator C or D does not result in complete loss of flow in either ESW loop; therefore, only the LPCI pump powered by diesel generator C or D would be lost and cooling water would continue to be supplied to the remaining LPCI pumps (A, B, C, or D).

The proposed modifications enable the ESW system to transfer heat from the equipment important to safety under normal operating and accident conditions assuming loss of offsite power and any single active failure in accordance with GDC 44, "Cooling Water."

On the basis of its review of the proposed modifications, the staff concludes that the ESW system meets the requirements of GDC 44 and that the proposed modifications resolve the concerns associated with a single failure in the ESW system resulting in less than 100% heat removal capability. The staff, therefore, concludes the proposed modifications are acceptable.

The Susquehanna Unit 2 license will be conditioned to require the completion of the design modifications to the ESW system before September 1, 1985.

9.2.3 Ultimate Heat Sink

In Section 9.2.3 of the SER, the staff accepted the utimate heat sink for single-unit operation because the applicant had used a less conservative method for determining decay heat loads than that in Branch Technical Position (BTP) ASB 9-2. In Section 2.4.4 of the SER, the staff required that, following spray pond efficiency tests, an analysis of actual maximum temperature be performed using either BTP ASB 9-2 or the American Nuclear Society (ANS) 5.1 curve plus 10% to estimate decay heat loads. The staff further required that if the temperature calculated in the new analysis is higher than the design maximum temperature (95°F), Technical Specifications should include provisions for actions to be taken in accordance with Position C.4 of Regulatory Guide 1.27, i.e., lowering the power level of one unit if the initial pond temperature reaches a certain value to be determined by analysis.

By letter dated December 21, 1983, the applicant provided the results of the spray pond efficiency test to justify two-unit operation. The results of the spray pond test and the new maximum temperature analysis showed that two-unit operation would be provided with sufficient cooling following a loss-of-coolant accident in one unit and a shutdown and cooldown of the remaining unit, if the spray pond operating temperature was limited to 81°F and the inventory was maintained at a minimum of 23 million gallons. An evaluation of the test results can be found in Section 2.4.4 of this supplement. As a result of these limitations, Technical Specifications will be modified to allow two-unit operation when the pond temperature is equal to or less than 81°F and the water level at the overflow weir is equal to or greater than 678 ft 1 in. mean sea level.

On the basis of its review of the applicant's analysis and Technical Specification limitations, the staff concludes that the ultimate heat sink will not exceed 95°F for two-unit operation. It, therefore, concludes that the ultimate heat sink is acceptable for two-unit operation.

9.5 <u>Fire Protection Systems</u>

9.5.5 Alternate Shutdown Systems

In Supplement 4 to the SER, the staff concluded that the fire protection for safe shutdown met staff guidelines. By letter dated December 13, 1983, the applicant identified a recently discovered deviation to the staff's guidelines concerning the separation of the switchgear cooling equipment.

The Unit 2 emergency switchgear cooling system provides switchgear and load center cooling in the event of a loss of offsite power. The load center and switchgear equipment is required for safe shutdown and must be kept at or below qualified temperatures.

The division I compressor motor and motor-operated valve are located within 9 ft of the division II compressor motor and motor-operated valve. Providing a 1-hour wrap for the motors is not possible; however, a 1-hour-rated barrier is provided for cables and conduits associated with one division of the cooling system. Automatic detection and sprinkler protection are provided in the area.

The in situ combustible loading is negligible, and the possibility for the introduction of transient combustible materials is low because access is by means of a vertical ladder.

This combination of protection constitutes an adequate level of safety and is an acceptable deviation from the staff's guidelines.

9.5.8 Appendix R Statement

On the basis of its evaluation, the staff concludes that with the following deviation, the fire protection program for Susquehanna Unit 1 and 2 will meet the technical requirements of Appendix R to 10 CFR 50 when the committed modifications have been completed, meets the requirements of GDC 3, and, therefore, is acceptable:

(1) The separation provided for the switchgear cooling equipment, fire zone 2-5A, is acceptable without a 1-hour-rated fire barrier for the divisions I and II compressor motors and motor-operated valves.

13 CONDUCT OF OPERATIONS

13.6 Industrial Security

13.6.1 Introduction

The applicant has revised and amended the "Susquehanna Steam Electric Station Physical Security Plan" to comply with the requirements of 10 CFR 73.55 (see Appendix A for a listing of transmittal letters).

On the basis of its review of the subject documents and visits to the site, the staff has concluded that the protection provided by the applicant against radiological sabotage at Susquehanna meets the requirements of 10 CFR 73. Accordingly, the protection ensures that the health and safety of the public will not be endangered. The appendix to Section 13.6 of this SER supplement contains safeguards information and must be protected in accordance with the provisions of 10 CFR 73.21.

13.6.2 Physical Security Organization

To satisfy the requirements of 10 CFR 73.55(b), the applicant has provided a physical security organization that includes a Security Shift Supervisor who is on site at all times with the authority to direct the physical protection activities. To implement the commitments made in the physical security plan, the training and qualification plan, and the safeguards contingency plan, written security procedures specifying the duties of the security organization members have been developed and are available for inspection. The training program and critical security tasks and duties for the security organization personnel are defined in the "Susquehanna Security Training and Qualification Plan," which meets the requirements of 10 CFR 73, Appendix B, for the training, equipping, and requalification of the security organization members. The physical security plan and the training program provide commitments that preclude the assignment of any individual to a security-related duty or task before the individual is trained, equipped, and qualified to perform the assigned duty in accordance with the approved guard training and qualification plan.

13.6.3 Physical Barriers

To meet the requirements of 10 CFR 73.55(c), the applicant has provided a protected area barrier that meets the definition in 10 CFR 73.2(f)(1). An isolation zone, to permit observation of activities along the barrier, of at least 20 ft is provided on both sides of the barrier with the exception of the locations listed in the protected appendix. The staff has reviewed those locations and determined that the security measures in place are satisfactory and continue to meet the requirements of 10 CFR 73.55(c).

Illumination of 0.2 ft-candle is maintained for the isolation zones, protected area barrier, and external portions of the protected area.

13.6.4 Identification of Vital Areas

The design basis for the applicant's program for identifying vital equipment included the regulatory definition of vital in 10 CFR 73.2(h)(i), 10 CFR 100 release limits, and the criteria contained in Regulatory Guide 1.29 and Review Guideline #17, "Definition of Vital Areas," Revision 2. The protected appendix contains a discussion of the applicant's program and identifies those areas and equipments determined to be vital.

Vital equipment is located within vital areas that are located within the protected area and that require passage through at least two barriers, as defined in 10 CFR 73.2(f)(1) and (2), to gain access to the vital equipment. Vital area barriers are separated from the protected area barrier.

The control room and central alarm station are provided with bullet-resistant walls, doors, ceilings, floors, and windows.

On the basis of these findings and the analysis set forth in Paragraph C of the protected appendix, the staff has concluded that the applicant's program for identification and protection of vital equipment satisfies the regulatory intent. However, this program is subject to onsite validation by the staff in the future and to subsequent changes if they are found to be necessary.

13.6.5 Access Requirements

In accordance with 10 CFR 73.55(d), all points of personnel and vehicle access to the protected area are controlled. The individual responsible for controlling the final point of access into the protected area is located in a bullet-resistant structure. As part of the access control program, vehicles (except under emergency conditions), personnel, packages, and materials entering the protected area are searched for explosives, firearms, and incendiary devices by electronic search equipment and/or physical search.

Vehicles admitted to the protected area, except applicant-designated vehicles, are controlled by escorts. Applicant-designated vehicles are limited to onsite station functions and remain in the protected area except for operational maintenance, repair, security, and emergency purposes. Positive control over the vehicles is maintained by personnel authorized to use the vehicles or by the escort personnel.

A picture badge/key card system, using encoded information, identifies individuals who are authorized unescorted access to protected and vital areas and is used to control access to these areas. Individuals not authorized unescorted access are issued non-picture badges that indicate an escort is required. Access authorizations are limited to those individuals who need access to perform their duties.

Unoccupied vital areas are locked and alarmed. During periods of refueling or major maintenance, access to the reactor containment(s) is positively controlled by a member of the security organization to ensure that only authorized individuals and materials are permitted to enter. In addition, all doors and personnel/equipment hatches into the reactor containment(s) are locked and alarmed. Keys, locks, combinations, and related equipment are changed on an annual basis. In addition, when an individual's access authorization has been terminated because of a lack of reliability or trustworthiness, or poor work performance, the keys, locks, combinations, and related equipment to which that person had access are changed.

13.6.6 Detection Aids

To satisfy the requirements of 10 CFR 73.55(e), the applicant has installed intrusion detection systems at the protected area barrier, at entrances to vital areas, and at all emergency exits. Alarms from the intrusion detection system annunciate within the continuously manned central alarm station and a secondary alarm station located within the protected area. The central alarm station is located so that the interior of the station is not visible from outside the perimeter of the protected area. In addition, the central station is constructed so that walls, floors, ceilings, doors, and windows are bullet resistant. The alarm stations are located and designed in such a manner that a single act cannot interdict the capability of calling for assistance or responding to alarms. No functions or duties that would interfere with its alarm response function are performed in the central alarm station. The intrusion detection system transmission lines and associated alarm annunciation hardware are self checking and tamper indicating. Alarm annunciators indicate the type of alarm and its location when activated. An automatic indication of when the alarm system is on standby power is provided in the central alarm station.

13.6.7 Communications

As required in 10 CFR 73.55(f), the applicant has provided for the capability of continuous communications between the central and secondary alarm station operators, guards, watchmen, and armed response personnel through the use of a conventional telephone system and a security radio system. In addition, direct communication with the local law enforcement authorities is maintained through the use of a conventional telephone system and two-way FM radio links. All nonportable communication links, except the conventional telephone system, are provided with an uninterruptible emergency power source.

13.6.8 Test and Maintenance Requirements

To meet the requirements of 10 CFR 73.55(g), the applicant has established a program for the testing and maintenance of all intrusion alarms, emergency alarms, communication equipment, physical barriers, and other security-related devices and equipment. Equipment or devices that do not meet the design performance criteria or that have failed to operate will be compensated for by appropriate measures as defined in the "Susquehanna Steam Electric Station Physical Security Plan" and onsite procedures. The compensatory measures will ensure that the effectiveness of the security system is not reduced by failures or other contingencies affecting the operation of the security-related equipment or structures. Intrusion detection systems are tested for proper performance at the beginning and end of any period during which they are used for security. Such testing will be conducted at least once every 7 days.

Systems for onsite communication are tested at the beginning of each security shift. Offsite communication systems are tested at least once each day.

Audits of the security program are conducted once every 12 months by personnel who are independent of site security management and supervision. The audits, focusing on the effectiveness of the physical protection provided by the onsite security organization implementing the approved security program plans, include, but are not limited to, a review of the security procedures and practices, system testing and maintenance programs, and local law enforcement assistance agreements. A report is prepared documenting audit findings and recommendations and is submitted to the plant management.

13.6.9 Response Requirements

To meet the requirements of 10 CFR 73.55(h), the applicant has provided for armed responders immediately available for response duties on all shifts consistent with the requirements of the regulations. Considerations used in support of this number are contained in the protected appendix. In addition, liaison with local law enforcement authorities to provide additional response support in the event of security events has been established and documented.

The applicant's safeguards contingency plan for dealing with thefts, threats, and radiological sabotage satisfies the requirements of 10 CFR 73, Appendix C. The plan identifies security events that could initiate radiological sabotage and identifies the applicant's preplanning, response resources, safeguards contingency participants, and coordination activities for each identified event. Through this plan, upon the detection of abnormal presence or activities within the protected or vital areas, response activities using the available resources would be initiated. The response activities and objectives include the neutralization of the existing threat by requiring the response force members to interpose themselves between the adversary and his objective, instructions to use force commensurate with that used by the adversary, and authority to request sufficient assistance from the local law enforcement authorities to maintain control over the situation.

To assist in the assessment/response activities, a closed circuit television system, providing the capability to observe the entire protected area perimeter, isolation zones, and most of the protected area, is provided to the security organization.

13.6.10 Employee Screening Program

To meet the requirements of 10 CFR 73.55(a) to protect against the design-basis threat as stated in 10 CFR 73.1(a)(1)(ii), the applicant has provided an employee screening program. Personnel who successfully complete the employee screening program or its equivalent may be granted unescorted access to protected and vital areas at the Susquehanna site. All other personnel requiring access to the site are escorted by persons authorized and trained for escort duties who have successfully completed the employee screening program. The employee screening program is based on accepted industry standards and includes a background investigation, a psychological evaluation, and a continuing observation program. In addition, the applicant may recognize the screening programs of other nuclear utilities or contractors on the basis of a comparability review conducted by PP&L. The plan also provides for a "grandfather clause" exclusion, which allows recognition of a certain period of trustworthy service with the utility or contractor as being equivalent to the overall employee screening program. The staff has reviewed the applicant's screening program against the accepted industry standard (ANSI N18.17-1973) and has determined that the program is acceptable.

14 INITIAL TEST PROGRAM

In letters from N. W. Curtis to A. Schwencer dated October 13, 1983, and December 29, 1983, PP&L forwarded revisions to Chapter 14 of the Susquehanna FSAR. The revisions add Sections 14.2.12.4, 14.2.12.5, and 14.2.12.6 to provide separate test descriptions for Unit 2 preoperational, acceptance, and startup tests. FSAR Sections 14.2.12.1, 14.2.12.2, and 14.2.12.3, which originally applied to both units, are retained as descriptions of Unit 1 tests. Since the Unit 1 startup has been successfully completed, the staff's review was limited to the new test descriptions for Unit 2 contained in Sections 14.2.12.4, 14.2.12.5, and 14.2.12.6.

The Unit 2 test descriptions do not include some tests that are included for Unit 1. These are tests of shared or identical systems for which all Unit 1 and Unit 2 test objectives were accomplished during the Unit 1 test program. Also, the test descriptions include some tests that were not included for Unit 1. They are descriptions of tests for systems, structures, and equipment unique to Unit 2 or which were not provided for Unit 1 before its licensing. These differences are described in a letter from N. W. Curtis to A. Schwencer dated December 21, 1983.

