NUREG-1047
Supplement No. 3

Safety Evaluation Report related to the operation of Nine Mile Point Nuclear Station, Unit No. 2

Docket No. 50-410

Niagara Mohawk Power Corporation
Rochester Gas and Electric Corporation
Central Hudson Gas and Electric Corporation
New York State Electric and Gas Corporation
Long Island Lighting Company

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

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ABSTRACT

This report supplements the Safety Evaluation Report (NUREG-1047, February 1985) for the application filed by Niagara Mohawk Power Corporation, as applicant and co-owner, for a license to operate the Nine Mile Point Nuclear Station, Unit No. 2 (Docket No. 50-410). It has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. The facility is located near Oswego, New York.

Supplement 1 to the Safety Evaluation Report was published in June 1985 and contained the report from the Advisory Committee on Reactor Safeguards as well as the resolution to a number of outstanding issues from the Safety Evaluation Report. Supplement 2 was published in November 1985 and contained the resolution to a number of outstanding and confirmatory issues.

Subject to favorable resolution of the issues discussed in this report, the NRC staff concludes that the facility can be operated by the applicant without endangering the health and safety of the public.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

APPENDICES

FIGURE

LIST OF TABLES

LIST OF TABLES (Continued)

1 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 Introduction

In February 1985, the Nuclear Regulatory Commission staff (NRC or staff) issued a Safety Evaluation Report (SER), NUREG-1047, on the application of the Niagara Mohawk Power Corporation (hereinafter referred to as the applicant) for a license to operate the Nine Mile Point Nuclear Station Unit 2 (NMP-2). Supplement 1 to the SER was issued in June 1985 and contained the report of the Advisory Committee on Reactor Safeguards (ACRS), as well as the staff evaluation of a number of outstanding issues. Supplement 2 was issued in November 1985 and contained the resolution to a number of outstanding and confirmatory issues. The present document is the third supplement to the SER (SSER 3). It provides the staff evaluation of outstanding and confirmatory issues that have been resolved since SSER 2 was published.

Each of the sections and appendices of this supplement is designated the same as the related portion of the SER. Appendix A, a continuation of the chronology of this safety review, lists in chronological order the correspondence and meetings between the applicant and staff. Appendix B lists reference materials cited in this document. Appendix D lists abbreviations used in this supplement, and Appendix E lists the principal staff contributors and consultant. Appendices C, F, G, H, and I have not been changed by this supplement. Appendix J has been modified by this supplement; additional information on the operability of the purge and vent valves has been included. A new appendix, K, has been added, containing the Lawrence Livermore National Laboratory Technical Evaluation Report of the detailed control room design review.

The contents of this document are supplementary to the initial SER, and not in lieu of the SER unless otherwise noted. The NRC Project Manager for the NMP-2 operating license is Ms. Mary F. Haughey. She may be reached by telephone at (301) 492-9422 or by mail at the following address:

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Copies of this SER supplement are available for inspection at the NRC Public Document Room, 1717 H Street, N.W., Washington, D.C. 20555 and at the Local Public Document Room at the Penfield Library, State University College, Oswego, N.Y. 13126.

1.8 Outstanding Issues

The SER identified certain outstanding issues in the staff review that had not been resolved with the applicant at the time the SER was issued. The list of those issues is reproduced in Table 1.3 and the current status of each issue is given.

1.9 Confirmatory Issues

The SER listed certain issues that have essentially been resolved to the staff's satisfaction, but for which certain confirmatory information has not yet been provided by the applicant. In these instances, the applicant has committed to provide the confirmatory information in the near future. If staff review of the information provided for an issue does not confirm preliminary conclusions, that issue will be treated as outstanding and the NRC staff will report on its resolution in another supplement to the SER. Table 1.4 contains a list of confirmatory issues and their current status. One new confirmatory issue, "Site drainage," has been added.

1.10 License Condition Items

Table 1.5, "License conditions" has been revised in this supplement. One license condition, "Thermal hydraulic stability analysis beyond Cycle 1," has been resolved as discussed in Section 4.4 of this supplement. License conditions 6 through 9 are new license conditions which are discussed in the referenced sections of this supplement.

1.12 Nuclear Waste Policy Act of 1982

Section 302(b) of the Nuclear Waste Policy Act of 1982 states that NRC shall not issue or renew a license for a nuclear power reactor unless the utility has signed a contract with the Department of Energy for disposal services. Niagara Mohawk Power Corporation has signed a contractual agreement with the Department of Energy dated August 13, 1985.

Table 1.3 Outstanding issues

Issue	SER Section	Status
(1) Snow loads	2.3.2	Closed, SSER 2
(2) Break analysis of reactor water cleanup line	3.6.2	Closed, SSER 1
(3) Preservice and inservice inspection plan	3.9.6, 5.2.4, 6.6	Awaiting information
(4) Equipment qualification	3.10, 3.11	Under review
(5) Steam bypass of the suppression pool	6.2.1.8	Closed, SSER 1
(6) Secondary containment bypass leakage	6.2.3.1, 15.6	Closed, SSER 2
(7) Containment isolation	6.2.4	Closed, SSER 3
(8) Containment leak testing	6.2.6	Closed, SSER 3
(9) Containment fracture toughness (GDC 51)	6.2.7	Closed, SSER 2
(10) Postaccident monitoring instrumentation	7.5.2.2	Under review
(11) Separation criteria	8.4.5	Under review
(12) Safe and alternate shutdown	9.5.1.4	Closed, SSER 2
(13) Essential lighting	9.5.3	Closed, SSER 2
(14) Air start system	9.5.4, 9.5.6	Closed, SSER 2
(15) Operations management	13.1, 13.4, 13.5	Closed, SSER 1
(16) Procedures generation package	13.5.2	Under review
(17) Preoperational and startup test abstracts	14	Under review
(18) DCRDR and SPDS		
(a) DCRDR	18.1	Under review
(b) SPDS	18.2	Closed, SSER 3

Table 1.4 Confirmatory issues

Issue	SER Section	Status
(1) Design of parapet scuppers on roofs of safety-related buildings	2.4.2.2	Closed, SSER 3
(2) Construction quality control tests on revetment ditch	2.5.6.2.4	Awaiting information
(3) Feedwater check valves	3.6.2	Closed, SSER 3
(4) Pipe break criteria	3.6.2	Closed, SSER 3
(5) Vertical floor flexibility	3.7.2, 3.7.3	Closed, SSER 2
(6) SRV/pool dynamic loads on containment interior structure	3.8.3	Under review
(7) Analytical results for the reactor internals for LOCA and SSE	3.9.2.4	Under review
(8) Results of Mark II hydrodynamic loads for NSSS piping, components, and equipment	3.9.3.1	Under review
(9) Leak rate test program	3.9.6	Closed, SSER 3
(10) Confirmation of number of ADS SRVs needed to achieve a rapid depressurization during a small-break LOCA based on a plant-specific ECCS analysis.	5.2.2	Closed, SSER 2
(11) Lead factors	5.3.1.2	Closed, SSER 3
(12) Verificaton of CONTEMPT LT/028 computer code	6.2.1.3	Closed, SSER 3
(13) Pool dynamics (a) Pool swell loads (b) Loads on submerged boundaries (c) Multivent, lateral load (d) CO and chugging loads inside the pedestal (e) Steam condensation submerged drag loads (f) Bulk-to-local temperature differences (g) Single-failure analysis	6.2.1.7.3	Closed, SSER 3

Table 1.4 (Continued)

Issue	SER Section	Status
(13) Pool dynamics (continued)		
(h) Quencher air clearing load		
(i) SRV submerged structure load		
(j) SRV inplant test		
(k) Wetwell-drywell vacuum breakers		
(l) Mark III containment concerns		
(14) Reverse flow testing	6.2.6	Closed, SSER 3
(15) Plant-specific LOCA analysis	6.3, 15.9.3	Closed, SSER 2
(16) Maximum hydrogen generation from the chemical reaction of the cladding with water or steam	6.3.5	Closed, SSER 2
(17) Instrument setpoints	7.2.2.3	Closed, SSER 3
(18) Anticipated transients without scram - mitigation system	7.2.2.4	Closed, SSER 3
(19) Minimum number of channels required to initiate protection actions	7.2.2.6	Closed, SSER 3
(20) Isolation of circuits	7.2.2.8	Under review
(21) Separation of Class 1E equipment and circuits	7.2.2.10	Awaiting information
(22) Testing of protection systems instrumentation	7.3.2.5	Closed, SSER 3
(23) Manual initiation of RCIC	7.4.2.2	Closed, SSER 2
(24) Capability for safe shutdown following loss of electrical power to instrumentation and controls	7.4.2.4	Closed, SSER 3
(25) LPCI and LPCS injection valves interlocks	7.6.2.1	Closed, SSER 3
(26) Multiple control system failures	7.7.2.1	Closed, SSER 3

Table 1.4 (Continued)

Issue	SER Section	Status
(27) High-energy-line breaks and consequential control systems failures	7.7.2.2	Closed, SSER 3
(28) Adequacy of station electric distribution system voltage	8.4.1	Awaiting information
(29) Supporting analysis required to confirm adequacy of LFMG motor circuit breaker as backup overcurrent protection for recirculation pump motor electrical penetration	8.4.2	Under review
(30) Site visit confirmation that the 15-ft color-marking interval for cables is sufficient to verify their correct separation	8.4.5	Under review
(31) Verification of the implementation of the electrical separation design criteria during site visit	8.4.5	Under review
(32) Review of analysis or design changes related to qualification of electrical equipment for flooding	8.4.7	Under review
(33) Portable radio communications demonstration	9.5.2	Closed, SSER 3
(34) Emergency lighting	9.5.3	Closed, SSER 2
(35) Procedures for filling fuel oil storage tanks	9.5.4.1	Under review
(36) Details of 1-in. vent line	9.5.4.1	Closed, SSER 2
(37) Division III diesel generator operation - severe conditions	9.5.4.1	Closed, SSER 2
(38) Fuel oil storage and transfer system - P&ID	9.5.4.2	Closed, SSER 2
(39) Procedures for maintaining diesel generator jacket water temperature	9.5.5	Closed, SSER 2

Table 1.4 (Continued)

Issue	SER Section	Status
(40) Diesel generator interface on P&ID	9.5.5, 9.5.6	Closed, SSER 3
(41) Procedures for minimum loading of diesel generators	9.5.5	Under review
(42) Divisions I, II, and III diesel generator air-start systems	9.5.6	Closed, SSER 2
(43) Division III air dryer - installation and performance monitoring	9.5.6	Closed, SSER 2
(44) Fire damper control of combustion products	9.5.8	Closed, SSER 2
(45) Concrete dust control	9.5.8	Closed, SSER 2
(46) Solid radioactive waste process control program and a compliance program to meet the requirements of 10 CFR 61 for land disposal of radioactive waste	11.4.2	Closed, SSER 3
(47) Alert and notification of the public within 15 minutes	13.3.2.5	Closed, SSER 3
(48) EOF staffing	13.3.2.8	Closed, SSER 3
(49) Basis for recommendations for protective measures	13.3.2.10	Closed, SSER 3
(50) Compliance with ATWS rule (10 CFR 50.62)	15.8	Closed, SSER 2
(51) IE Bulletin 79-08 item 6 (NUREG-0737 Item II.K.1.5, Review ESF Valves) and item 8 (NUREG-0737 Item II.K.1.10, Operability Status)	15.9.2	Under review
(52) Installation of equipment for the automatic restart of RCIC on low water level	15.9.3	Under review
(53) NUREG-0737 Item II.K.3.18, Modification of ADS Logic	15.9.3	Closed, SSER 2

Table 1.4 (Continued)

Issue	SER Section	Status
(54) NUREG-0737 Item II.K.3.15, Installation of Modification to RCIC Pipe Break Detection Circuitry	15.9.3	Under review
(55) NUREG-0737 Item III.D.1.1, Integrity of Systems Outside Containment Likely to Contain Radioactive Material	15.9.4	Closed, SSER 3
(56) Site drainage	2.4.2	Under review

Table 1.5 License conditions

Issue	SER Section
(1) Turbine system maintenance program	3.5.1.3 (SER)
(2) Thermal hydraulic stability analysis beyond Cycle 1	4.4.4 (Removed)
(3) Fire protection	9.5.1.9 (SER)
(4) Operability of PASS system	9.3.2 (SER)
(5) Operation with partial feedwater	15.1 (SER)
(6) Inservice testing of pumps and valves	3.9.6 (SSER 3)
(7) Solid Waste Process Control Program	11.4 (SSER 3)
(8) Safety Parameters Display System (SPDS)	18.2 (SSER 3)
(9) Initial leak test results (NUREG-0737 Item III.D.1.1)	15.9.4 (SSER 3)

2 SITE CHARACTERISTICS

2.4 Hydrologic Engineering

2.4.2 Floods

2.4.2.2 Effects of Local Intense Precipitation

In the SER the staff stated that the applicant had agreed to limit water buildup on the roofs of safety-related buildings using parapet scuppers, and that this issue would remain a confirmatory issue until the scupper design was submitted for review.

The applicant has responded with plans for modifying the roofs of the screenwell building and the reactor building. The applicant has stated that all other safety-related buildings are capable of withstanding a depth of water to the top of the parapets. The modification to the screenwell building consists of ten 6-inch scuppers inserted in the parapet walls on one section of the building roof and an 8-foot opening cut in one of the parapet walls of the other section. The screenwell building will be modified before the plant goes into full operation. The modifications for the reactor building roof (two 2-foot gaps to be cut in the parapet walls) will be made during the first refueling outage. Also, the applicant has committed to inspecting the drains in the reactor building roof at the time of fuel loading and in the fall of each year until the parapet modifications are completed.

The staff has reviewed the applicant's proposed modifications and concludes that with these modifications and interim procedures the plant meets GDC 2 with respect to local intense precipitation on the roofs of safety-related buildings through FSAR Amendment 22.

However, in Amendment 23 to the FSAR, the applicant made significant revisions to Section 2.4.2 which may affect the above conclusions. The staff has requested the applicant to provide additional information concerning these changes. The staff will report on the acceptability of these changes in a future supplement.

2.4.10 Flooding Protection Requirements

In the SER, the staff stated that the applicant had agreed to place neoprene gaskets in between the missile protection barriers of the diesel generator building. As an alternate, the applicant has now installed a flexible caulking material in all joints of the concrete missile protection stop logs up to elevation 263 feet msl. This material is compatible with concrete and can withstand mechanically induced vibration and movement and the temperature extremes expected at the NMP-2 site. The applicant has stated that the design life expectancy of the caulk exceeds 20 years and that it will be replaced after 20 years or whenever the stop logs are removed, whichever occurs first. Any replacement caulking which has a different life expectancy than 20 years will be replaced when that life expectancy is exceeded. The staff considers the use of the described caulking between the concrete barriers or stop logs to be adequate to protect the diesel generator building from serious inleakage in the event of a local intense flooding event.

2.4.13 Accidental Releases of Liquid Effluents in Groundwater and Surface Waters

In the SER, the staff concluded that a steel liner in the radwaste building would prevent contamination of the groundwater should the tanks leak. At the time the SER was written, it was the staff's understanding that the steel liner would contain the entire volume of the liquid radioactive waste stored within the radwaste building.

In Amendments 19 and 21, the applicant revised the FSAR to indicate that the steel liner is sufficient to contain the liquid inventory of only one of three tanks in the radwaste building. Although this reduction in capacity is significant, the liner volume still meets the single-failure criterion (failure of one tank), used to ensure that radionuclide concentrations at the nearest potable water supply are not in excess of the 10 CFR 20, Appendix B, Table II limits.

The staff concludes that the findings in SER Section 2.4.13 are still valid, i.e., the plant meets the requirements of SRP Section 2.4.13, 10 CFR 20, and 10 CFR 100 with regard to accidental releases of liquid effluents.

2.5 Geology and Seismology

2.5.6 Embankments and Dams

This evaluation covers the resolution of confirmatory issue 2 which is described in SER Section 2.5.6.2.4. Confirmatory issue 2 is concerned with the applicant's documentation of the quality control measures which were employed during the construction of the revetment-ditch structure and the periodic monitoring to be required to ensure the structure's safe performance during years of plant operation. The revetment-ditch structure is seismic Category I because its postulated failure during extreme storm conditions could adversely affect the safe shutdown of Unit 2.

The revetment-ditch structure is located at the shoreline of Lake Ontario at the Nine Mile Point Nuclear Station, Unit 2 (NMP-2). This shore protection barrier is approximately 1100 feet in length and was founded on bedrock following the removal of soft natural soils. Figure 2.5 (FSAR Figure 2.5-127) shows a typical sectional view of the revetment-ditch structure which consists of an approximately 20-foot-high rock-filled dike with side slopes of 2 horizontal to 1 vertical. The 10-foot-wide ditch located at the toe of the landside slope is intended for carrying rainfall runoff and return flow from wave overtopping during the assumed design condition of probable maximum surge.

Since the issuance of the SER in February 1985, the applicant has provided information to address confirmatory issue 2 in its submittals to the NRC of March 5, August 20, and September 27, 1985. On August 27, 1985, the staff visited the plant site to visually inspect the completed revetment-ditch structure.

A record of the staff's site visit is documented in a September 18, 1985, meeting summary by M. Haughey, NRC. The previously identified submittals by the applicant and the August 1985 site visit are the major bases for the staff's evaluation which is provided in this supplement.

2.5.6.2 Revetment Ditch

2.5.6.2.4 Construction Notes and Monitoring

Figure 2.5 shows the thickness of the various rock layers and zones that make up the revetment-ditch structure. The materials include (1) the front armor reinforced concrete dolos (each with a minimum weight of 4900 pounds) which were individually and uniformly placed in two layers on the lakeside slope to resist erosion and wave action, (2) the landside back armor stones (granite) (5- to 7-ton stones), (3) underlayer No. 2 stones (granite) (2000- to 5000-pound stones), (4) underlayer No. 2 stones (limestone) (75- to 225-pound stones), and (5) underlayer No. 3 stones (limestone) (2.3 to 12.8 pounds). To prevent migration of soil fines from the existing natural soils, where these soils border the revetment-ditch structure, a two-layered (filters No. 1 and 2) granular filter system was placed to allow for a material transition from the finer natural soils to the larger stones.

The applicant has provided the staff with the results of inspections and quality control testing on the materials placed in the revetment-ditch structure. The testing and the inspections included the following:

(1) laboratory tests on representative samples of quarried stone to assess durability, quality and weathering characteristics [petrographic examinations, bulk specific gravity, absorption, and accelerated weathering tests (freeze/thaw and wetting/drying)]

(2) laboratory gradation tests on filter materials

(3) field testing of concrete placed in the dolos units to verify attainment of minimum wet density in the concrete

(4) field testing to demonstrate proper sizing of revetment stones (actual weighing and dimensional measuring of stones in selected test samples)

(5) visual examinations to detect deterioration and defects, presence of cracks, or presence of undesirable elongated pieces in the stones produced from quarry operations

On the basis of the results from the completed testing and inspections, the applicant has concluded that the as-built revetment-ditch structure is in compliance with FSAR criteria and commitments (for criteria see FSAR Section 2.5.5, Tables 2.5-34 and 2.5-35).

In the staff's review of the testing results, several minor deviations were noted from the weight and gradation limits established in the FSAR for the underlayer stones, the back armor stone units, and the filter materials. The extent of the deviations can be seen in the applicant's submittal of August 20, 1985. In addressing the deviations in the specified weight of stones, the applicant has adopted a statistical approach to support its position for accepting the stones which were placed in the revetment-ditch structure. For the small deviations in the FSAR filter gradation limits, the applicant has evaluated their impact and concluded that these deviations would have no adverse impact on the intended design function of the multiple layer filter zone.

On the basis of its review, the staff agrees with the applicant's conclusion that the deviations in stone weights and filter gradations are minor and will not adversely affect the safe performance of the revetment-ditch structure. This conclusion is further supported by the August 27, 1985, site visit during which the revetment-ditch structure was observed to be well constructed with good interlocking of the concrete dolos units and with the very large back armor stones. The stones in underlayer No. 2, where this layer is exposed on the surface, were observed to be reasonably well graded and to have no visible areas of open gaps or voids.

To ensure the continued safety of the revetment-ditch structure during years of plant operation, the staff will require the applicant to commit to periodically scheduled visual inspections and field surveys to detect any significant settlement or dike erosion, and to make necessary repairs to maintain the revetment ditch in a structurally sound condition. In addition, the applicant should commit to perform surveys and visual inspections at least once a year and within 7 days following an earthquake event having an intensity greater than the operating basis earthquake (OBE). The staff will also require the applicant to implement an inspection program, within 1 year of fuel load, which will include visual inspection of the revetment-ditch structure after a severe storm. Repair and restoration measures on the revetment-ditch structure are required to be planned and submitted for staff approval within 90 days, if the recorded settlements are in excess of 1 foot from October 1985 baseline control elevations or if the visual inspection detects significant damage. The staff is awaiting commitments as discussed above. The staff will report on the results of the review of the applicant's commitments in a future supplement to the SER.

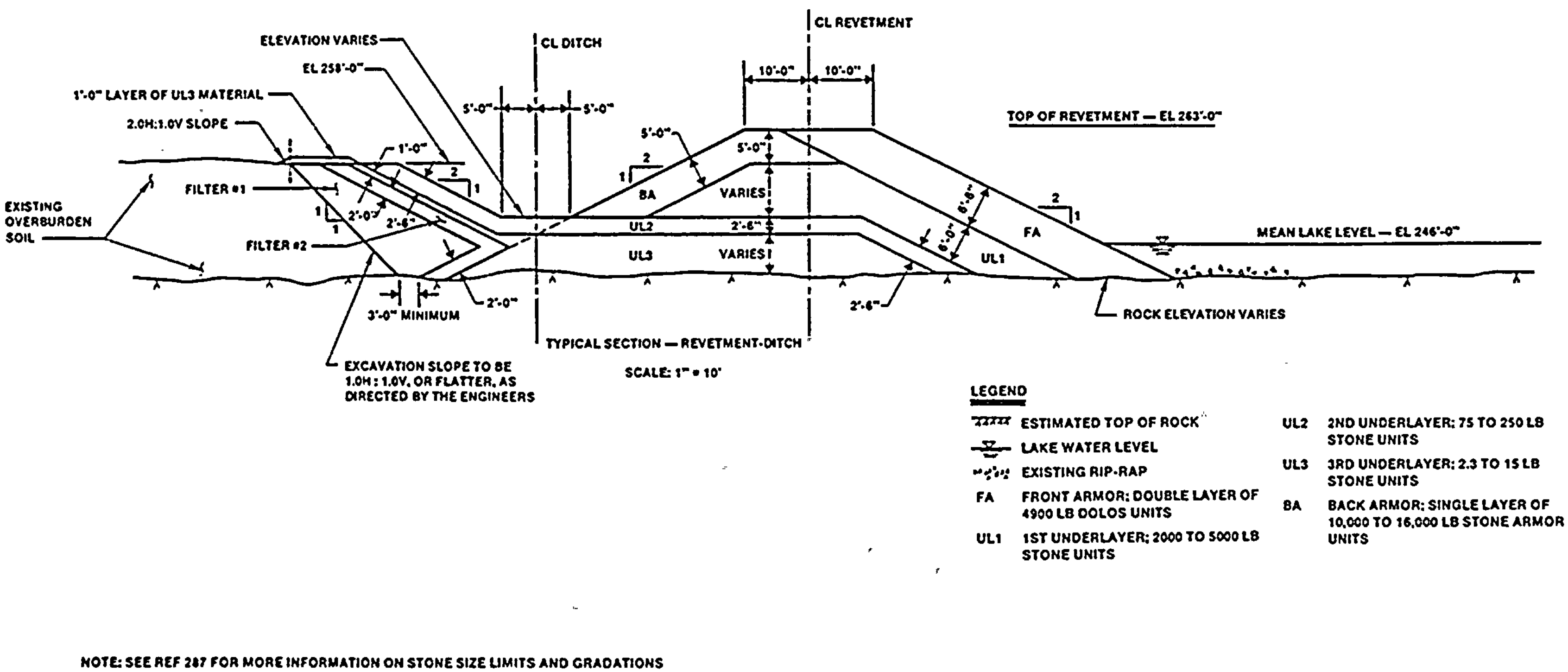

Figure 2.5 Revetment-ditch plan and typical sections (revised from SER Figure 2.5)
Source: FSAR Amendment 22, November 1985

3 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.6 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping

3.6.2 Determination of Rupture Locations and Dynamic Effects Associated With the Postulated Rupture of Piping

In Section 3.6.2 of the SER, the staff addressed the issue of postulated break locations of ASME Code Class 1 piping. For ASME Code Section III Class 1 high-energy fluid system piping not in the containment penetration area, SRP Section 3.6.2 (NUREG-0800) states that breaks are to be postulated at every location at which the fatigue cumulative usage factor, as determined by the ASME Code, is greater than 0.1. Additionally, breaks are also to be postulated at those ASME Code Class 1 piping locations at which the primary or secondary stress intensity range (including the zero load set) as calculated by equation 10 and either equation 12 or 13 in Paragraph NB-3653 of ASME Code Section III exceeds 2.4 S_m for normal and upset conditions including the operating basis earthquake. During the design of Nine Mile Point Nuclear Station, Unit 2 (NMP-2), the SRP Section 3.6.2 criteria for postulated break locations were used with one exception: for ASME Code Class 1 piping when the piping stresses calculated by equation 10 of NB-3650 exceeds 2.4 S_m but are not greater than 3.0 S_m, no break is postulated unless the cumulative usage factor for fatigue exceeds 0.1. In a letter from C. V. Mangan to W. Butler dated July 18, 1985, the applicant stated that for the balance of plant, breaks have been postulated in accordance with the NUREG-0800 criteria. For nuclear steam supply system (NSSS) scope of supply, the applicant stated that in its latest recirculation line stress analysis for the New Loads evaluation, its design-basis pipe break criteria were compared with the NUREG-0800 criteria. The study showed that using the SRP criteria did not result in any additional pipe breaks beyond those postulated in the design-basis calculation. The applicant further stated that the as-built piping stress for the recirculation loops has not been analyzed. However, the postulated break location from the New Loads evaluation is not expected to be changed by any future as-built piping stress analysis.

On the basis of the staff's review of the information provided by the applicant, the staff has determined that the applicant's study has demonstrated compliance with the SRP criteria for Postulating pipe break location and, therefore, the staff considers confirmatory issue 4 to be closed.

In Section 3.6.2 of the SER, the staff also addressed the issue of the dynamic analysis of the feedwater isolation check valves for the effects of a postulated pipe break in the feedwater piping outside containment and stated that the applicant should provide the results of this analysis. In a letter from C. V. Mangan to W. Butler dated August 29, 1985, the applicant provided its results for the analysis of the feedwater check valves.

In the event of a pipe break in the feedwater piping outside containment, containment isolation is provided by two Anchor/Darling check valves. Breaks are not postulated in the region between the two check valves because that region is classified as a break exclusion area. The applicant performed dynamic analyses to demonstrate that the feedwater isolation check valves can perform their intended function following a postulated pipe break of the feedwater piping outside containment.

The reverse flow caused by the sudden pressure reduction at the break rapidly closes both feedwater isolation check valves. A stress analysis was performed to determine the ability of the feedwater isolation check valves to withstand the dynamic impact of the valve disk on the seat. An inelastic analysis was performed in accordance with the ASME Code Section III Appendix F for Class 1 components using the ANSYS computer program. The acceptance criterion was based on the ability of the valves to preclude gross leakage due to disk rupture, fracture of the seat/disk interface, or misalignment of the disk. The analysis verified that the structural integrity of the feedwater check valves is maintained.

On the basis of the results of the applicant's analysis confirming the ability of the feedwater isolation check valves to perform their intended function following a feedwater line break outside containment, the staff concludes that the applicant has provided a reasonable basis to conclude that the safety concerns raised in confirmatory issue 3 have been acceptably resolved. Thus, the staff considers confirmatory issue 3 to be closed.

3.8 Design of Seismic Category I Structures

3.8.4 Other Seismic Category I Structures

3.8.4.2 Applicable Codes, Standards, and Specifications and 3.8.4.6.3 Structural Steel

In a letter dated July 26, 1985, the applicant requested approval of the use of the "Visual Weld Acceptance Criteria for Structural Welding at Nuclear Power Plants" at NMP-2.

The staff concludes that the use of these Nuclear Construction Issues Group. (NCIG) visual weld acceptance criteria (VWAC) will provide adequate quality of non-ASME Code structural steel welds. These criteria are limited to non-ASME Code class welded steel structures where fatigue is not the governing design consideration. Typical examples of structures to which these criteria may be applied are main building framing members and connecting members; supports for equipment and piping (non-ASME Code); cable trays and conduit; heating, ventilation, and air conditioning (HVAC) ducts and duct supports; and miscellaneous steel, including bracing and stiffeners, embedments, stairways and handrails, doors and door frames, windows and window frames, gratings, and covers.

Eleven criteria are addressed in VWAC. For cracks, the same criteria as exist in American Welding Society (AWS) Standard D.1.1-85 are specified; the welds shall have no cracks. For underfilled craters, if proper weld size is achieved and cracks are absent, there is no reason for rejecting them; and therefore, they are acceptable.

For arc strikes, surface slag, and weld spatter, the VWAC criteria are based more on the effects on structural strength rather than workmanship. Arc strikes are acceptable provided cracks are not visually detectable. Weld spatter that remains after cleaning is acceptable. For surface slag, the criteria are designed to prevent the acceptance of a weld that shows a gross lack of control by the welder. Isolated surface slag that remains after weld cleaning has no structural significance.

Criteria for the following types of defects/faults are also provided in VWAC:

(1) fillet weld size
(2) incomplete fusion
(3) weld overlap
(4) weld profiles
(5) undercut
(6) surface porosity
(7) weld length and location

The basis for the acceptance criteria in VWAC is the amount of reduction in cross-sectional area caused by the defect or fault. In such calculations, the conservative approach used is to consider the length of weld in which a defect occurs as being nonexistent, i.e., does not support any of the load. Such cross-section reductions are usually less than 12.5%

There are some exceptions to this, particularly in thinner section members. This occurs because measurements of defects/faults are rounded off up to the smallest unit specified. For instance, a 1/32-inch maximum undercut for the entire length on one side for 3/16-inch thickness material results in a 16.7% reduction in area. Because the 1/32 undercut will not be uniform along the entire length, most of the undercut will be less than 1/32 inch depth. Although the 16.7% maximum reduction is a theoretical possibility, it is not likely to occur.

The 12.5% "benchmark" was chosen on the basis of the presently allowed percent reduction in area allowed by the undercut criteria in AWS D.1.1-85 for the most limiting case in the thinnest member. The reasoning behind this is that if undercut is allowed to reduce the load-carrying capability by a given amount because of reductions in area, other defects/faults that would result in a reduction of similar magnitude should also be acceptable.

The acceptance by engineering evaluation of thousands of field weldments with similar defects/faults not meeting the criteria of AWS D.1.1-85 has resulted in the decision to use the weldments "as is" without repair. This is possible because common engineering design practices result in such significant margins above design requirements, that a small reduction of 10 to 12% can be easily accommodated. The present undercut criterion in AWS D.1.1-85 is a practical demonstration of this.

The deviations from AWS D.1.1-85 as proposed in VWAC are relatively insignificant in that the redundancy of these structures and their individual welds, as well as the conservative design practices used, allow non-ASME Code structural steel weldments (which are not designed for fatigue) to use alternative criteria as provided in Criterion II of 10 CFR 50, Appendix B. The staff finds these criteria appropriate and provide adequate integrity of the affected structures and, accordingly, General Design Criterion (GDC) 1 of Appendix A to 10 CFR 50, has been met.

The staff recommended that the applicant make the following changes/corrections to the proposed FSAR changes for Section 3.8.4.6.3, page 3.8-73 submitted in its letter of September 18, 1985:

(1) As the applicant has used a criterion for undercut different from the VWAC undercut criteria, it is suggested that the applicant indicate the date when the new criteria are to apply, and the acceptability of work inspected and accepted to the former criteria.

(2) Review the use of the word "fillers" in the third paragraph. It appears the more appropriate word would be "fillets."

(3) In the bottom paragraph, "approved" is used which has specific regulatory meaning. A more appropriate word would be "accepted."

In FSAR Amendment 23, the applicant made the recommended changes.

3.9 Mechanical Systems and Components

3.9.6 Inservice Testing of Pumps and Valves

When the SER was issued, the applicant had not yet submitted an inservice testing (IST) program for pumps and valves. Thus, the SER stated that the resolution of this issue would be addressed in an SER supplement. By a letter dated November 27, 1985, the applicant submitted an IST program.

The staff has not completed a detailed review of the NMP-2 IST program. A preliminary review was completed, and it was found that it is impractical within the limitations of design, geometry, and accessibility for the applicant to meet certain of the ASME Code requirements. A delay in the imposition of those requirements will not endanger life or property or the common defense and security of the public. Such a delay is in the public interest, giving due consideration to the burden on the applicant that could result if the requirements were imposed. On the basis of experience at similar plants where no adverse health and safety effects were found, the staff concludes that the requirements of 10 CFR 50.55a(g)(6)(i) are satisfied. If this relief were not granted, the applicant might be forced to curtail the operation of the plant, which constitutes a considerable burden. Therefore, pursuant to 10 CFR 50.55a(g)(6)(i), the relief that the applicant has requested from the pump and valve testing requirements of the 1980 Edition of ASME Code Section XI through Winter 1981 Addenda should be granted for a period of no longer than 2 years from the date of issue of the operating license or until the detailed review has been completed, whichever comes first. If the review results in additional testing requirements, the applicant will be required to comply with them at that time.

The staff stated in the SER that the maximum allowable leakage rate for pressure isolation valves (PIVs) was to be 1 gpm per valve. Since that time, the NRC has approved a more liberal leak rate acceptance criterion of 0.5 gpm per nominal inch of valve size up to a maximum leakage of 5 gpm for any valve. The indexing criteria of ASME Code Paragraph IWV-3427(b) are to be strictly observed. Accordingly, it is expected that the applicant will adopt the new criteria in the Technical Specifications for NMP-2.

3.10 <u>Seismic and Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment</u>

3.10.5 Demonstration of Containment Purge and Vent Valve Operability

Appendix J to Supplement 2 of the SER (SSER 2, November 1985) contained a report on the demonstration of containment purge and vent valve operability prepared by the staff's consultants at Brookhaven National Laboratory (BNL). That report indicated that information provided by the applicant through March 1985 had demonstrated the ability of valves AOV-106, -108, and -109 to close against the rise in containment pressure in the event of a DBA/LOCA (design-basis accident/loss-of-coolant accident) and the operability of valve AOV-104 pending reorientation of the valve or a limitation of the valve travel. Furthermore, the report indicated that the information submitted failed to demonstrate the ability of valves AOV-105, -107, -110, and -111 to close under the same conditions.

In a letter dated November 19, 1985 (from C. V. Mangan to W. Butler), the applicant provided additional information and commitments concerning operability of the purge and vent valves. The staff has received that additional information and the details of that review are provided in the revised report on the demonstration of containment purge and vent valve operability prepared by the staff's consultants at BNL and included as Appendix J to this SER supplement. That report concludes that subject to the proposed modifications, the operability of valves AOV-104, -105, -107, -110, and -111 has been demonstrated. The staff agrees with those conclusions.

4 REACTOR

4.4 Thermal and Hydraulic Design

4.4.4 Thermal-Hydraulic Stability

4.4.4.1 Single-Loop Operation

By letter dated December 30, 1985, the applicant proposed Technical Specifications to (1) permit reactor operation with one recirculation loop out of service and (2) include General Electric Company's (GE's) Service Information Letter (SIL) No. 380, Revision 1, recommendations regarding thermal-hydraulic stability concerns for single-loop operation (SLO). The recent resolution of Generic Issue B-19 regarding thermal-hydraulic stability has provided a basis to permit operation in the single-loop mode with appropriate restrictions relating to stability concerns. GE, in SIL No. 380, Revision 1, addressed these concerns by providing boiling-water-reactor applicants with generic guidance for actions that suppress thermal-hydraulic instability-induced neutron flux oscillations. The applicant has proposed Technical Specifications in accordance with the guidance provided by GE in SIL No. 380, Revision 1.

Specifically, the proposed Technical Specifications requested by the applicant consist of (1) single-loop operation Technical Specifications for average power range monitor (APRM) flux scram trip and rod block settings, an increase in the safety limit minimum critical power ratio (MCPR) value, and a revision to the allowable average planar linear heat generation rate (APLHGR) values; (2) for single-loop operation, incorporating requirements in the Technical Specifications which should result in the detection and suppression of thermal-hydraulic instability-induced neutron flux oscillations if they should occur; and (3) jet pump operability requirements for single-loop operation.

An operation analysis report was provided to support the proposed Technical Specifications.

(1) <u>Accidents (Other Than Loss-of-Coolant Accident) and Transients Affected by One Recirculation Loop Out of Service</u>

<u>One-Pump-Seizure Accident</u>

Plant-specific analysis was not performed for this event. Previous analyses for similar plants have shown that the event results in an MCPR value significantly above the SLO safety limit MCPR.

<u>Abnormal Operational Transients</u>

The applicant discussed the effects of SLO on the course of operational transients. Pressurization and cold-water-increase events, as well as rod withdrawal error, were addressed. Flow decrease is covered by the pump seizure accident already described. The results of calculations for the limiting event for each category were also presented. Initial operating conditions were conservatively assumed to be 75% rated power and 60% core flow.

- Pressurization Events

  The limiting pressurization event is the generator load rejection without bypass transient. For single-loop operation, the applicant has calculated that the maximum vessel pressure is 1160 psig and the MCPR is 1.27. Each of the values satisfies its respective safety limit.

- Cold Water Increase

  The limiting cold-water-increase event is the feedwater controller failure to maximum demand transient. The reactor is conservatively assumed to be in single-loop operation at 75% rated power and 60% core flow when failure of the feedwater control system instantaneously increases the feedwater flow to the runout capacity of 167% of rated power. The peak pressure is calculated to be 1060 psig and the MCPR is 1.20, each satisfying its respective safety limit.

- Rod Withdrawal Error

  The rod withdrawal error at rated power is given in the FSAR for the initial core. These analyses are performed to demonstrate that, even if the operator ignores all instrument indications and the alarms which could occur during the course of the transient, the rod block system will stop rod withdrawal at a minimum critical power ratio which is higher than the fuel cladding integrity safety limit. Correction of the rod block equation and lower initial power for single-loop operation ensures that the MCPR safety limit is not violated.

  One-pump operation results in backflow through 10 of 20 jet pumps while flow is being supplied to the lower plenum from the active jet pumps. Because of this backflow through the inactive jet pumps, present rod-block equation and APRM settings must be modified. The applicant has modified the two-pump rod block equation and APRM settings that exist in the Technical Specification for one-pump operation and the staff has found them acceptable.

The staff finds that one-loop transients and accidents other than LOCA, which is discussed below, are bounded by the two-loop operation analyses and are, therefore, acceptable.

MCPR Uncertainties

For single-loop operation, the MCPR fuel cladding integrity safety limit is increased by 0.01 to account for increased uncertainties in the core total flow and traversing in-core probe (TIP) readings. The limiting transients were analyzed to verify that there is more than enough margin during SLO to compensate for this increase in safety limit.

A feedwater controller failure initiating at 75% rated power and 60% rated core flow results in a transient delta CPR of 0.24 (compared with 0.27 for rated power). A generator load reject with bypass failure initiated at the same initial conditions resulted in a transient delta CPR of 0.18. Since the initial operating limit in SLO is equal to or greater than at rated power and the transient delta CPR is less in SLO, there is more margin to the safety limit in SLO than at rated power. For SLO, the operating MCPR limit remains unchanged from the normal two-loop operation limit. For single-loop operation at lower flows, the steady-state operating MCPR limit is established by multiplying the rated flow steady state by the same K_f factor. This ensures that the 99.9% statistical limit requirement is always satisfied for any postulated abnormal operational occurrence. Because the maximum core flow runout during single-loop operation is only about 60% of rated power, the current flow-dependent MCPR limits which are generated based on the flow runout up to rated core flow are also adequate to protect the flow runout events during single-loop operation.

(2) Loss-of-Coolant Accident

The applicant has performed analyses of a spectrum of recirculation suction line breaks under single-loop operation conditions. The applicant states that evaluation of these calculations which are performed according to the procedure outlined in the GE document NEDO-20556-2, Revision 1, indicates that a multiplier of 0.81 should be applied to the MAPLHGR limits for single-loop operation of the Susquehanna Steam Electric Station (SSES). This emergency core cooling system (ECCS) evaluation methodology has been approved by the staff in a letter dated March 5, 1986 (H. N. Berkow, NRC, to J. F. Quirk, GE).

The major differences between operating with both recirculation pumps running and operating with only one active recirculation pump are: reduced operating core flow, reduced core power, and reverse flow through the inactive loop jet pumps. Flow-dependent MCPR limits ensure reduced maximum assembly power during single-loop operation. The primary system coolant inventory and LOCA break conditions are essentially unchanged from the two-loop operation. Thus, the uncovery of the jet pump suction, recirculation suction line uncovery, and system depressurization rate would be expected to change little between one- and two-loop operation. The phenomena associated with these key parameters largely determine LOCA analysis results for GE analyses. The analyses performed by GE confirm this system behavior in that the limiting pipe break LOCA is essentially unchanged from the two-loop analysis, as are the break size and core uncovery times.

The principal LOCA concern associated with single-loop operation is the possibility of the LOCA break occurring in the operating loop, in which case there is no coastdown of an intact loop recirculation pump to sustain jet pump and core flow during the early portion of the system blowdown. An early boiling transition may result from this early loss of flow capability.

To account for this possibility, GE derived a single-loop operation MAPLHGR multiplier of 0.81 to be used with calculated two-loop MAPLHGR limits during single-loop operation. The analyses which determined this multiplier assumed a near instantaneous boiling transition (0.1 second) even though a longer boiling transition time may have been calculated using approved models. This assumption is very conservative when applied to the GE fuel.

(3) Thermal-Hydraulic Stability in Single-Loop Operation

The staff has evaluated the applicant's proposed Technical Specification changes to ensure that the changes provide adequate detection and suppression of potential thermal-hydraulic instabilities.

GE recently presented the staff with stability test data which 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 APRMs and were suppressed with control rod insertion. It was predicted that limit cycle oscillations would occur at the operating condition 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 LPRM indications oscillated out of phase with the APRM signal and at amplitudes as great as six times the core average. GE has prepared and released a service information letter, SIL No. 380, to alert the BWR owners of these new data and to recommend actions to avoid and control abnormal neutron flux oscillations.

The GE recommendations were reviewed by the staff and were found to be prudent recommendations which provide adequate detection and suppression of potential thermal-hydraulic instabilities as required by General Design Criteria (GDC) 10 and 12. The staff compared these recommendations with the NMP-2 Technical Specifications for operation with a recirculation loop out of service and found that the proposed changes are in conformance with the SIL No. 380, Revision 1, recommendations and are acceptable to the staff. As the Technical Specifications will contain limitations on operation to avoid areas of potential thermal-hydraulic instability, a license condition requiring a thermal-hydraulic stability analyses is not needed.

(4) Summary of Single-Loop Operation

Long-Term Single-Loop Operation

SLO with appropriate Technical Specification changes has been previously approved on a permanent basis for Duane Arnold. It is concluded for NMP-2 that appropriate provisions have been made so that transient and accident bounds will not be exceeded during SLO.

Minimum Critical Power Ratio Safety Limit Will Be Increased to 1.07

The MCPR safety limit will be increased by 0.01 to account for increased uncertainties in TIP readings. The applicant has determined that the change conservatively bounds the uncertainties introduced by single-loop operation.

Minimum Critical Power Ratio Limiting Condition for Operation

The applicant proposed that the operating limit MCPR be multiplied by the appropriate two-loop K_f factors that are in the NMP-2 Technical Specifications. This will preclude an inadvertent flow increase from causing the MCPR to drop below the safety limit MCPR.

The Maximum Average Planar Linear Heat Generation Rate Limits Will Be Reduced by Appropriate Multipliers

The applicant proposed reducing the Technical Specifications MAPLHGR by 0.81 for single-loop operation. These reductions were based on an analysis method proposed by GE in NEDE-20566-2.

The APRM Scram and Rod Block Setpoints Will Be Reduced

The applicant proposed to modify the two-loop APRM scram, rod block, and rod block monitor (RBM) setpoints to account for backflow through half the jet pumps. These setpoint equations are included in the NMP-2 Technical Specification. The changes are similar to other plant Technical Specification changes and are acceptable to the staff.

The Recirculation Control Will Be in Manual Control

The applicant proposed that NMP-2 be operated with the recirculation system in the manual mode to eliminate the need for control system analyses and to reduce the effects of potential flow instabilities.

On the basis of the discussion presented above, the staff concludes that the proposed Technical Specifications for single-loop operation of NMP-2 are acceptable.

5 REACTOR COOLANT SYSTEMS

5.3 Reactor Vessel

5.3.1 Reactor Vessel Materials

Compliance With Appendix H, 10 CFR 50

In SSER 2 (p. 5-13) the staff indicated that the applicant's surveillance program had complied with all the requirements of Appendix H to 10 CFR 50 except that the surveillance capsules have been positioned inside the vessel at locations that result in low lead (lag) factors. As a result of these lag factors, the NMP-2 surveillance capsules will provide dosimetry data, but not meaningful material surveillance data, throughout the life of NMP-2.

To provide additional material surveillance data, the applicant, in letters dated December 3, 1984 (from C. V. Mangan to A. Schwencer), and December 17, 1985 (from C. V. Mangan to H. Denton), has committed to monitor the effect of neutron irradiation on its beltline materials using the surveillance data from its capsules and those in LaSalle County Station Units 1 and 2 (LaSalle) and Washington Public Power Supply Nuclear Plant No. 2 (WNP-2). To ensure that the applicant's surveillance program will adequately monitor neutron irradiation damage, it must conform to the integrated surveillance program criteria of Section II.C of Appendix H to 10 CFR 50. The criteria are:

(1) There must be substantial advantages to be gained, such as reduced power outages or reduced personnel exposure to radiation.

(2) The design and operating features of the reactors in the set must be sufficiently similar to permit accurate comparisons of the predicted amount of radiation damage as a function of total power output.

(3) There must be an adequate dosimetry program for each reactor.

(4) There must be a contingency plan to ensure that the surveillance program for each reactor will not be jeopardized by operation at reduced power level or by an extended outage of another reactor from which data are expected.

(5) No reduction in the requirements for number of materials to be irradiated, specimen type, or number of specimens per reactor is permitted.

(6) There must be an adequate arrangement for data sharing between plants.

In letters dated May 16 (from T. E. Lempges to W. Butler), September 30 (from C. V. Mangan to H. Denton), and November 18, 1985 (from C. V. Mangan to H. Denton), the applicant provided information to demonstrate that its surveillance program satisfies the criteria in Section II.C of Appendix H to 10 CFR 50. A summary of these submittals follows.

The alternative to an integrated surveillance program is that the capsules in the NMP-2 vessel be moved to other locations in the NMP-2 vessel that have higher lead factors. Capsules at locations with higher lead factors would provide meaningful material surveillance data. However, the applicant indicates that the NMP-2 surveillance capsules have been located in positions that are advantageous for withdrawal, thus reducing occupational radiation to the technicians removing the capsules. Thus, the advantage gained by the integrated surveillance program is that the capsules would not be moved to locations that could increase personnel exposure to radiation, thereby satisfying criterion 1.

The NMP-2, WNP-2, and LaSalle reactors are all BWR-5 251 series vessels and have predicted end-of-life neutron fluence (E > 1 MeV) at the 1/4T position of 1×10^{18} n/cm^2. The reactor power (3323 MWt), the number of fuel bundles (764), and the vessel diameter (251 inches) are all identical. In addition, the materials placed into the WNP-2 and LaSalle capsules are similar to those in the NMP-2 vessel. Because the vessel and reactor designs of NMP-2, WNP-2, and LaSalle are equivalent and the materials in the WNP-2 and LaSalle capsules are similar to those in the NMP-2 vessel, the test results from the WNP-2 and LaSalle surveillance capsules will permit a determination of the amount of radiation damage to the NMP-2 vessel as a function of its power output. Therefore, criterion 2 is satisfied.

Each capsule in NMP-2, WNP-2, and LaSalle has sufficient dosimetry and Charpy V-notch specimens to monitor neutron irradiation and damage to the vessel materials. Hence, the dosimetry and Charpy V-notch specimens placed in each capsule satisfy criteria 3 and 5, above.

Because NMP-2 can utilize data from capsules in three other vessels (WNP-2 and LaSalle 1 and 2), the surveillance program will not be jeopardized by operation at reduced power level or extended outage of another reactor from which data are expected. Therefore, criterion 4 is satisfied.

By a letter dated January 16, 1986 (from C. V. Mangan to H. Denton), the applicant indicated that the Washington Public Power Supply System (WNP-2) and Commonwealth Edison (LaSalle Units 1 and 2) have agreed to participate in the reactor vessel material surveillance program as described in the applicant's letters of September 30, November 18, and December 17, 1985. Therefore, criterion 6 is satisfied. In addition, the WNP-2 and LaSalle surveillance data are required by Appendix H to 10 CFR 50 to be submitted for staff review. Hence, the staff and the applicant should be able to utilize the WNP-2 and LaSalle surveillance data to monitor the effect of neutron irradiation on the NMP-2 vessel.

On the basis of the previous discussion, the applicant has demonstrated that the proposed integrated surveillance program complies with the criteria in Section II.C of Appendix H to 10 CFR 50. Compliance with the criteria in Section II.C of Appendix H to 10 CFR 50, ensures that the effect of neutron irradiation on the NMP-2 reactor vessel beltline materials will be monitored throughout the life of the plant.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.1 Containment Functional Design

6.2.1.3 Short-Term Pressure Response

The drywell and suppression chamber design pressure is 45 psig. In FSAR Amendment 21, the applicant provided the results of a sensitivity analysis based on a change in the number of downcomers from 123, which was used in the original FSAR analysis, to 121, which reflects the as-built plant condition after 2 downcomers were blocked off. The 2 downcomers were eliminated in a design modification to accommodate quenchers which were installed on the RHR heat exchanger relief valve discharge lines. The results of the analysis show that the drywell peak pressure increased nominally from 39.75 psig to 39.86 psig.

The staff has performed a comparison of the NMP-2 values of peak short-term drywell and suppression chamber pressures with a group of plants with the Mark II containment for which the staff performed satisfactory confirmatory analyses using the CONTEMPT LT/028 computer code. This comparison is shown in Table 6.1. Table 6.2 contains an additional comparison of selected NMP-2 containment characteristics with a similar Mark II plant designed by the same architect-engineer, Stone & Webster Engineering. This comparison indicates that the difference in calculated drywell peak pressures between 39.9 psig for NMP-2 and 41.9 psig for Shoreham is 5%. Similarly the difference for peak pressures in the suppression chamber is 12%. These differences are within an acceptable range, given the slight variations in plant parameters shown in Table 6.2. Since the peak pressures calculated for Shoreham have been verified by the staff as being accurate given the postulated accident assumptions, the staff concludes that, by comparison, the values submitted by the applicant for the short-term analysis of drywell and suppression chamber peak pressures resulting from a double-ended rupture of the recirculation line is acceptable.

6.2.1.7 Pool Dynamic Analyses

6.2.1.7.3 Plant-Unique Loads

The following subsections have the same numbers and titles as those in the SER Section 6.2.1.7.3.

(1) Pool Swell Loads

The staff stated in the SER that it had requested the applicant to provide comparisons to demonstrate the conservatisms of the results obtained from LOCTVS and Stone & Webster Engineering Corp. (SWEC) computer codes to those results obtained from the General Electric (GE) PSAM code and GE Topical Report NEDO-10320 and Appendix B of GE report NEDO-20533.

In Amendment 21 to the design assessment report (DAR), the applicant provided the requested information. On the basis of its review of the information submitted by the applicant, the staff concludes that, except for bubble pressures, the comparison shows favorable agreement and, therefore, is acceptable.

With respect to the bubble pressure prediction, the LOCTVS result is 3.5 psi less than bubble pressures calculated by PSAM. The applicant indicated that it has evaluated all safety-related components and structures that are affected by the higher air bubble load and has concluded that such components and structures can withstand the additional 3.5 psi. The structural capability of the NMP-2 downcomers to withstand all loss-of-coolant accident (LOCA) and safety/relief valve (SRV) hydrodynamic loads is discussed in Section 6.2.1.7.4 of this supplement.

(4) Loads on Submerged Boundaries

In the SER, the staff stated that information is needed about the magnitude of the pool swell bounding loads inside and outside the pedestal. In Amendment 21 to the DAR, the applicant stated that a bounding analysis was done to estimate the differential pressure loading across the pedestal wall. This differential pressure was obtained by modifying the containment value by the ratio of pool surface area per downcomer within this area per downcomer in the main pool. On the basis of its review of the applicant's submittal, the staff finds that the applicant's approach to assessing this load is acceptable.

(5) Multi-event Lateral Load

In the SER, the staff indicated that additional information is needed to define how the multi-event lateral load is applied to the diaphragm floor. In a letter dated September 16, 1985, the applicant stated that the diaphragm floor is designed to withstand the moment and shears caused by the multi-event lateral loads at the junction of the downcomers with the drywell floor. The individual multi-event lateral loads are applied simultaneously and in the same direction at all downcomers and, therefore, are added algebraically. On the basis of its review of the applicant's submittal, the staff concludes that this approach is bounding and, therefore, is acceptable.

(6) Condensation Oscillation Loads Inside the Pedestal

In the SER, the staff indicated that the applicant's proposal to use the same time-history segments specified in the Mark II generic condensation oscillation (CO) load definition for the annular pool region, multiplied by 1.25, as the load definition for the cylindrical pool to be acceptable pending approval of the methodology regarding the SWEC computer program.

In Amendment 21 to the DAR, the applicant indicated that the 1.25 multiplier was determined on the basis of the SWEC computer code results that calculated the differential pressure between both regions (cylindrical and annular) of the suppression pool by applying the CO source between 0 and 30 Hz. The average pressure amplitude ratio between the inner and the outer pool varied between 1.04 and 1.24. Therefore, the use of the 1.25 multiplier to define the CO inside the pedestal region is conservative. On the basis of its review of the applicant's submittal, the staff concludes that the use of the 1.25 multiplier is acceptable; the staff now considers this issue closed.

(8) Steam Condensation Submerged Drag Loads

In the SER, the staff indicated that it needed additional information before it could conclude on the acceptability of this load. Reexamination of the DAR revealed that the applicant is using the same methodology that was previously reviewed and found acceptable in the Shoreham SER. Therefore, this issue is closed.