The objective of this review was to determine if the new Unit 2 test descriptions describe an initial test program that is as comprehensive as that of the previously evaluated and accepted Unit 1 test program. The staff's review included verification of the following items:

(1) There are test descriptions for those Unit 2 structures, systems, components, and design features that (a) will be used for shutdown and cooldown of the reactor under normal, transient, and accident conditions and for maintaining the reactor in a safe shutdown condition for an extended period of time; (b) will be used for establishing conformance with safety limits or limiting conditions for operation that will be included in the facility Technical Specifications; (c) are classified as engineered safety features or will be relied on to support or ensure the operations of engineered safety features within design limits; (d) are assumed to function or for which credit is taken in the accident analysis of the facility, as described in the FSAR; or (e) will be used to process, store, control, or limit the release of radioactive materials.

(2) The test objectives, prerequisites, test methods, and acceptance criteria for each Unit 2 test description include sufficient detail to establish that the functional adequacy of the structures, systems, components, and design features will be demonstrated.

On the basis of this review and its previous evaluation, the staff has concluded that the Unit 2 initial test program is acceptable and meets the requirements of 10 CFR 50.34(b)(6)(iii), which requires inclusion of plans for preoperational testing and initial operations in the FSAR, and 10 CFR 50, Appendix B, Section XI, which requires a test program to ensure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures that incorporate the requirements and acceptance limits contained in applicable design documents. The staff has further concluded that the initial test program described in the application meets the acceptance criteria of SRP Section 14.2 (NUREG-0800), and the successful completion of the test program will demonstrate the functional adequacy of Unit 2 structures, systems, and components.

Because the holder of an operating license has the legal option to make changes to the initial test program pursuant to 10 CFR 50.59, the staff will condition the Unit 2 operating license, similarly to that of Unit 1, to require the applicant to complete the initial startup test program described in the FSAR without making any major modifications unless such modifications have prior NRC approval. Major modifications will be defined in the license as

(1) Elimination of any test described in FSAR Chapter 14 and not identified therein as being nonessential

(2) Modification of objectives, methods, or acceptance criteria for any test described in FSAR Chapter 14 and not identified therein as being nonessential

(3) Performance of any test not identified as nonessential at a power level different from that stated in the FSAR by more than 5% of rated power

(4) Failure to satisfactorily complete any test not identified as nonessential

(5) Failure to satisfactorily complete the entire initial startup test program by the time core burnup equals 120 effective full-power days

(6) Deviation from initial test program administrative procedures or initial test program quality assurance controls described in the FSAR (Chapters 13, 14, and 17)

(7) Delays in excess of 30 additional days (14 additional days if power level exceeds 50%) between any two successive milestones depicted in the startup test schedule in the FSAR. If continued power operation for purposes other than testing is desired during such a delay, the licensee shall submit a safety analysis to show that adequate testing has been performed and evaluated to demonstrate that the facility can be operated without increased risk to public safety.

17 QUALITY ASSURANCE

17.6 Confirmatory In-Depth Review Program

In Section 1.10 of Supplement 5 to the SER, the staff provided a list of issues for which a condition was included in the operating license for Susquehanna Unit 1 for which a similar license condition would be required for Unit 2 unless satisfactory resolution was reached on the issue before licensing of Unit 2. One such issue regarded the assurance of proper design and construction.

In a letter dated March 16, 1983, the applicant provided the staff with a summary of recent audits and reviews conducted on Susquehanna Unit 2 activities as a means of confirming Unit 2 design adequacy. In addition, PP&L provided in a letter dated April 7, 1983, a copy of the self-initiated evaluation of the Susquehanna Unit 2 construction project using Institute of Nuclear Power Operations Performance Objectives and Criteria for Project Evaluations.

The staff reviewed these submittals and determined that a separate independent design verification process (IDVP) is not required on Unit 2 because the design process of Unit 2 is essentially the same as that applied to Unit 1 and incorporates improvements made as a result of lessons learned on the Unit 1 IDVP. The staff finds this issue resolved for Unit 2.

22 TMI-2 REQUIREMENTS

22.2 TMI Action Plan Requirements for Applicants for Operating Licenses

I Operational Safety

I.D.1 Control Room Design Review

In Section 1.10 of Supplement 5 to the SER, the staff provided a list of issues for which a condition was included in the operating license for Susquehanna Unit 1 for which a similar license condition would be required for Unit 2 unless satisfactory resolution was reached on the issue for licensing Unit 2. One such issue regarded the display control system report discussing the experience, including demonstrated reliability, of the system.

Because SSES uses a common control room design for Units 1 and 2, and the multiple cathode ray tube display design is essentially identical for each unit, the staff will require only a single report from the applicant on the experience and reliability of the display control system for use in making future decisions. Therefore, the staff concludes the license condition contained in the Unit 1 license is sufficient for current staff needs and a similar condition in the Unit 2 license is not required.

The applicant's preliminary design assessment (PDA) and the staff's audit of the Susquehanna Unit 1 control room identified 42 human engineering discrepancies (HEDs) that required correction before licensing. On July 17, 1982, Unit 1 received a license for low-power operation on the bsais of the applicant's correction of most of these HEDs. Correction of the remaining HEDs was completed, in accordance with the license condition, by September 1, 1982. Supplement 3 noted that the Susquehanna Unit 2 control room must be subjected to either a PDA or a detailed control room design review (DCRDR) before licensing of that unit. To satisfy that requirement, the applicant verbally committed to incorporate all HED corrections applied to the Unit 1 control room into the design for the Unit 2 control room. Supplement 5 noted that the applicant should provide a written commitment to this effect. This commitment was subsequently received by the staff. In addition, Supplement 5 noted that if the applicant expects licensing of Unit 2 to be based on the PDA for Unit 1, any differences between the two control rooms must be determined and addressed in a supplement to the Unit 1 PDA.

Supplement 5 also noted that corrections of HEDs in the Unit 2 control room based on the applicant's PDA for Unit 1 should be completed before licensing. In addition, the applicant should submit a report addressing all HEDs at least 6 months before licensing to ensure timely closeout of the prelicensing control room design review. The report should list proposed corrective actions for the HEDs, implementation schedules, and any deviations from previous commitments. Justifications for deviations from previous commitments should also be provided.

The staff will require written confirmation before licensing that the Unit 1 HED corrections have been incorporated in the Unit 2 control room. It will require a report before licensing, describing any differences between the Unit 1 and Unit 2 control rooms and addressing any HEDs resulting from these differences. The staff will also require as a condition of the Unit 2 license that all Unit 1 HEDs requiring correction as a result of the applicant's DCRDR be corrected in the Unit 2 control room. PP&L will be required to submit, for review and approval by the NRC staff, the schedule for implementing all HED corrective actions resulting from the DCRDR by March 1, 1985.

I.G.1 Training During Low-Power Testing

In Supplement 1 the staff stated that it would review the applicant's safety analysis and test procedures for a simulated loss of onsite and offsite ac power test (station blackout or SBO test). This test was to be performed subject to a safety analysis finding that the test would not constitute a risk to public safety or a risk of damage to plant equipment. In Supplement 3 the staff stated that an analysis had been received from the applicant, but that it contained insufficient information. In a letter dated August 25, 1982, the applicant forwarded additional information. The staff evaluated the information and concluded, as reported in Generic Letter 83-24 dated June 29, 1983, that the SBO test is not warranted in view of the possibility of damage to plant equipment. This generic letter further stated that compliance with the BWR Owners Group recommendations in a letter dated February 4, 1981, constitutes an acceptable Item I.G.1 program.

In a letter dated August 19, 1983, the applicant reaffirmed his commitment to the BWR Owners Group recommendations.

On the basis of the applicant's commitment to the BWR Owners Group program and consistent with its position in the generic letter, the staff concludes that the applicant's program meets the requirements of Item I.G.1.

II Siting and Design

II.E System Design

II.E.4.2 Containment Isolation Dependability

In Section 1.10 of Supplement 5 to the SER, the staff provided a list of issues for which a condition was included in the operating license for Susquehanna Unit 1 for which a similar license condition would be required for Unit 2 unless satisfactory resolution was reached on the issue before licensing of Unit 2. One such issue regarded the operability of containment purge and vent valves.

Requirements

Demonstration of operability of the containment purge and vent valves, particularly the ability of these valves to close during a design-basis accident, is necessary to ensure containment isolation. This demonstration of operability is required by Branch Technical Position CSB 6-4 and SRP Section 3.10 (NUREG-0800) for containment purge and vent valves that are not sealed closed during operational conditions 1, 2, 3, and 4.

Description of Purge and Vent Valves

The valves identified as the containment isolation valves in the purge and vent system in which operability has not previously been demonstrated are:

Valve P&ID number	Valve size (inches)	Type	Location
HV-1,2 25703	18	Butterfly	Outside containment
HV-1,2 25704	18	Butterfly	Outside containment
HV-1,2 25724	18	Butterfly	Outside containment
HV-1,2 25725	18	Butterfly	Outside containment
HV-1,2 25713	24	Butterfly	Outside containment
HV-1,2 25714	24	Butterfly	Outside containment
HV-1,2 25722	24	Butterfly	Outside containment
HV-1,2 25723	24	Butterfly	Outside containment

The 18- and 24-in. valves are H. Pratt valves Model 1200, 150 lb, with an offset asymmetric disc. The 18-in. valves are equipped with Bettis Operators, Model T312-SR3, air open-spring close. The 24-in. valves are equipped with Bettis Operators, Model T416-SR3. PP&L's assessment is that the valves are capable of closing from the full-open (90°) position under the accident case postulated. PP&L has previously demonstrated operability of the 6-in. valves installed in the purge vent system.

Demonstration of Operability

PP&L has provided information in a letter dated April 13, 1983, demonstrating operability of the purge and vent system isolation valves for SSES units in the following submittals:

(1) H. Pratt Qualification Analysis Report for the 18-in. valves HBB-BF-AO-5703, 5704, 5724, and 5725 dated January 11, 1983

(2) H. Pratt Qualification Analysis Report for the 24-in. valves HBB-BF-AO-5713, 5714, 5722, and 5723 dated January 28, 1983

PP&L's approach to operability demonstration is based on the following considerations:

(1) The maximum dynamic torque occurs when initial sonic flow occurs. This corresponds with an open angle of 68° for an asymmetric disc.

(2) Closure plus delay time equalled 11 sec.

(3) Closure time under LOCA conditions is less than no-load stroke times.

(4) Flow direction through the valve is toward the hub side (asymmetric disc), which is the worst-case dynamic torque developed.

(5) Single valve closure is assumed.

(6) All valves are air operated and are located outside containment. Containment back-pressure effect is not applicable.

(7) Accumulators are not part of any valve assembly.

(8) The analysis of the structural integrity and operational adequacy of the valve assembly is based principally on containment pressure versus time data, system response (delay) time, piping geometry upstream of the valve, back pressure resulting from ventilation components downstream of the valve, valve orientation, and direction of valve closure.

Evaluation

Revised pressure response and temperature response curves for a recirculation line break are presented. A peak wetwell pressure of 41 psia and a peak drywell pressure of 58.2 psia were used in the analysis. FSAR Section 6.2.1.1.3.1 states that the calculated accident parameter is 43.8 psig and 29 psig for the drywell and suppression chamber, respectively. The staff bases its review on the latest submittal or the 41 psia and 58.2 psia values.

The analysis presented states that the maximum dynamic torque occurs when initial sonic flow occurs. This corresponds with an open angle of 68° for an asymmetric disc. Downstream pressure was selected by considering the valve closure time and pressure time curves so that the downstream pressure at 68° would yield the critical ratio for the air/stream mixture. This was considered by H. Pratt and the staff, on the basis of the information submitted, to be the worst-case approach in determining valve loading.

H. Pratt's approach to determining dyamic torque T_D for the subject valves is based, in part, on the fact that H. Pratt has determined from the model valve tests that the maximum value of T_D occurs when initial sonic flow occurs coincident with a disc angle of 68° for the asymmetric disc (90° = full open). On the basis of this, the T_D equation for sonic flow (given in the submittal) is used with appropriate dynamic torque coefficient, media difference (steam/air mixture), and size difference factors to determine the maximum value of T_D possible in the subject valves.

Coefficient of friction used for the bronze bearings is 0.25.

Seating torques (T_S) are calculated by an equation in American Water Works Association (AWWA) C504-80. Seating factor or coefficient of seating (C_S) is said to be determined by Pratt laboratory tests.

T_8 defined as "maximum operating torque for valve" is used in the applicable areas of the stress analysis as the torque load. T_8 is shown to be the higher value of the algebraically combined T_D and T_B or T_B plus T_S. For the 18.0-in. valves, T_8 is 20,551 in.-lb or basically equal to T_D, which is more conservative than $T_D - T_B$. For the 24.0-in. valves, T_8 is 69,617 in.-lb or basically equal to T_D, which again is more conservative than $T_D - T_B$, to which the staff agrees.

In the analysis reports, H. Pratt has indicated that the stress analysis is structured to comply with Paragraph NB-3550 of Section III of the ASME Code and that design rules for Class 1 valves are used (exceed rules for Classes 2 and 3).

H. Pratt states that valve components are analyzed under the assumption that the valve is either at maximum fluid dynamic torque or seating against the maximum design pressure. An analysis temperature of 300°F is used along with 5g seismic accelerations statically applied simultaneously in each of three mutually perpendicular directions.

Stress summary tables were provided for both the 18- and 24-in. isolation valves. As requested by the NRC, H. Pratt has revised the allowable shear stress to 0.4Sy. Using the revised peak post-LOCA wetwell pressure in combination with the allowable shear stress of 0.4Sy and with the addition of new materials in the top disc pin and redesign of the bonnet for the 24-in. valve, the stress levels for the 18- and 24-in. valves were found to be below the Code allowable values and acceptable.