(9) Pool Temperature Limit

(c) Bulk-to-Local Temperature Differences

In the SER, the staff stated that it would require the applicant to perform confirmatory calculations by using data from comprehensive SRV inplant tests, to demonstrate that the maximum local pool temperature specifications will not be exceeded. In a letter dated September 30, 1985, the applicant provided a comparison of the NMP-2 pool geometry to the LaSalle pool geometry, where the SRV inplant tests were conducted. The applicant also provided a comparison between predictions of the LaSalle pool temperature to SRV actuation transient to those measured during an extended blowdown test. On the basis of its review of the information provided by the applicant, the staff concluded that the NMP-2 and LaSalle geometries are very similar. The staff has also concluded that the predicted temperature transients compare favorably with the measured values. Therefore, this issue is now resolved and the use of a local-to-bulk temperature difference of 10°F is acceptable.

(d) Single-Failure Analysis

The applicant stated that the normal shutdown cooling mode could be unavailable as a result of a failure of the suction line isolation valve inside the drywell. For this case, alternate shutdown cooling could be achieved by pumping suppression pool water into the reactor vessel through the residual heat removal (RHR) system and returning water to the pool through manually opened SRVs. The staff finds this alternate mode of removing the decay heat to be acceptable.

(10) Quencher Air Clearing Load

As stated in the SER, the applicant indicated that the acceptance criteria for the T-quencher as set forth in NUREG-0802 is utilized in the design of Nine Mile Point, Unit 2, except for the criterion on frequency range. The applicant concluded that a frequency range of 3 to 9 Hz instead of the staff-recommended value of 3 to 11 Hz, is conservative for NMP-2. To support this conclusion, the applicant provided comparisons of the response spectrum of an extrapolated Karlstein test trace 21.1 which has the highest dominant frequency with the NMP-2 design load. The Karlstein trace was modified by an amplitude reduction factor and dominant frequency factor to account for NMP-2 specific parameters. The comparison indicated that the NMP-2 specification is conservative and, therefore, acceptable. The staff concludes that this issue has been resolved.

(11) SRV Submerged Structure Load

The SRV air bubble submerged structure drag loads are computed on the basis of a bubble pressure source strength of 1.5 times the Kraftwerk Union (KWU) specification. Since this pressure has been found acceptable for the boundary load specification, its use of submerged structure drag load is also acceptable.

The flow pattern of the fluid about the structure is calculated using the Rayleigh bubble equation for a spherical bubble that uses the pressure field outlined above. The applicant included the NRC-recommended 1.1 factor for bubble asymmetry to the fluid velocity and acceleration. Interference effects of adjacent structures are accounted for in calculating the acceleration drag coefficient in accordance with NUREG-0487, Supplement 1.

The applicant has presented a comparison between the above-described methodology and the previously approved KWU methodology. The results of this comparison indicate that the downcomer responses are within 1% of each other. On the basis of the above discussion, the staff concludes that the use of the Rayleigh bubble equation approach produces equivalent results to the KWU methodology previously found acceptable and, therefore, is acceptable.

In calculating the effective submerged structure drag load for NMP-2, the velocity and acceleration drag terms are modified to include the relative velocity and acceleration of the fluid and the downcomer at each instant in time. This issue is now considered resolved.

(12) SRV Inplant Test

In NUREG-0763, "Guidelines for Confirmatory Inplant Test of Safety-Relief Valve Discharge of BWR Plants," the staff stated in part that inplant tests will be required for those plants in which parameters potentially affecting SRV-discharge performance are deemed to be plant unique. In Section 4 of the report, the staff listed five conditions which, if satisfied (i.e., if applicants are able to demonstrate that the conditions in their plant are similar to the conditions in plants previously tested), will obviate the need for any new tests.

In its letter dated September 16, 1985, the applicant submitted the requested evaluation and justification. The applicant concluded that inplant SRV testing is not required for NMP-2 since the comparison of key parameters for each of the five conditions demonstrates that discharge conditions are sufficiently similar between NMP-2 and LaSalle, where SRV inplant tests were performed. The applicant also stated that other parameters, which differ slightly (such as soil shear wave velocity), do not have a significant effect on SRV loading.

On the basis of its evaluation, the staff concludes that SRV inplant tests are not required for NMP-2.

(13) Wetwell-Drywell Vacuum Breakers

In response to the staff's concern identified in the SER, the applicant provided the following information.

The vacuum breakers are located inside the drywell and are mounted in piping that connects the drywell to the suppression chamber. Since the vacuum breakers are not mounted on downcomers, they are removed from the direct effects of chugging transients. The vacuum breakers' valves are of the same size and of similar design as the LaSalle valves which have undergone modification and testing to ensure that they can withstand the pool swell phenomena. The staff had previously reviewed and found acceptable the LaSalle vacuum breaker valve tests and design modification. Since the modified valve's design has been incorporated in the NMP-2 plants, and since similarly modified valves have undergone tests at the expected opening and closing velocities for NMP-2, the staff concludes that the design of the vacuum breaker valves for NMP-2 is acceptable and can accommodate the effects of pool swell impact loading following a design-basis LOCA.

(15) Secondary Loads

Following the pool swell process, continued flow through the vent system generates random pool motion. This pool motion creates waves which may impinge upon the downcomers. The staff has determined generically that these loads are considered to be secondary by virtue of their low magnitude when compared with the primary loads discussed in the previous section. However, since the NMP-2 downcomers are unbraced and have a natural frequency of about 0.89 Hz, the random pool motion discussed above may exert loads on the downcomers at a frequency corresponding to the downcomers' natural frequency and consequently amplify these loads. Therefore, the generic conclusion that these loads are secondary by virtue of their low magnitude might not be applicable to NMP-2.

In a meeting on December 20, 1985, the applicant was requested to assess the potential of secondary load of becoming significant load due to resonance. This issue is addressed in the "Load and Load Applications" section of Section 6.2.1.7.4 of this supplement.

6.2.1.7.4 Downcomer Design

The NMP-2 containment design utilizes the BWR Mark II concept of over-under pressure suppression with multiple downcomers (121) connecting the drywell to the pressure-suppression chambers. These downcomers channel the steam resulting from a loss-of-coolant accident (LOCA) from the drywell into the suppression pool.

The NMP-2 downcomers are made of type 304 stainless steel (SA 312-304) pipes, 24 inches in diameter, 3/8 inch in thickness, and 30 to 45 feet in length. Approximately 11 feet of each downcomer is submerged below the high water level of the suppression pool. These pipes are designed to ASME Boiler and Pressure Vessel Code (hereinafter referred to as the Code) rules for Class 2 piping, in accordance with staff criteria on load combinations specified in Standard Review Plan (SRP) Section 3.9.2 and in NUREG-0484, Revision 1, "Methodology for Combining Dynamic Responses."

The downcomer design at NMP-2 is unique in that it does not provide lateral supports at the free ends of downcomers; i.e., at the bottom, the downcomers are free to move in the plane perpendicular to downcomers. All other domestic Mark II plants have employed a bracing system to tie all downcomers together at the bottom to prevent free movement of an individual downcomer pipe. The design of the unbraced downcomers at NMP-2 is very "soft," i.e., the natural frequency of the fundamental mode is 1.0 to 2.0 Hz. The diameter-to-thickness ratio (D/t) is 64; this exceeds the value of 50 that is generally viewed as the upper limit of the applicability of design procedures for nuclear piping specified in the ASME Code. In a "soft" structure, the deformation is expected to be large; this can invalidate the basic assumptions for performing a linear-elastic structural system analysis. Although there are no clear definitions of "large" deformations (e.g., excessive ovalization and flexure) in the theory, the range of uncertainties in the analysis is expected to become larger and results of the analyses become less reliable as deformation increases.

Because the unbraced downcomer design is unique and because of the concern over the potential loss of structural stability before reaching the design limits, the staff requested the detailed design calculations on the NMP-2 downcomers. The staff performed a preliminary review of the design calculations and in a meeting in Bethesda, Maryland, on December 20, 1985, stated that the design appeared inadequate because the unbraced design did not meet some of the licensing criteria established by the NRC and accepted by the applicant. In the meeting, the staff also presented its specific concerns relating to the applicant's analysis of the downcomer design. Subsequent to the meeting, the downcomer analysis that was discussed at the meeting was submitted in a letter dated December 31, 1985, from C. V. Mangan to E. Adensam. After performing a detailed review of that analysis, a draft safety evaluation report was transmitted to the applicant by letter dated January 8, 1986. On January 15, 1986, a meeting was again held in Bethesda, Maryland, between the staff, the applicant, and the applicant's consultants: Stone & Webster Engineering Corp., General Electric Corp., Stevenson & Associates, and Management Analysis Company. After reviewing the staff's concerns described in the staff's January 8, 1986, letter, the applicant reanalyzed the NMP-2 downcomers on the following bases:

- A time-history analysis was made for the seismic loads.
- Chugging loads were revised according to NUREG-0808.
- Allowable stresses were revised on the basis of the temperatures in the NMP-2 wetwell.
- Damping values were revised.
- The method for combining loads was revised.
- A rigorous ASME Class 1 fatigue reanalysis was completed that superseded the original one presented in the applicant's letters of December 31, 1985, in which the stress intensification factor was not properly considered.

The applicant has also indicated that snap-back tests with deflections of 1.2 and 3 inches were performed to justify the higher damping factors used in the reanalysis. The details of the above reanalysis were submitted by letters dated January 23 and 24, 1986.

On January 24, 1986, the staff met with its consultants to discuss the adequacy of NMP-2 downcomer design in the context of the reanalysis submitted by the applicant on January 23. After a detailed discussion, the staff and the consultants concluded that: (1) the unbraced downcomer design at NMP-2 met the licensing criteria for upset and emergency conditions but met the criteria marginally; and (2) the applicant had not adequately demonstrated the design adequacy for the faulted condition. These conclusions along with staff recommendations for the possible resolution were furnished to the applicant by letter dated January 31, 1986. In the material that follows, the staff's specific concerns about the design adequacy of NMP-2 downcomers, the recommendations for resolution, and the bases for the recommendations are discussed.

Design Philosophy

The downcomers are essential elements of the suppression-type containment system and, strictly speaking, are not a piping system. The downcomers channel the steam that can result from a loss-of-coolant accident (LOCA) or other accidents from the drywell into the suppression pool. In fulfilling this suppression function, the downcomers will be subjected to flow-induced and pool hydrodynamic loads in addition to other loads that are considered in the design of structures inside the containment. Both the flow-induced and pool hydrodynamic loads can be influenced by the structural characteristics of the downcomers. These loads have been determined from model testing of a "rigid" downcomer. Therefore, the staff believes that the use of rigid downcomers would obviate the potential problems of resonance, buckling (loss of geometric stability), low-cycle fatigue, and functional capability.

Even though the applicant has demonstrated that the design meets the Code criteria, the applicant has not used an adequate safety factor to accommodate the uncertainties (for example, those associated with the definition of the loading, material properties, imperfections in the geometrical configuration, and method of analysis), since some design convervatisms have been reduced in the reanalysis. In a letter dated January 24, 1986 (from C. V. Mangan to E. Adensam), the applicant noted that Stevenson & Associates observed that "there may be no inherent margin in failure mechanism formation between multi-supported statically indeterminate piping systems and statically determinate simply supported or cantilever supported systems." The staff believes this observation is basically irrelevant because in installing a bracing system connecting adjacent downcomers, thus resulting in a highly redundant (statically indeterminate) space frame, the structural capability of the downcomers would be greatly enhanced. The letter of January 24 further noted that a cantilevered downcomer could be visualized as a pendulum that would be stable under dead and transient loads. If the downcomers act as visualized in the LOCA case, their behavior would be unpredictable and the displacements could be so large as to eventually lead to collapse or break, resulting in functional impairment of the downcomers. The applicant should either demonstrate that this failure mechanism could not occur or should design the downcomer to prevent it from occurring.

Loads and Load Applications

In the resolution of Unresolved Safety Issue (USI) A-8, "Mark II Containment Pool Dynamic Loads," the staff and its consultants evaluated and approved the bases for concluding that certain loads were secondary by virtue of their low magnitude and, therefore, were negligible. These secondary loads included water sloshing during and after the pool swell, seismic sloshing, and fluid/structural interactions. These conclusions were based on results of scale-model tests of pool swell, the chugging phenomenon, and pool response to SRV discharges.

The dynamic characteristics of downcomers were not considered in the modeling and, therefore, possible resonance effects were also not considered. Also, the single downcomer in the test chamber was supported laterally. Therefore, the conclusion that these loads were secondary and negligible may not be applicable to NMP-2 unbraced downcomer design.

In a meeting held on December 20, 1985, the applicant was requested to assess the potential of secondary loads being amplified to become significant as a result of resonance. The applicant reviewed all secondary loads as identified in NUREG-0487 and -0808. In this new light, only two loads were found to be cyclic in nature and, therefore, potentially susceptible to resonance effects: they are seismic sloshing and post-pool-swell loads. The annulus pool seismic sloshing frequency was estimated by the applicant to be 0.13 Hz, which is far from the downcomer resonance frequency of 1.55 Hz. Because of this wide separation, the applicant has concluded that resonance will not occur. The staff concurs with this conclusion.

With respect to post-pool-swell loads, the test data base was reviewed by the applicant, who concluded, and the staff concurs, that water fallback will not effectively excite the sloshing waves. Notwithstanding this conclusion, the applicant computed the frequencies of these waves, if they were to occur, to be between 0.29 Hz and 0.56 Hz. This range is well below the 1.94-Hz downcomer natural frequency in case of a LOCA when the water column inside a downcomer would be displaced by steam. The staff agrees with the applicant that, on the basis of this analysis, resonance will not occur. Therefore, the staff concludes that the applicant has adequately considered all secondary loads. Furthermore, it is noted that in its downcomer design analysis for chugging loads, the applicant utilized GE 800-series in lieu of the GE 700-series tests that had been used in earlier analyses. The applicant performed downcomer analyses considering both the GE 801 and GE 804 chugs. For the remaining 800-series chugs, the applicant was able to demonstrate that the previous analyses using the 700-series or the two 800-series cases were bounding. Since the above approach conforms to the staff acceptance criteria, the staff finds the revised design chugging loads acceptable.

<u>Load Combinations</u>

In FSAR Section 6A.2.2.5, "Design Assessment Report for Hydrodynamic Loads," it is indicated that for all mechanical systems, components, and supports, the structural responses to dynamic loads such as LOCA, SRV, and OBE/SSE (operating basis earthquake/safe shutdown earthquake) are combined by the square-root-of-the-sum-of-the-squares (SRSS) method, and then responses to similar dynamic loads for applicable seismic Category I structures are combined by the absolute-sum method. Even though the downcomers are part of the pressure-suppression system, they have been designed as a mechanical piping system. As a result, the staff has accepted the SRSS method for combining the responses of the above-mentioned dynamic loads in the design analysis of the downcomers. The staff position on the combination of dynamic responses by the SRSS method is given in NUREG-0484, Revision 1.

In reviewing the load combination method presented in the applicant's letter dated December 31, 1985, the staff noted that the SRSS method for response combinations for the NMP-2 downcomer was not in conformance with the staff position provided in NUREG-0484, Revision 1. In a letter dated January 8, 1986, the applicant was requested to assess its load combination method in accordance with the staff position. In response to the staff's concern, the applicant has revised its methodology for load combinations in accordance with the methodology described in NUREG-0484, Revision 1. This resolved the staff's concern on the load combinations.

Functional Capability

In response to an earlier staff concern on the functional capability of essential piping systems for NMP-2, the applicant made a commitment in its FSAR, as amended, that all essential ASME Code Class 1, 2, and 3 piping system would be designed to meet the functional capability criteria provided in the topical report NEDO-21985 submitted to the staff by GE. On the basis of this commitment, the staff stated in SER Section 3.9.3.1 that "for those piping systems identified as essential that are subjected to loads in excess of Service Level B limits, their functional capability has been evaluated in accordance with the criteria provided in the GE Topical Report NEDO-21985, 'Functional Capability Criteria for Essential Mark II Piping,' dated September 1978, which the staff has previously reviewed and approved."

In the detailed design report (December 31, 1985, letter from C. V. Mangan to E. Adensam) for the NMP-2 downcomers previously submitted, the applicant indicated that the design of the NMP-2 downcomers failed to meet the functional capability criteria presented in GE's report NEDO-21985. The applicant then elected to perform a detailed dynamic stability analysis, which is an option provided in the staff evaluation of the topical report dated February 27, 1981. On the basis of the review of the analysis provided in the December 31 letter, the staff concluded that the applicant did not adequately demonstrate the functional capability of the downcomers, and conveyed its specific concerns to the applicant in its letter of January 8, 1986.

In response to the staff concern, the applicant reevaluated the functional capability of the NMP-2 downcomers (letters from C. V. Mangan to E. Adensam, January 23 and 24, 1985). In this reevaluation, the applicant performed a finite element elasto-plastic shell analysis using the revised limiting loads for the faulted condition. The results were compared to criteria contained in NUREG-0261 on deflection, in GE's report NEDO-21985 on functional capability, and in NUREG-1061, Volume 2, on strain. Note that the strain criteria proposed in NUREG-1061, Volume 2, have not been accepted as a staff position. Furthermore, NUREG-1061, Volume 2, recommended that a factor of safety of 1.5 to 2.0 be applied for the design.

On the basis of the review of the information provided in the applicant's letters of January 23 and 24, 1985, the staff concludes that the applicant has not adequately demonstrated the design adequacy for the faulted conditions; i.e., the downcomer may lose geometrical stability before reaching the calculated stress levels for the faulted condition. The bases for this conclusion are as follows:

NUREG-0261 is based on a small displacement analysis that can not predict buckling. Accordingly, the comparison to the NUREG-0261 results is not meaningful. NEDO-21985 was developed for piping systems. The NMP-2 unbraced downcomers are different from typical piping systems because of the following:

(1) Piping systems have two or more anchors; hence, a single plastic hinge will not lead to gross plastic displacements of the piping system.

(2) Piping systems usually have internal pressure. The stress criteria presented in the NEDO-21985 report includes a pressure term of PD/4t. For piping with a large D/t, the pressure effect may be significant even for a relatively small internal pressure. It is noted that the applicant has not considered the effects from internal pressure and dead weight of downcomers in making comparison to the NEDO-21985 stress criteria. If these two effects were included, the result of the comparison to NEDO-21985 criteria would have changed from being acceptable by a factor of 1.03 to being not acceptable.

Figure 2 in the applicant's letter of January 24, 1986, presents a comparison of the maximum calculated strain of 0.0059 at the limiting moment for NMP-2 downcomers to the strain criterion of $\varepsilon = 0.2$ (t/r), where t is the thickness and r is the nominal radius of a downcomer pipe, as suggested in NUREG-1061 (i.e., $\varepsilon = 0.00625$ at D/t = 64) as well as the test data from Reddy's paper (1979). The validity of this comparison depends largely on the results presented there. However, in reviewing Reddy's paper, the staff notes that several key parameters relevant to material properties of the test specimens have not been clearly specified; e.g, actual wall thickness, out-of-roundness, type of material. The staff believes that there are considerable uncertainties associated with these parameters that could invalidate their direct applicability to the NMP-2 downcomer design.

Fatigue Evaluation

In the December 31, 1985, letter, the applicant provided its fatigue evaluation of the NMP-2 downcomers. The staff's review of that material raised the concern that because the downcomers as designed have a fundamental mode natural frequency between 1 and 2 Hz, the most significant fatigue damage may incur from the low-cycle/high-stress oscillations. The applicant was requested to clarify its analysis to demonstrate the adequacy of the fatigue design of the NMP-2 downcomers.

In response to the staff concern, the applicant provided a revised fatigue evaluation for the NMP-2 downcomers in its letter of January 23, 1986. The applicant stated that a rigorous ASME Code Class 1 fatigue reanalysis has been performed and the result satisfies the ASME Code Class 1 requirement. The applicant also stated that this revised fatigue analysis is performed for the critical location of the downcomers; i.e., at the junction between the downcomers and the drywell floor, and all postulated loading events that can occur on Mark II plant and can affect the downcomers are considered.

In reviewing the calculations provided in the applicant's January 23, 1986, letter, the staff noted the applicant's analysis method is not a straightforward application of ASME Code rules and, in some areas of calculations, the results were nonconservative as compared with the Code. However, in view of the substantial margin of the calculated cumulative usage factor (CUF) to the Code requirement; i.e., CUF = 0.182 which is significantly less than 1.0, the staff believes that the results provide a sufficient margin to ensure the adequacy of the fatigue design of the NMP-2 downcomers.

The above conclusions along with staff recommendations were furnished to the applicant by letter dated January 31, 1986 (R. Bernero to B. G. Hooten).

Evaluation of Request for Schedular Exemption

As a result of staff's January 31, 1986, letter (C. V. Mangan to R. Bernero), the applicant submitted a letter dated February 18, 1986, to request a schedular exemption pursuant to the Commission's regulations under 10 CFR 50.12(a) to allow completion of the analysis and any resulting requirement for modification of the installed downcomers in an orderly manner. Specifically, the requested exemption is to permit operation during the time that confirmatory analyses of design margins for the NMP-2 downcomers are being performed. Furthermore, it is requested that the Commission permit any hardware changes to the facility required as a result of this confirmatory evaluation to be completed before startup following the first refueling outage. On the basis of the results of the analysis provided in its exemption request of February 18, 1986, the applicant has concluded that the granting of the schedular exemption would be in accordance with the requirements of 10 CFR 50.12(a). The following material details the applicant's request for a schedular exemption as described in the exemption request and provides the staff's evaluation and conclusion.

Under 10 CFR 50.12(a), the Commission may grant specific exemptions from the requirements of the regulations if (1) the exemptions are authorized by law, will not present an undue risk to the public health and safety, and are consistent with the common defense and security and (2) special circumstances are present.

The specific design requirement from which the applicant requested exemption is General Design Criterion (GDC) 2, "Design Bases for Protection Against Natural Phenomena," of Appendix A to 10 CFR 50.

GDC 2 requires that the structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes without loss of capability to perform their safety functions. Furthermore, GDC 2 specifically states that the design bases for these structures, systems, and components shall reflect appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena. It is this particular load combination for which the applicant has requested a schedular exemption to allow additional time to perform further analyses. In the interim, the applicant has requested that the LOCA and safe shutdown earthquake (SSE) loads not be combined because of the low probability of simultaneous occurrence of both events.

In the February 18, 1986, letter, the applicant presented the following technical arguments to support its request for schedular exemption at NMP-2. The applicant contended that (1) the analyses performed support the adequacy of the design; (2) there are margins to failure beyond the ASME Code limits; and (3) there are further unquantified margins based on conservatisms in load combinations and definitions. More specifically, the applicant contended:

(1) The probability of simultaneous occurrence of an SSE and a LOCA is small; therefore, if this load combination were neglected, sufficient additional margins would exist to preclude questions regarding the design adequacy,

(2) The probability of a large LOCA is now considered to be significantly lower than previously believed.

As discussed in the above evaluation, on the basis of the information presented to the staff to date, the staff does not agree with the applicant's contention that the current analyses demonstrate that sufficient margins are available in the downcomer design to accommodate uncertainties for the LOCA and SSE load combination. The staff in this evaluation addresses the separation of the LOCA and SSE loads for one cycle of operation on the basis of event probabilities and on the materials of construction. The simultaneous occurrence of a LOCA and SSE has two possible scenarios: (1) a double-ended-guillotine break (DEGB) of the recirculation piping (LOCA) simultaneously with an earthquake when both events are unrelated and (2) the seismically induced failure of the recirculation piping during an earthquake. The applicant has presented results from a recent Lawrence Livermore National Laboratory study (the study) on pipe rupture in BWR plants. For the first scenario, the study concluded that the likelihood of simultaneous occurrence of two independent and random events is negligibly low. The staff has estimated that, in the relatively seismically stable region east of the Rocky Mountains, the probability of exceeding the SSE peak acceleration (0.1 g to 0.25 g, depending on the location) is on the order of 10^{-3} or 10^{-4} per year (Reiter, 1983). The probability of a large-break LOCA for boiling-water reactor (BWR) piping is about 10^{-4} to 10^{-8} per year for a large size pipe (> 6.0 inches), independent of seismic event (NUREG-75/014 (formerly WASH-1400); NUREG/CR-3085, -3028, -3600). For BWR piping free of intergranular stress corrosion cracking (IGSCC), the probability of a DEGB (or its equivalence in a longitudinal split) tends to be closer to the lower value. Although the staff recognizes the uncertainties associated with these probabilities and believes a quantitative combination of the two event probabilities may not be meaningful, the staff agrees with the applicant that the probability of simultaneous occurrence of two independent and random events is of extremely low probability.

For the second scenario, the study calculates the probability of LOCA in terms of direct and indirect DEGB. A direct DEGB is pipe failure due to the crack growth at welded joints by either exceeding net section stress for austenitic stainless steels or the tearing modulus for carbon steels. An indirect DEGB is the pipe rupture caused by the seismically induced support failure. That is, an earthquake could cause the failure of component supports or other heavy equipment whose failure in turn would lead to recirculation pipe breaks. The study showed that earthquakes were not a significant contributor to the failure mode of a direct DEGB, especially if the piping was fabricated with an IGSCC-resistant material. The recirculation piping at NMP-2 is made of type 316NG stainless steel that is more IGSCC resistant. The applicant has committed to take additional steps to avoid stress corrosion cracking (see FSAR Section 5.2.3.4.1). With minor exceptions, all other wrought austenitic stainless steels in the reactor coolant pressure boundary are IGSCC-resistant, low-carbon type 304L or 316L. The study showed that the failure probability of a direct DEGB is from 1.5×10^{-9} to 2.5×10^{-10} events per plant year at the 90% confidence limit. The probability of an indirect DEGB induced by an earthquake is about 5.0×10^{-7} events per plant year at the 90% confidence limit.

The staff agrees with the applicant that the likelihood of a large-break LOCA is even more remote at NMP-2 than at some other BWR plants which do not have piping materials that are resistant to IGSCC. Furthermore, even if the piping were of a conventional type of austenitic stainless steel, any potential degradation from the operating environment during first fuel cycle would be limited because of the limited exposure time (one fuel cycle) to the BWR cool environment.

In the applicant's exemption request, three categories of special circumstances were discussed: (1) undue hardship, (2) good-faith effort, and (3) "other" or specifically, future rulemaking.

The staff does not believe that the costs directly associated with design and installation of the downcomer bracings would result in undue hardship or other costs significantly in excess of those incurred by others similarly situated, inasmuch as all other BWRs of this design have installed lateral bracing to support the downcomers.

However, although as stated in the SER, confirmatory items for which the information provided by the applicant does not confirm preliminary conclusions (as in the case of the NMP-2 pool loads) will be treated as open, the staff has recognized that concerns directly relating to the structural adequacy of the downcomers were identified late in the review process. Subsequently, the applicant has made good-faith efforts to verify the adequacy of the downcomer design and thereby meet the requirements of GDC 2. In addition, this exemption would be for temporary relief, not to exceed startup following the first refueling period. Inasmuch as the present design presents no undue risk to the public health and safety for the interim period, requiring the applicant to delay operation of the plant for the period of time that additional analysis and/or required modifications to the plant are being completed would present an undue hardship on the applicant. Accordingly, the staff recommends granting the exemption request for the downcomer design as described above.