Closing time, including delay time, is said to be 11 sec. However, this is not an issue because the analysis has considered a constant peak containment pressure throughout the analysis.

In the submittal dated April 13, 1983, PP&L committed to make the modifications to the 24-in. valves before startup following the first refueling outage for Unit 1. For Unit 2, the modification will be made before fuel loading. This schedule is acceptable to the staff.

Summary

The staff has completed its review of the information submitted to date concerning operability of 18- and 24-in. containment purge and vent valves for the Susquehanna Steam Electric Station. The staff finds the information submitted demonstrates the ability of the 18- and 24-in. purge and vent valves to close against the buildup of containment pressure in the event of a LOCA. The staff considers this issue resolved.

II.F:2 Instrumentation for Detection of Inadequate Core Cooling

Supplement 4 to the SER indicated that PP&L was expected to submit a report by August 31, 1982, addressing the analyses performed by the BWR Owners Group regarding additional instrumentation relative to inadequate core cooling and that PP&L would be requested to implement the staff's requirements after the completion of the staff's review of this report. Accordingly, the Susquehanna Unit 1 license was conditioned on the submittal of this report.

In response to the license condition, PP&L submitted a report by letter of August 31, 1982, from N. W. Curtis (PP&L) to A. Schwencer (NRC). This submittal addressed the analyses in BWR Owners Group report, SLI-8211, "Review of BWR Reactor Water Level Measurement Systems," and BWR Owners Group report, SLI-8218, "Inadequate Core Cooling Detection in BWRs."

The staff has not developed a final position on inadequate core cooling instrument requirements. Any additional requirements stemming from the staff's review of the inadequate core cooling instrumentation will be imposed following the development of a final position. The operating license for Susquehanna Unit 2 will be conditioned to require PP&L to implement such additional requirements, if any.

II.K.3 Final Recomendations of Bulletins and Orders Task Force

II.K.3.18 Modification of Automatic Depressurization System Logic - Feasibility for Increased Diversity for Some Event Sequences

The automatic depressurization system (ADS), through selected safety relief valves, functions as a backup to the operation of the high-pressure coolant systems. The ADS depressurizes the vessel so that low-pressure systems may inject water into the reactor vessel. The ADS is typically activated automatically on receipt of coincident signals of low water level in the reactor vessel, high drywell pressure, and the running of any low-pressure emergency core cooling system pump. A time delay of approximately 2 min after receipt of the coincident signals allows time for the automatic blowdown to be bypassed manually if the operator believes the signals are erroneous or if the water level can be restored.

For transient and accident events that do not directly produce a high drywell pressure signal (e.g., stuck-open relief valve or steamline break outside containment) and are degraded by a loss of high-pressure coolant systems, manual actuation of the ADS is required to provide adequate core cooling. A reliability and risk assessment was requested so that the optimum approach to eliminate the need for manual actuation could be obtained. A further consideration is that proposed modifications to the ADS logic should be such that operator actions that may be required during an anticipated transient without scram (ATWS) would not be complicated by the ADS.

The BWR Owners Group response provided in a letter to D. G. Eisenhut (NRC) from T. J. Dente (BWR Owners Group) (BWROG-8260) dated October 28, 1982, did not provide the requested reliability and risk assessment. It did provide a discussion of the advantages and disadvantages of each of several options. A qualitative discussion of the risk and reliability was provided.

Eight ADS logic options are considered in the BWR Owners Group response: the current design and seven logic modifications. The seven modifications are

(1) elimination of the high drywell pressure permissive with the addition of a manual switch to inhibit automatic depressurization

(2) elimination of the high drywell pressure permissive and changing the low reactor pressure vessel (RPV) level trip setpoint to the top of the active fuel (TAF)

(3) addition of a manual switch to inhibit automatic blowdown in conjunction with a timer that bypasses the high drywell pressure permissive if the reactor water level is low for a sustained period

(4) addition of a timer that bypasses the high drywell pressure permissive if the reactor water level is low for a sustained period and changing the low RPV water level trip setpoint to the TAF

(5) addition of a manual switch to inhibit automatic blowdown in conjunction with a suppression pool temperature permissive in parallel with the high drywell pressure permissive

(6) addition of a suppression pool temperature permissive in parallel with the high drywell pressure permissive and changing the low RPV water level trip setpoint to the TAF

(7) addition of a manual switch to inhibit automatic blowdown

As indicated initially in the staff position, the present ADS logic design (except for those few plants that do not have the high drywell pressure permissive) does not satisfy the requirement to eliminate the need for operator action because it has not been demonstrated that the high drywell pressure signal would be present for all situations requiring ADS actuation.

The second option, elimination of the high drywell pressure permissive and addition of a manual inhibit switch, satisfies the requirement and is simple to implement. Further, the manual inhibit switch permits the operator to override the automatic blowdown logic if necessary. Therefore, the second option is acceptable.

The third option, elimination of the high drywell pressure permissive and changing the low RPV water level trip setpoint to the TAF, satisfies the requirement to eliminate the need for manual action to blow down the vessel but could require repeated operator action (approximately every 2 min) to reset the ADS timer for ATWS events where low water level is deliberately maintained to reduce power. Changing the low level trip setpoint may also be very expensive because installation of new water level instrumentation would be required for many plants. This option was, therefore, not recommended by the BWR Owners Group.

The fourth option, addition of a timer that bypasses the high drywell pressure permissive if the reactor water level is low for a sustained period and addition of a manual inhibit switch, also satisfies the requirement and is simple to implement. The time delay used must be justified by analysis if this option is chosen, and the Technical Specifications must be modified to require testing of the timer. The fourth option is acceptable to the staff.

The fifth option, addition of a timer that bypasses the high drywell pressure permissive if the reactor water level is low for a sustained period and changing the low RPV water level trip setpoint, was not recommended for the same reasons as those discussed for the third option.

The sixth option, addition of a suppression pool temperature permissive in parallel with the high drywell pressure permissive and a manual inhibit switch, would theoretically satisfy the requirements. However, temperature variations within the suppression pool would necessitate the use of many thermocouples connected through averaging circuits. This option was rejected by the BWR Owners Group because it is relatively impractical.

The seventh option, addition of a suppression pool temperature trip in parallel with the high drywell pressure trip and changing the low RPV water level trip setpoint to the TAF, was rejected by the BWR Owners Group for the same reason as that given for the sixth option.

The eighth option, addition of a manual inhibit switch, does not satisfy the requirement because manual action would still be required for breaks that do not pressurize the drywell.

The second, third, fourth, and fifth options effectively remove the high drywell pressure permissive for ADS actuation. Addition of the manual inhibit switch (options 2, 4, and 8) enables the operator to override the ADS should this be necessary (as for some ATWS events). Suppression pool temperature permissives are judged to be impractical. Changes to the RPV low water level trip setpoint may not be sufficient to provide the operator with the flexibility needed to override the ADS when needed.

It was concluded, therefore, that two of the eight options proposed are acceptable. They are option 2, elimination of the high drywell permissive and the addition of a manual inhibit switch, and option 4, bypass of the high drywell pressure permissive after sustained low water level and the addition of a manual inhibit switch.

By letter dated October 1, 1982 (PLA-1312), PP&L adopted the results of the BWR Owners Group study on TMI Action Plan Item II.K.3.18. The applicant has committed to modify the ADS logic to bypass the high drywell pressure trip after a sustained low water level signal, and to add a manual switch that may be used to inhibit ADS actuation if necessary. This is consistent with option 4 of the BWR Owners Group study and is acceptable to the staff with the following conditions:

(1) Installation at Unit 1 must be completed before startup following the first refueling outage; installation at Unit 2 must be completed before initial criticality.

(2) Technical Specifications must be provided for the bypass timer and manual inhibit switch.

(3) The use of the inhibit switch must be addressed in the plant emergency procedures.

(4) A plant-specific analysis must be provided to justify the bypass timer setting.

In a letter dated July 7, 1983, PP&L provided the results of analyses to determine the setting for the ADS high drywell pressure permissive bypass timer. The timer setting was determined by consideration of LOCAs, loss of inventory events, and ATWS events. The analyses were initially performed using realistic models and inputs in order to establish a range of possible settings. PP&L

then selected a 480-sec setting and performed LOCA and loss-of-inventory-event calculations using approved Appendix K models. The peak cladding temperature (PCT) for the worst-case event with a timer setting of 480 sec was calculated to be 1500°F. This is below the PCT limit of 2200°F.

The staff has reviewed the applicant's proposed setting for the ADS bypass timer and the results of his supporting analysis. The staff concludes that the proposed timer setting of 480 sec is acceptable.

In a letter dated February 22, 1984, from N. W. Curtis to the Director, NRR, PP&L requested a change to conditions of the applicant's response to TMI Action Plan Item II.K.3.18. The applicant has requested that the completion date for plant emergency procedures and Technical Specifications related to the manual inhibit switch for the ADS be delayed for Unit 2 to be concurrent with the first refueling outage for Unit 1.

The staff has reviewed the applicant's submittal and the current requirements for TMI Action Plan Item II.K.3.18 for Susquehanna Units 1 and 2. The staff notes that the currently required implementation schedules are different for Units 1 and 2 for both hardware installation and for preparation of procedures and Technical Specifications. This was based on the different construction schedules for the two units and equipment availability. The staff also notes that operators at Susquehanna are normally qualified on both Units 1 and 2. Implementation of the current requirements would therefore dictate the training of the same operators on different sets of equipment and to differing procedures for the two units. The staff considers this to be undesirable. Furthermore, the staff has considered the intended function of the manual inhibit switch, which is to allow the operator to prevent automatic ADS initiation under certain ATWS conditions. It is the staff's judgment that the likelihood of an ATWS event requiring the use of the manual inhibit switch in the time period of the proposed delay is small. Therefore, because of the potential complication in operator training and the low likelihood of the ATWS event, the staff concludes that the implementation delay proposed by the applicant is acceptable. During the interim period, the manual inhibit switch, which is already installed, should be disabled because there are no procedures for its use.

The following condition will be included in the license for Susquehanna Unit 2:

(1) Prior to achieving initial criticality, PP&L shall:

  (i) Install modifications to the Automatic Depressurization System acceptable to the NRC, and

  (ii) Propose Technical Specifications for the bypass timer setting and surveillance requirements for the bypass timer.

(2) Prior to September 1, 1985, PP&L shall:

  (i) Incorporate into the Plant Emergency Procedures the usage of the manual inhibit switch, and

  (ii) Propose Technical Specifications for the manual inhibit switch.

(3) PP&L shall maintain the manual inhibit switch disabled until License Condition (2) above is satisfied.

II.K.3.25 Effect of Loss of Power on Alternating Current Pump Seals

In Supplement 1 to the SER, the staff indicated the Unit 1 operating license would be conditioned to require, by first refueling, that the applicant provide an emergency power supply to the cooling system for the recirculation pump seals. In Section 1.10 of Suppement 5 to the SER, the staff indicated a similar condition would be required for Unit 2 unless satisfactory resolution was reached on the issue before the licensing of Unit 2.

Three tests have been performed on pumps that are representative of BWR recirculation pumps in which all seal cooling water was lost. Although the pump seal cavity temperature exceeded normal operating conditions and pump seal leakage increased following loss of cooling, the observed leakage from the seals was acceptably low.

The first test, which was of the Hanford Unit 2 BWR recirculation pump manufactured by the Bingham Pump Company, was performed at the pump vendor's test facility in July 1973. During the operability testing of that pump at rated temperature and pressure, plant power to the pump was inadvertently lost. Upon loss of plant power, the recirculation pump seal cavity was deprived of seal purge (direct injection), and the pump was unable to recirculate the seal coolant through the external heat exchanger. As a result, the seal cavity temperature exceeded 270°F. During this event the seal leakage recorder was inoperative; however, test personnel continued to monitor pump leakage visually and observed or recorded no leakages beyond the capability of the 1-in. seal drain lines (under 5 gpm). This is well within the makeup capacity of the reactor core isolation cooling (RCIC) system. These leakage observations continued for more than 5 hours after cooling was lost. These test results provide confirmation that loss of cooling to the tested Bingham pump seal for 5 hours does not lead to unacceptable seal leakage.

The second test was performed on a Byron Jackson pump in December 1978 by exposing the seal to 530°F water and observing and recording seal leakage following a loss of seal cooling water for 30 min. Although this test duration does not exceed the 2-hour criterion, the peak seal temperature, which is limited by the temperature of the primary system water, was reached during the 30-min test. Consequently, if any significant seal deterioration were to occur, it would have occurred during this 30-min test period. The details of the testing and associated hardware are described in ASME Paper No. 80-C2-PVP-28. The test results showed a measured seal leak rate of 2.39 gpm, which is well within the makeup capacity of the RCIC system. Consequently, this test shows that loss of seal cooling for the tested Byron Jackson pump does not lead to unacceptable seal leakage.

The third test was performed on a Byron Jackson (BJ) pump at Byron Jackson Pump Division, Borg-Warner Corp. in Los Angeles in August 1980. Water at 550°F and 2,300 psig was piped from the discharge leg of a test loop through a test fixture that closely simulated a typical BJ seal cavity and heat exchanger arrangement and back to the suction leg of the test loop. When the test loop water reached this temperature and pressure, the cooling water to the test fixture was discontinued and the test commenced. The test results showed that the seal leakage remained steady and low (30 cc/hour) for the first 4 hours of the test. The test continued for 56 hours and leakage did not increase appreciably. As with the earlier Byron Jackson test, this test showed that loss of seal cooling to that pump does not lead to unacceptable seal leakage, i.e., leakage beyond the makeup capacity of the RCIC system.

The above test results are representative or bounding for BWR recirculation pumps as described below.

(1) Bingham Pumps - The seal design for the tested pump is the same design and the largest size used in BWR recirculation pump application. In addition, the test conditions for the tested pump are applicable to BWR recirculation pumps. The test results are, therefore, applicable to the inplant BWR pumps.