The staff knows of no imminent rulemaking that would alter the staff's conclusions on the adequacy of the downcomer design and, therefore, the issue of additional rulemaking is considered not applicable and is not addressed.

Conclusions and Recommendations

On the basis of the review of the information provided by the applicant in letters of January 23 and 24, 1986, the staff concludes that the unbraced downcomer design at NMP-2 satisfies the licensing criteria for upset and emergency conditions but the design is marginal. The applicant has not adequately demonstrated the design adequacy for the faulted condition as discussed above. Specifically, the downcomers may lose geometrical stability before reaching the calculated stress levels for the faulted condition.

The staff has reviewed the applicant's request for exemption under the provisions of 10 CFR 50.12. Under these provisions, a finding must be made in accordance with (1) 10 CFR 50.12(a)(1) that the proposed action is authorized by law, will not present an undue risk to the public health and safety, and is consistent with the common defense and security; and (2) 10 CFR 50.12(a)(2) that the proposed exemption involves special circumstances as defined in 10 CFR 50.12(a)(2)(i) through (vi).

On the basis of the estimates of the probability of the seismically induced pipe rupture at NMP-2 and the short exposure time of the piping to the operating environment during one fuel cycle, the staff concludes that the likelihood of a

LOCA and SSE occurring simultaneously is small during the period for which the exemption was requested, i.e., the first fuel cycle. With decoupling of these loads for the first fuel cycle, the staff finds that sufficient margin exists in the design of the downcomers. For these reasons, the staff finds that the proposed exemption is authorized by law and will not present an undue risk to the public health and safety, and is consistent with the common defense and security. Furthermore, as addressed above and in accordance with 10 CFR 50.12, the staff finds that special circumstances are present. Therefore, the staff recommends that a schedular exemption be granted for NMP-2 downcomers until the end of the first refueling outage. Before startup following the first refueling outage, the applicant should demonstrate the design adequacy of the downcomers with respect to the faulted condition and complete any required modifications to the downcomers.

6.2.3 Secondary Containment

In the SER (NUREG-1047), the staff reported on the applicant's drawdown analysis which functions to bring the secondary containment to a pressure of negative 0.25 inch water gauge. Amendment 23, issued in December 1985, revised the drawdown time from 90 seconds, as previously reported, to 129 seconds. In addition, the capacity of a standby gas treatment system train has been reduced to 3500 cfm from 3600 cfm. To verify the drawdown time, the applicant has committed to perform drawdown tests on the secondary containment every 18 months. The drawdown time acceptance criteria will be reduced below 129 seconds to account for the fact that emergency heat loads are not present in the periodic test, but were included in the FSAR analysis.

The staff has reviewed the changes made by the applicant, discussed above, as well as the proposed inservice testing and finds them acceptable with respect to containment concerns. The effect of the revised drawdown time on the radiological consequences of a LOCA will be discussed in Section 15 in a future supplement to the SER.

6.2.3.1 Bypass Leak Paths

In SSER 2, the staff provided Table 6.1, "Potential Bypass Leakage Paths," which was developed from FSAR information. Amendment 23 makes one change to that table. The drywell floor vent line which terminates in the radwaste tunnel contains a 3-inch valve with Technical Specification leakage of 0.9375 standard cubic feet per hour (scfh) rather than a 6-inch valve as had previously been reported. The staff finds this revision acceptable. See Table 6.3 (revised from SSER 2, Table 6.1).

6.2.4 Containment Isolation System

The containment isolation system includes the containment isolation valves and associated piping and penetrations necessary to isolate the primary containment in the event of LOCA. Staff review of this system included the determination of the number of isolation valves, valve location, the valve actuation signals and valve control features, the valve position under various plant conditions, the protection afforded isolation valves from missiles and pipe whip, and the environmental design conditions specified in the design of components.

The design objective of the containment isolation system is to allow the normal or emergency passage of fluids through the containment boundary while preserving the integrity of the containment boundary to prevent or limit the escape of fission products from a postulated LOCA. The applicant specified design bases and design criteria as well as the isolation valve arrangements to be used for isolating primary containment penetrations.

The containment isolation system is designed to automatically isolate the containment atmosphere from the outside environment under accident conditions. Double barrier protection, in the form of two isolation valves in series or a closed system and an isolation valve, are provided to ensure that no single active failure will result in the loss of containment integrity. The containment isolation system components, including valves, controls, piping, and penetrations, are protected from internally or externally generated missiles, water jets, and pipe whip.

The basis for staff acceptance has been the conformance of the containment isolation provisions to the Commission's regulations as set forth in the General Design Criteria (GDC) of Appendix A to 10 CFR 50, and to applicable regulatory guides, staff technical positions, the Standard Review Plan (SRP), and industry codes and standards.

The containment isolation systems are designed to the American Society of Mechanical Engineers Code, Section III, Class 1 or 2, and are classified as seismic Category I design systems.

The containment isolation provisions for the lines penetrating containment conform to the requirements of GDC 55, 56, or 57, except as noted below. As provided by GDC 55 and 56, there are containment penetrations whose isolation provisions do not have to satisfy the explicit requirements of the GDC but can be acceptable on some other defined basis.

Most of those penetrations not satisfying the explicit requirements of the GDC were found acceptable based on their meeting alternative criteria as specified in SRP Section 6.2.4, item II. These alternative acceptance criteria are summarized below:

(1) Lines that must remain in service following an accident and lines that should remain in service during normal operation for safety reasons are provided with at least one isolation valve. A second isolation boundary is formed by a closed system outside the containment. The following penetrations rely on a single isolation valve and a closed system outside containment.

Penetration No.	Description
Z-5A, B, and C	RHR pump suction from suppression pool
Z-6A and B	RHR test return line to suppression pool
Z-7A and B	RHR containment spray to suppression pool
Z-12	HPCS pump suction from suppression pool
Z-13	HPCS test return and minimum flow bypass to suppression pool

Penetration No.	Description
Z-15	LPCS pump suction from suppression pool
Z-17	RCIC suction from suppression pool
Z-18	RCIC minimum flow to suppression pool
Z-19	RCIC turbine exhaust
Z-73	RHR relief valve discharge to suppression pool
Z-88A and B	RHR safety valve discharge to suppression pool
Z-98A and B	RHR relief valve discharge to suppression pool

System piping and valves outside the containment, which are a part of the closed system boundary, are of seismic Category I, Safety Class 2, design; are protected from missiles; and have design temperature and pressure ratings at least equal to those for the containment. Branch lines from the closed system are valved closed and procedurally controlled. Leakage testing of the closed engineered safety feature systems outside containment will be performed in accordance with Section XI of the ASME Code. Relief valve isolation valves listed above seat on accident pressure and contain setpoints greater than 1.5 times the containment design pressure.

(2) On some engineered safety features or a related system, remote manual valves are used in lieu of automatic valves, since these lines must remain in service following an accident. Periodic inspection, testing, and maintenance procedures under normal operating conditions serve to minimize the potential for leakage. For fluid system lines equipped with remote manual isolation valves, the operator in the main control room is provided with information necessary to determine the existence and magnitude of a potential leak. Parameters used to detect leakage are high radiation, high area temperature, high sump level, and reactor vessel and system pressure. By using these parameters, the operator will be able to detect degraded system performance attributable to system leakage and take appropriate action to isolate systems that are potential leak paths.

(3) On some penetrations, the containment isolation provisions consist of two valves in series, both of which are outside the containment. The location of a valve inside containment would subject it to more severe environmental conditions (including suppression pool dynamic loads), and it would not be easily accessible for inspection. An example of this is the purge lines in the drywell and suppression chamber.

(4) Instrument lines that penetrate the primary containment and connect to the reactor coolant pressure boundary (RCPB) are equipped with a restricting orifice located outside and as close as practical to the primary containment, in accordance with Regulatory Guide (RG) 1.11. Those instrument lines that do not connect to the RCPB are equipped with automatic isolation valves whose status is indicated in the control room.

(5) Test connections located before the containment isolation valves in systems containing closed loop boundaries will have two valves in each test, drain, or vent line to ensure that double barrier protection exists in maintaining containment integrity.

Lines penetrating the containment described below do not meet either the explicit requirements of the General Design Criteria or the alternative Standard Review Plan acceptance bases, but either meet acceptable isolation criteria on other defined acceptance bases or require an exemption from the General Design Criteria.

Feedwater Lines

(1) The feedwater line (penetration Z-4) penetrates the drywell to connect with the reactor pressure vessel (RPV). It has three isolation valves. The isolation valve inside the drywell is a check valve. Outside the primary containment is another check valve. Farther away from the primary containment is a motor-operated gate valve. Should a break occur in the feedwater line, the check valves prevent significant loss of reactor coolant inventory and offer prompt primary containment isolation. During the postulated loss-of-coolant accident it is desirable to maintain reactor coolant makeup water from all sources of supply. For this reason, the outermost valve does not automatically isolate upon a signal from the protection system. The motor-operated gate valve meets the same environmental and seismic qualifications as the outboard check valve. The valve can be remotely closed from the control room to provide long-term leakage protection once the operator determines that feedwater makeup is unavailable or unnecessary.

(2) Similar to the feedwater lines is the RCIC/RHR head spray line, penetration Z-22. The head spray line penetrates the drywell and discharges directly into the RPV. It contains testable check valves inside and outside containment.

Upstream of the check valves are a remote manual gate valve (2ICS*MOV126) on the RCIC line and an automatic isolation globe valve (2RHS*MOVI04) on the RHR supply line. The check valves provide a measure of containment integrity in the short term; the gate/globe valves provide long-term leak integrity. All four valves are listed in FSAR Table 6.2-56, "Containment Isolation Provisions for Fluid Line," as being isolation valves. GDC 55, 56, and 57 require that containment isolation valves be located as close as practical to the containment boundary. The RHR reactor head spray line isolation valve is located a piping run of 29 feet 5 inches from the containment and the RCIC isolation valve pipe run is 4 feet 3 inches. The staff believes that these distances are acceptable because by locating the valves there, the applicant is able to reduce the number of penetrations since the RHR head spray and the RCIC line are combined downstream of these valves to form one penetration.

(3) Each of the four main steam line penetrations, Z-1A, B, C, and D, is equipped with a 3/4-inch drain line located before the outermost isolation valve and outside primary containment. These lines each contain a remote manually operated solenoid valve which is normally closed. Downstream of these valves the four 3/4-inch lines join together to form a 2-inch-diameter line which contains the outboard automatic motor-operated, containment isolation valve. This valve, 2MSS*MOV208, is considered to be

the outboard isolation valve for the four drain lines. Because of this arrangement, the applicant has committed to lock closed the 3/4-inch solenoid valves during normal operation to provide an additional margin of safety since the outboard containment isolation valve is a 36-foot pipe run from the containment boundary.

(4) The standby liquid control system penetration Z-29 contains a simple check valve inside containment and stop check valves on each of two branch lines that feed into the RPV. The stop check valves have a motor operator which acts to keep them closed during normal operation. The system also contains an explosive shear valve that acts as a blind flange during normal plant operation by making a leak-tight seal. Operation of the system requires firing the explosive shear valve to break the seal. The containment isolation provisions are acceptable with a check valve outside containment because the penetration does not communicate with the secondary containment unless the shear valve is fired.

Each of the systems mentioned above meet the General Design Criteria requirements because they satisfy "other defined bases" established by the staff as meeting the GDC requirements but not specifically listed in the SRP. In addition to these systems, the applicant has requested an exemption from GDC 55 for penetrations Z-38A and B, the control rod drive (CRD) hydraulic lines to the reactor recirculation seal purge equipment. GDC 55 does not allow a simple check valve to be used as the automatic isolation valve outside containment. The applicant has proposed to use two simple check valves (spring closing) outside containment in this 3/4-inch line. Furthermore, all three isolation valves (one inboard, two outboard) will be subject to type C leak testing.

The control rod hydraulic system supplies water to the recirculation system for purging of the pump seals. This water cleans and cools the seal area to ensure proper operation during normal plant conditions. Continued recirculation pump seal purge is needed whenever reactor coolant temperature is above 200°F and the pump is not isolated. This prevents premature aging and possible damage to the pump seals from high temperature. The check valves provide containment isolation while permitting seal purge, if available. The check valves are designed so that they are held shut by a spring under no-flow conditions. This isolation valve arrangement for the seal purge line is similar to the arrangements at other BWR-5 plants.

The system leakage boundary leak path does not directly communicate with the environment following a loss-of-coolant accident (LOCA). The system leakage boundary piping components are designed in accordance with Quality Group B standards as defined by RG 1.26, are designed to meet seismic Category I design requirements, and are designed to protect against pipe whip, missiles, and jet forces in a manner similar to that for engineered safety features. The system leakage boundary is continually pressurized to reactor pressure and, therefore, system integrity is continually demonstrated during normal plant operations.

In addition, TMI Action Plan Item II.K.3.25, "RCS Pump Seal Design," addresses the importance of providing a source of coolant to the seal coolers by indicating that a loss of seal coolers with resultant seal failure may be the cause for a small LOCA inside containment. For these reasons, the staff believes that automatic isolation valves are not necessary for this system. The benefits gained by providing check valves outweigh the disadvantages, since the check valves provide a more reliable flow of coolant to the seals in a plant condition that calls for containment isolation. If automatic isolation valves were used, an isolation signal would isolate the seal purge line. In FSAR Amendment 24, Table II.E.4.2-1 of Section 1.10 was revised to indicate the pump seal purge line is required for seal operation and is considered an "essential" part of the reactor coolant recirculation system. Consequently, the staff concludes an exemption to GDC 55 is justified in this case and the staff recommends granting this request.

In accordance with 10 CFR 50.12(a)(2), special circumstances exist which would warrant issuance of the requested exemption. As discussed above, availability of the reactor recirculation pump seal purge water is necessary to protect the reactor recirculation pump seals. The check valves provide containment isolation while permitting seal purge, if available. Also, as discussed above, the benefits gained by providing check valves outweigh the disadvantages, since the check valves provide a more reliable flow of coolant to the seals in a plant condition which would call for containment isolation. If automatic isolation valves were used, an isolation signal would isolate the seal purge line, thus making seal water unavailable to the reactor recirculation pump seals. Since availability of the pump seal purge water is necessary to protect the seals, granting an exemption to GDC 55 in this case would provide a benefit to the public health and safety that compensates for any decrease in safety that may result from granting the exemption.

The staff informed the applicant that penetration Z-32 represented an unacceptable isolation arrangement because it did not provide for positive isolation for post-LOCA of a nonessential system as required by TMI Action Plan Item II.E.4.2, "Containment Isolation Dependability," and because it deviated from GDC 56 which does not allow use of a simple check valve outside containment. The staff indicated to the applicant that this penetration, N_2 Purge to TIP Indexing Mechanism, would need to be modified to bring it into conformance with the GDC and TMI requirements, because the staff did not believe that an adequate basis existed to consider an exemption. In FSAR Amendment 23, the applicant revised the system by replacing the outboard check valve with an automatic solenoid-operated valve. This revised valve arrangement does meet the provisions of GDC 56 and TMI Action Plan Item II.E.4.2, since the nonessential system receives automatic isolation provisions. The staff finds this change acceptable.

6.2.4.1 Containment Isolation Dependability (TMI Action Plan Item II.E.4.2)

Position

(1) The design of the containment isolation system complies with the provisions of SRP Section 6.2.4; i.e., in that there is diversity in the parameters sensed for the initiation of containment isolation.

(2) Essential and nonessential systems for the purpose of isolation are properly identified.

(3) All nonessential systems are automatically isolated by the containment isolation signal.

(4) Control systems for automatic containment isolation valves are designed so that resetting the isolation signal will not result in the automatic reopening of containment isolation valves. Reopening containment isolation valves shall require deliberate operator action.

(5) Purge valves that do not meet the requirements set forth in Branch Technical Position (BTP) CSB 6-4 should have administrative control that governs "sealed closed" valves during Operational Conditions 1, 2, 3, and 4. Furthermore, these valves are to be verified closed at least once every 31 days.

Clarification

(1) The reference to SRP 6.2.4 in position 1 (above) is only to the diversity requirements set forth in that document.

(2) For postaccident situations, each nonessential penetration (except instrument lines) is required to have two isolation barriers in series that meet the requirements of GDC 54, 55, 56, and 57, as clarified by SRP Section 6.2.4. Isolation must be performed automatically (i.e., no credit can be given for operator action). Manual valves must be sealed closed, as defined by SPR Section 6.2.4, to qualify as an isolation barrier. Each automatic isolation valve in a nonessential penetration must receive the diverse isolation signals.

(3) Revision 2 to RG 1.141 will contain guidance on the classification of essential versus nonessential systems. Requirements for operating plants to review their list of essential and nonessential systems, and an appropriate time schedule for completion, will be issued in conjunction with this regulatory guide.

(4) Administrative provision to close all isolation valves manually before resetting the isolation signals is not an acceptable method of meeting position 4 (above).

(5) Ganged reopening of containment isolation valves is not acceptable. Isolation valves must be reopened on a valve-by-valve basis, or on a line-by-line basis, provided that electrical independence and other single-failure criteria continue to be satisfied.

(6) The containment pressure history during normal operation should be used as a basis for arriving at an appropriate minimum pressure setpoint for initiating containment isolation. The pressure setpoint selected should be far enough above the maximum observed (or expected) pressure inside containment during normal operation so that inadvertent containment isolation does not occur during normal operation from instrument drift or fluctuation because of the accuracy of the pressure sensor. A margin of 1 psi above the maximum expected containment pressure should be adequate to account for instrument error. Any proposed values greater than 1 psi will require detailed justification. Applicants for operating licenses and licensees of plants that have operated less than 1 year should use pressure history data from similar plants that have operated more than 1 year, if possible, to arrive at a minimum containment setpoint pressure.

(7) Sealed-closed purge isolation valves shall be under administrative control to ensure that they cannot be inadvertently opened. Administrative control includes mechanical devices to seal or lock the valve closed, or to prevent power from being supplied to the valve operator. Checking the valve position light in the control room is an adequate method for verifying every 24 hours that the purge valves are closed.

Discussion and Conclusions

The following discussion summarizes the applicant's response and the staff's evaluation for each item stated above.

(1) Diversity in Parameters. Table 6.4 shows the containment isolation signals and the parameters sensed to initiate each signal. Automatic valves receive two or more of these signals and consequently satisfy the diversity requirement.

(2) Essential and Nonessential Systems. The applicant has evaluated essential and nonessential systems. Table 6.5 lists the essential and nonessential systems as provided by the applicant, along with the basis used for making that determination. The staff finds this list acceptable.

(3) Isolation of Nonessential Systems. All nonessential system lines are automatically isolated by (diverse) containment isolation signals:

Reactor recirculation pump seal purge (Z-38A, B). As discussed in the request for exemption (Section 6.2.4 above) for this system, isolation of these lines is provided by simple check valves. Operating the recirculation pump seal purge line is desirable during pump operation, and whenever the reactor coolant temperature is greater than 200°F, regardless of whether or not the pump is running. Automatic isolation valves are, therefore, undesirable, whereas check valves enhance the operational reliability of the seal purge system. Furthermore, in Amendment 24 to the FSAR the applicant has indicated that the pump seal purge line is an essential part of the reactor recirculation system. Consequently, the staff concludes that the isolation provisions for these penetrations conform to the requirements of Item II.E.4.2.(3). The staff finds this acceptable.

(4) The applicant has indicated that all necessary modifications have been completed so that resetting the containment isolation signal will not result in the automatic reopening of containment isolation valves, i.e., reopening isolation valves requires deliberate operator action.

(5) The applicant has verified that the containment setpoint pressure is the minimum that is compatible with normal operating conditions. Also, ganged reopening of containment isolation valves will not occur.

(6) Containment purge valve operability, including the ability of these valves to close against a LOCA, was addressed in Appendix J to SSER 2, November 1985, and in this SER supplement. The functions to be performed by the purge system are: inerting, deinerting, and pressure control. The 12-inch and 14-inch purge valves will be in use during the operations of inerting and purging. For these functions, there is a limit of 90 hours' use every year described in SRP Section 6.2.4.II.6.n. The pressure control function is accomplished by operation of a 2-inch bypass line which is open to the

standby gas treatment system (SGTS). The 2-inch bypass line taps off the larger purge valve line downstream of the outboard containment isolation purge valve, thus requiring both inboard and outboard valves to be open. The applicant has shown that the SGTS will survive the pressure pulse resulting from a postulated LOCA concurrent with the bypass line open. While the pressure control function takes place, the containment purge valves are partially open; however, flow is eliminated through all but the 2-inch line because of the presence of a closed (fail-closed) 20-inch safety-related valve, 2GTS*AOV101, in the flowpath to the SGTS. Containment isolation is achieved when needed by closing the 12- and 14-inch containment purge valves. To summarize the restriction of 90 hours of operation for the 12- and 14-inch purge valves applies to the functions of inerting and deinerting which take place when 20-inch valve 2GTS*AOV101 is open. The function of pressure control through the 2-inch bypass line, through partially open purge valves, does not have a time limit but is understood by the applicant to be no more than necessary to maintain the containment pressure between the Technical Specification limits. This is acceptable to the staff because the SGTS has been predicted to survive a pressure pulse through the 2-inch line, and the 20-inch safety-related valve discussed above will serve to limit flow through the purge penetration to only the amount going through the bypass line. Finally, any leakage through the closed 20-inch valve would also leak into the SGTS and would be processed by it.

(7) The applicant has indicated that the control logic for the containment purge supply and exhaust lines has been revised to incorporate automatic isolation on high radiation.

Conclusion

On the basis of its review, the staff concludes that the applicant is in compliance with the requirements for containment isolation dependability given in Item II.E.4-2 of the TMI Action Plan.

6.2.6 Containment Leakage Testing Program

Item 1: CRD System Type A Test

In the SER (NUREG-1047), the staff indicated that the control rod drive (CRD) system insert and withdraw line isolation valves need not be type C tested. However, the staff also stated that the CRD system should be vented for the type A test in order to expose the system to containment accident pressure, P_a. In order to meet this requirement, the applicant has proposed to open (vent) the scram discharge volume vent and drain valves during the type A test in lieu of venting the entire CRD system. In addition, 10 CFR 50, Appendix J, type C leak tests will be performed on these valves and the leakage results will be added to the type A test results. The staff finds that this test procedure meets the the Appendix J requirement that all such systems be vented for the type A test and recognizes that the unique aspects of the CRD system preclude conventional venting/draining arrangements. Consequently, the staff finds the proposed test procedure for venting the CRD system during the type A test acceptable. The staff will require that the type C leakage values obtained above be added to the type B and C test allowable leakage of 0.6 L_a

In a letter dated September 3, 1985, the applicant requested an exemption from the test requirements of 10 CFR 50, Appendix J. Specifically, the applicant requested an exemption from the provisions requiring venting and draining of the CRD hydraulic lines to the scram discharge volume during the type A containment integrated leak test. The staff recognizes that the CRD is a unique system in that it is needed to function in the postaccident condition via operation of the scram system. Appendix J provides relief from the venting requirement for systems such as the CRD system which "are normally filled with water and operating under postaccident conditions." These systems, according to Section III.A.1.d of Appendix J need not to be vented provided the isolation valves are type C tested and the leakage measured is added to the type A test results. The applicant has committed to do so and consequently no exemption need be granted in this circumstance.

Item II: Reverse Direction Type C Testing

Appendix J (10 CFR 50), Section III.C.1, prescribes methods for conducting the containment isolation valve leak rate tests. These requirements state that isolation valves should be leak tested with the test pressure applied in the same direction the valve must function to preclude leakage in the accident condition. Reverse direction testing is permitted if it can be demonstrated that such testing yields results that are equivalent or more conservative than results obtained using same direction as postaccident flow testing. In letter NMP2L-0282 (from C. V. Mangan, NMPC, to A. Schwencer, NRC, December 7, 1984), the applicant provided Table 6.6 which lists the containment isolation valves the applicant proposes to reverse direction test, the valve type, and the justification. The staff has reviewed the bases used as justification for reverse direction testing of these valves and concludes that they are acceptable. Consequently, the staff approves the reverse direction testing of the containment isolation valves listed in Table 6.6.

Item III: Hydraulic Control System for Recirculation Flow Control Valves

By letters dated April 26, 1985, and September 3, 1985, the applicant requested exemption from certain requirements of 10 CFR 50, Appendix J. Specifically, exemptions were requested from both type A and type C leak testing for the hydraulic control system for the reactor recirculation flow control valves because testing these lines would require the system to be disabled and drained of hydraulic fluid.

System Description

The hydraulic control system for the reactor recirculation system flow control valves operates to control the reactor recirculation flow during normal operation and is automatically isolated following a postulated accident. The system provides hydraulic fluid through eight containment penetrations (Z-99A, Z-99B, Z-99C, Z-99D, Z-100A, Z-100B, Z-100C, Z-100D) to the hydraulic operators on the two recirculation flow control valves. The hydraulic lines terminate in the reactor building; therefore, the system does not constitute a potential bypass leak path. The system leakage boundary piping components are designed as Quality Group B between the isolation valves and Quality Group D outside the isolation valves. Although the recirculation flow control valve actuator, which is part of the high-pressure hydraulic system, is not environmentally qualified for operation following the post-LOCA containment temperatures and pressures expected in the drywell, the system is designed to withstand a safe shutdown earthquake and is protected against pipe whip, missiles, and jet forces in a manner similar to that for engineered safety features. For this system, the applicant has requested exemptions from both type A and type C leak testing because testing these lines would require the system to be disabled and drained of hydraulic fluid. The applicant has stated that testing could be especially detrimental to the proper operation of the system, because possible damage could occur to the system not normally exposed to air in establishing the test condition or restoring it to normal. The staff has evaluated this request and concludes that a basis exists for granting an exemption for this system from both the type A and the type C tests of 10 CFR 50, Appendix J. The staff believes that although the system is not operationally qualified to the post-LOCA containment environment, because it is protected against pipe whip, missiles, and jet forces, there is a reasonable basis for concluding that the system boundary will maintain its integrity and, therefore, will not become a containment atmosphere leak path. In addition, the staff agrees it is not advisable to drain this type of hydraulic line because of possible damage that may result from either establishing the test or restoring the system to proper operation.

Special Circumstances

In accordance with 10 CFR 50.12(a)(2), special circumstances exist which would warrant issuance of the requested exemption. Application of the requirements in this particular circumstance would not be necessary to achieve the underlying purpose of the requirement and the exemption would result in an overall benefit to the public health and safety that would compensate for any decrease in safety that might result in granting of the exemption.

The hydraulic control system lines terminate in the reactor building; therefore the system does not constitute a potential bypass leak path. The system leakage boundary piping components are designed as Quality Group B between the isolation valves and Quality Group D outside the isolation valves. Although the recirculation flow control valve actuator, which is part of the high-pressure hydraulic system, is not environmentally qualified for operation following the post-LOCA containment temperatures and pressures expected in the drywell, the system is designed to withstand a safe shutdown earthquake and is protected against pipe whip, missiles, and jet forces in a manner similar to that for engineered safety features. Therefore, although the system is not operationally qualified to the post-LOCA containment environment, because it is protected against pipe whip, missiles, and jet forces, there is a reasonable basis for concluding that the system boundary would maintain its integrity and, therefore, will not become a containment atmosphere leak path. Therefore, the underlying purpose of the leak testing (assuring that the containment leakage is minimized) is sufficiently achieved by the design of the system, thereby meeting the requirements of 10 CFR 50.12(a)(ii).

Type A and C testing of this system would require the system to be disabled and drained of hydraulic fluid. Possible damage could occur to the system not normally exposed to air in establishing the test condition or restoring it to normal conditions. Therefore, not subjecting this system to the increased probability of damage would benefit the public sufficiently to compensate for any decrease in safety that might result in granting of the exemption following the considerations discussed above. Therefore, special circumstance as discussed in 10 CFR 50.12(a)(iv) is met.

Item IV: Traversing Incore Probe (TIP)

After the SER was printed, the applicant requested an exemption from the type C Appendix J test on the TIP ball valve on the grounds that the system is in operation approximately 4 hours a month, the leakage potential is small, and the dosages incident to the test program itself were high relative to the benefit gained from the test. The staff has evaluated this request and has concluded that an adequate basis does not exist to grant an exemption for the TIP system from type C testing. The potential leakage from the TIP system is not inconsequential and may impact the successful completion of the type A and/or C tests.

In addition, the staff does not believe, on the basis of information provided to date, that the exposure rates of the plant personnel performing the tests are excessively high or significantly higher than normal rates expected to be encountered in the drywell during other routine maintenance operations conducted during the refueling outage. For these reasons, the staff believes that the TIP system must be type C tested in accordance with 10 CFR 50, Appendix J. The Technical Specifications for NMP-2 will require these valves to be type C tested.

The staff has completed its review of the applicant's proposed containment leak test program. The staff finds the test program, as described in the SER and its supplements, to be acceptable. With the exception of the recirculation flow control system, for which an exemption was requested and for which adequate basis exists, the test program reviewed by the staff conforms to 10 CFR 50, Appendix J.

In letters dated March 3, and 5, 1986, the applicant requested additional exemptions from the requirements of 10 CFR 50, Appendix J. Those exemption requests concern the exclusion of leakage of the main steam isolation valves from the acceptance criteria contained in Section III.C.3 of Appendix J, the relaxation of testing requirements for airlock doors, and the exclusion of certain relief valves from type C testing. These exemption requests are under staff review. The staff will discuss the findings of the review of these requests in a future supplement to the SER.

Table 6.1 Comparison of short-term peak pressures

Plant	Drywell (psig)	Suppression chamber (psig)
Nine Mile Point 2	39.9	34
Susquehanna 1 & 2	43.8	28.9
Shoreham 1	41.9	30
WPPSS 2	34.7	27.6
LaSalle 1 & 2	32.4	24.8

Table 6.2 Comparison of selected containment characteristics

Containment characteristics	Shoreham	NMP-2
Downcomers, no.	88	121
Downcomer ID, in.	23.25	23.25
Design pressure, psig	48	45
Free volume ratio (drywell/wetwell)	1.44	1.51

Table 6.3 Potential bypass leakage paths (revised from SSER Table 6.1)

Line description	Termination region	Bypass leakage barrier	Leak rate* Tech. Spec. (scfh)**
4 main steamlines	Turbine bldg.	Two 21" valves in each line	6
Main steam drain line (inboard)	Turbine bldg.	One 6" valve	1.875
Main steam drain line (outboard)	Turbine bldg.	One 2" valve	0.625
4 postaccident sampling lines	Radwaste tunnel	One 3/4" valve in each line	0.2344
Drywell equipment drain line	Radwaste tunnel	One 4" valve	1.25
Drywell equipment vent line	Radwaste tunnel	One 2" valve	0.625
Drywell floor drain line	Radwaste tunnel	one 6" valve	1.875
Drywell floor vent line	Radwaste tunnel	One 3" valve	0.9375
RWCU line	Turbine bldg.	One 8" valve	2.5
Feedwater line	Turbine bldg.	Two 24" check valves	12
Containment purge system supply line to drywell	Standby gas treatment area	Two 14" valves Two 2" valves	4.38 0.625
Containment purge system supply line to supply chamber	Standby gas treatment area	Two 12" valves Two 2" valves	3.75 0.625

*Test conditions: Air medium; 40 psig and 80°F; leak rate per valve.
**Standard conditions: 14.7 psia and 68°F.

Table 6.4 Key to isolation signals

Signal	Parameter sensed
A	Low reactor vessel water, Level 3
B	Low reactor vessel water, Level 2
C	High main steam line radiation
D	High main steam line flow
E	High main steam line tunnel area ambient temperature
F	High drywell pressure
H	Steam supply pressure low
J	High reactor water cleanup system equipment area differential or ambient temperatures, or turbine building high space temperature, or reactor water cleanup high differential flow
K	Reactor core isolation cooling high pipe routing or equipment area ambient or differential temperatures, low steam supply pressure. High steam line differential pressure, high turbine exhaust diaphragm pressure
L	High reactor vessel pressure
M	High residual heat removal system equipment area differential or ambient temperatures
P	Low main steam line turbine inlet pressure
R	Low main condenser vacuum
S	Standby liquid control system actuated
T	High main steam line tunnel differential temperature
W	High reactor water cleanup system nonregenerative heat exchanger outlet temperature
X	Low reactor vessel water, Level 1
Y	Standby gas treatment exhaust radiation high
LC	Locked closed
RM	Remote manual switch from control room

Table 6.5 Essential and nonessential systems

System	Classification	Basis for classification
1. Main steam	Nonessential	Not required for safe shutdown
2. Feedwater	Nonessential	Not required for safe shutdown. Class 1 portion of feedwater line essential. It is desirable to maintain all sources of cooling supply, if available.
3. Reactor coolant recirculation	Nonessential	Not required for safe shutdown
	Essential	Pump seal purge line is required for seal operation
4. Instrument air	Nonessential	Not required in short term for safe shutdown.
	Essential	Required in long term to support LPCI and LPCS by recharging ADS accumulators from tanks outside containment
5. Service air	Nonessential	Not required for safe shutdown
6. Breathing air	Nonessential	Not required for safe shutdown
7. Standby liquid control	Essential	Should be available as backup to the CRD system
8. RHR		
a. LPCI mode	Essential	Safety function
b. Suppression pool cooling mode	Essential	Required to control suppression pool temperature
c. Containment spray cooling mode	Essential	Required to control drywell/ containment pressure
d. Reactor steam condensing mode	Nonessential	Not required for safe shutdown
e. Shutdown cooling mode	Nonessential	Not required for safe shutdown
9. Reactor water cleanup	Nonessential	Not required during or immediately following an accident

Table 6.5 (Continued)

System	Classification	Basis for classification
10. Reactor core isolation cleanup	Essential	Used as a backup to HPCS when the reactor becomes isolated from main condenser
11. Low-pressure core spray	Essential	Safety system
12. High-pressure core spray	Essential	Safety system
13. Reactor building equipment drains	Nonessential	Not required for safe shutdown
14. Containment leakage monitoring	Nonessential	Not required for safe shutdown
15. Reactor building closed loop cooling water	Nonessential	Not required for safe shutdown
16. Reactor containment inerting and purge	Nonessential	Not required for safe shutdown; however, used if available as backup to Category I DBA hydrogen recombiner
17. Containment atmospheric monitoring	Essential	Required for postaccident monitoring of containment pressure, hydrogen, temperature, and level. Radiation monitors are nonessential because they are not required for safe shutdown
18. DBA hydrogen recombiner	Essential	Required for safe shutdown. Following a LOCA, system is used to remove excess hydrogen that would react with oxygen and lead to high temperature and overpressurization that would result in loss of containment integrity
19. Fire protection water	Nonessential	Not required for safe shutdown

Table 6.5 (Continued)

System	Classification	Basis for classification
20. Reactor building floor drains	Nonessential	Not required for safe shutdown
21. Control rod	Essential	Required for safe shutdown
22. Traversing incore probe (TIP)	Nonessential	Not required for safe shutdown

Table 6.6 Reverse tested containment isolation valves

Penetration no.	System	Valve ID	Valve type	Justification*
Z-8A	RHR	MOV25A	Split disc gate	1
Z-8B	RHR	MOV25B	Split disc gate	1
Z-12	CHS	MOV118	Split disc gate	1
Z-18	ICS	MOV143	Globe	2
Z-17	ICS	MOV136	Split disc gate	1
Z-19	ICS	MOV122	Split disc gate	1
Z-21A	ICS	MOV128	Split disc gate	1
Z-48	CPS	AOV108	Butterfly	3
Z-51	CPS	AOV109	Butterfly	3
Z-50	CPS	AOV107	Butterfly	3
Z-49	CPS	AOV106	Butterfly	3
Z-55A	HCS	MOV4A	Globe	2
Z-55B	HCS	MOV4B	Globe	2
Z-56A	HCS	MOV6A	Globe	2
Z-57A	HCS	MOV5A	Globe	2
Z-56B	HCS	MOV6B	Globe	2
Z-57B	HCS	MOV5B	Globe	2
Z-58	CPS	SOV122	Globe	2
Z-59	CPS	SOV121	Globe	2
Z-60A	CMS	SOV61A	Plug	4
Z-60C	CMS	SOV63A	Plug	4
Z-60D	CMS	SOV33A	Plug	4
Z-61C	CMS	SOV34A	Plug	4
Z-60E	CMS	SOV61B	Plug	4
Z-60G	CMS	SOV63B	Plug	4
Z-60H	CMS	SOV33B	Plug	4
Z-61F	CMS	SOV34B	Plug	4

* Justification:

1. Split disc gate valves may be tested using a test connection (TC) between the discs. This is a conservative test since both LOCA and non-LOCA seat leakage is measured.

2. Globe valves are orientated to ensure LLRT test pressure tends to unseat the valve, whereas LOCA pressure will tend to seat the valve. This is conservative for testing.

3. On butterfly valves reverse testing will provide equivalent results since the seating area(s) and test pressure force(s) will be equal in either direction.

4. Plug valves are bi-directional plug-type solenoid valves that are oriented so that LOCA pressure will tend to seat the valve and LLRT pressure will tend to unseat the valve.

7 INSTRUCTIONS AND CONTROLS

7.2 Reactor Trip System

7.2.2 Specific Findings

7.2.2.3 Instrument Setpoints (Supplemental)

The NMP-2 Safety Evaluation Report (SER) identified a staff concern with respect to instrument setpoints (Section 7.2.2.3) for the reactor protection system. It was determined that additional information would be required to confirm the applicant's conformance with the Commission's regulations relevant to the issue of protection system setpoints.

The protection system setpoints were addressed in Supplement 2 to the SER dated November 1985. In Supplement 2, the staff accepted the Instrumentation Setpoint Methodology Group's (ISMG's) setpoint methodology concept and concluded that there was reasonable assurance that the results of the ISMG effort would verify the acceptability of the proposed setpoints.

Supplement 2 also contained a confirmatory item that stated that before licensing the applicant will be required to document a commitment in the FSAR to provide for staff review and approval, before startup following the first refueling outage, a detailed technical assessment of the methods used to establish the NMP-2 protection system trip setpoints and allowable values based on the generic findings of the ISMG program.

In response to this confirmatory item and by letter dated February 7, 1986, the applicant documented the required information stating that the commitment will be incorporated into the FSAR.

This resolves the confirmatory item contained in Supplement 2 of the SER and resolves confirmatory issue 17 addressed in Section 7.2.2.3 of the SER.

7.2.2.4 Anticipated Transients Without Scram - Mitigation System

An anticipated transient without scram (ATWS) is an expected operational transient (such as a loss of feedwater, loss of condenser vacuum, or loss of offsite power to the reactor) which is accompanied by a failure of the reactor trip system to shut down the reactor. ATWS accidents are a cause of concern because, under certain postulated conditions, they could lead to severe core damage and release of radioactivity to the environment.

On June 26, 1984, the Commission amended the regulations to add 10 CFR 50.62, requiring each boiling-water reactor (BWR) to have an alternate rod injection (ARI) system that is diverse from the reactor trip system from the sensor output to the final actuation device. The ARI system must have redundant scram air header exhaust valves. In addition, each BWR must have a standby liquid control system (SLCS) capable of injecting the equivalent of 86 gallons per minute (gpm) of 13 weight percent sodium pentaborate solution. The SLCS initiation must be automatic for plants granted a construction permit before July 26, 1984, that have already been designed and built to include this feature. Furthermore, each BWR must have equipment to trip the reactor coolant recirculation pumps automatically under conditions indicative of an ATWS.

In FSAR Amendment 18, the applicant has provided additional information relative to the equipment used in NMP-2 to mitigate the effects of ATWS. The design includes scram discharge volume modifications, reactor coolant recirculation pump trip, and SLCS operation. The redundant reactivity control system (RRCS) uses transient detection sensors for high vessel dome pressure and low vessel water level to initiate alternate rod injection and recirculation pump trip (RPT).

The staff has reviewed the applicant's design for the prevention and mitigation of ATWS only to the extent that the RRCS and its subsystems will not adversely impact any other existing safety systems. The staff will be performing a generic review of the ATWS mitigation system against the requirements set forth in 10 CFR 50.62. The applicant will be required to comply with any requirements that result from that generic review.

7.2.2.6 Minimum Number of Channels Required To Initiate Protective Actions

The NMP-2 SER identified a staff concern with respect to the minimum number of channels required to initiate protective actions.

From a review of the FSAR and referenced drawings, the staff had been unable to find sufficient information to determine the minimum number of sensors required to monitor plant variables that initiate protective functions. For certain protective functions the NMP-2 design incorporates additional sensors and channels to permit bypassing selected items for maintenance and testing. The requirement for the minimum number of channels operable is discussed in paragraph 4.11 of IEEE Standard 279-1971. Paragraph 4.11 states in part that the protective system shall be designed to permit maintenance, testing, and calibration without compromising the single-failure criterion.

In response to a request from the staff, FSAR Question 421.66, the applicant submitted a report dated December 19, 1985, which delineated the total number of channels provided, the minimum number of channels required to be operable, and the design details necessary for the staff to verify that the Technical Specifications for NMP-2 will be consistent with the provisions of IEEE Std. 279-1971.

The report listed the total number of channels provided and the minimum number of channels required to be operable to initiate protective actions. The staff established the following criteria as the bases for its review of the applicant's report and the Technical Specifications:

(1) the number of channels provided must at least be equal to the minimum number of channels required by the Technical Specifications;

(2) the minimum number of channels provided must meet the single-failure criteria provided for in IEEE Std. 279-1971, Paragraph 4.11; and

(3) the number of channels provided may exceed the minimum number of channels required in order to provide for and to accommodate additional operational flexibility such as testing, calibration, and maintenance.

The staff concentrated its review effort on those areas which met criterion 3.

Those areas in which the total number of channels provided exceeded the minimum number of required channels are:

(1) the intermediate range monitor (IRM) and the average power range monitor (APRM) trip functions of the reactor protection system

(2) the source range monitor (SRM), IRM, APRM, and the reactor coolant system recirculation flow trip functions of the control rod block (CRB) instrumentation

(3) the 4.16-kV emergency bus undervoltage trip functions

(4) the main control room ventilation system trip functions of the radiation monitoring instrumentation

The neutron monitoring system (NMS) gives signals to the reactor protection system (RPS) from the IRM and the APRM. Both the IRM and the APRM have been provided with an additional channel, beyond the minimum number required, allowing extra operational flexibility for test and maintenance. FSAR Sections 7.6.1.4.1 and 7.6.1.4.3 analyze the NMS circuits and describe the scenarios of bypassed and/or failed channels as not affecting the ability of the RPS to achieve a reactor scram before damaging fuel.

The CRB instrumentation utilizes the same grouping of NMS equipment that is used in the RPS with the recirculation flow comparator trip units inputting their rod block trip signals through the APRM reactor manual control system (RMCS). As done for the RPS, additional channels have been provided to permit continued power operation during repair or calibration of equipment for those functions that provide rod block interlocks. FSAR Section 7.7.1.1.2 analyzes the rod block bypasses. The permissible IRM and APRM bypasses are arranged in the same manner as they are in the RPS.

The emergency core cooling system (ECCS) actuation instrumentation contains input signals from the 4.16-kV emergency bus. The emergency bus has two sets of three undervoltage relays to monitor the three phases. One set monitors the bus for loss of voltage and the other set of undervoltage relays monitors the bus for a degraded voltage condition. To initiate a trip function, only two of the three undervoltage relays from one of the sets need to operate, i.e., two of the loss-of-voltage relays or two of the degraded voltage relays. This arrangement provides for the maintenance and calibration of the relays.

The radiation monitoring system for the main control room ventilation system intake air is provided with four radiation monitors. Two monitors are assigned to Division 1 and two monitors are assigned to Division 2. Each radiation monitor is worth half a trip signal. The control room emergency filtration system is initiated when both channels, i.e., two half-trips from a single system, either Division 1 or Division 2, produce a trip condition (high radiation signal).

On the basis of the staff's review, the first three areas were determined to be acceptable. However, the staff's review of the fourth area (i.e., radiation monitors) led to the conclusion that the requirements of Paragraph 4.11 of IEEE Std. 279 were not being met. The applicant's proposed Technical Specification was written so that with a channel bypassed or inoperable the single failure criterion was not being met. The applicant proposed Technical Specifications so that when the radiation monitoring system channels for the main control room ventilation systems were bypassed or inoperable they would be placed (automatically or manually) in a tripped condition. This would produce a half-trip, thus alleviating the staff's single-failure concern.

On the basis of its review of Chapter 7 of the FSAR, the proof and review copy of the Technical Specifications, and the additional information submitted by the applicant in a letter dated December 19, 1985, from C. V. Mangan to E. Adensam, the staff has determined that the applicant has shown that the single-failure criterion can be satisfied for those cases in which the minimum number of operable channels is less than the total number of channels provided. Therefore, the staff finds that the requirements of IEEE Std. 279, Paragraph 4.11, have been adhered to by the applicant and that the concerns previously identified by the staff have been satisfied. This resolves confirmatory issue 19 (FSAR Question 421.26) as discussed in Section 7.2.2.6 of the NMP-2 SER. The staff will confirm that the Technical Specifications contain the appropriate modifications (discussed above) concerning the main control room ventilation system trip functions for the radiation monitoring instrumentation.

7.2.2.8 Isolation of Circuits

The NMP-2 SER identified a staff concern with respect to isolation devices. The isolation devices are used to maintain independence between redundant Class 1E circuits, divisional Class 1E circuits, and between Class 1E circuits and non-Class 1E circuits.

During operating or fault conditions, the isolation devices are required to protect the Class 1E circuits from the maximum credible fault (MCF) voltage/current to which the devices could be exposed. In order to qualify the devices as approved isolation devices, the applicant has committed to a design verification test program. This program will test each type of isolation device used to accomplish electrical isolation to demonstrate isolation capability under maximum credible fault conditions. These tests will verify that the maximum voltage/current to which the device could be exposed will not jeopardize the integrity of the Class 1E circuits. In addition, these tests will verify that any destructive effects caused by application of the worst credible fault will not jeopardize the function of any redundant divisional circuits or devices in close physical proximity to the isolation device.

The types of isolation devices currently utilized at NMP-2 are as follows:

(1) GE optical isolator
(2) Potter & Brumfield (P&B) MDR relay
(3) Validyne multiplexer
(4) Kaman Industries SRMS interface board

(a) Hewlett-Packard (HP) HCPL-2630 optical isolator
(b) Intronic Model IA-184 amplifier module

The GE optical isolator, the Potter & Brumfield MDR relay, and the Validyne multiplexer have been previously reviewed and accepted as qualified isolation devices. For example, they were reviewed and accepted by the staff during the Hope Creek Generating Station operating license review (Supplemental Safety Evaluation Report No. 5, Section 7.2.2.6).

During the site instrumentation and control (I&C) audit, January 7-9, 1986, the applicant presented to the staff a draft document entitled, "Test Procedure, Fault Voltage Withstand Capability, Kaman Instrumentation Isolation Modules," prepared by the Stone & Webster Engineering Corporation (SWEC). The draft document described test procedures and tests that were to be performed on the Kaman isolation devices and it also referenced a Kaman Qualification Summary Report. The staff reviewed the test procedure and noted that the procedure did not give the value of the MCF voltage/current to be used during the test. In addition, the procedure did not describe the application of the MCF in the transverse mode, the fail/pass monitoring circuits with the acceptance criteria, nor did it provide for the review and signature of a responsible party. Furthermore, the procedure listed isolation devices (4a and 4b above) that were different from those previously stated. For example, the NMP-2 SER lists a Kaman KESIMS, a DEI-D, and a KEI-A; the test procedure, however, lists a Kaman SRMS interface board, an HP optical isolator, and an Intronic isolation amplifier module as the Kaman system isolation device. As a result of this review, the staff believed that the test procedure was lacking in several important areas and, therefore, was not acceptable.

On March 15, 1986, the applicant submitted a revised test report and the test results for the staff's review and evaluation. This report is presently under review.

In summary, the applicant may apply and use, as qualified isolation devices, the GE optical isolators, the P&B MDR relays, and the Validyne multiplexers. The issue of the Kaman isolation system will remain a confirmatory issue until such time as the staff has determined that the Kaman isolators are properly qualified as electrical isolation devices.

7.3 Engineered Safety Features Systems

7.3.2 Specific Findings

7.3.2.5 Testing of Protection Systems Instrumentation

The NMP-2 SER identified a staff concern with respect to the testing of protection system instrumentation by making temporary modifications to the instrumentation circuits undergoing tests. These temporary modifications are the lifting of leads or conductors, the installation of jumpers or shorts, and the opening of circuit breakers or the removal of fuses. The staff's concern relates to the fact that the temporary modifications made to facilitate testing of the protection system instrumentation may result in a degradation of safety. Several instances of serious degradation of safety-related systems in connection with such modifications are discussed in IE Information Notice 84-37, "Use of Lifted Leads and Jumpers During Maintenance or Surveillance Testing."

In response to the staff's concern, the applicant provided a submittal on March 6, 1986. This submittal listed all of the test procedures which require making temporary modifications to safety-related instrumentation circuits. The list identified 14 test procedures that called for the lifting of leads or the disconnection of sensors, and two test procedures that called for the installation of jumpers. No one test procedure required the opening of circuit breakers or the removal of fuses. The submittal also stated that the 16 listed test procedures provide for an independent verification of return to service subsequent to the termination of the test as required by the plant's administrative procedures.

By letter dated March 21, 1986, from C. V. Mangan to E. G. Adensam, the applicant stated (1) a copy of administrative procedures is kept in the control room and is controlled by control room personnel, (2) the test procedures contain provisions for signoff by both the testing party and the independent verification of return to service party, and (3) the respective channel undergoing testing will be declared inoperable but will not be immediately placed in the trip condition. This inoperable condition will be subject to the limiting condition for operation criteria of the Technical Specifications. The applicant further stated that the inoperable channels were taken into consideration during the "minimum number of channels" analyses (SSER Section 7.2.2.6), and that the system with a channel under test and declared inoperable meets the single-failure criterion.

The staff has concluded that the applicant has taken the necessary steps and precautions to permit the testing of safety-related systems by making temporary modifications to the instrumentation circuits without defeating or degrading system functions. On the basis of the results of its review, the NRC staff finds the applicant's above commitments acceptable and, furthermore, these commitments follow the guidance of IE Information Notice 84-37. This will provide reasonable assurance that the instrumentation will be restored to the correct configuration following the 16 surveillance tests where lifted leads (14) or jumpers (2) are needed.

This resolves confirmatory issue 22 of the SER.

7.4 Systems Required for Safe Shutdown

7.4.2 Specific Findings

7.4.2.4 Capability for Safe Shutdown Following Loss of Electrical Power to Instrumentation and Controls

The NMP-2 SER identified a staff concern with respect to a failure of a power bus (supplying power to control systems and vital instrumentation) resulting in a malfunction of the control systems and a simultaneous loss to the operator of information required for safe shutdown. This concern is addressed in IE Bulletin 79-27, "Loss of Non-Class 1E Instrumentation and Control System Power Bus During Operation."

The applicant was also requested to review the safety-related display instrumentation (SRDI) and to rereview IE Circular 79-02. The SRDI review was to confirm that clear and unambiguous annunciation is provided upon the loss of power for each bus that could affect the ability to achieve a cold shutdown condition. The rereview of IE Circular 79-02 was to include both Class IE and non-Class IE power supply inverters.

The purpose of these reviews was to verify that the loss of power to any Class 1E or non-Class 1E power bus (ac or dc) supplying power to plant instrumentation and control systems would not result in an event prohibiting the plant operators from being able to bring the reactor to cold shutdown.

In response to the staff's concerns, the applicant submitted a report, "IE Bulletin No. 79-27 Study-Report of Findings for Nine Mile Point Nuclear Station-Unit 2," dated January 16, 1986. The applicant's evaluation concluded that there was no situation in which a single-bus power failure would prevent plant personnel from achieving a reactor cold shutdown. An electrical bus tree was constructed that showed the various ac and dc buses that could be used to achieve cold shutdown by normal and emergency means. The applicant then identified the various paths available to the operator to achieve cold shutdown, the instrumentation and control systems (including indications) in each path, and the respective loads in each of these systems. The report describes three shutdown paths and their relationship to one another. Any one of the three paths may be used to initiate cold shutdown or, depending upon availability, the paths may be mixed, e.g., start cold shutdown using the normal shutdown path, use the first alternate shutdown path for high-pressure cooldown, and finish the cooldown using the normal shutdown path.

The applicant's evaluation also concluded that cold shutdown can be achieved following any single-bus failure, and that clear and unambiguous indication of an undervoltage condition (alarms and/or annunciations) is provided in the main control room to alert the operator to the loss of power. The alarms and/or annunciations cover the bus failures of the 13.8-kV, the 4-kV, and the 125-V dc buses, the 600-V ac load centers, and the uninterruptible power supply (UPS) inverters. These bus failure indications will allow the operator to switch to an alternate shutdown path, if necessary, as governed by the procedures. The applicant also stated that IE Bulletin 79-27 was rereviewed, concurrent with a review of the plant design, to determine if possible Class 1E and non-Class 1E power supply inverter failure modes exist as discussed in IE Circular 79-02. The applicant's review concluded that the design of the inverters was acceptable and the problems described in IE Circular 79-02 were not present in the NMP-2 UPS design.

As a result of the staff review of the additional information submitted by the applicant and of the NMP-2 FSAR, the staff has concluded that the applicant has adequately addressed the issues and concerns denoted in IE Bulletin 79-27 and that the NMP-2 reactor can be successfully brought to a cold shutdown condition following the loss of a single power bus. Therefore, confirmatory issue 24, as discussed in the SER (Section 7.4.2.4), is resolved.

7.6 Other Instrumentation Systems Important to Safety

7.6.2 Specific Findings

7.6.2.1 Low-Pressure Coolant Injection and Low-Pressure Core-Spray-Injection Valves Interlocks

The NMP-2 SER identified a staff concern with respect to the pressure interlocks associated with the low-pressure coolant injection (LPCI) valves and the low-pressure core-spray (LPCS) injection valves.

During normal and emergency conditions, it is necessary to keep low-pressure systems that are connected to the high-pressure reactor coolant system properly isolated to avoid damage by overpressurization or the potential for loss of integrity of the low-pressure system and possible radioactive releases. To accomplish this, at least two valves in series should be provided to isolate the low-pressure system from the reactor coolant system. It is the staff's position (Branch Technical Position (BTP) ICSB 3) that where motor-operated isolation valves are provided, the motor-operated valves should have independent and diverse interlocks to prevent the valves from opening (automatically or by remote-manual action) whenever the primary system pressure is above the subsystem design pressure, and to close automatically whenever the primary system pressure exceeds the subsystem design pressure.