(2) Byron Jackson (BJ) Pumps - The test results for the tested BJ pumps are bounding for the BJ pumps used for BWR recirculation systems because

   (a) The tested BJ pumps had a three-stage seal assembly with a fourth vapor seal. General Electric BWR recirculation pumps utilize two-stage seals. However, because the seal leak rates were small, the impact of the number of stages on the leak rate is also small. For the BJ pumps in BWR applications, the differential pressure per stage across the seal is approximately 190 psi lower (525 psi vs 716 psi) than for the BJ pump seals tested. Consequently, the leak rate through the tested pump seal would be higher than that for the inplant BWR pump seal.

   (b) The BJ test seal is a larger size seal than that used in a BWR recirculation pump, and the expected leakage from the seal would be higher than for a BWR pump.

   (c) Other than the differences identified in (a) and (b), the design of the BJ test seal is similar to that of a typical BJ seal used in BWR recirculation pump application.

Seal leakage data on Bingham and Byron Jackson pumps show the leakage rates to be acceptable following loss of cooling to the pump seals. The test pumps were typical of recirculation pumps used in BWRs. Therefore, no modifications to the seal cooling for recirculation pumps are required. The staff considers this issue resolved for Susquehanna Unit 2.

APPENDIX A

CONTINUATION OF CHRONOLOGY OF NRC STAFF RADIOLOGICAL REVIEW OF SUSQUEHANNA STEAM ELECTRIC STATION, UNITS 1 and 2

Appendix A in the Safety Evaluation Report and Supplements 1, 2, 3, 4, and 5 provided a chronology of the NRC staff's radiological safety review of the application for the period April 10, 1978, to February 11, 1983; the purpose of this appendix is to update that chronology.

February 14, 1983	Letter from applicant transmitting the January 1983 Monthly Operating Report.
February 16, 1983	Letter from Teledyne Engineering Services transmitting Independent Design Review - Susquehanna Steam Electric Station, Review of Category III Anchors.
February 18, 1983	Letter from applicant concerning License Condition 2.C.17(a) of License NPF-14.
February 23, 1983	Letter to applicant concerning Susquehanna Unit 2 seismic and dynamic qualification review and audit.
February 25, 1983	Letter to applicant concerning Nuclear Waste Policy Act of 1982 (PL 97-425).
February 25, 1983	Letter from applicant concerning response to License Condition 2.C(13) of License NPF-14.
February 28, 1983	Letter from applicant concerning Humphrey Issue 3.0.
February 28, 1983	Letter from applicant concerning qualification of the reactor recirculation discharge valve assemblies - License Condition 2.C(23) (e).
February 28, 1983	Letter from applicant concerning operator licensing examination site visits (Generic Letter 83-01 response).
February 28, 1983	Letter from applicant concerning emergency preparedness - Licensing Conditions 2.C(2) (a), (b), and (c).
March 1, 1983	Letter from applicant concerning low level radwaste holding facility - response to NRC questions.
March 7, 1983	Letter from applicant concerning request for information - emergency operations facilities.
March 7, 1983	Letter from applicant concerning design assessment report, Revision 8.

March 9, 1983	Letter from applicant concerning startup testing.
March 10, 1983	Letter to applicant responding to request for exemption from 10 CFR 50.44 requirements based on installation of operable inerting system.
March 11, 1983	Letter from applicant transmitting Amendment 21 to License NPF-14 proposing changes to Appendix A of the Technical Specification regarding typographical and administrative errors.
March 11, 1983	Letter from applicant transmitting Revision 3 to Evaluation of Feedwater Check Valves Due to Postulated Pipe Rupture.
March 14, 1983	Letter from applicant transmitting Exercise Manual for full-scale NRC/Federal Emergency Management Agency-observed emergency preparedness exercise.
March 14, 1983	Letter from applicant concerning request for exemption from testing.
March 15, 1983	Letter from applicant transmitting the February 1983 Monthly Operating Report.
March 15, 1983	Letter to applicant requesting information regarding determination of effect operation and maintenance may have on archaeological sites.
March 16, 1983	Letter from applicant transmitting the 1982 Annual Financial Report.
March 16, 1983	Letter from applicant discussing final results of additional tests of adequacy of design process.
March 17, 1983	Letter from applicant discussing results of analysis of proposed Transcontinental Gas Pipe Line Corp. (Transco) natural gas pipeline installation.
March 18, 1983	Letter from applicant transmitting "Susquehanna Post-Accident Airborne and Plateout Dose Calculation for Equipment Qualification," per NUREG-0588.
March 22, 1983	Letter from applicant transmitting revision to National Pollution Discharge Elimination System Permit regarding sewage treatment.
March 23, 1983	Letter to applicant regarding implementation of Regulatory Guide (RG) 1.150 (Generic Letter 83-15).
March 23, 1983	Letter from applicant advising that Change N to the physical security plan originally scheduled for February 1983 will be transmitted in April 1983.

March 24, 1983	Letter from applicant concerning annual personnel monitoring report.
March 24, 1983	Letter to applicant concerning NUREG-0977 anticipated transient without scram (ATWS) events at Salem Generating Station, Unit 1 (Generic Letter 83-16).
March 24, 1983	Letter to applicant transmitting additional guidance on reporting offsite radiation doses to the public.
March 24, 1983	Letter from applicant transmitting temporary change notices for emergency plan implementation procedures.
March 29, 1983	Letter from applicant transmitting 223 oversize updated drawings in accordance with RG 1.70.
March 30, 1983	Letter from applicant transmitting supporting information on request for one-time exemption from performing integrated leak rate test on containment penetrations.
April 4, 1983	Letter to applicant concerning ATWS events at Salem (Generic Letter 83-16A).
April 4, 1983	Letter from applicant transmitting table complying with Preservice Inspection Program.
April 4, 1983	Letter from applicant transmitting correction to application for License Amendment 21.
April 6, 1983	Letter from applicant transmitting status of evaluation and results regarding Humphrey issues.
April 7, 1983	Letter from applicant concerning independent evaluation of Unit 2.
April 7, 1983	Letter from applicant transmitting payment for additional fees incurred for review of additional technical issue in proposed License Amendment 19 for review of administrative issues in proposed License Amendment 21.
April 8, 1983	Letter to applicant regarding integrity of requalification examinations for renewal of reactor operator and senior operator licenses (Generic Letter 83-17).
April 11, 1983	Letter from applicant transmitting Susquehanna Steam Electric Station Offsite Dose Calculation Manual.
April 11, 1983	Letter to applicant transmitting Supplement 5 to the SER.
April 13, 1983	Letter from applicant transmitting Revision 1 to 18-in. containment purge valve qualification analysis and 24-in. containment purge valve qualification analysis.

April 13, 1983	Letter from applicant requesting that the review of Item 7 of proposed Amendment 15 to License NPF-14 in letter dated December 10, 1982, be held in abeyance pending further investigation of fuses in use at facility.
April 14, 1983	Letter to applicant transmitting Amendment 13 to License NPF-14.
April 14, 1983	Letter from applicant transmitting Temporary Change 83-575 to emergency plan procedure.
April 15, 1983	Letter from applicant transmitting the March 1983 Monthly Operating Report.
April 15, 1983	Letter from applicant transmitting proposed Amendment 22 to License NPF-14 changing Technical Specifications to incorporate final setpoint data developed during startup test program.
April 15, 1983	Letter from applicant advising that maintenance and surveillance schedule for components requiring initial maintenance and surveillance after first year of operation is implemented.
April 15, 1983	Letter from applicant responding to Generic Letter 82-33, Supplement 1 to NUREG-0737.
April 15, 1983	Letter to applicant transmitting Amendment 14 to License NPF-14 modifying Technical Specifications 3.9.1 and 4.9.1 to enhance operator awareness of testing provisions of reactor mode switch.
April 18, 1983	Letter from applicant advising of negotiation initiation to bring about contract with Department of Energy (DOE) to dispose of spent nuclear fuel or high level radwaste per License Condition 3.
April 20, 1983	Letter from applicant transmitting Revision 1 to Emergency Plan Implementing Procedure EP-IP-030.
April 22, 1983	Letter from applicant informing of discrepancies between Technical Specifications and sample Standard Technical Specifications provided in Enclosure 2 to Generic Letter 83-02 - Modification of Automatic Depressurization System Logic, TMI Item II.K.3.18.
April 25, 1983	Letter to applicant transmitting an SER on BWR Owners Group generic response to NUREG-0737.
April 25, 1983	Letter to applicant granting preservice inspection relief requests in letter dated March 3, 1983.
April 25, 1983	Letter from applicant transmitting 467 oversize drawings in accordance with RG 1.70.

April 27, 1983	Letter to applicant requesting remittance of Class II fee for application regarding nonconformance with NUREG-0737 on containment isolation dependability.
April 28, 1983	Letter from applicant responding to questions regarding proposed Amendment 19.
April 29, 1983	Letter from applicant transmitting application for proposed Amendment 23 to License NPF-14 changing License Condition 2.C to extend completion date for safety parameter display system.
May 2, 1983	Letter to applicant regarding procedures for providing public notice concerning issuance of amendment to service list (Generic Letter 83-19).
May 2, 1983	Letter acknowledging completion of action required by Amendment 7 to License NPF-14, Paragraph 3, by initiating DOE negotiations concerning disposal of high level waste or spent nuclear fuel.
May 4, 1983	Letter from applicant transmitting proposed Amendment 24 to License NPF-14 changing Appendix A, Technical Specifications, concerning circuit breaker location, gaseous type.
May 5, 1983	Letter from applicant transmitting "Offsite Dose Calculation Manual."
May 5, 1983	Letter from applicant transmitting an application for Amendment 54 to the OL application consisting of Revision 33 to the FSAR.
May 6, 1983	Letter from applicant transmitting Change N to the physical security plan.
May 9, 1983	Letter to applicant concerning integrated scheduling for implementation of plant modes (Generic Letter 83-20).
May 9, 1983	Letter to applicant requesting additional information concerning Revision 6 to the emergency plan.
May 10, 1983	Letter from applicant transmitting responses to questions concerning ultimate heat sink test plan.
May 10, 1983	Letter to applicant concerning gas pipeline near Susquehanna facility - License Condition 2.C(13)(c).
May 10, 1983	Letter from applicant transmitting the April 1983 Monthly Operating Report.
May 16, 1983	Letter from applicant concerning hydrodynamic loads on control rod drive piping.

May 16, 1983	Letter from applicant concerning response to License Condition 2.C(32) - modifications to resolve the emergency service water single-failure issue.
May 20, 1983	Letter from applicant concerning equipment qualification summary report.
May 25, 1983	Letter from applicant concerning fee for NRC review.
May 25-27, 1983	Representatives from NRC and PP&L meet at the site of Susquehanna Unit 2 to assess status of construction and completion schedules. (Summary issued June 22, 1983.)
May 26, 1983	Letter from applicant transmitting a response to Generic Letter 83-18.
May 26, 1983	Letter from applicant responding to request for additional information - Revision 6 to the emergency plan for Susquehanna.
May 31, 1983	Letter from applicant concerning cultural resources.
June 15, 1983	Letter from applicant concerning Humphrey Issues 3.1 and 3.3.
June 15, 1983	Letter from applicant transmitting the May 1983 Monthly Operating Report.
June 17, 1983	Representatives from NRC and PP&L meet in Bethesda, Maryland, to discuss emergency core cooling system activation instrumentation. (Summary issued June 29, 1983.)
June 20, 1983	Letter from applicant transmitting a response to SER Supplement 5, Item 3.11.1(1)(C).
June 20, 1983	Letter from applicant transmitting a response to SER Supplement 5 Item 3.11.1(1)(a).
June 27, 1983	Letter from applicant concerning qualification of primary containment vacuum breakers.
June 27, 1983	Letter from applicant concerning License Condition 2.C.28(f).
June 27, 1983	Letter from applicant concerning proposed Amendment 25 to License NPF-14.
June 28, 1983	Letter to applicant concerning request for additional information regarding proposed Transco pipeline.
June 29, 1983	Letter to applicant concerning Susquehanna Unit 2 design reviews.
June 30, 1983	Letter from applicant concerning License Condition 2.C.10.

June 30, 1983	Letter from applicant transmitting Revision 2 to the pump and valve Inservice Inspection Program
July 6, 1983	Letter to applicant concerning outstanding requests for proposed changes to License NPF-14.
July 7, 1983	Letter from applicant concerning License Condition 2.C.25(a).
July 7, 1983	Letter from applicant concerning TMI Item II.K.3.18 - automatic depressurization system timer setting and justification for setting.
July 7, 1983	Letter from applicant concerning additional information regarding the proposed Transco pipeline.
July 11, 1983	Letter from applicant concerning Appendix F to Supplement 5.
July 14, 1983	Letter from applicant transmitting June 1983 Monthly Operating Report.
July 18, 1983	Letter to applicant concerning Issuance of Notices of Consideration of Issuance of Amendments.
July 20, 1983	Letter to applicant concerning detailed control room design review program plan.
July 21, 1983	Letter to applicant concerning control of heavy loads (Phase I) - NUREG-0612.
July 22, 1983	Letter from applicant concerning proposed Amendment 27 to License NPF-14.
July 22, 1983	Letter from applicant concerning requested changes to Generic Letter 82-33 schedule.
July 22, 1983	Letter from applicant transmitting 6-month response to NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants."
July 26, 1983	Letter from applicant concerning additional information to support proposed Amendment 27 to License NPF-14.
July 29, 1983	Letter from applicant concerning relief request for transformer replacement.
August 2, 1983	Letter from applicant concerning Unit 2 Preservice Inspection Program and requesting relief.
August 2, 1983	Letter from applicant concerning revision to proposed Amendment 27 to License NPF-14.
August 3, 1983	Letter from applicant concerning Unit 2 license conditions.

August 3, 1983	Letter from applicant concerning clarification to the response to Generic Letter 82-33.
August 4, 1983	Letter from applicant concerning additional clarification on the relief request for transformer replacement.
August 8, 1983	Letter from applicant concerning proposed Unit 2 Technical Specifications.
August 15, 1983	Letter from applicant transmitting the July 1983 Monthly Operating Report.
August 15, 1983	Letter from applicant concerning additional information on proposed Amendment 19 to License NPF-14.
August 15, 1983	Letter from applicant concerning proposed Amendment 28 to License NPF-14.
August 17, 1983	Letter from applicant concerning Annual Financial Report.
August 19, 1983	Letter from applicant concerning TMI response for Unit 2.
August 22, 1983	Letter from applicant concerning proposed Amendment 26 to License NPF-14.
August 23, 1983	Letter from applicant concerning Issuance of Notices of Consideration of Issuance of Amendments.
August 24, 1983	Letter from applicant concerning modification to emergency service water system.
August 25, 1983	Letter from applicant concerning independent evaluation of Unit 2.
August 26, 1983	Letter from applicant concerning NUREG-0737, Item II.E.4.2 - ganged valve opening.
August 29, 1983	Letter from applicant concerning FSAR Section 13.2.
August 29, 1983	Letter from applicant concerning emergency operating procedure for heating, ventilation, and air conditioning.
August 31, 1983	Letter to applicant requesting additional information on Susquehanna feedwater check valve analysis.
September 2, 1983	Letter to applicant transmitting Amendment 15 to License NPF-14.
September 9, 1983	Letter from applicant concerning Equipment Qualification Summary Report, Revision 4 - response to SER Supplement 5 Items 1.9 and 3.11.1(1)(a) and 10 CFR 50.49(i).
September 12, 1983	Letter from applicant transmitting the August 1983 Monthly Operating Report.

September 13, 1983	Letter to applicant transmitting Issuance of Notices of Consideration of Issuance of Amendments.
September 15, 1983	Letter from applicant transmitting additional information concerning proposed Amendment 26 to License NPF-14.
September 15, 1983	Letter from applicant concerning relief request for transformer replacement.
September 15, 1983	Letter from applicant concerning FSAR Section 7.1.
September 15, 1983	Letter from applicant concerning FSAR Section 7.4.
September 16, 1983	Letter to applicant concerning drywell-to-wetwell vacuum breaker valves.
September 20, 1983	Letter to applicant concerning Susquehanna automatic depressurization system (ADS) timer setting.
September 22, 1983	Letter from applicant concerning License Condition 2.C.25(b) of License NPF-14.
September 23, 1983	Letter from applicant concerning SER Supplement 5, Section 1.10, Item (10) - installation of debris screens on drywell containment purge system.
September 26, 1983	Letter from applicant transmitting revised FSAR sections concerning installation of new engineered safety system transformers, retention of construction substation, and update of stability analysis.
September 28, 1983	Letter to applicant concerning diesel generator surveillance requirement Technical Specification 4.8.1.1.2.d.12.
September 28, 1983	Letter to applicant transmitting Amendment 16 to License NPF-14.
September 29, 1983	Letter to applicant concerning nonconformance with NUREG-0737, Item II.E.4.2.
September 29, 1983	Letter from applicant concerning NUREG-0612 - Unit 2 9-month response.
September 30, 1983	Letter from applicant concerning FSAR Section 3.13.
September 30, 1983	Letter from applicant concerning safety evaluation of the safety parameter display system.
October 3, 1983	Letter from applicant concerning SER Issue No. 112.
October 3, 1983	Letter from applicant concerning FSAR Section 7.5.
October 6, 1983	Letter from applicant concerning FSAR Section 3.6A.

October 6, 1983	Letter from applicant concerning FSAR Section 10.4.
October 6, 1983	Letter from applicant concerning FSAR Section 12.2.
October 7, 1983	Letter from applicant concerning proposed Amendment 30 to License NPF-14.
October 7, 1983	Letter from applicant concerning FSAR Section 7.7.
October 10, 1983	Letter from applicant concerning new final rule, 10 CFR 50.72.
October 10, 1983	Letter from applicant concerning SER Supplement 5, Section 1.9, "Loss of Non-Class 1E Instrumentation and Control Power System Bus During Operation."
October 12, 1983	Letter from applicant concerning spray pond report.
October 12, 1983	Letter from applicant transmitting the September 1983 Monthly Operating Report.
October 13, 1983	Letter from applicant concerning FSAR Section 9.1.
October 13, 1983	Letter from applicant concerning startup test program.
October 13, 1983	Letter from applicant concerning preoperational test program for Unit 2.
October 14, 1983	Letter from applicant concerning FSAR Section 9.3.
October 20, 1983	Letter from applicant concerning proposed Amendment 31 to License NPF-14.
October 20, 1983	Letter from applicant concerning position on diesel start requirement.
October 24, 1983	Letter from applicant concerning drywell-to-wetwell vacuum breakers.
October 24, 1983	Letter from applicant concerning proposed Amendment 32 to License NPF-14.
October 24, 1983	Letter from applicant concerning change to service list.
October 25, 1938	Letter to applicant concerning clarification of required actions based on generic implications of Salem ATWS events (Generic Letter 83-28).
October 28, 1983	Letter from applicant requesting approval of Code Case N-253-2.
October 28, 1983	Letter from BWR Owners Group (T. J. Dente) to NRC (D. Eisenhut) concerning NUREG-0737, Item II.K.3.18, "Modification of Automatic Depressurization Logic."

October 31, 1983	Letter to applicant concerning review of Revision 6 to the emergency plan for Susquehanna, Units 1 and 2.
October 31, 1983	Letter to applicant transmitting EG&G "Control of Heavy Loads at Nuclear Power Plants, Susquehanna Steam Electric Station, Unit 2, Phase I."
November 1, 1983	Letter from applicant transmitting Revision 1 to preservice inspection plan and Revision 0 to preservice inspection relief requests 8 through 12 in connection with SER Item 111.
November 2, 1983	Letter to applicant transmitting Amendment 17 to License NPF-14.
November 3, 1983	Letter from applicant responding to staff questions on environmental qualification.
November 3, 1983	Letter from applicant responding to questions and forwarding equipment qualification report.
November 4, 1983	Letter from applicant concerning proposed Amendment 34 to License NPF-14.
November 7, 1983	Letter from applicant requesting exigency for proposed Amendment 31 to License NPF-14.
November 7, 1983	Letter from applicant concerning RG 1.97 modifications for Unit 2 - environmental qualifications.
November 8, 1983	Letter from applicant concerning environmental protection plan.
November 8, 1983	Letter to applicant requesting additional information regarding submittals for License Conditions 2.C.(25)(a) and 2.C.(25)(b).
November 11, 1983	Letter from applicant concerning control room design review summary report.
November 11, 1983	Letter from applicant concerning safety parameter display system (SPDS) configuration clarifications.
November 11, 1983	Letter from applicant concerning FSAR Section 3.4.
November 11, 1983	Letter from applicant concerning License Condition 2.C(13).
November 14, 1983	Letter from applicant transmitting the October 1983 Monthly Operating Report.
November 17, 1983	Letter to applicant concerning use of ASME Code Case N-253.2.

November 21, 1983	Letter from applicant transmitting proprietary report, "Evaluation of NUREG-0783 Local Pool Temperature Limits for Susquehanna Steam Electric Station," in response to License Condition 2.C.29. Report withheld from public disclosure pursuant to 10 CFR 2.790.
November 21, 1983	Letter from applicant concerning FSAR Section 7.3.
November 29, 1983	Letter from applicant concerning fuel load schedule for Unit 2.
December 5, 1983	Representatives from NRC and PP&L meet in Silver Spring, Maryland, NRC offices to discuss proposed changes to physical security plan (closed meeting).
December 6, 1983	Letter from applicant concerning justification regarding proposed Amendment 25 to License NPF-14.
December 7, 1983	Letter from applicant concerning response to request for additional information on proposed Amendment 54 to License NPF-14.
December 8, 1983	Letter from applicant concerning proposed Amendment 33 to License NPF-14.
December 8, 1983	Letter to applicant concerning status of outstanding items to support operating license for Susquehanna Unit 2.
December 9, 1983	Letter from applicant concerning proposed Amendment 35 to License NPF-14.
December 12, 1983	Letter to applicant transmitting Amendment 19 to License NPF-14.
December 12, 1983	Letter to applicant transmitting Amendment 20 to License NPF-14.
December 13, 1983	Letter from applicant concerning NUREG-0612 - Unit 2 9-month response, equipment qualification.
December 13, 1983	Letter from applicant concerning FSAR Section 12.3.
December 13, 1983	Letter from applicant concerning vent and purge valves.
December 13, 1983	Letter from applicant concerning fire protection - request for variance.
December 13, 1983	Letter from applicant concerning Unit 2 Seismic Qualification Review Team status update.
December 15, 1983	Letter from applicant transmitting the November 1983 Monthly Operating Report.

December 16, 1983	Letter from applicant clarifying additional information submitted in December 1982 for proposed Amendment 53 to License NPF-14.
December 19, 1983	Letter from applicant concerning proposed Amendment 36 to License NPF-14.
December 21, 1983	Letter from applicant transmitting final spray pond report.
December 21, 1983	Letter from applicant concerning initial test program - Unit 1/Unit 2 differences.
December 21, 1983	Letter from applicant transmitting revisions to FSAR Section 14.2.
December 21, 1983	Letter from applicant concerning SER Item No. 111.
December 21, 1983	Letter from applicant concerning a response to request for additional information on equipment qualification.
December 21, 1983	Letter from applicant concerning facility staffing survey.
December 29, 1983	Letter from applicant transmitting additional test abstracts to FSAR Section 14.2 for preoperational and acceptance tests.
December 30, 1983	Letter from applicant concerning qualification of Unit 2 RG 1.97 modifications.
December 30, 1983	Letter to applicant concerning conformance to RG 1.97, Revision 2.
January 5, 1984	Letter from applicant concerning fast cold starts of diesel generators (Generic Letter 83-41).
January 5, 1984	Letter from applicant transmitting Revision 1 to proposed Amendment 36 to License NPF-14.
January 5, 1984	Letter from applicant transmitting a response to NRC request for information on environmental qualification.
January 10, 1984	Letter from applicant concerning the level switch dynamic qualification - SSER 3, Section 3.10.2.2.
January 11, 1984	Letter from applicant concerning equipment qualification - target rock solenoid valves.
January 12, 1984	Letter from applicant transmitting Monthly Operating Report - December 1983.
January 18, 1984	Letter from applicant concerning the safety parameter display.
January 19, 1984	Letter from applicant concerning TMI Item II.K.3.25.

January 21, 1984	Letter from applicant transmitting Revision 2 to proposed Amendment 36 to License NPF-14.
January 23, 1984	Letter from applicant concerning emergency planning exercise exemption request.
January 25, 1984	Letter from applicant concerning FSAR Section 14.2..
January 27, 1984	Letter from applicant concerning NUREG-0803 BWR Owners Group endorsement.
January 31, 1984	Letter from applicant concerning SER Supplement 5, Section 1.10, Item (14) - Nuclear steam supply system-vendor review of procedures.
February 1, 1984	Letter from applicant concerning dynamic qualification of the standby liquid control explosive valve.
February 1, 1984	Letter from applicant concerning SPDS completion schedule.
February 2, 1984	Letter to applicant concerning review of detailed control room design review summary report.
February 2, 1984	Letter from applicant concerning license conditions for Unit 2 license.
February 2, 1984	Letter from applicant concerning response to Generic Letter 84-01.
February 3, 1984	Letter from applicant concerning feedwater lines.
February 8, 1984	Letter from applicant concerning hydrodynamic loads on control rod drive piping.
February 9, 1984	Letter to applicant concerning deletion of home telephone numbers, unlisted utility numbers, etc. from emergency plans.
February 10, 1984	Letter from applicant transmitting an application for amendment of Construction Permit CPPR-102 to extend the construction completion date.
February 13, 1984	Letter from applicant concerning control room design review.
February 14, 1984	Letter from applicant transmitting the January 1984 Monthly Operating Report for Susquehanna Unit 1.
February 21, 1984	Letter from applicant concerning additional information regarding the proposed Transco pipeline.
February 22, 1984	Letter from applicant concerning TMI Item II.K.3.18.

February 22, 1984	Representatives from NRC and PP&L meet in Bethesda, Maryland, to discuss proposed changes to standby gas treatment system Technical Specifications. (Summary issued March 14, 1984)
February 27, 1984	Representatives from NRC and PP&L meet in Bethesda, Maryland, to discuss Revision 7 of the Susquehanna Emergency Plan.
February 27, 1984	Letter from applicant concerning common power supply and sensor malfunction study for Unit 2.
March 15, 1984	Letter from applicant concerning boiling-water reactor core stability.

APPENDIX B

BIBLIOGRAPHY

American Society of Mechanical Engineers, Paper No. 80-C2-PVP-28, "Loss of Component Cooling Water Capability of a PWR Reactor Coolant Pump," by A. H-C Marr, 1980.

American Water Works Association (AWWA) C504-80, "Standard for Rubber-Seated Butterfly Valves," revised Jan. 28, 1980.

BWR Owners Group, SLI-8211, "Review of BWR Reactor Water Level Measurement Systems," July 1982.

---, SLI-8218, "Inadequate Core Cooling Detection in BWRs," Nov. 12, 1983.

EG&G Idaho, Inc., review of Pennsylvania Power & Light Co. submittal, dated July 22, 1983, forwarding 6-month response to NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants."

Federal Register, 48 FR 24008, U.S. Nuclear Regulatory Commission, 10 CFR Part 50, Final Rule, "Fracture Toughness Requirements for Light-Water Nuclear Power Reactors," May 27, 1983.

General Electric Company, NEDE-22178-P, "Mark II Containment Drywell-to-Wetwell Vacuum Breaker Models," Aug. 1982 (proprietary - not publicly available).

---, Topical Report NEDO-22209, "Analysis of Scram Discharge Volume System Piping Integrity," Aug. 1982.

---, Topical Report NEDO-24342, "GE Evaluation in Response to NRC Request Regarding BWR Scram System Pipe Breaks," Apr. 1981.

Letter, Feb. 4, 1981, from D. B. Waters (BWR Owners Group) to D. G. Eisenhut (NRC), Subject: Additional Preoperational Tests and Augmented Operator Training During Startup.