The NMP-2 design provides for pressure interlocks on the LPCI and LPCS valves to prevent overpressurization of these low-pressure systems that interface with the reactor coolant system. In both cases, these systems provide low-pressure core spray or coolant to the reactor vessel following a loss-of-coolant accident (LOCA) when the vessel has been depressurized and vessel water level has not been restored or maintained by the high-pressure core-spray (HPCS) system. The systems are initiated automatically by reactor vessel low-water level and/or by high drywell pressure. The LPCI and LPCS discharge valves were prevented from opening until differential pressure across the valves was low enough to prevent system overpressurization.

However, from its review of the control system for the LPCS and LPCI pumps, the staff found that for a small-break LOCA the LPCS/LPCI pumps will quickly develop a discharge head sufficient to satisfy the interlocks, even though the reactor vessel pressure can still be at normal operating pressure. This design permitted the injection valve to open when the differential pressure across the valve was equal to or less than 730 psi. Therefore, the injection valve could open when the reactor pressure is equal to 1,080 psig (i.e., 730 psi plus the LPCI pump discharge pressure of approximately 350 psi). The staff position is that this design is unacceptable because a single failure of the inboard check valve (F042 A, B, C, and D) could result in overpressurization of the LPCI low-pressure piping upstream of the injection valve (causing a LOCA). As a result, the reactor pressure could cause significant damage to the low-pressure piping on the pump side of the injection valve.

In discussions with the staff, the applicant has proposed to modify the interlock design. The existing differential pressure transmitter will be utilized; however, the high-pressure tap will be connected to a reactor vessel pressure-sensing line. This modification will permit the interlock to compare valve supply pressure (low-pressure side of the injection valve) with the reactor vessel pressure. The interlock setpoints are to be set at 88 psid for LPCS and 130 psid for LPCI.

The applicant formally responded to the low-pressure interlock concern by letter dated October 30, 1985, from C. V. Mangan to W. Butler. In the letter, the applicant delineated the changes to the FSAR to be made to address this staff concern. With respect to the LPCI, the differential pressure transmitters will monitor the pressure difference between the low-pressure side of each LPCI valve MO F042A (MOV24A), F042B (MOV24B), F0042C (MOV42C), and the reactor vessel pressure. For LPCS, the differential pressure transmitter will monitor the pressure difference between the low-pressure side of the injection valve MO F005 (MOV104) and the reactor pressure vessel. FSAR Amendment 24 (February 1986) states that the ECCS low-pressure interlocks (e.g., LPCI and LPCS) would remain operable during and after transfer switch operation from the remote shutdown room. This alleviates the staff concern regarding reactor pressure causing significant damage to LPCI and LPCS low-pressure piping when operated from the remote shutdown panels.

On the basis of its review of the additional information provided by the applicant, the staff finds that the LPCI and LPCS valve interlock designs as discussed above are satisfactory and meet the guidance of BTP 3. Therefore, confirmatory issue 26, as discussed in the SER (Section 7.6.2.1), is resolved.

7.7 Control Systems

7.7.2 Specific Findings

7.7.2.1 Multiple Control System Failures

The NMP-2 SER identified a staff concern with respect to: (1) common sensor or sensing line failure and (2) common power source failure. The concern stems from the fact that these multiple control system failures could cause events not bounded by the safety analyses contained in the NMP-2 FSAR Chapter 15.

In Section 7.7.2.1 of the SER, the staff reported that the applicant had initiated a detailed study to determine what, if any, design or procedural changes are necessary to ensure that the effects of failures of any power sources, sensors, or sensor impulse lines (which are shared by two or more control systems) will not result in consequences outside the bounds of FSAR Chapter 15 analyses or beyond the capability of operator or safety systems. The staff considered completion of this detailed study to be an outstanding unresolved issue.

In response to the staff concerns, the applicant performed two studies:

(1) "Control Systems Common Sensor Line Failure Analysis Evaluation Report for Nine Mile Point Nuclear Station Unit 2," Revision 0, July 1985

(2) "Control Systems Common Power Failures Evaluation Report," Revision 0, July 1985

These reports identified those control systems not related to safety that could affect critical reactor parameters, i.e., reactor vessel water level and pressure, and reactor power level.

In the case of the common sensors, the strategic reactor process sensor lines or sensors commonly shared by two or more plant systems were identified and an analysis was performed on (1) a common instrument line failure in both the broken line and plugged line modes and (2) a common instrument sensor failure. The postulated failures were analyzed for primary and secondary effects and for the combined effect.

The transient category events that were postulated as a result of the study have been determined to be less severe than the events discussed in FSAR Chapter 15 and are bounded by events discussed in FSAR Chapter 15. The report showed that the limits of minimum critical power ratio, peak vessel and main steamline pressures, and peak fuel cladding temperature for the expected operational occurrence category of the identified events would not be exceeded as a result of a common sensor line failure.

In the case of the common power supplies, the analyses were limited to those systems which in their normal control mode had the potential to affect reactor pressure vessel water level, pressure, or reactor power. The selected systems were grouped according to the power bus driving the system. Each system represented a load on the bus. The power loss was then analyzed for primary and secondary effects and for combined effects.

As a result of the analyses, no postulated event was identified with consequences that were not directly bounded by consequences of the event analyses described in Chapter 15 and, as a result, no modifications to FSAR Chapter 15 were necessary. As with the common sensors, the report showed that the peak vessel and main steamline pressures, minimum critical power ratio, and peak fuel cladding temperature for the expected operational occurrence category of the identified events would not be exceeded as a result of common power source failures.

The staff reviewed the basis of the applicant's detailed study and concluded, with reasonable assurance, that the consequences of shared-power source failures and common sensor/sensor-line failures within the control systems are bounded by the analysis documented in the NMP-2 FSAR Chapter 15. From its review of the applicant's findings, the staff concludes that its concerns regarding multiple control system failures resulting from the failure of common sensors or sensor (instrument) lines in the NMP-2 control system design are resolved. Therefore, confirmatory issue 26 as discussed in the SER (Section 7.7.2.1, FSAR Question 421.42) is closed.

7.7.2.2 High-Energy-Line Breaks and Consequential Control System Failures

The NMP-2 SER identified a staff concern with respect to control systems that were exposed to the adverse environment caused by a high-energy-line break (HELB). This issue pertains to IE Bulletin 79-22, which states in part that if non-safety grade or control equipment were subjected to the adverse environment of a high-energy-line break, it could affect the ability of protective functions to mitigate the consequences of the high-energy-line break. The applicant was requested to review the NMP-2 design to determine whether the harsh environment associated with high-energy-line breaks might cause control system malfunctions, resulting in consequences more severe than those analyzed in the FSAR, or beyond the capability of operators or safety systems.

In Section 7.7.2.2 of the SER, the staff reported that the applicant had initiated a detailed study to determine what, if any, design or procedural changes were necessary to ensure that the effects of HELBs will not result in consequences more severe than those analyzed in the FSAR.

In response to a request from the staff (FSAR Question 421.23), the applicant in a letter dated January 2, 1986, from C. V. Mangan to E. Adensam submitted a report entitled "High Energy Line Break (HELB) Evaluation Report" (December 11, 1985), which confirms that the consequence of all postulated failures are bounded by the FSAR analyses.

The applicant identified all non-safety-grade control systems which may impact critical reactor parameters (e.g., reactor vessel pressure, reactor vessel water level, critical power ratio, etc.) or the performance of safety-related equipment. Next, the applicant identified and located all high-energy lines and their postulated worst-case break locations.

In the identification of high-energy lines, the applicant used the criteria for high-energy lines established in Section 3.6.1 of the Standard Review Plan and Section 3.6.2 of the NMP-2 FSAR. High-energy lines are those lines that, during normal plant conditions, contain a fluid which exceeds either a temperature of 200°F or a pressure of 275 psig. High-energy lines that operate above these limits for less than 2% of the time are classified as moderate-energy lines and were excluded from the analysis. High-energy lines that are less than 1-inch in diameter were also excluded.

The plant was then subdivided into HELB zones: (1) the HELB zones containing control systems components of interest and (2) HELB locations were defined using the appropriate equipment qualification environmental design criteria (EQEDC) zone maps as a guide. The zones are uniquely identified and are open areas bounded by walls, ceiling, floors, etc. Certain HELB zones extend between elevations because some floor elevations have open gratings or hoist openings that are common to all the floors.

Next, the applicant determined those zones where components that can affect critical reactor parameters were located. The high-energy lines identified were then assumed to break in each zone where the control components not related to safety are located. The applicant used a "sacrificial approach" when analyzing the effects of a pipe break in a given zone (i.e., all control components in the zone that were not related to safety were assumed to fail). All possible component failure modes were considered in an effort to determine the worst-case failure mode for the components. Where a HELB could affect control components not related to safety in more than one zone (e.g., a break within a small cubicle could be postulated to blow out the door and the environmental effects of the break could then affect components in the adjoining, larger volume zone), all components in the affected zones were considered to fail in their worst states. The sacrificial approach covered all potential component failure mechanisms (i.e., pipe whip, jet impingement, humidity, temperature, pressure, and radiation) since this approach assumes that the break will adversely affect all components in the respective zone(s).

The applicant then performed a detailed analysis of each postulated break on a zone basis. Each HELB zone was analyzed with respect to high-energy systems, control systems, and combined effects. Each high-energy line was reviewed to determine the effects of a piping failure upon its own system. This was done independently for each high-energy line or group of lines having the same function, since only a single pipe break is postulated as the initiating event. A list was made of all control system components within the zone on a system basis. Where control components were grouped together, they have similar system failure effects. The failure mode(s) of each component or group of components and the effects of their failure were reviewed. The worst possible failure mode was identified. Each postulated HELB in the zone was examined in combination with the resulting worst possible failures of control system components in the zone to determine whether any combination of possible failures could exacerbate the results of the postulated HELB. The sacrificial approach was used, and the worst possible combined HELB and consequential control system failures were defined. Finally the worst possible event combinations were identified and examined.

The NMP-2 worst possible HELB event was postulated to occur from a pipe break within the turbine building. This pipe break could cause a partial loss of feedwater heating and a turbine trip to occur simultaneously, if the appropriate controls are disabled. The resulting reduction in feedwater inlet temperature would cause a gradual rise in reactor power. Depending upon the specific timing of the event, the turbine trip might occur at a reactor power level between the operating level and the trip level. The report concluded that the occurrence of this event is highly unlikely. This conclusion is based in part on the low probability of the following conditions happening concurrently:

(1) The worst possible pipe segment breaks on the most important line.

(2) Pipe whip or jet impingement can strike all targets in an area and cause failures in the worst possible modes.

(3) Breaks occur at the worst possible locations.

(4) Both turbine trip and reactor high-power-level trip occur at the worst possible time.

Should the unlikely, worst possible combined sequence occur, the reactor may experience for a short time a change in critical power ratio (CPR), which is not considered in the analyses discussed in FSAR Section 15.0.3.1.1., "Unacceptable Results for Incidents of Moderate Frequency (Anticipated Operational Transients)." However, the effects of this accident event, even considering a single active component failure in a mitigating safety system, do not affect the conclusions in FSAR Section 15.0.3.1.3, "Unacceptable Results for Limiting Faults (Design-Basis Accidents)."

The staff has reviewed the additional information submitted in the January 2, 1986, letter, and the relevant information provided in the FSAR and concludes that the applicant has satisfactorily responded to all of the staff's concerns relating to the high-energy-line-break concern. As stated earlier, the sacrifical approach has been strictly applied and conservative assumptions have been made to all analyses of system failure. The analysis does not assume operator action in any event beyond those already assumed in the existing FSAR Chapter 15 analyses. On the basis of this conclusion and the conclusions contained in the applicant's study (which indicates that the radiological consequences of the worst possible event combinations are bounded by the radiological con quences currently provided for the Chapter 15 design-basis accident), the sta finds that confirmatory issue 27, as discussed in the SER (Section 7.7.2.2), has been fully resolved.

9 AUXILIARY SYSTEMS

9.5 <u>Other Auxiliary Systems</u>

9.5.2 Communications Systems

9.5.2.1 Intraplant Systems

Safe shutdown, without an audio or visual communications system during a seismic event, is a concern that was addressed in the NMP-2 Safety Evaluation Report (confirmatory issue 33).

By letter dated December 20, 1985, the applicant advised the staff that a portable radio communications system was tested to show adequate communication between the control room and plant safety-related areas. Subsequently, during discussions with the applicant, the staff was advised that:

(1) The portable radio test could not be demonstrated to be independent of seismic Category I components or equipment.

(2) The plant could be shut down safely without dependence on audio or visual communications outside the control room during and following a seismic event.

By letter dated February 21, 1986, the applicant advised the NRC that the plant communications equipment was not necessary for the safe shutdown of the reactor during a design-basis earthquake, and that the safe shutdown function could be completed from the control room.

The staff concurs with the applicant's position. The staff finds the existing plant communications system to be acceptable. Staff review indicates that NMP-2 may be taken to cold shutdown by controlling safety-related equipment entirely from within the control room, without the need for sending anyone outside the control room.

Hence, the plant has the capability to achieve and maintain, on a long-term basis, a safe cold shutdown after a seismic event, without the necessity of communicating with anyone outside the control room. The staff considers confirmatory issue 33 to be closed.

9.5.5 Emergency Diesel Engine Cooling Water System

In a letter dated October 4, 1985, the applicant provided Figures 9.5-40a, 9.5-40b, 9.5-40c, and 9.5-42. These figures show the diesel engine interfaces and were subsequently included in the FSAR. The staff has reviewed the information provided in the October 4, 1985, letter and finds that the information provided acceptably resolves staff concerns related to the connections of the cooling water and air start systems to the diesel generator.

This action closes confirmatory issue 40.

9.5.6 Emergency Diesel Engine Starting System

See Section 9.5.5 above.

11 RADIOACTIVE WASTE MANAGEMENT

11.4 Solid Waste Management System

11.4.2 Evaluation Findings

In the SER, the staff stated

> The applicant has committed to provide (1) the NMP-2 solid radioactive waste process control program (PCP), and (2) a compliance program to satisfy the requirements specified in 10 CFR 61 for land disposal of radioactive waste. The applicant stated that these programs will be provided to the staff for review by the second quarter of 1985. These programs will be subject to review and approval by the staff before plant startup....
>
> On receipt of the PCP and a compliance program to meet 10 CFR 61 from the applicant, the staff will perform the review, and its evaluation will be provided in a supplement to the SER.

By letter dated January 17, 1986, the applicant submitted an acceptable NMP-2 process control program (PCP) and a compliance program to meet the requirements in 10 CFR 61 for offsite disposal of radioactive waste.

The NMP-2 PCP describes the radwaste solidification process envelope within which the processing and packaging of radioactive waste will be accomplished. The intent of this program is to provide reasonable assurance of compliance with Branch Technical Position (BTP) ETSB 11-3 and BTPs on waste form and classification. The PCP provides for minimum operable components to process waste, a prequalified mixture formula, sampling requirements, specific process parameters, administrative controls, a shipping manifest, and a quality assurance program to verify compliance with applicable regulations and requirements.

By letter dated April 11, 1986, the applicant submitted the results of a testing program to demonstrate the ability of the asphalt binder to maintain the stability of waste products required in accordance with 10 CFR 61.56. The staff is currently reviewing the test results submitted on a generic basis (Waste Chem Corporation topical report on 10 CFR 61 Waste Form Conformance Program).

In the letter referenced above, the applicant also indicated that the applicant would perform a full-scale preoperational test of the asphalt-based volume reduction and solidification system after installation.

By letter dated May 19, 1986, the applicant stated that it intends to use the contract services of NUS Process Services Corp. to solidify wastes on an interim basis until the staff completes its review of test results on asphalt binder submitted by the applicant. The applicant stated in its May 19, 1986, letter that the NUS system will be used in full compliance with NRC-approved NUS Process Services Corporation Topical Report, PS-53-0378, Rev. 0, dated April 1983, "Radwaste Solidification System." On May 30, 1985, in a letter from Cecil Thomas to Raymond Powell, the staff accepted the NUS topical report for referencing in future license applications for light-water reactors. The basis for the staff's acceptance was the staff's conclusion that the NUS system is designed and can be operated in accordance with current guidance of applicable regulatory guides, standard review plans, branch technical positions, and Federal regulations in effect at that time. In the staff's supplemental Safety Evaluation Report (SSER) on the NUS system, dated May 30, 1985, it was stated that the staff will provide an evaluation in a separate safety evaluation on the waste form requirements upon completion of its review of a separate NUS topical report, "Topical Report on 10 CFR 61 Qualified Radioactive Waste Forms." The licensed radioactive waste burial sites are currently accepting cement-solidified wastes by the NUS system. Therefore, the applicant may proceed with waste solidification utilizing the NUS system on an interim basis until the staff completes its review of the NUS topical report on 10 CFR 61 waste form stability requirements. The applicant further stated that there will be no exceptions or deviations from the NUS topical report cited above. The mobile and truck-mounted NUS system will be temporarily located in the Nine Mile Point, Unit 2 radwaste building truck bay. The staff concludes the applicant's proposal to utilize an NRC-approved NUS system on an interim basis until the staff completes its review of the Waste Chem Topical Report on 10 CFR 61 Waste Form Conformance Program to be acceptable.

13 CONDUCT OF OPERATIONS

13.1 Organizational Structures and Operations

The applicant, by letters dated December 10 and 23, 1985, submitted Amendments 22 and 23, respectively, to its Final Safety Analysis Report (FSAR). In those amendments, the applicant made minor changes to its organizational arrangement. The applicant assigned the Vice President Nuclear Generation as the individual to replace the Project Director with responsibility for plant operations, maintenance, testing, and other operational functions. Also, FSAR Figure 13.1-5 was changed to correct the reporting relationship of the Assistant Station Shift Supervisor (ASSS) Nuclear. The ASSS was previously shown as reporting to the Assistant Operations Superintendent Nuclear instead of to the Station Shift Supervisor Nuclear. In addition, the titles of several of the positions in the NMP-2 operating organization were changed, but their position responsibilities were not changed. The staff reviewed these changes and found them consistent with the guidelines in the Standard Review Plan. They are, therefore, acceptable.

13.3 Emergency Planning

13.3.1 Introduction

The staff's evaluation of the Nine Mile Point Nuclear Station, Unit 2 (NMP-2), emergency plan* presented in the SER identified three confirmatory issues requiring the review of additional information. In addition, the staff reported that State and local radiological response plans for the NMP facility were under review by the Federal Emergency Management Agency (FEMA) and that FEMA's findings would be provided at a later date. This supplement provides information regarding the confirmatory and other issues related to emergency planning for NMP-2 based upon a review of the emergency plan through Revision 15 dated October 1985. FEMA findings on the adequacy of offsite emergency preparedness are presented in Section 13.3.3 below. The staff's overall conclusions on emergency preparedness are given in Section 13.3.4.

13.3.2 Evaluation of the Emergency Plan

13.3.2.2 Onsite Emergency Organization

The staff reported in the SER that the applicant had committed to revise the minimum staffing for emergencies shown in Figure 5.3 of the emergency plan to meet the staffing objectives of Table 2 of Supplement 1 to NUREG-0737. The staff has verified that Figure 5.3 in the emergency plan has been revised to reflect the minimum staffing goals of Supplement 1 to NUREG-0737.

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*The "Niagara Mohawk Power Corporation, Nine Mile Point Nuclear Station, Site Emergency Plan," submitted as Appendix 13B, "Site Emergency Plan," to the NMP-2 FSAR.

13.3.2.5 Notification Methods and Procedures

The staff reported in the SER that it would confirm, with the assistance of FEMA, the capability of offsite authorities to promptly alert and notify the public upon being notified by NMP of an emergency requiring urgent action. In a letter to the NRC dated February 1, 1985 (see Appendix L), FEMA stated that the adequacy of the public alerting and notification system has been verified by FEMA in accordance with the criteria in FEMA 44 CFR 350, Appendix 3 of NUREG-0654/FEMA-REP-1, and FEMA-43, "Standard Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants." On the basis of the FEMA response and information in Revision 14 of the emergency plan, the staff confirms the capability of offsite authorities to promptly alert and notify the public in the area around the NMP facility in the event of an emergency.

13.3.2.8 Emergency Facilities and Equipment

(2) <u>Technical Support Center</u>

The NMP site Technical Support Center (TSC) is located in the Administration Building at elevation 248 feet and serves both Unit 1 and Unit 2. The site TSC replaces an interim TSC which was located at elevation 277 feet in the Administration Building. In a letter to the NRC dated May 29, 1985, the applicant stated that the site TSC would be fully functional before fuel load. The site TSC facility was utilized during the annual emergency preparedness exercise conducted at NMP Unit 1 on November 13, 1985.

(4) <u>Emergency Operations Facility</u>

The NMP site Emergency Operations Facility (EOF), as described in Revision 14 of the emergency plan, is located in the Nuclear Training Center just outside the site's protected area. Previously an interim EOF was located in the Emergency Information Center. The new EOF is designed to conform to the requirements of Supplement 1 to NUREG-0737. It is a hardened facility with a protection factor greater than 5, a ventilation system with high-efficiency particulate air (HEPA) and charcoal filters which can be isolated, and space for 10 NRC employees. EOF personnel will be notified at the Alert level, and the EOF will be fully staffed by Niagara Mohawk Power Corp. personnel within 1 hour of reaching a Site Area or General Emergency. In a letter to the NRC dated May 29, 1985, the applicant stated that the EOF would be fully functional before fuel load. The new EOF was used during the November 13, 1985, emergency preparedness exercise at NMP Unit 1.

On the basis of information in the emergency plan and procedures, and observations made during exercises conducted at the NMP site, the staff concludes that, on an interim basis, the NMP emergency response facilities (ERFs) are adequate to support a response effort in the event of an emergency. The NRC will evaluate the readiness of the ERFs as part of the onsite emergency plan implementation appraisal conducted before plant operation. As noted in the SER, the staff will further evaluate the completed ERFs as part of the post-implementation review of emergency response capabilities against the requirements contained in Supplement 1 to NUREG-0737.

13.3.2.10 Protective Response

In a letter dated December 3, 1984, the applicant committed to revise the plan to indicate that protective actions will be based on plant and core conditions as well as on the projected dose to the environs. The staff has confirmed that Section 6.3.6 of the emergency plan, Revision 14, has been revised to reflect this commitment.

13.3.2.12 Medical and Public Health Services

In a decision, GUARD v. NRC 753 F.2d 1144 (D.C. Cir. 1985), the U.S. Court of Appeals vacated the Commission's interpretation of 10 CFR 50.47(b)(12) to the extent that a list of facilities was found to constitute adequate arrangements for medical services for members of the public off site exposed to dangerous levels of radiation. The Commission has provided guidance to be followed in determining compliance with this regulation pending its determination of how it will proceed in response to the Court's remand. In particular, the Commission directed that Licensing Boards, and, in uncontested cases, the staff, should consider the uncertainty attendant to the Commission's interpretation of this regulation, especially in regard to its interpretation of the term "contaminated injured individuals." In GUARD, the Court left open to the Commission the discretion to reconsider whether that term should include members of the offsite public exposed to dangerous levels of radiation and, thus, whether arrangements for this population of individuals are required at all. For this reason, the Commission observed that it may reasonably be concluded that "no additional actions should be taken now on the strength of the present interpretation of that term." Accordingly, the Commission observed that it can be found "that any deficiency which may be found in complying with a finalized post GUARD planning standard (b)(12) is insignificant for the purposes of 10 CFR 50.47(c)(1)." In this regard, the Commission, as a generic matter, noted the low probability of accidents that might result in exposure of members of the offsite public to dangerous levels of radiation as well as the slow development of adverse reactions to overexposure (see "Emergency Planning: Statement of Policy," 50 FR 20892, May 21, 1985).

Consistent with the foregoing Statement of Policy, by letter dated December 2, 1985, the applicant confirmed that the emergency plans of the involved offsite response jurisdictions contain a list of medical service facilities. The existence of such a list in the pertinent plans has also been confirmed by FEMA in a letter to the NRC dated February 28, 1986. Furthermore, the applicant has committed by letter dated February 19, 1986, to fully comply with the Commission's response to the Court's remand.

Accordingly, on the basis of the factors identified by the Commission in its Statement of Policy, the staff has determined that the requirements of 10 CFR 50.47(c)(12) have been satisfied to warrant issuance of the operating license pending further action by the Commission with respect to the requirements of 10 CFR 50.47(b)(12).

13.3.2.6 Exercises and Drills

The latest full participation emergency preparedness exercise for the Nine Mile Point site was conducted on November 13, 1985, for Unit 1. The NRC report of the onsite portion of the exercise was issued on December 6, 1985, in Inspection Report 50-220/85-19. The NRC Regional staff concluded that although there were areas identified for corrective action, the NRC determined that within the scope and limitations of the scenario, the applicant's performance demonstrated that the applicant could implement its emergency plan and procedures in a manner which would adequately provide protective measures for the health and safety of the public. The applicant will conduct a drill of the Unit 2 specific aspects of the NMP emergency plan before licensing. This drill will be observed by the NRC as part of the preoperational emergency plan implementation appraisal effort for Unit 2.

13.3.3 Federal Emergency Management Agency (FEMA) Findings on Offsite Emergency Plans and Preparedness

In a letter to the NRC dated February 1, 1985 (see Appendix L of the report), FEMA provided its findings and determinations on the adequacy of offsite plans and preparedness for the Nine Mile Point Nuclear Station in accordance with FEMA rule 44 CFR 350. FEMA stated that the State and local plans and preparedness are adequate to protect the health and safety of the public in that there is reasonable assurance that the appropriate protective measures can be taken offsite in the event of a radiological emergency. The adequacy of the public alerting and notification system was also verified by FEMA in accordance with the criteria in FEMA 44 CFR 350, Appendix 3 to NUREG-0654/FEMA-REP-1, and FEMA-43, "Standard Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants."

On March 19, 1986, FEMA issued its report of the November 13, 1985, exercise at Nine Mile Point. FEMA stated that there were no deficiencies observed in the exercise which would cause a finding that offsite preparedness was inadequate.

13.3.4 Conclusions

On the basis of the staff's review of the Nine Mile Point, Unit 2 emergency plan for conformance with the requirements of 10 CFR 50 and Appendix E to 10 CFR 50, and the guidance criteria in NUREG-0654/FEMA-REP-1, the staff concludes that the Nine Mile Point emergency plan provides an adequate planning basis for an acceptable state of onsite emergency preparedness. FEMA has provided its findings and determinations on the adequacy of offsite emergency planning and preparedness for the Nine Mile Point facility. On the basis of the staff's review of the FEMA findings on the adequacy of offsite plans and preparedness, and on the staff's assessment of the adequacy of the applicant's onsite emergency plan and preparedness, the staff concludes that the overall state of onsite and offsite emergency preparedness provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency at the Nine Mile Point Nuclear Station.

13.5 Station Procedures

In Amendments 23 and 24, the applicant made minor changes to this section of its FSAR by changing the numbering system of procedures, deleting extraneous information, and reformatting information related to the approval of procedures. These changes were judged acceptable.