---, June 17, 1983, from D. M. O'Conner (Bechtel Power Corporation) to R. W. Houston (NRC), Subject: AGCO Vacuum Breaker Test Program.

---, June 29, 1983 (Generic Letter 83-24), from D. G. Eisenhut (NRC) to all BWR Applicants for an Operating License and Holders of Operating Licenses for Grand Gulf, La Salle, and Susquehanna, Subject: TMI Task Item I.G., "Special Low Power Testing and Training, Recommendations for BWRs."

---, July 25, 1983, from D. G. Eisenhut (NRC) to T. J. Dente (BWR Owners Group), Subject: Safety Concerns With Pipe Breaks in the BWR Scram System.

---, Nov. 18, 1983, from D. R. Helwig (BWR Owners Group) to D. G. Eisenhut (NRC), Subject: Scram Discharge Piping.

Pennsylvania Power & Light Company, "Final Safety Analysis Report, Susquehanna Steam Electric Station, Units 1 and 2," dated Apr. 1981 (Dockets 50-387 and 50-388).

U.S. Nuclear Regulatory Commission, NUREG-0484, "Methodology for Combining Dynamic Responses," Rev. 1, May 1980.

---, NUREG-0487, "Mark II Lead Plant Program Evaluation Report," Nov. 1978.

---, NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," Nov. 1979; Rev. 1, July 1981.

---, NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants - Resolution of Generic Technical Activity A-36," July 1980.

---, NUREG-0737, "Clarification of TMI Action Plan Requirements," Nov. 1980; Supplement 1, Jan. 1983.

---, NUREG-0776, "Safety Evaluation Report Related to the Operation of Susquehanna Steam Electric Station, Units 1 and 2," Apr. 1981; Supplement 1, June 1981; Supplement 2, Sept. 1981; Supplement 3, July 1982; Supplement 4, Nov. 1982; Supplement 5, Mar. 1983.

---, NUREG-0783, "Suppression Pool Temperature Limits for BWR Containments for Generic Technical Activity A-39" (to be issued pending approval by Committee to Review Generic Requirements).

---, NUREG-0800, "Standard Review Plan for Review of Safety Analysis Reports for Nuclear Power Plants," Rev. 2, July 1981.

---, NUREG-0803, "Generic Safety Evaluation Report Regarding the Integrity of BWR Scram System Piping," Aug. 1981.

---, NUREG-0808, "Mark II Containment Program Load Evaluation and Acceptance Criteria," Aug. 1981.

---, NUREG-0977, "NRC Fact-Finding Task Force Report on the ATWS Event at Salem Nuclear Generating Station, Unit 1, on February 22 and 25, 1983," Mar. 1983.

U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Bulletin (IEB) 79-01B, "Environmental Qualification of Class 1E Equipment," Jan. 14, 1980, and supplements dated Feb. 29, Sept. 30, and Oct. 24, 1980.

---, IEB 79-27, "Loss of Non-Class 1E Instrumentation and Control Power System Bus During Operation," Nov. 30, 1979.

APPENDIX H

REVIEW OF THE PRESERVICE INSPECTION PROGRAM FOR SUSQUEHANNA UNIT 2

H.1 INTRODUCTION

For nuclear power facilities whose construction permits were issued on or after January 1, 1971, but before July 1, 1974, 10 CFR 50.55a(g)(2) specifies that components shall meet the preservice examination requirements set forth in Editions of Section XI of the ASME Code in effect 6 months before the date of issuance of the construction permit. The provisions of 10 CFR 50.55a(g)(2) also state that the components (including supports) may meet the requirements set forth in subsequent editions and addenda of this Code which are incorporated by reference in 10 CFR 50.55a(b), subject to the limitations and modifications listed therein.

In letters dated August 2, 1983, November 1, 1983, and December 21, 1983, Pennsylvania Power & Light Company (the applicant) submitted requests for relief from Code requirements and provided supporting information pursuant to 10 CFR 50.55a(a)(2)(i). Therefore, the staff's evaluation consisted of reviewing the applicant's submittals to the requirements of the 1974 Edition of Section XI through Summer 1975 Addenda and determining if relief from the Code requirements were justified.

As a result of its review of this information, the staff has determined that certain preservice examinations are impractical and performing these required examinations would result in hardships or unusual difficulties without compensating increase in the level of quality and safety. The basis for this conclusion is discussed in the subsequent paragraphs of this appendix.

H.2 TECHNICAL REVIEW CONSIDERATIONS

(1) The construction permit for Susquehanna Unit 2 was issued on November 2, 1973. In accordance with 10 CFR 50.55a(g)(2), components (including supports), which were classified as ASME Code Class 1 and 2, must be designed and provided with access to enable the performance of required inservice and preservice examinations set forth in the 1971 Edition of ASME Code, Section XI, including the Addenda through Summer 1972. The ASME first published rules for inservice inspection in the 1970 Edition of Section XI. No preservice or inservice inspection requirements existed before that date. Because the plant system design and ordering of long lead-time components were well under way by the time Section XI rules became effective, full compliance with the exact Section XI access and inspectability requirements of the Code were not always practical. The applicant optionally revised the Preservice Inspection (PSI) Program on the basis of the requirements of the 1974 Edition through Summer 1975 Addenda in consideration of the updating requirements of 10 CFR 50.55a(g) for inservice inspection.

(2) Verification of as-built structural integrity of the primary pressure boundary is not dependent on the Section XI preservice examination. The applicable construction codes to which the Susquehanna Unit 2 primary pressure boundary was fabricated contain examination and testing requirements that by themselves provide the necessary assurance that the pressure boundary components are capable of performing safely under all operating conditions reviewed in the Final Safety Analysis Report and described in the plant design specification. As a part of these examinations, all of the primary pressure boundary full penetration welds were volumetrically inspected (radiographed) and the system was subjected to hydrostatic pressure tests.

(3) The intent of the preservice examination is to establish a reference or baseline before the initial operation of the facility. The results of subsequent inservice examinations can then be compared with the original condition to determine if changes have occurred. If review of the inservice inspection results shows no change from the original condition, no action is required. In the case where baseline data are not available, all indications must be treated as new indications and evaluated accordingly. Section XI of the ASME Code contains acceptance standards that may be used as the basis for evaluating the acceptability of such indications.

(4) Other benefits of the preservice examination include providing redundant or alternative volumetric inspection of the primary pressure boundary using a test method different from that employed during the component fabrication. Successful performance of preservice examination also demonstrates that the welds so examined are capable of being inspected during the subsequent inservice examination using a similar test method.

In the case of Susquehanna Unit 2, a large portion of the preservice examination required by the ASME Code was performed. The staff has concluded that failure to perform a 100% preservice examination of the welds identified below will not significantly affect the assurance of the initial structural integrity.

(5) In some instances where the required preservice examinations were not performed to the full extent specified by the applicable ASME Code, the staff will require that these or supplemental examinations be conducted as part of the inservice inspection program. The staff has concluded that requiring these supplemental examinations to be performed at this time (before plant startup) would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The performance of supplemental examinations, such as surface examinations, in areas where volumetric inspection is difficult will be more meaningful after a period of operation. Acceptable preoperational integrity has already been established by similar Section III (ASME Code) fabrication examinations.

In cases where parts of the required examination areas cannot be effectively examined because of a combination of component design or current inspection technique limitations, the staff will continue to evaluate the development of new or improved volumetric examination techniques. As improvements in these areas are achieved, the staff will require that these new techniques be made a part of the inservice examination requirements for those components or welds which received a limited preservice examination.

H.3 EVALUATION OF RELIEF REQUESTS

The applicant requested to use the requirements of subsequent editions and addenda of the Code, which the staff has evaluated and found acceptable, because these new requirements are referenced in the regulations. These requests are identified in Section H.3.9, which follows.

Evaluation of the remaining relief requests is summarized below. (Unless otherwise stated, references to the Code refer to the ASME Code, Section XI, 1974 Edition, including Addenda through Summer 1975.)

On the basis of the information submitted by the applicant and the staff's review of the design, geometry, and materials of construction of the components, certain preservice requirements of the ASME Code, Section XI, have been determined to be impractical; imposing these requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, pursuant to 10 CFR 50.55a(a)(2), the staff's conclusions that these preservice requirements are impractical are justified as follows.

H.3.1 All Class 1 and Class 2 Piping Systems Requiring Ultrasonic Examination as the Method of Examination (Relief Request #1)

Code Requirement

Ultrasonic examination shall be conducted in accordance with the provisions of Appendix I (Section XI, ASME Code). Where Appendix I (I-2000) is not applicable, the provisions of Article 5 of Section V (ASME Code) shall apply.

Code Relief Request

The applicant requested to use Appendix III of Section XI from the Winter 1975 Addenda in lieu of ASME Code, Section V, Article 5, for piping examination.

Reason for Request

Appendix III, 1977 Edition to the Summer 1978 Addenda, has been accepted for use by incorporation of this Edition and Addenda into 10 CFR 50.55a. Appendix III, Winter 1975 Addenda, closely parallels the later Code except that the required examination volume is more conservative in the Winter 1975 Addenda (i.e., Figure IWB-3514.1(a) of Winter 1975 compared with Figure IWB-2500-8 of the 1977 Edition).

Staff Evaluation

Section XI of the ASME Code, Summer 1975 Addenda, does not specifically provide volumetric inspection methods for welds in piping, but references Article 5 of Section V. The provisions of 1975 Section V do not specifically address piping welds either, nor do they stipulate recording levels for ultrasonic flaw indications. Appendix III of Section XI gives specific guidance for ultrasonic examination of piping systems. However, recording criteria for ultrasonic indications differ between Appendix III and Article 5 of Section V, which requires that all indications exceeding 20% of the reference level be investigated. The applicant's procedures require that indications exceeding 50% of the reference level be recorded. Recording and evaluating indications that exceed 20% but are less than 50% distance amplitude correction (DAC) are difficult for the following reasons:

(1) The welded joints in nuclear piping frequently contain Code-allowable wall thickness differences (12% of nominal thickness) as well as weld dropthrough, counterbore taper, crown height, and other surface conditions that generate a large number of geometric reflectors which produce ultrasonic testing (UT) indications greater than 20% DAC.

(2) Weld metal in stainless steel piping contains reflectors because of the metallurgical structure, which produce a large number of UT indications.

The staff has determined that Appendix III of Section XI is an acceptable alternative because it is technically acceptable and is also referenced in 10 CFR 50.55a(b). On the basis of the fabrication examination required by Section III, the staff concluded that a recording level of 50% is acceptable for the preservice inspection. However, for the inservice inspection, the staff has determined that recording at a 50% level is acceptable with the following conditions:

(1) All indications 50% DAC or greater shall be recorded.

(2) All indications 100% DAC or greater shall be investigated by a Level II or Level III examiner to the extent necessary to determine the shape, identity, and location of the reflector.

(3) Any cracklike indication, 20% DAC or greater, discovered during a UT examination of piping welds and base metal materials shall be recorded and investigated by a Level II or Level III examiner to the extent necessary to determine the shape, identity, and location of the reflector. The applicant should take appropriate action concerning all reflectors that are not metallurgical or geometric in origin.

H.3.2 Reactor Pressure Vessel Examination (Relief Request #4)

Code Requirement

An ultrasonic examination of the reactor pressure vessel shall be performed in accordance with Appendix I, "Ultrasonic Examination," contained in the 1974 Edition of Section XI including Addenda through Summer 1975.

Code Relief Request

Relief was requested to use the examination requirements stated in the 1974 Edition through Winter 1975 Addenda of Section XI.

Reason for Request

Use of the Winter 1975 Edition of ASME Code, Section XI, for reactor pressure vessel examination is justified for the following reasons:

(1) The major differences applicable to the reactor pressure vessel between the Summer 1975 Addenda and the Winter 1975 Addenda are:

   (a) Table IWB-2500, Examination Category B-A revision; however, for preservice examination, this change has no impact.

   (b) Acceptance standards were added and/or changed; however, all changes were more conservative.

   (c) Changes were made to Appendix I; however, primary changes were made to correct typographical errors or to provide clarification.

   (d) Personnel qualification requirements were expanded and were made more conservative (IWA-2300).

(2) Areas forming the basis for not accepting the use of Winter 1975 Addenda are not applicable to Susquehanna Unit 2 reactor pressure vessel (RPV) preservice examination.

Staff Evaluation

The staff has evaluated the differences between the Winter 1975 Addenda and Summer 1975 Addenda of Section XI. Staff evaluation has shown that there are no significant technical changes in examination requirements between the subject Code addenda. The staff, therefore, has determined that an ultrasonic examination of the reactor vessel based on Appendix I in the Winter 1975 Addenda is an acceptable alternative to the ASME Code requirement defined in 10 CFR 50.55a(g)(2).

H.3.3 Reactor Pressure Vessel Head Meridional Weld Seams DA, DB, DC, DD, DE, and DF (Relief Request #5)

Code Requirement

Examination Category B-A of ASME Code, Section XI, 1974 Edition to Winter 1975 Addenda, requires volumetric examination of essentially 100% of the accessible length of each meridional weld in vessel heads.

Appendix I, Article I-5000, requires the examinations be conducted using two beam angles from each direction (nominal angle of 45° and 60°).

These examinations must be performed completely as a preservice examination requirement before initial plant startup.

Code Relief Request

Relief was requested from performing 100% of the Section XI examination requirements.

Reason for Request

Interference from the vessel skirt attachment weld buildup results in the unexamined volumes as follows:

0° base metal examination	12% missed
0° weld metal examination	12% missed
45° examination	4% missed
60° examination	2% missed

Physical limitations because of the geometry of the reactor vessel result in the above unexamined volumes for the subject welds. The applicant's documentation shows the following:

(1) A composite of all examination angles shows that a volume equal to 2% of the required examination volumes for welds DA, DB, DC, DD, DE, and DF is completely unexamined. All other areas have been covered by any or all of the 0°, 45°, and 60° scans.

(2) The integrity of the welds has been verified by ultrasonic and magnetic particle testing during fabrication.