15 ACCIDENT ANALYSES

15.1 Anticipated Operational Occurrences

End-of-Cycle Recirculation Pump Trip Inoperable and Turbine Bypass Inoperable

The operating limit on minimum critical power ratio (MCPR) is dependent on the status of the end-of-cycle recirculation pump trip (EOC-RPT) feature of the recirculation system. The EOC-RPT logic, once satisfied, trips the fast speed circuit breakers to the recirculation pump motors. This causes a fairly rapid core flow coastdown which improves the thermal margins to safety on certain limiting transients. In the Technical Specifications, the operating limit MCPR value is higher if the EOC-RPT feature is inoperable. The applicant has proposed Technical Specifications (Section 3.3.4.2) for EOC-RPT system instrumentation which are based on General Electric Standard Technical Specifications. The current limiting condition of operation (LCO) requires that the thermal power be reduced to less than 30% if the end-of-cycle recirculation pump trip becomes inoperable. By letter dated December 30, 1985, the applicant proposed a revised LCO based on a plot of operating limit critical power ratio (OLCPR) versus control rod scram speed. A curve is generated by examining two limiting transient cases (feedwater controller failure without bypass and generator load rejection without bypass). The transient code ODYN was used in the analysis, and the bounding OLCPR is selected from the two transients. The scram speed is determined from a statistical analysis in accordance with ODYN Option B statistical adjustment factors. The NRC staff has previously reviewed and approved the methodology associated with the use of ODYN Option B (letter from R. L. Tedesco (NRC) to G. G. Sherwood (GE), "Acceptance for Referencing General Electric Licensing Topical Report NEDO-24154/NEDE-24154 P," February 4, 1981). Utilities using Option B must demonstrate that their plant's scram speed distribution is consistent with that used in the statistical analysis. This is accomplished through an approved Technical Specification which consists of testing at a 5% significance level. The applicant has chosen to use Option B, which the staff finds acceptable.

With regard to the turbine bypass inoperable Technical Specification, the applicant has adopted the same approach as EOC-RPT inoperable with a reanalysis of limiting transients with ODYN to establish an OLCPR-scram time plot to replace the thermal power reduction requirement. As in the case of EOC-RPT inoperable, the staff finds the proposed limiting conditions of operation for turbine bypass inoperable to be acceptable.

15.9 TMI Action Plan Requirements

15.9.4 NUREG-0737 Item III.D.1, Primary Coolant Outside Containment

NUREG-0737, Item III.D.1.1, Integrity of Systems Outside Containment Likely To Contain Radioactive Material for Pressurized-Water Reactors and Boiling-Water Reactors

In the SER, the staff stated:

The applicant committed that a detailed description of the full program with the initial leak rate test results will be provided at least 4 months before the operating license is issued. The staff will review this program and the results of the initial leak testing at that time. The results of the review of those submittals will be presented in a supplement to this SER.

In a letter dated January 16, 1986, the applicant submitted an acceptable description of a program to reduce leakage from systems outside the containment. The applicant's program describes measures for leak reduction to as-low-as-practical levels for those systems that could contain highly radioactive fluids during a serious transient or accident. However, the applicant has not provided the initial leak test results.

In the letter referenced above, the applicant stated that the initial leak test results, along with corrective maintenance performed as a direct result of its evaluation of the leakage program, will be submitted to the NRC staff for review not later than 2 months after fuel loading. In a letter dated April 4, 1986, the applicant stated that additional time would be needed to provide the leak rate test data for the reactor core isolation cooling (RCIC) system. In that letter the applicant indicated that the temporary steam supply used for testing the RCIC turbine is not adequate to run the system at rated pressure; thus, additional time is needed to run the waterladen portion of the RCIC system. In a letter dated April 21, 1986, the applicant committed to provide the results of the RCIC system leakage test no later than five months following the Nine Mile Point Unit 2 reactor reaching the 5% power level. All other leakage data will be submitted no later than 2 months following fuel load.

The staff finds this proposal acceptable, since many of the systems required to be tested may not be available for testing until after the initial stages of heatup.

The staff will condition the license to require submittal of the initial leak test results in accordance with the schedule described in the applicant's letter of April 21, 1986.

17 QUALITY ASSURANCE

17.5 Independent Design Verification/Engineering Assurance

17.5.1 Background

In a letter dated April 3, 1985, the applicant forwarded to the NRC staff a program plan for the completion of engineering assurance (EA) in-depth technical audits of the NMP-2 project. This plan was subsequently revised as EA In-Depth Technical Audit, Revision 1, dated April 18, 1985, as a result of discussions with the NRC staff. This program was approved with conditions stated in an NRC letter (from A. Schwencer, NRC, to C. V. Mangan, NMPC) dated May 2, 1985.

The program plan provided for the performance of four in-depth technical audits of the engineering and design activities of the project, three of which had been previously completed. The Phase I activity involved performance of the fourth audit, an assessment of the design adequacy and the design process of NMP-2 by evaluating the design of the reactor core isolation cooling system (ICS). Phase II activities involved an evaluation and assessment of the results of the four audits to form conclusions about the adequacy of the design process implemented for NMP-2 and to determine if any trends existed pointing to a weakness in the design process.

Stone & Webster Engineering Corporation (SWEC) performed the engineering assurance program (EAP). The NRC staff closely monitored the conduct of the program including:

(1) Inspection of EAP technical audit preparation at the SWEC office in Boston, Massachusetts, on April 22 and 23, 1985. The NRC staff's report of this inspection, Inspection Report 50-410/85-14, was provided to the applicant in a letter dated May 10, 1985 (from B. K. Grimes, NRC, to C. V. Mangan, NMPC).

(2) Inspection of EAP technical audit implementation at the SWEC office in Cherry Hill, New Jersey, on May 21 through 24, 1985. The NRC staff's report of this inspection, Inspection Report 50-410/85-18, was provided to the applicant in a letter dated June 17, 1985 (from B. K. Grimes, NRC, to C. V. Mangan, NMPC).

(3) Inspection of the NMP-2 site on June 7, 1985.

(4) Attendance at the post-audit conference held at the SWEC office in Cherry Hill, New Jersey, on July 11, 1985.

(5) Inspection of EAP technical audit results and corrective action at the SWEC office in Cherry Hill, New Jersey, on August 12 through 16, 1985. The NRC staff's report of this inspection, Inspection Report 50-410/85-28, was provided to the applicant in a letter dated September 12, 1985 (from B. K. Grimes, NRC, to C. V. Mangan, NMPC).

(6) Followup inspection of EAP technical audit results and corrective actions at the SWEC office in Cherry Hill, New Jersey, on January 3 and 7, 1986.

17.5.2 Engineering Assurance Program Technical Audit

The audit team consisted of senior level SWEC and applicant personnel. The team of technical specialists functioned under the direction of the SWEC Engineering Assurance (EA) Division, Boston. Experienced, senior level, off-project personnel from appropriate disciplines participated in the audit.

The EAP technical audit program provided for the performance of four in-depth technical audits of NMP-2 engineering and design activities. The program was conducted in two phases. Phase I consisted of an audit to assess the adequacy of design and implementation of the design process for the reactor core ICS, including design interface aspects of other systems, structures, and components. Phase II consisted of the evaluation and assessment of the results of the Phase I audit plus three previously completed audits to form conclusions as to the adequacy of the design process implemented for NMP-2.

The Phase I audit (Audit No. 50, dated August 2, 1985) represents the efforts of a team of qualified off-project personnel reviewing numerous documents over a period of more than 3 months. Where problems or concerns were identified, action items were prepared. Of a total of 166 action items issued, 94 resulted in corrective and/or preventive action. The remaining items did not require action because the potential concern identified was determined to be of no concern after appropriate information was provided. For those action items for which corrective actions were not complete before the audit was finished, audit observations were issued to track the continuing action. Further information concerning the audit observations as well as additional information requested by the NRC staff was subsequently provided in Supplemental Report to Audit No. 50, dated September 27, 1985.

In Phase II, audit findings of the four EA Division technical audits, along with the NRC's Construction Assessment Team inspection report and technical audits of a design subcontractor (Reactor Controls, Inc.), were itemized, categorized, and coded according to a formal plan. Categorization consisted of assigning codes to define the specific nature of each finding. These codes were: finding type, document type, responsible discipline, corrective and preventive action, cause, extent of condition, and an exclusion code used to establish the potential consequences of a finding. Information on coding sheets was then input to a computerized data base for composite analysis of the data. Data base information was sorted into finding-type subcategories, and each subcategory was reviewed for commonalities and significance of occurrence. The Phase II audit results were documented in a formal report dated October 24, 1985.

17.5.3 Conclusions of the SWEC Engineering Assurance Division Technical Audit

Phase I

The SWEC EA technical audit reached conclusions as to the adequacy of the design and design process at NMP-2, relative to both the systems reviewed and the overall plant. In Audit Report No. 50, the conclusions of the EA Division are set forth in detail, including the bases for the conclusions. The discrepancies identified during the audit were studied and evaluated both individually and collectively; none were attributed to an overall programmatic or systematic weakness. The EA Division concluded that the implementation of the design process was adequate in most areas. Discrepancies observed were mostly minor or random instances of incomplete compliance to individual procedural requirements.

Phase II

On the basis of the evaluations conducted in Phase II, the EA Division concluded that there is assurance that the overall design of NMP-2 is technically adequate. This conclusion was based on:

(1) the total scope of the audits performed and the depth of reviews conducted

(2) the level of audit review as reflected in the detail of the audit findings

(3) investigation of all audit findings regardless of significance with action taken to bound and correct the condition along with action to prevent recurrence

(4) on the basis of the comprehensive scope of the audit and the nature of the audit findings, the determination that there is no indication that areas not audited would have findings of any greater importance or occurring in any greater frequency than in the audited areas

17.5.4 Assessment by the NRC Staff

The NRC staff has assessed the results of the engineering assurance program for NMP-2, including a detailed review of the subsequent corrective actions, both completed and in progress. As part of the staff's assessment, three inspections were conducted at the site of Technical Audit No. 50 (SWEC, Cherry Hill, New Jersey) to review documentation supporting the action items and conclusions of the audit or to review implementation of corrective actions. These inspections focused on the review of individual action items, the response of the NMP-2 project personnel, and the proposed corrective actions that formed the basis for the conclusions of the EA Division.

Through its inspections, the staff found the EA audit to be well documented. It was also evident by evaluating the review plans prepared by the individual reviewers that the EA Division had reviewed NMP-2 project documentation in considerable technical detail. On the basis of its review of the Audit Report, the Supplemental Report, and the Phase II Report and a detailed technical review of a sample of the calculations reviewed by the SWEC EA team in each technical discipline, the staff concurs with the findings and conclusions of the EA Division. Action items for which corrective actions are not complete will be held open pending receipt of a confirmatory letter from the applicant that the corrective actions have been completed.

17.5.4.1 FSAR Changes

The following action items were resolved on the basis of a commitment by the applicant to revise the FSAR. The action items that required FSAR revisions were items E-C01; E-E03, 04; E-M02, 03; E-P44, and E-S01, 02, 05, 013. These action items are considered closed for design review purposes since the proposed changes have been formally submitted.

17.5.4.2 Technical Assessments

NRC staff assessments of the specific discipline areas reviewed by the EA technical audits are provided below.

(1) Mechanical Systems and Components

The mechanical discipline encompasses both mechanical system design aspects (power engineering discipline) and pipe stress and pipe support analysis (engineering mechanics discipline). There were 56 action items initiated in the power discipline and 25 action items in the engineering mechanics area. The following NRC staff comments are provided on these action items.

Action Items E-M04-0 and E-M05-0 (action items are described in SWEC, "Engineering Assurance Audit Report - Nine Mile Point Unit 2 Project Audit No. 50, April 29, 1985-July 11, 1985," submitted to the NRC by letter dated August 2, 1985, from C. V. Mangan, and its supplement dated September 27, 1985, submitted by C. V. Mangan on October 24, 1985) identified design specification and qualification deficiencies associated with motor-operated valve (MOV) 2ICS*MOV126 and its associated specification P304R. Action Item E-M04-0 dealt with the lack of stress cycle evaluation and treatment of hydrodynamic loads in the Velan valve qualification report for MOV 2ICS*MOV126; Action Item E-M05-0 identified the omission of hydrodynamic loadings (i.e., safety/relief valve discharge) in design specification P304R. It was also determined that several of the balance-of-plant (BOP) Limitorque operators (i.e., SB-00-5, SB-2-60, SB-3-150, and SMB-2-60/H6BC) were not shown to be qualified for hydrodynamic and seismic effects, since the necessary testing program was not complete. The staff reviewed the existing documentation during the inspection conducted from August 12 through 16, 1985, and concluded that the hydrodynamic criteria requirements had been satisfactorily incorporated into the governing specification. The applicant submitted a supplementary report entitled "Engineering Assurance Supplement to Audit No. 50, Nine Mile Point Unit 2 Project," dated September 27, 1985, in which the applicant provided supplementary information regarding the qualification of the body and motor operator, as well as a response to NRC's Corrective Actions Inspection Report 50-410/85-28. The staff has reviewed this report and concludes, on the basis of the statements it contains, that the concern regarding valve body qualification has been adequately addressed. However, the information provided regarding qualification of the Limitorque operators was incomplete and, therefore, unacceptable. The applicant presented additional testing information regarding the mechanical qualification of the BOP Limitorque operators during an inspection conducted January 7, 1986. The NRC staff reviewed this information and concluded that the required corrective actions had been established. The item is considered closed.

Action Item E-M09-0 identified the use of a non-locking mechanical snubber to resist a steady-state rupture-disc blowdown force in the ICS. The use of such a device is generally unacceptable because of the high magnitude of the blowdown force and low load resistance characteristics of the snubber. The response of the project personnel to the finding was that since the ICS turbine has an automatic shutdown feature that initiates the turbine stop valve trip within 0.3 second (on an excessive back pressure signal), the resulting blowdown force is essentially a short-duration pulse. Hence, the effect on the system can be treated as a static force. To substantiate this premise, and provide a corrective action to rectify the problem, a time-history analysis of the blowdown force generated by the event was performed. The staff has reviewed the response of the project personnel, the implemented corrective actions, and is satisfied that the matter has been adequately resolved. This item is considered closed.

Action Item E-M10-0 identified the failure to consider the evaluation of the stress intensification that occurs at the intersection of a branch-to-run pipe. This technical concern was previously identified in "Engineering Assurance Audit Report No. 44," dated April 3, 1984. The resolution of this issue was to perform the required evaluation during the final stress reconciliation/qualification phase for the piping and pipe supports. The staff has reviewed this matter and the proposed resolution and finds it acceptable. The applicant performed a review of additional calculations which had gone through the final stress reconciliation phase to supplement the sampling performed as part of Engineering Assurance Audit No. 50. The staff reviewed these results during an inspection on January 7, 1986, and determined that the required corrective actions were being implemented in accordance with the applicant's commitments. This item is considered closed.

Action Item E-M12-0 resulted from a deficiency in a SWEC design document (CHOC-EMTR-602-2, "Design and Installation of Seismic Small Bore Piping, Instrumentation, Tubing and Supports") to address the development of piping nozzle loads and the qualification of the nozzle connection at the equipment. All small-bore piping connected to quality assurance (QA) Category I equipment was affected. As a result of this finding, CHOC-EMTR-602-2 was revised to provide nozzle load allowable values when vendor-supplied allowable values are unavailable and nozzle load limits for situations where manual piping qualifications are performed, and to require that the equipment nozzle qualification be addressed in the pipe analysis. Also, Procedure PP-93, "Category I Pipe Stress and Supports Final Reconciliation," was revised to provide specific direction to evaluate all equipment nozzle loadings for small-bore piping. The applicant has provided supplementary information to Audit Report No. 50, indicating that a limited review of final stress reconciled piping has been performed. This information was supplemented by additional reviews performed by the SWEC EA Division. The staff evaluated the results of these additional audits and concluded that the required corrective actions are being implemented properly. In a letter dated May 14, 1986, the applicant indicated that all corrective actions have been completed. The staff considers this item closed.

Action Item E-M23-0 identified the fact that the Nuclear Technology Division (NTD) was not formally consulted when field conditions necessitated relocation of components that might affect shielding calculations. As a result, the original design basis for calculation 2RCS*SHLD2NC was altered by the field conditions described in Engineering and Design Change Report (E&DCR) C90642, but a mechanism was not in place to require a reevaluation of the calculation. The applicant has taken steps to identify this type of situation and now requires information on as-built conditions to be supplied for the affected NTD calculations. The staff has reviewed the problem, the scope of the corrective action, and concluded that it adequately addresses the findings. The applicant has implemented corrective actions to prevent a recurrence of the problem and has identified those calculations associated with shielding hardware field changes that will have to be reevaluated for the effects of the change. In addition, the applicant stated during a meeting on January 7, 1986, that it would review all NTD calculations after fuel loading for the effects of actual field conditions. The basic concern of this action item was its programmatic aspects. It is not anticipated that any significant changes will result because of reassessment of the calculation. The staff reviewed those corrective actions that have been implemented and concludes that they adequately address the intent of the action item. In addition, on the basis of the applicant's commitments to review all NTD calculations, the staff concurs with the resolution of the action item. It is considered closed.

Action Item E-P07-1 involved the sizing of relief valve 2ICS*RV112. The action item questioned the sufficiency of the relief valve to provide protection with the full-open failure of an upstream pressure control valve. Further investigation by the EA auditor indicated that the NMP-2 project personnel had identified this problem about 8 months before the audit, as addressed in Revision No. 1 of the design calculation. The relief valve had been appropriately modified and was sufficient to handle failure of the pressure control valve. Nevertheless, to provide additional assurance of relief valve design adequacy, the project personnel reviewed all other systems for a similar concern and identified one other valve, 2RHS*RV108, with a similar problem. In the case of 2RHS*RV108, the relief valve was capable of accommodating failure of an upstream level control valve but was not capable of accommodating failure in a pressure-reducing valve in the steam supply line to the residual heat removal system (RHRS) heat exchanger with the reactor at high pressure in the steam-condensing mode and the RHRS heat exchangers supplying water to the ICS pump. This condition is considered extremely unlikely because it requires both the inadvertent opening of a pressure control valve, which is designed to fail closed, and the simultaneous failure of a separate pressure transmitter and control valve designed to isolate the high-pressure system from the low-pressure system. Under this multiple-failure scenario, pressure in the low-pressure piping would reach approximately 225 psig, which corresponds to the hydrostatic test pressure of the system and, therefore, is within the pressure-retaining capabilities of the piping. Hence, the project personnel concluded that this condition does not represent an equipment hazard. In addition, the condition only exists with the reactor shut down, since this is the only time when the steam-condensing mode is used. Nevertheless, to ensure compliance with the ASME Code, the steam-condensing mode level control valves are to be modified to limit flow to a value within the capacity of relief valve RHS*RV108.

The staff reviewed all aspects of Action Item E-P07-1 and concluded that sufficient action has been taken. There is no design process concern relative to this matter because the original problem was originally identified by the project personnel. The fact that all relief valves in the plant with similar potential overcapacity conditions have been reviewed (revealing the RHS*RV108 problem) gives further confidence with regard to the effectiveness of the design process. Finally, the staff does not consider this item to have been of safety significance for the following reasons:

(a) The problem occurs only in a multiple-failure scenario, with the reactor in a shutdown condition.

(b) The steam-condensing mode is used only for a small part of the operating life of the plant.

(c) Under any scenario, the overpressure condition does not exceed the static test pressure of the piping and, therefore, no piping failure occur.

In a letter dated May 14, 1986 the applicant confirmed that the modifications to the level control valves to limit the flow have been completed. The staff considers this item closed.

Action Item E-P27-0 involved the potential overpressure of non-safety-related test line piping to the condensate storage tank. This matter had been evaluated by the project personnel before the audit, and the project personnel had determined that no problem existed on the basis of operating procedures preventing the overpressure condition. For the low-pressure portion of the piping to be overpressurized, two normally locked-open valves would have to be shut with the high-pressure core spray pump or the reactor core isolation cooling pump lined up to the condensate storage tanks. This condition was evaluated by the audit team, which determined, on the basis of its interpretation of ANSI B31.1 (ANSI B31.1 applied because only non-safety-related piping is involved), the previously described position of the project personnel was unacceptable. The project personnel responded by agreeing to develop administrative controls to prevent the occurrence of this condition. This response was found acceptable to both the audit team and the applicant.

The staff reviewed the action in this matter and finds it acceptable. There are no design process concerns because this matter had been previously evaluated by the project personnel and the difference in the determinations by the project personnel and the audit team was the result of an interpretation of the ANSI B31.1 requirements. The staff considers the overpressurization question closed. Furthermore, in response to the concern raised by Action Item E-P27, the project personnel evaluated other high/low-pressure interfaces and identified other potential problems, none of which involved safety-related piping. These potential problems were resolved to the satisfaction of the EA audit team. Consequently, the staff considers this item closed.

Action Item E-P31-0 involved the location of level switches on a condensate drain pot, which control condensate level to preclude water induction to the steam turbine of the ICS. The final resolution of this item involved relocation of the level switches to prevent potential waterhammer due to condensate buildup. All other steam systems were reviewed for this type of problem with no similar instances being identified. On June 25, 1985, this matter was reported to the NRC staff as a potential deficiency under 10 CFR 50.55e. Subsequent evaluation by the project personnel determined that had this problem remained uncorrected, no damage to equipment would have occurred because the turbine is designed to accept water slugs. The piping and supports can also accommodate potential waterhammers that might occur. On the basis of its review of this matter, the staff concluded that sufficient action has been taken. The staff concurs that the safety significance of this item is extremely low because it has been demonstrated that no adverse impact on the safe operation of the plant would have occurred had this hardware change not been made. Furthermore, the potential for waterhammer exists only on startup of the turbine, since during operation condensate is swept clear by steam flow. Because the startup of the turbine is relatively slow (approximately 10 seconds), the gradual draining and clearing of condensate would also minimize potential waterhammer. In any event, this condition was determined to be an isolated case and appropriate corrective action has been taken. The staff considers this item closed.

Action Item E-P37-0 involved the ability of the system to prevent water loss from the suppression pool due to backflow through a non-safety-related flow path considering single-failure analysis. The problem was resolved by the addition of a check valve in the ICS to prevent backflow of suppression pool water to the condensate storage tank area in a condition involving a unique single failure combined with a design-basis event. The problem was under evaluation by the NMP-2 project personnel before Audit No. 50 as a result of a similar finding during a technical audit of the River Bend project by the Stone & Webster EA Division. Consequently, this hardware change did not directly result from Audit No. 50. Nevertheless, the implications of this hardware change with respect to design adequacy and the design process for NMP-2 are discussed here.

As a result of the River Bend finding, the NMP-2 project personnel reviewed all other plant systems for similar problems. None were found. Further, the original design of the ICS at NMP-2 represents a potential problem only under a unique combination of single failure and design-basis event. The single failure involved the failure of a motor control center powering two ICS isolation valves, one for the suppression pool and the other for the condensate storage tank. The failure must occur within the specific 60-second interval of ICS operation during which both valves are open in order for the flow path to exist. Further, this specific failure must occur during a design-basis event in which suppression pool pressure is sufficient to overcome the static head created by the higher elevation of the storage tank. Nevertheless, a conservative decision was made to add the check valve to eliminate the potential for any adverse consequences. In view of the above discussion, the NRC staff considers the original problem not to be of high safety significance. In addition, the design process at NMP-2 was effective in that a potential problem identified at a different project was in the process of being evaluated by the NMP-2 project personnel. Finally, the problem was determined to be an isolated case by reviewing similar system configurations throughout the plant. Consequently, the staff finds the action taken in this matter to be both conservative and sufficient to resolve the concern. This item is considered closed.

Action Item E-P54-0 resulted from a concern raised by the NRC staff during its inspection of technical audit activities from August 12 to 16, 1985. In this calculation (A10.1-H-8), an incorrect pipe internal diameter (ID) was used in deriving a flow head loss coefficient (K) for valve 2ICS*FV108. This error affected the total head loss calculation and also the sizing of a restrictive orifice in the system (2ICS*RO125). The project personnel determined that the use of the incorrect ID was the result of a failure on the part of the preparer of the calculation to understand the proper application of diameter adjustments when converting between different flow coefficients (i.e., valve Cv factors to equivalent piping K factors). The project personnel reviewed all QA Category I calculations where Cv-to-K or K-to-K conversions for different pipe diameters were used. Similar problems were found in five other calculations; however, the only one that affected the conclusion of the calculation was the calculation noted by the NRC staff (A10.1-H-8). In the case of A10.1-H-8, the bore size of the orifice had to be increased and a replacement orifice was ordered. In addition, the project personnel conducted a training session for appropriate engineers to review this type of concern and to alert all system engineers as to the effect of diameter adjustments on pressure drop calculations. The staff considers this action sufficient and considers this item to have been of minor significance for the following reasons:

(a) The replaced orifice is used in the test mode of the ICS and has no impact on the system's safety function or plant safe shutdown.

(b) The orifice with the smaller hole would have passed less water during system testing and would have been identified during preoperational startup testing.

(c) Orifice sizing calculations are often treated as first-order approximations, with subsequent calculations being performed following system testing.

During a followup inspection at SWEC on January 7, 1986, the staff verified the revision to the calculation and also reviewed the E&DCR written to rebore the orifice hole, to revise vendor calculations, and to change vendor drawings. Accordingly, the staff considers this item closed.

The remaining action items in the mechanical discipline are not specifically addressed in this supplement because they either required no corrective action or were generally deemed to be of lesser safety significance. The staff concurs that those items that were resolved by the EA team by acceptance of the project personnel's response and that required no corrective action are closed. Action items that required corrective action were reviewed by the staff, and the staff concurs that the proposed actions resolve the EA concerns. The majority of these action items were reported to be closed in the Supplementary Report to Audit No. 50 dated September 27, 1985. The staff verified completion of the remaining open items during the followup inspection at the SWEC office on January 7, 1986. All action items in the mechanical discipline are closed.

(2) Electrical Power and Instrumentation and Control

The electrical discipline encompasses the area of electrical power and also instrumentation and control. There were 38 action items initiated in the electrical power area and 17 in the instrumentation and control area. The following NRC staff comments are provided on these action items.

Action Item E-C15-0 dealt with the procedure to confirm the accuracy of test equipment, as assumed in the setpoint calculations, with actual field information. The project personnel stated that their approach was that the accuracies of the test equipment must be equal to or better than those stated in the setpoint calculations. After Audit Report No. 50 was issued, the EA team confirmed the existence of several procedures to ensure the accuracy of test equipment with regard to the assumptions used in the calculations. These procedures included (a) Instrument Test Procedure No. 1E, GENE.013, Revision 3, dated December 12, 1984, titled "Switches"; (b) Startup Administrative Procedure No. N2-SAP-115, Revision 0, dated December 11, 1984, titled "Control of Measuring of Test Equipment"; (c) Interim Instrument Surveillance Procedure No. N2-ISP-CMS-R107 (draft copy), titled "Channel Calibration of the Accident Monitoring Primary Containment Pressure"; and (d) Loop Calibration Report No. IL2CMS-139, Revision 0, dated January 3, 1985, titled "Test Loop Diagram." On the basis of its review, the EA team concluded that sufficient procedures were in place to ensure that the accuracies of the test equipment used in the calibration of permanent plant instruments satisfy the criteria established in the setpoint calculations. The staff has reviewed the above-mentioned procedures and concurs with the conclusions of the EA team. Consequently, this item is considered closed.

Action Item E-E11-0 dealt with the need to develop maintenance and surveillance plans that would address the qualified life status of the equipment. The EA team determined that environmental qualification requirements for preventive maintenance had not been uniquely identified in the NMP-2 preventive maintenance program. The response of the project personnel was that since the applicant had not yet taken possession of the affected Category I equipment, a need for this information did not exist. However, it was agreed that this information must be developed. Work on extracting the information from the environmental qualification reports was begun on August 1, 1985. In a letter dated March 6, 1986, the applicant confirmed that the EA team performed a review and evaluation of the program to collect the maintenance and surveillance data necessary to assure equipment qualification is maintained. The EA team concluded that this program is generally adequate. This item is considered closed.