(3) Welds are visually examined for leakage during RPV hydrotest.

Staff Evaluation

The meridional welds in the vessel head are physically inaccessible for inspection because of the existing design. The staff concludes that the limited Section XI volumetric examination, the volumetric and surface examination performed during fabrication, and the hydrostatic test demonstrate an acceptable level of preservice structural integrity.

H.3.4 Class 1 Valves Exceeding 4-in. Nominal Pipe Size and Class 1 Reactor Recirculation Pump Casings (Relief Request #6)

Code Requirement

Category B-M-2 of ASME Code, Section XI, 1974 Edition to Summer 1975 Addenda, requires visual examination of the internal pressure boundary surfaces on valves exceeding 4-in. nominal pipe size. One valve in each group of valves of the same constructional design must be inspected.

Category B-L-2 of ASME Code, Section XI, 1974 Edition to Summer 1975 Addenda, requires visual examination of the internal pressure boundary surfaces of one pump in each group of pumps performing similar functions in the system.

Code Relief Request

Relief was requested from the preservice visual examination of internal pressure boundary surfaces for Class 1 valves greater than 4-in. nominal pipe size and visual examination of reactor recirculation pump internal surfaces.

Reason for Relief Requests

The justification for requesting relief from ASME Code, Section XI, preservice examination requirements is as follows:

(1) The structural integrity of the piping pressure boundary has been verified by construction code testing requirements.

(2) The body, bonnet, and disc of the valves have received shop surface examinations, i.e., liquid penetrant and/or magnetic particle. Radiography was also performed on the body.

(3) The pump casings received radiographic and penetrant testing before being machined. All machined surfaces were penetrant tested, and pumps were hydrostatic leak tested after final machining.

(4) All pressure-retaining materials have met ASME Code, Section III, specifications, which require visual examination of the casting or forging surfaces free of injurious defect.

Staff Evaluation

The intent of the visual examination required by the Code is the detection of corrosion and wear during service. The staff has determined that the manufacturer's fabrication examinations exceed Section XI nondestructive examination requirements and, therefore, are acceptable as an alternative for the required visual examination. The staff concluded that the fabrication examinations and Section XI hydrostatic tests demonstrate adequate evidence of preservice integrity. In addition, the applicant has committed to perform the visual examinations in the event that the components become accessible during maintenance activities.

H.3.5 Class 2 Category C-F and C-G Pressure-Retaining Welds in Core Spray and Residual Heat Removal Pumps (Relief Request #7)

Code Requirements

Category CF/CG - Table IWC-2600, Item Number C3.1 of ASME Code, Section XI, 1974 Edition to Summer 1975 Addenda, requires full volumetric examination of 100% and 50%, respectively, of pump casing welds. These examinations must be performed completely as a preservice examination requirement before initial plant startup.

Relief Request

Relief is requested from the volumetric examinations required in Section XI.

Reason for Request

The justification for requesting relief from ASME Code, Section XI, examination requirements is as follows:

(1) The structural integrity of the pump pressure boundary has been established by ASME Code, Section III, radiography and liquid penetrant testing requirements.

(2) Accessible pump casing welds have been satisfactorily inspected to ASME Code, Section XI.

(3) Pump installation meets manufacturer requirements.

Staff Evaluation

Because of the installation design of the pumps listed in Table H.1, the welds are totally encased in concrete and are inaccessible. Subsequent approved editions of the Code, 1977 Edition, including Summer 1978 Addenda, IWC-1230, address the issue of exemption components encased in concrete. 10 CFR 50.55a(g) permits updating to newer approved editions of the Code. The applicant's submittal discusses the safety significance of failure of individual pumps. The staff has reached the conclusion that the volumetric and surface examination performed during fabrication and the hydrostatic test demonstrate an acceptable level of preservice structural integrity.

H.3.6 Class 1 Examination Category B-J and Class 2 Examination Categories C-F and C-G Circumferential Butt Welds (Relief Requests #8, #9, and #10)

Code Requirement

Category B-J requires that the examination areas shall include essentially 100% of the longitudinal and circumferential welds and the base metal for one wall thickness beyond the edge of the weld. In the case of pipe branch connections, the areas shall include the weld metal, the base metal for one pipe wall thickness beyond the edge of the weld on the main pipe run, and at least 2 in. of the base metal along the branch run.

Categories C-F and C-G require volumetric examination of circumferential butt welds, longitudinal weld joints in welded fittings, and branch connections exceeding 4-in. diameter, including the weld metal and base metal for one wall thickness, by a sampling procedure defined by IWC-2520.

Code Relief Request

Relief was requested from performing 100% of the Code-required examination.

Reason for Request

Relief is requested from the ASME Code, Section XI, examination requirements on the basis of partial inaccessibility of the weld and required volume as a result of plant design. The applicant has identified the piping system welds that are impractical to examine in Table H.2. The applicant has described in his submittals the fabrication examination performed on each weld and the safety significance of not performing the examination required in Section XI.

Staff Evaluation

The staff has determined that examination of the welds in Table H.2 to the extent required by the Code is impractical because of the design of the piping system and/or location of piping hangers and suppports. The applicant conducted surface examinations on those areas that cannot be completely scanned by the ultrasonic inspection. The staff concludes that the limited Section XI examinations, the volumetric examinations performed during fabrication, and the hydrostatic test demonstrate an acceptable level of preservice structural integrity.

H.3.7 Class 2 Pressure-Retaining Vessel Welds and Nozzle Welds in the Residual Heat Removal Heat Exchanger (Relief Request #11)

Code Requirement

Category C-A of ASME Code, Section XI, 1974 Edition to Summer 1975 Addenda, requires volumetric examination of shell and head circumferential discontinuity welds and base material for one plate thickness beyond the edge of the weld joint.

Category C-B of ASME Code, Section XI, 1974 Edition to Summer 1975 Addenda, requires volumetric examination of 100% of the nozzle-to-vessel attachment welds.

These examinations must be performed completely once as a preservice examination requirement before initial plant startup.

Code Relief Request

Relief is requested from 100% of the volumetric examinations required by Section XI.

Reason for Request

The justification for requesting relief from ASME Code, Section XI, preservice examination requirements is as follows:

(1) The structural integrity of the pressure boundary has been verified by ASME Code, Section III, construction code testing requirements.

(2) Accessible portions of the welded attachments have been satisfactorily inspected to ASME Code, Section XI.

Staff Evaluation

Physical limitations resulting from the design of the residual heat removal heat exchangers result in uninspectable portions of the welds listed in Table H.3.

The staff concludes that the limited Section XI volumetric examinations performed during fabrication and the hydrostatic test demonstrate an acceptable level of preservice structural integrity.

H.3.8 Feedwater Inlet Nozzles N4A and N4D (Relief Request #12)

Code Requirement

Category B-D requires a 100% preservice volumetric examination of the nozzle-to-vessel weld and adjacent areas of the nozzle-to-vessel weld.

Code Relief Request

Relief was requested from performing 100% of the ultrasonic examination requirements.

Reason for Request

The proximity of nozzles N11A and B to the subject feedwater nozzles precludes complete examination of weld seams N4A and N4D as follows:

N4A

300° - completely examined (automatic)
60° - not examined because of interference from nozzle N11A

N4D

300° - completely examined (automatic)
60° - not examined because of interference from nozzle N11B

Spacing of only 4.5 in. between the nozzles allows only a best-effort manual examination of the affected areas. The applicant's documentation shows the following:

(1) The excluded area is 16.67% of the weld seam; 83.33% has been completely examined.

(2) Four nozzles of the same configuration and service (N4B, N4C, N4E, and N4F) have been completely examined.

(3) The integrity of welds has been verified by ultrasonic and magnetic particle examination during fabrication.

(4) All N4 nozzle-to-vessel welds were liquid penetrant tested following RPV hydrotest and accepted.

Staff Evaluation

Physical limitations because of the design of the reactor vessel (i.e., location of nozzles N11A and B) result in the above unexamined volumes for the subject welds. The staff concludes that the limited Section XI volumetric examination, the volumetric and surface examinations performed during fabrication, and the hydrostatic test demonstrate an acceptable level of preservice structural integrity.

H.3.9 Additional Relief Requests

In addition to the relief requests evaluated in Sections H.3.1 through H.3.8, the applicant submitted two other requests for relief that involved updating examination requirements to subsequent approved editions and addenda of Section XI. The staff has determined that the following relief requests are acceptable and in accordance with subsequent editions of Section XI referenced by 10 CFR 50.55a(b):

Relief request identification	Examination category	Component
2	B-G-1, B-G-2, and C-D	Bolting
3	B-K-1, C-E-1, and C-C	Welded supports

H.4 CONCLUSION

On the basis of the foregoing, the staff has determined, pursuant to 10 CFR 50.55a(a)(2), that certain Section XI-required preservice examinations are impractical, and compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

The technical evaluation has not identified any practical method by which the existing Susquehanna Unit 2 can meet all the specific preservice inspection requirements of Section XI of the ASME Code. To require exacting compliance with Section XI would delay the startup of the plant in order to redesign a significant number of plant systems, obtain sufficient replacement components, install the new components, and repeat the preservice examination of these components. Examples of components that would require redesign to meet the specific preservice examination provisions are the reactor vessel, residual heat removal pumps, and a significant number of the piping and component support systems. Even after the redesign effort, complete compliance with the preservice examination requirements probably could not be achieved. However, the as-built structural integrity of the existing primary pressure boundary has already been established by the construction code fabrication examinations.

On the basis of its review and evaluation, the staff concludes that the public interest is not served by imposing certain provisions of Section XI of the ASME Code that have been determined to be impractical. Pursuant to 10 CFR 50.55a(a)(2), the staff has allowed relief from these requirements, which are impractical to implement and would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

Table H.1 Pressure-retaining welds that are impractical to examine (Relief Request #7)

Weld identification number	Code category and item number	System	Configuration	Nature of obstruction	Approximate % of scan obstructed
2P-206A,B, C-359-2-L2	CG C3.1	Core spray	Shell longitudinal seam	Encased in concrete	100
2P-206B, D-359-1-2	CG C3.1	Core spray	Hub flange to shell	Encased in concrete	100
2P-206A-359-2-L1	CG C3.1	Core spray	Shell longitudinal seam	Encased in concrete	100
2P202A,B,C D-359-1-2	CF C3.1	Residual heat removal	Hub flange to shell	Encased in concrete	100
2P202A,B,C, D-359-2-L2	CF C3.1	Residual heat removal	Shell longitudinal seam	Encased in concrete	100
2P202A,B,C, D-359-2-2	CF C3.1	Residual heat removal	Shell circumferential seam	Encased in concrete	100
2P202A,B,C, D-359-2-L1	CF C3.1	Residual heat removal	Shell longitudinal seam	Encased in concrete	100
2P202A,B,C, D-359-2-3	CF C3.1	Residual heat removal	Shell to bottom head	Encased in concrete	100
2P202A,B,C, D-359-3-7	CF C3.1	Residual heat removal	Bottom head to bearing housing	Encased in concrete	100
2P202A,B,C, D-361-2-6	CF C3.1	Residual heat removal	Discharge elbow to bottom plate flange	Encased in concrete	100
2P202A,B,C, D-361-6-7	CF C3.1	Residual heat removal	Discharge elbow to sleeve forging	Encased in concrete	100
2P-202A,B,C, D-361-7-8	CF C3.1	Residual heat removal	Sleeve forging to top closure plate	Encased in concrete	100

Table H.2 Piping system welds that are impractical to examine (Relief Requests #8, #9, and #10)

Weld identification number	Code category and item number	System	Configuration	Nature of obstruction	Approximate % of scan obstructed
DBB-221-1-FW1	CF C2.1	Reactor core isolation cooling	Pipe to valve	Wrapper plate	100
VNB-B21-3-20-F	BJ B4.5	Main steam	Pipe to sweep-o-let	1 Lug	3
DBB-204-1-5A	CG C2.1	Main steam	Pipe to restraint insert	4 restraint braces	25
DBB-202-1-3A	CG C2.1	Main steam	Pipe to restraint insert	4 restraint braces	25
DBB-202-1-5A	CG C2.1	Main steam	Pipe to restraint insert	4 restraint braces	25
DBB-201-1-3A	CG C2.1	Main steam	Pipe to restraint insert	4 restraint braces	25
DBB-203-1-5B	CG C2.1	Main steam	Pipe to restraint insert	4 restraint braces	25
VNB-B21-4-17-F	BJ B4.5	Main steam	Pipe to sweep-o-let	1 lug	5
DBB-204-1-5B	CG C2.1	Main steam	Pipe to restraint insert	4 restraint braces	25
VRR-B31-3-10-M[1]	BJ B4.5	Recirculation	Longitudinal seam	Branch line	5
VRR-B31-3-10-L[1]	BJ B4.5	Recirculation	Longitudinal seam	Branch line	5
VRR-B31-4-10-P[1]	BJ B4.5	Recirculation	Longitudinal seam	Branch line	10
VRR-B31-3-10-Q[1]	BJ B4.5	Recirculation	Longitudinal seam	Branch line	10
DBA-201-2-FW34	BJ B4.5	Reactor water cleanup	Pipe to elbow	Rigid restraint	35
VRR-B31-4-2W[1]	BJ B4.5	Recirculation	Longitudinal seam	Hanger	5
VRR-B31-3-2W[1]	BJ B4.5	Recirculation	Longitudinal seam	Lugs	2

[1]Obstructed areas are located outside the required examination area (12 in. from the intersection with the edge of a circumferential weld) for subsequent inservice inspections.

Table H.2 (Continued)

Weld identification number	Code category and item number	System	Configuration	Nature of obstruction	Approximate % of scan obstructed
DBB-203-1-3A	CG C2.1	Main steam	Pipe to restraint insert	4 restraint braces	13
DBB-201-1-5B	CG C2.1	Main steam	Pipe to restraint insert	4 restraint braces	13
DLA-202-1-FW19	BJ B4.5	Feedwater	Pipe to elbow	Branch line	7
HBB-211-2-3-D	CF C2.1	Residual heat removal	Pipe to elbow	Hanger weld	10
GBB-215-1-5A	CF C2.1	Residual heat removal	Pipe to elbow	Lugs	5
DBB-214-1-9A	CF C2.1	High-pressure coolant injection	Pipe to elbow	Lugs	5
DCA-208-1-FW11	BJ B4.5	Residual heat removal	Elbow to valve	Branch line	5
DLA-201-1-FW6	BJ B4.5	Feedwater	Pipe to valve	Welded whip restraint	60
DBB-207-1-FW3	CF C2.1	Residual heat removal	Pipe to valve	Branch line	10
DBB-207-2-FW3	CF C2.1	Residual heat removal	Pipe to valve	Branch line	5
DBB-219-1-1C	CF C2.1	Feedwater	Pipe to tee	Branch line	5
DBB-213-1-FW3	CG C2.1	Core spray	Pipe to pipe	Branch line	5
DBB-207-1-FW1	CF C2.1	Residual heat removal	Pipe to valve	Branch line	15
VBB-202-1-FW1	CG C2.1	Control rod drive	Pipe to reducer	Branch line	5
DBB-214-1-10B	CG C2.1	High-pressure coolant injection	Pipe to flange	Branch line	15
DBB-221-3-FW3	CF C2.1	Reactor core isolation cooling	Pipe to valve	(1) Branch line (2) Geometry	18

Table H.2 (Continued)

Weld identification number	Code category and item number	System	Configuration	Nature of obstruction	Approximate % of scan obstructed
HBB-211-2-11B	CF C2.1	Residual heat removal	Pipe to tee	Plate adjacent to weld	5
DBB-221-3-FW2	CF C2.1	Reactor core isolation cooling	Tee to valve	(1) Branch line (2) Geometry	10
DBB-217-1-FW2	CG C2.1	High-pressure coolant injection	Pipe to valve	Pipe support	8
GBB-205-2-1A	CF C.2.1	Residual heat removal	Reducer to reducer	Welded hanger	25
DLA-204-1-FW1	BJ B4.5	Feedwater	Pipe to valve	Welded hanger	50
VNB-B21-3-20W	BJ B4.5	Main steam	Pipe to elbow	Lamination	2
VBB-202-1-5A	CG C2.1	Control rod drive	Pipe to elbow	Lamination	5
DCA-210-2-FW2	BJ B4.5	Residual heat removal	Valve to flued head	Joint configuration	30
VRR-B31-3-FWA10	BJ B4.5	Recirculation	Sweep-o-let to riser pipe	Part geometry	25
VRR-B31-3-FWA11	BJ B4.5	Recirculation	Sweep-o-let to riser pipe	Part geometry	25
VRR-B31-3-FWA13	BJ B4.5	Recirculation	Sweep-o-let to riser pipe	Part geometry	25
VRR-B31-3-FWA14	BJ B4.5	Recirculation	Sweep-o-let to riser pipe	Part geometry	25
VRR-B31-4-FWB10	BJ B4.5	Recirculation	Sweep-o-let to riser pipe	Part geometry	25
VRR-B31-4-FWB11	BJ B4.5	Recirculation	Sweep-o-let to riser pipe	Part geometry	25
VRR-B31-4-FWB13	BJ B4.5	Recirculation	Sweep-o-let to riser pipe	Part geometry	25
VRR-B31-4-FWB14	BJ B4.5	Recirculation	Sweep-o-let to riser pipe	Part geometry	25
VRR-B31-3-FWA33	BJ B4.5	Recirculation	Tee to valve	Part geometry	100
VRR-B31-4-FWB33	BJ B4.5	Recirculation	Tee to valve	Part geometry	100

Table H.2 (Continued)

Weld identification number	Code category and item number	System	Configuration	Nature of obstruction	Approximate % of scan obstructed
VRR-B31-3-FWA24	BJ B4.5	Recirculation	Valve F032A to pipe	Part geometry	100
VRR-B31-4-FWB24	BJ B4.5	Recirculation	Valve F032B to pipe	Part geometry	100
VRR-B31-4-FWB23	BJ B4.5	Recirculation	Elbow to valve	Part geometry	25
VRR-B31-3-3-F	BJ B4.5	Recirculation	Pipe to cross	Part geometry	15
DCA-207-1-FW-3	BJ B4.5	Core spray	Valve F006A to valve F007A	Part geometry	100
DCA-207-2-FW3	BJ B4.5	Core spray	Valve F006B to valve F007A	Part geometry	100
DLA-204-1-FW5	BJ B4.5	Feedwater	Pipe to safe end	Part geometry	35
DLA-204-1-FW21	BJ B4.5	Feedwater	Pipe to safe end	Part geometry	35
DLA-202-1-FW5	BJ B4.5	Feedwater	Pipe to safe end	Part geometry	35
DLA-202-1-FW10	BJ B4.5	Feedwater	Pipe to safe end	Part geometry	35
DBA-216-1-FWC14	NA	Main steam (augmented)	Elbow to branch	Part geometry	30
DBA-214-1-FWA14	NA	Main steam (augmented)	Elbow to branch	Part geometry	30
DBA-214-1-FW22	NA	Main steam (augmented)	Elbow to tee	Part geometry	30
DBA-212-1-FW4	BJ B4.5	Main steam	Tee to tee	Part geometry	30
DBB-215-1-FW10	CF C2.1	Residual heat removal	Elbow to valve	Part geometry	10
GBB-212-2-FW14	CF C2.1	Residual heat removal	Valve F007B to flued head	Part geometry	8
GBB-212-1-FW14	CF C2.1	Residual heat removal	Valve F007A to flued head	Part geometry	33
GBB-216-2-FW1	CF C2.1	Residual heat removal	Reducer to nozzle	Part geometry	10

Table H.2 (Continued)

Weld identification number	Code category and item number	System	Configuration	Nature of obstruction	Approximate % of scan obstructed
GBB-206-1-FW2	CF C2.1	Residual heat removal	Tee to valve	Part geometry	33
GBB-216-1-FW1	CF C2.1	Residual heat removal	Reducer to nozzle	Part geometry	15
GBB-205-1-FW1	CF C2.1	Residual heat removal	Valve to reducer	Part geometry	65
DBB-203-1-FW2	BJ B4.5	Feedwater	Flued head to valve	Part geometry	25
DCA-207-1-FW5	BJ B4.5	Core spray	Reducer to nozzle	Part geometry	20
DCA-207-2-FW10	BJ B4.5	Core spray	Reducer to nozzle	Part geometry	15
DCA-202-2 FW1	BJ B4.5	Reactor water cleanup	Tee to weld-o-let	Part geometry	60
DCA-209-1-FW2	BJ B4.5	Core spray	Flued head to valve	Part geometry	50
DCA-209-2-FW2	BJ B4.5	Core spray	Flued head to valve	Part geometry	50
DBA-201-1-FW10	BJ B4.5	Reactor water cleanup	Flued head to valve	Part geometry	20
DBA-202-2-FW6	BJ B4.5	High-pressure coolant injection	Flued head to valve	Part geometry	18
DCA-210-1-FW8	BJ B4.5	Residual heat removal	Elbow to valve	Part geometry	10
DCA-211-3-FW12	BJ B4.5	Residual heat removal	Elbow to flange	Part geometry	8
GBB-201-4-FW1	CG C2.1	Core spray	Pipe to valve	Part geometry	8
GBB-204-3-FW15	CF C2.1	Residual heat removal	Pipe to flange	Part geometry	10

Table H.2 (Continued)

Weld identification number	Code category and item number	System	Configuration	Nature of obstruction	Approximate % of scan obstructed
EBB-202-1-FW4	CG C2.1	High-pressure coolant injection	Pipe to flange	Part geometry	8
EBB-202-1-FW5	CG C2.1	High-pressure coolant injection	Pipe to flange	Part geometry	8
DBB-222-1-3B	NA	Reactor water cleanup (augmented)	Tee to flange	Part geometry	10
DCA-211-3-2A	BJ B4.5	Residual heat removal	Pipe to flange	Part geometry	20
HBB-218-2-FW5	CG C2.1	Containment atmosphere control	Pipe to valve	Part geometry	13
HBB-201-1-FW3	CG C2.1	Reactor core isolation cooling	Pipe to valve	Part geometry	13
HBB-201-1-FW10	CG C2.1	Reactor core isolation cooling	Pipe to valve	Part geometry	10
GBB-205-2-FW3	CF C2.1	Residual heat removal	Pipe to valve	Part geometry	10
HBB-211-2-FW14	CF C2.1	Residual heat removal	Valve to elbow	Part geometry	10
HBB-201-1-FW4	CG C1.2	Reactor core isolation cooling	Flued head to valve	Part geometry	10
2P-206-A, B,C,D-361-4-6	CG C2.1	Core spray (pump)	Elbow to nozzle	Part geometry	10
2P-202-A, B,C,D-361-4-6	CF C2.1	Residual heat removal (pump)	Elbow to nozzle	Part geometry	30
2P-202-A, B,C,D-361-1-5	CF C2.1	Residual heat removal (pump)	Support shell to head hub	Part geometry	10

Table H.2 (Continued)

Weld identification number	Code category and item number	System	Configuration	Nature of obstruction	Approximate % of scan obstructed
2P-202-A, B,C,D-361-5-13	CF C2.1	Residual heat removal (pump)	Nozzle to vertical support shell	Part geometry	10
2P-202-A, B,C,D-361-3-13	CF 2.1	Residual heat removal (pump)	Flange to nozzle	Part geometry	10
2P-202-A, B,C,D-361-5-6	CF C2.1	Residual heat removal (pump)	Elbow to vertical support shell	Part geometry	10
2P-206-A, B,C,D-361-5-13	CG C2.1	Core spray (pump)	Inlet nozzle to vertical support shell	Part geometry	10
2P-206-A, B,C,D-361-5-6	CF C2.1	Core spray (pump)	Elbow to vertical support shell	Part geometry	10
GBB-201-1-FW2	CG C2.1	Core spray	Valve to pipe	Part geometry	25
GBB-204-1-FW7	CF C2.1	Residual heat removal	Valve to pipe	Part geometry	5
DBB-215-1-FW7	CF C2.1	Residual heat removal	Valve to pipe	Part geometry	5
DLA-202-1 FW6	BJ B4.5	Feedwater	Pipe to tee	Part geometry	15

Table H.3 Pressure-retaining welds that are impractical to examine (Relief Request #11)

Weld identification number	Code category and item number	System	Configuration	Nature of obstruction	Approximate % of scan obstructed
2E-205-A-R	CA C1.1	Residual heat removal	Shell to head	Welded attachment	5
2E-205-A-A	CB C1.2	Residual heat removal	Shell to nozzle	Adjacent weld	20
2E-205-A-AC	CA C1.1	Residual heat removal	Shell to flange	Outlet nozzle	20
2E-205-B-R	CA C1.1	Residual heat removal	Shell to head	Welded attachment	5
2E-205-B-A	CB C1.2	Residual heat removal	Shell to nozzle	Adjacent weld	20
2E-205-B-AC	CA C1.1	Residual heat removal	Shell to flange	Outlet nozzle	20
2E-205-A-P	CB C1.2	Residual heat removal	Shell to nozzle	Adjacent weld-o-let	5
2E-205-B-P	CB C1.2	Residual heat removal	Shell to nozzle	Adjacent weld-o-let	5

NRC FORM 335
(11-81)

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

1. REPORT NUMBER *(Assigned by DDC)*
NUREG-0776 Supplement No. 6

4. TITLE AND SUBTITLE *(Add Volume No., if appropriate)*
Safety Evaluation Report related to the operation of Susquehanna Steam Electric Station, Units 1 and 2. Docket Nos. 50-387 and 50-388.

2. *(Leave blank)*

3. RECIPIENT'S ACCESSION NO.

7. AUTHOR(S)

5. DATE REPORT COMPLETED

MONTH	YEAR
March	1984

9. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS *(Include Zip Code)*
Division of Licensing
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

DATE REPORT ISSUED

MONTH	YEAR
March	1984

6. *(Leave blank)*

8. *(Leave blank)*

12. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS *(Include Zip Code)*
Same as 9 above.

10. PROJECT/TASK/WORK UNIT NO.

11. FIN NO.

13. TYPE OF REPORT
Technical

PERIOD COVERED *(Inclusive dates)*
March 1983 - March 1984

15. SUPPLEMENTARY NOTES
Docket Nos. 50-387 and 50-388

14. *(Leave blank)*

16. ABSTRACT *(200 words or less)*

In April 1981, the staff of the Nuclear Regulatory Commission issued its Safety Evaluation Report (NUREG-0776) regarding the application of the Pennsylvania Power and Light Company (applicant or licensee) and the Allegheny Electric Cooperative, Inc. (co-applicant) for licenses to operate the Susquehanna Steam Electric Station, Units 1 and 2, located on a site in Luzerne County, Pennsylvania.

Supplements 1 and 2 were issued in June 1981 and September 1981, respectively and addressed several outstanding issues. Supplement No. 2 also contains NRC staff responses to the comments made by the Advisory Committee on Reactor Safeguards in its report, dated August 11, 1981. Supplement 3 was issued in July 1982 and addressed five items that remained open and closed them out. On July 17, 1982, Operating License NPF-14 was issued to allow Unit 1 operation at power levels not to exceed 5% of rated power. Supplement 4 was issued November 1982 and discusses the resolution of several license conditions. On November 12, 1982, Operating License NPF-14 was amended to remove the 5% power restriction, thereby permitting full-power operation of Unit 1. Supplement 5 and this Supplement, No. 6 addresses several issues that require resolution before licensing operation of Unit 2.

17. KEY WORDS AND DOCUMENT ANALYSIS

17a. DESCRIPTORS

17b. IDENTIFIERS/OPEN-ENDED TERMS

18. AVAILABILITY STATEMENT
Unlimited

19. SECURITY CLASS *(This report)*
UNCLASSIFIED

20. SECURITY CLASS *(This page)*
UNCLASSIFIED

21. NO. OF PAGES

22. PRICE
S

431-02-0392
Box 23