Action Item E-E33-0 identified a generic problem with the sizing of the dc switchgear control circuits. Electrical Design Criterion EDC-4 specified maximum allowable length of control wire for a given voltage drop and wire sizes. For lengths greater than the maximum, engineering personnel were to be consulted. The EA team determined that the "close" control circuit to residual heat removal (RHR) pump motor No. 2RHS-P1A was inadequately sized in that the actual circuit length exceeded the maximum permissible length. Further, it was determined that Institute of Nuclear Power Operation Evaluation No. CP-84-06, Finding DC 3-1, Item C, previously identified the same problem. In response to these findings, a cable size verification program for power, control, and dc cables is in progress to correct any cable size deficiencies. The staff has reviewed the action item, and a sampling of the changes needed to correct observed deficiencies and is satisfied that an adequate corrective action plan is in place. In a letter dated March 6, 1986, the applicant confirmed that the EA team performed a review to verify the adequacy of the dc control cable sizing. This review concluded that the sizing of the dc control cable is adequate. This item is considered closed.

Action Item E-E36-0 resulted from a review of a large pump-motor combination relative to cooling capacity required to remove the sensible heat gain from the cubicle containing the pump-motor. The EA team selected pump-motor 2RHS*P1A for this review, since the ICS did not contain a sufficiently large pump-motor combination. In performing this review, inconsistencies were identified between the power division calculation, which verified cooling capacity (HVR-38), and the equipment qualification environmental design criteria (EQEDC). Subsequently, HVR-38 was revised. The revised calculation increased the maximum expected cubicle temperature from 103°F to 115°F, which remained within the qualification of the equipment. The EA team reviewed this matter and agreed that the cooling capacity had been verified as adequate to handle the required cooling load based on total sensible heat gain. The staff reviewed the documentation during the inspection of January 4, 1986, and concurred with the EA team's conclusion. Furthermore, as a result of the revision to HVR-38, all cooling zones were reviewed by the project personnel for a potential effect on the qualification of installed equipment. No effect was discovered. The staff reviewed the documentation of this review during the inspection of January 7, 1986, and concurred with this result. Because the temperatures in the revised calculation were not substantially changed and all zones were reviewed for a potential effect on the hardware, the matter of Action Item E-E36-0 was considered resolved, except for the updating of four equipment specifications to be consistent with the latest revision to the EQEDC (Revision 3 of December 20, 1985). In a letter dated March 6, 1986, the applicant confirmed the four equipment specifications had been updated. This item is considered closed. Action Item E-E36-0 remains open pending confirmation by the applicant that these specifications have been revised.

The NRC staff was concerned about the depth of review conducted in the electrical discipline as discussed in Inspection Report 50-410/85-28. To address this concern, the EA team performed additional reviews that supplemented the scope and depth of the original audit. These additional reviews were discussed in "Engineering Assurance Supplement to Audit Report #50, Nine Mile Point Unit 2 Project, dated September 27, 1985." The NRC staff's comments are provided on the major items.

Item 6.2.2.4 - Review of Pump-Motor Combinations

This additional review stemmed from the staff's concern that a large pump-motor combination should be investigated to ensure that attributes such as driven equipment brake horsepower requirements, minimum voltage acceleration, and interdiscipline interfaces as they relate to maintaining proper environmental conditions are being evaluated. The 4-kV residual heat removal pump 2RHS*P1A, which is part of the engineered safety features system, was selected for review. The following is a synopsis of the attributes studied and resulting observations:

(a) Motor Size - The EA team compared the motor output torque necessary to start and accelerate the pump to the maximum required pump flow at 80% motor-rated voltage. The EA team concluded that the design was satisfactory. The staff reviewed the supporting documentation and agreed with that conclusion.

(b) Heat Gain and Removal - The EA team identified apparent inconsistencies between the power discipline, heating, ventilation, and air conditioning calculation temperature (115°F), and the equipment qualification environmental design criterion (temperature of 99°F). The EA team's efforts concentrated on the differences in calculated ambient temperatures and not on the actual requirements for the motor design. The staff independently confirmed that the motor was qualified for the worst-case condition because it was designed for a 65°C (149°F) ambient.

(c) Power Cable Size - The EA team incorrectly stated that the power cable was sized for a temperature of 40°C (104°F). The EA team failed to note that this was lower than the correct environmental design temperature as determined by the room cooler design temperature of 120°F. However, the NRC staff independently confirmed that the power cable for the RHR pump-motor was correctly sized at an earlier stage in the design using an assumed room temperature of 65°C, which bounds both conditions.

(d) Motor Protection - The EA team confirmed that the motor was adequately protected in accordance with criteria in FSAR Section 8.3.1.1.8. A graphical calculation (ER-101T-SK) was reviewed, which showed the motor and cable characteristics and the protective relay characteristics. The staff reviewed the substantiating documentation and is satisfied that the matter has been adequately handled.

Item 6.2.2.8 - Battery Performance Test

This item was a response to the staff's concern that the EA team had not documented the results of its review of the acceptance tests for the NMP-2 batteries. The EA audit checklist did not document whether a performance test (constant current discharge), or acceptance test (load profile discharge), according to the requirements of IEEE Standard 450, had been reviewed. In a letter dated March 6, 1986, the applicant confirmed that the EA team performed a review and evaluation of acceptance tests for the NMP-2 batteries. This review verified the tests were technically adequate and the batteries meet or exceed the requirements of IEEE 450. This item is considered closed.

The remaining action items in the electrical power and instrumentation and control disciplines are not specifically addressed in this supplement because they either required no corrective action or were generally deemed to be of lesser safety significance. The staff concurs that those items that were resolved by the EA team by acceptance of the project personnel's response and that required no corrective action are closed. Action items that required corrective action were reviewed by the staff, and the staff concurs that the proposed actions resolve the EA concerns. The majority of these action items were reported closed in Supplementary Report to Audit No. 50, dated September 27, 1985. The remaining corrective actions indicated in Action Items E-E11-0, E-E33-0, and E-E36-0 and Item 6.2.2.8 (as discussed above) have been satisfactorily completed. All items in the electrical power and instrumentation and control disciplines are closed.

(3) Civil/Structural Discipline

There were 30 valid action items in the civil/structural area. Most of these items were resolved by the EA audit team on the basis of the SWEC response. The remaining required corrective action. The following NRC staff comments are provided on the major action items.

Action Item E-S03-0 states that the factors of safety against sliding as required in FSAR Section 3.8.5.5 should be 1.5 and 1.1 for load combinations: (1) D + H + OBE and (3) D + H + SSE,* respectively. Calculation C58-TAB21, Revision 2, which was performed to determine the stability of the control and diesel generator building, shows factors of safety of 1.19 and 0.63 for the above load combinations, which violate the FSAR commitments. The project personnel have responded to this finding by revising the above calculation to include the effect of adhesion between the rock surface and the fill concrete. An adhesion stress of 15 psi was used in this revised calculation. The safety factors against sliding are shown to be 3.44 and 2.14 for load combinations (1) and (3), respectively, which are acceptable. In addition, the capacity of the fill concrete to transmit shear and overturning moments was addressed and

*D = dead weight; H = hydrostatic loads; OBE = operating basis earthquake; SSE = safe shutdown earthquake.

shown to be adequate. The staff has reviewed the supporting documentation and concurs with the resolution of the action item. Therefore, this action item is considered closed.

Action Items E-S06-0 and E-S07-0 addressed the omission of required loadings, which is contrary to the requirements of FSAR Section 3.8.4. In the case of Item E-S06-0, seismic, design wind, tornado wind, and missile loads were omitted from the control building mat design; in the case of Item E-S07-0, tornado wind, differential pressure, missile, and extreme snow loads were omitted from the control building roof slab design. The project personnel's corrective action was to perform the additional calculations that were required to address these omissions and review all other similar calculations to confirm that these were isolated occurrences. The NRC staff has reviewed the supporting documentation and concludes that the action items have been adequately addressed. Therefore, these action items are considered closed.

Action Item E-S09-0 states that the review of Specification S208G, Revision 1, indicated no requirement for doors to be designed for tornado wind and jet impingement loads. This finding by the EA audit team has led the project personnel to initiate a program to check the design of all doors for jet impingement and tornado wind loads.

As a result of the action item, all doors were found acceptable, except door R328-7. Later work, performed by the project personnel, indicated that the door would be capable of adequately resisting imposed loadings by using, in the calculations, actual material yield strength values which are typically greater than those specified in codes. The staff reviewed the supporting documentation to confirm the conclusions of the EA team and considers this item closed.

Action Item E-S17-0 states that a reaction load shown on Drawing ES-53A is lower than the value shown on Calculation S53-TAB2. These reaction forces, which should be identical, were used by the steel fabricator to design the structural steel connections. The problem arose because the project personnel failed to revise drawings to be consistent with revisions of design loading. To resolve this discrepancy, the project personnel initiated a review of the steel drawings for all Category I structures. This has resulted in the reevaluation of various connections for increases in loading. After detailed review, all connections were found to be structurally adequate. The staff has reviewed the documentation and resulting corrective actions, and on the basis of this review, concludes that the item has been adequately resolved. The item is considered closed.

Action Item E-S23-0 states that the disposition of Nonconformance and Deviation Report 6532 did not consider the effects of prying forces in the calculation of tension in the drilled-in anchor bolts. Although it was acknowledged that the bolt tension loads were small, justification for neglecting the prying forces was not provided and the EA team was concerned that prying may not have been considered programmatically. The EA team reviewed the programmatic aspects of the problem and determined that the item was an isolated occurrence. The NRC staff has reviewed the technical and programmatic aspects of this action item and concurs with the conclusion of the EA team. The item is considered closed.

The remaining action items in the civil/structural discipline are not specifically addressed in this supplement because they either required no corrective action or were generally deemed to be of lesser safety significance. The staff concurs that those items that were resolved by the EA team by acceptance of the project personnel's response and that required no corrective action are closed. Action items that required corrective action were reviewed by the staff, and the staff concurs that the proposed actions resolve the EA concerns. The majority of these action items were reported closed in Supplementary Report to Audit No. 50, dated September 27, 1985. The remaining items were closed during the January 7, 1986, inspection. Hence, all structural action items are closed.

17.5.4.3 Trend Analysis

In the Phase II report, the EA team discusses a number of concerns or trends indicated from the Phase II evaluation. The Phase II report states that in most cases, corrective and preventive action taken as a result of individual audits resolved concerns and alleviated trends. Nevertheless, in some instances, the EA team recommended additional project or SWEC action. NRC staff comments on the more significant of these potential trends are provided below.

FSAR Inconsistencies

Inconsistencies between the FSAR and other design documents were noted in several EA audits of NMP-2. Some discrepancies involved incorrectly or unclearly written text. Most discrepancies reflected a failure to update the FSAR and were generally editorial in nature and had no design impact. Furthermore, an extensive reeducation of project personnel, undertaken following an EA audit in 1984 to upgrade FSAR consistency, was apparently effective on the basis of the number and type of similar deficiencies uncovered in subsequent audits (including Audit No. 50). Finally, the applicant has established a program for the independent verification of the FSAR to certify its accuracy before fuel load.

Calculational Deficiencies

In view of the large number of calculations reviewed throughout the various audits of the NMP-2 EA program, it is not unusual to uncover a number of errors or other inconsistencies and deficiencies. The EA team found that comprehensive reviews were performed by the project personnel to determine the extent of individual issues and the completeness of the audits in all design process areas. On this basis, the EA team concluded that the corrective and preventive actions taken adequately address the overall implementation of the design process. Nevertheless, a concern was expressed by the NRC staff that the number of deficiencies associated with power discipline calculations indicated a possible breakdown of the calculation checking process. In response to the NRC staff's concern, the EA team recommended a review of 40 additional power QA Category I calculations to further evaluate calculational effectiveness. The results of this review were provided to the NRC staff in a letter from the applicant dated January 14, 1986. The evaluation revealed that the program for the preparation, review, and verification of Power Division calculations was adequate, although five calculations were revised because they contained outdated information, and approximately 50% of the calculations reviewed contained minor administrative inconsistencies. The calculations containing administrative errors will be revised before fuel load as discussed below. The nature of these administrative errors generally is the referencing of superseded revisions of calculations or drawings where the information referenced in the outdated revisions was still valid; that is, referenced areas of the drawing or calculation had not been changed in subsequent revisions. A number of other minor discrepancies had been revealed but were considered inconsequential. The evaluation also concluded that the project personnel were not following Departmental Procedure PTP 0.11.1, which required annual review of Category I calculations. (This annual review was not being performed by the Power Discipline personnel (SWEC) in accordance with an agreement between SWEC and the applicant that a final as-built calculation check would be performed). As a result of this evaluation, the project personnel agreed to additional training for their personnel in calculation procedures and also agreed to an update of all Category I calculations before fuel load.

The EA team agreed with the results and conclusions of the audit. During the followup inspection at SWEC on January 7, 1986, the staff reviewed the results of the evaluation, including some of the calculations. The staff considers the conclusions and planned corrective action satisfactory. The additional training and resumption of Procedure PTP 0.11.1 should prevent recurrence of similar problems, and the full review of all calculations before fuel load will ensure that the type of problems identified by the audit will be corrected before fuel load. In a letter dated May 14, 1986, the applicant confirmed that the review of all the QA Category 1 power calculations had been completed. This issue is closed.

Technical Guidance

In some design areas, specific technical guidance was needed to correct a number of actual or potential problems. Specifically, in the area of high energy line break (HELB), additional guidance and criteria were required to provide adequate documentation that the plant can survive an HELB and maintain safe shutdown capability. The portions of the procedures that were revised did not adversely affect the work that had been performed but rather provided for enhanced documentation of the final design product. The staff reviewed the HELB program of NMP-2, particularly with regard to the reviews performed by the EA team, and concluded that the program was enhanced by the improvements resulting from the audit with regard to design documentation.

The staff concurs with the conclusion of the EA team that SWEC corporate guidance is needed in the HELB area for the benefit of future projects and agrees that the EA team should make appropriate recommendations to corporate management. At the same time, the current program in place at NMP-2 has been found acceptable to the staff. Consequently, this issue is closed as related to NMP-2.

17.5.4.4 NRC Staff Conclusions

The Niagara Mohawk Power Corporation engaged the Stone and Webster Engineering Assurance Division to conduct an in-depth technical audit of the design activities at NMP-2. This audit, along with the Phase II analysis of it and previous audits relative to the effectiveness of design process implementation, was accepted by the NRC staff as an acceptable method for providing additional assurance that NMP-2 complies with all licensing commitments and regulatory requirements. The audit and subsequent analysis of several audits involved a substantial effort that evaluated numerous documents. The NRC staff closely monitored the audit, including a technical review of a sample of the material reviewed by the EA team, and evaluated all stages of activity, including monitoring of corrective actions. The staff concludes that the engineering assurance program audits provide substantial additional confidence that the design of NMP-2 is in accordance with design commitments and regulatory requirements.

18 HUMAN FACTORS ENGINEERING

18.1 Detailed Control Room Design Review

Item I.D.1, "Control Room Design Reviews," of Task I.D, "Control Room Design," of the Nuclear Regulatory Commission (NRC) Action Plan, NUREG-0660, developed as a result of the accident at Three Mile Island Unit 2 (TMI-2) states that operating licensees and applicants for operating licenses will be required to perform a Detailed Control Room Design Review (DCRDR) to identify and correct design discrepancies. The objective, as stated in NUREG-0660, is to improve the ability of nuclear power plant control room operators to prevent or cope with accidents if they occur by improving the information provided to them. Supplement 1 to NUREG-0737 confirmed and clarified the DCRDR requirement in NUREG-0660. As a result of Supplement 1 to NUREG-0737, each applicant or licensee is required to conduct its DCRDR on a schedule negotiated with NRC.

Niagara Mohawk Power Corporation (the applicant) submitted a Program Plan (June 1984) for conducting a DCRDR at the Nine Mile Point Nuclear Station, Unit No. 2 (NMP-2), to the NRC on June 29, 1984 (letter from T. E. Lempges to A. Schwencer). Staff comments on the Program Plan were issued on February 6, 1985, by a letter from A. Schwencer to B. G. Hooten.

The staff conducted an onsite in-progress audit of the DCRDR program on March 19-22, 1985, aided by consultants from Lawrence Livermore National Laboratory (LLNL). The applicant's DCRDR for NMP-2 has been evaluated on the basis of information provided in the applicant's NMP-2 Program Plan, Summary Report, and during the in-progress audit at NMP-2.

The organization, process, and results of the NMP-2 DCRDR were compared with the requirements in Supplement 1 to NUREG-0737, and with guidance contained in NUREG-0700 and NUREG-0800 (SRP Section 18.1, Revision 0, and Appendix A to SRP Section 18.1, Revision 0). Consultants from LLNL assisted the staff in the evaluation and prepared a Technical Evaluation Report (TER) (see Appendix K). The NRC agrees with the technical positions and conclusions presented in the TER.

The following material summarizes the staff's conclusions with regard to each element of the DCRDR required by Supplement 1 to NUREG-0737.

18.1.1 Multidisciplinary Review Team

On the basis of the NMP-2 Summary Report, the in-progress audit, and the discussions during the audit, the staff concludes that the applicant has established a qualified multidisciplinary review team that meets the requirements of Supplement 1 to NUREG-0737.

18.1.2 System Function and Task Analyses

The use of emergency operating procedures (EOPs) prepared from the Boiling Water Reactor Owners Group (BWROG) Emergency Procedure Guidelines (EPGs), Revision 3, as the basis of the NMP-2 system function and task analysis (SFTA) process is acceptable as discussed in NUREG-0800 (SRP Section 18.1, Appendix A).

The process as described in the NMP-2 Summary Report is acceptable and meets the requirements of Supplement 1 to NUREG-0737.

18.1.3 Control Room Inventory

The information and control needs derived from the SFTA were compared with the control room inventory. The control room inventory meets the requirements of Supplement 1 to NUREG-0737.

18.1.4 Control Room Survey

The NMP-2 Summary Report does not positively identify the criteria used in conducting the control room survey. It implies that Section 6 of NUREG-0700 was used. The applicant should confirm the specific criteria used in the survey.

18.1.5 Assessment of Human Engineering Discrepancies

The assessment process as described in the NMP-2 Summary Report meets the requirements of Supplement 1 to NUREG-0737. However, the assessment and disposition of all human engineering discrepancies (HEDs) identified during completion of the unfinished portions of the DCRDR should be reported in a supplement to the Summary Report.

18.1.6 Selection of Design Improvements

The applicant's process to select design improvements is adequate and meets the requirements of Supplement 1 to NUREG-0737. However, the applicant should describe the method of monitoring implementation of HED corrective actions in a supplement to the NMP-2 Summary Report.

18.1.7 Verification That Design Improvements Provide Necessary Correction and Do Not Introduce New HEDs

The verification and validation methods used earlier in the DCRDR by the applicant are adequate; however, the applicant has not supplied enough information to determine that these methods will be used appropriately to evaluate HED corrective actions and design improvements and to verify that selected design improvements will provide the necessary correction of HEDs and will not introduce new HEDs.

Requirements of Supplement 1 to NUREG-0737, relevant to this element of the DCRDR, are not satisfied.

18.1.8 Coordination of the DCRDR With Other Programs

The applicant's coordination program is adequate and meets the requirements of Supplement 1 to NUREG-0737.

18.1.9 Conclusions

In order to complete the review of the NMP-2 DCRDR, the staff requires the applicant to submit the additional information identified in Sections 18.1.4 through 18.1.7.

18.2 Safety Parameter Display System

All licensees and applicants for an operating license are required to provide a safety parameter display system (SPDS) in response to TMI Action Plan Item I.D.2 (NUREG-0660, May 1980, and NUREG-0737, November 1980 as supplemented by Generic Letter 82-33, December 17, 1982). The purpose of the SPDS is to continuously display information from which plant safety status can be readily and reliably assessed. The principal function of the SPDS is to aid control room personnel during abnormal and emergency conditions in determining the safety status of the plant and in assessing whether abnormal conditions warrant corrective action by operators to avoid a degraded core. A written SPDS safety analysis shall be prepared describing the basis for determining the selected parameters are sufficient to assess the safety of each identified function for a wide range of events including symptoms of severe accidents.

In response to Supplement 1 to NUREG-0737 (Generic Letter 82-33), the applicant amended its Final Safety Analysis Report to reflect the basis of parameter selection and provide details of the SPDS implementation plan (letter from applicant, October 5, 1984). This amendment was reviewed by the staff and found to be insufficient in scope and depth.

The staff requested further information on November 8, 1984, and the applicant responded on December 12, 1984, and May 13, 1985. On July 17 and 18, 1985, the staff conducted a design verification audit of the NMP-2 SPDS. Subsequently, an audit report was issued, outlining the staff's findings (letter to applicant, September 13, 1985). On November 19, 1985, the applicant proposed a program for resolving the staff's audit findings (letter from applicant, November 19, 1985). The audit did not include a review of the adequacy of the isolation devices used in the NMP-2 SPDS design. The staff concludes that this program (with the exception of the isolation devices), if properly executed, should resolve the staff's findings. On the basis of the review conducted thus far, the staff does not have sufficient evidence to conclude that the NMP-2 SPDS will be adequately isolated from safety systems. Therefore, the staff concludes that the SPDS should not be operated until the isolation devices have been adequately tested. A detailed discussion of the review of the isolation devices for the SPDS is included in Section 18.2.1.

Once the staff has reviewed the results of the isolation device testing, the next step in the staff's review is an evaluation of the Validation Testing Program for the NMP-2 SPDS. This Validation Testing Program, which includes a thorough man-in-the-loop testing program, will not be completed until the end of the first refueling outage. At that time the staff will review the test results and may choose to conduct a design validation audit to gather further information.

18.2.1 Isolation Devices for the SPDS

In order to satisfy the NRC requirements concerning the safety parameter display system (SPDS), Niagara Mohawk Power Corporation, the applicant for the Nine Mile Point Nuclear Station, Unit 2 (NMP-2), submitted a Safety Analysis Report by letter dated January 3, 1984. This report provided a description and a safety analysis of the SPDS at NMP-2. This report did not address the requirement that the SPDS must be suitably isolated from equipment and sensors that are used in safety systems to prevent electrical and electronic interference. A request for additional information which included specific questions on these isolators was sent to the applicant. The requested information was received by letters dated September 9, 1984; December 18, 1984; and May 13, 1985. Several telephone conferences were held with the applicant to clarify the information submitted on the Validyne multiplexers and to discuss the Kaman isolation devices that are incorporated as part of the digital radiation monitoring system.

This section addresses the qualification and documentation of the isolators as acceptable interface devices between the Class 1E safety-related instrumentation systems and the SPDS.

The SPDS at NMP-2 is implemented as part of the emergency response facility (ERF) computer system and is composed of three subsystems. The subsystems are: (1) the Honeywell system which is a graphic display system for parameters relating to the plant, (2) the digital radiation monitoring system (DRMS) which is a graphic display of the plant radiation monitoring parameters, and (3) the gaseous effluent monitoring system (GEMS) which is an analog display of the radiation levels of plant gaseous releases.

The Honeywell graphic display system and the DRMS interface with the plant's safety-related systems and therefore require Class 1E isolation devices while the GEMS interfaces with non-safety-related systems and as such does not require Class 1E isolation devices.

The Honeywell graphic display system uses GE optical isolators, Potter & Brumfield MDR relays, and Validyne multiplexers. These isolators have been previously reviewed and accepted as qualified isolators. The GE optical isolators and the MDR relays were accepted by the staff as part of the River Bend licensing review, and the Validyne multiplexers were accepted as part of the Hope Creek SPDS isolation device review.

The DRMS is a Kaman Industries-supplied system utilizing a Kaman Industries safety-related monitoring system (SRMS) interface module, an indicating control unit (ICU), a safety isolation module (SIM) which contains a Hewlett-Packard (HP) HCPL-2630 optical isolator for digital signal isolation, and an analog isolation module (AIM) which contains an Intronic Model 1A-184 amplifier module for analog signal isolation. The SIM and the AIM interface with the non-Class 1E SPDS. In the system configuration, a bidirectional communication link is established between the ICU and either a SIM or an AIM.

The applicant has committed to the testing of the Kaman isolators to verify that this communication link and thus the isolation between the ICU and the isolation module (SIM or AIM) remains intact upon the application of the maximum credible fault (MCF). The system conforms to IEEE Standard 344-1974, and to IEEE Standard 323-1974, and is located in a mild environment.

The applicant submitted a test report for these isolators on March 15, 198.. As stated in Section 7.2.2.8 of this supplement, this report is under review The staff will report the results of the review of the Kaman isolator test report in Section 7.2.2.8 of a future supplement to the SER.

Conclusion

On the basis of the staff's review of the applicant's submittals with respect to the Class 1E electrical isolation systems and prior review and acceptance of identical devices at other plants, the staff concludes that the GE optical isolators, the MDR relays, and the Validyne multiplexers as used in the Honeywell graphic display system are qualified isolators and are acceptable for interfacing the SPDS with Class 1E safety systems. The staff also concludes that this equipment meets the Commission's requirements in NUREG-0737, Supplement 1. However, as stated above, the March 15, 1986, test report on the Kaman isolators is under review and the results of that review will be reported in Section 7.2.2.8 of a future supplement.

APPENDIX A

CONTINUATION OF CHRONOLOGY OF NRC STAFF RADIOLOGICAL REVIEW OF NINE MILE POINT NUCLEAR STATION, UNIT 2

September 18, 1985	Letter from applicant forwarding revised Final Safety Analysis Report (FSAR) pages incorporating Revision 2 to visual weld acceptance criteria for structural welding into inspection program, per August 7, 1985, discussion. Approval is requested. Revisions will be incorporated into amendment after approval.
September 18, 1985	Letter from applicant requesting approval to invoke visual weld acceptance criteria for structural welding (Rev. 2). Revised FSAR pages are enclosed to indicate how use of criteria is incorporated into the utility's inspection program.
September 20, 1985	Letter from applicant forwarding affidavit of service indicating that Amendment 21 to the FSAR was provided to appropriate parties per March 29, 1983, letter.
September 24, 1985	Letter from applicant forwarding proprietary figures omitted from September 16, 1985, submittal about status of various subordinate issues included in Safety Evaluation Report (SER) confirmatory issue 13 on pool dynamics. Affidavit requesting withholding of figures per 10 CFR 2.790(a)(4) is enclosed.
September 26, 1985	Letter to applicant informing that American Society of Mechanical Engineers (ASME) Code Case N-395 is acceptable for use at facility subject to limitations stated in inquiry and reply section of code case. Use of case should be documented in a future amendment to the FSAR.
September 27, 1985	Generic Letter 85-18 issued to all power licensees regarding "Operator Licensing Exams."
September 27, 1985	Generic Letter 85-19 issued to all licensees and applicants for operating reactors and holders of construction permits for power reactors about reporting requirements on primary coolant iodine spikes.
September 27, 1985	Letter from applicant forwarding supplemental information to August 1985 letter about revetment ditch, including changes to previously submitted information and draft Technical Specification 3/4.7.3 concerning shore barrier protection. Visual inspection and distance information are discussed, per August 27, 1985, meeting request.

September 30, 1985	Letter from applicant forwarding integrated reactor vessel material surveillance program for review and approval, in response to request during recent meeting, because of low lead factors incorporated in facility design.
September 30, 1985	Letter from applicant forwarding responses to seismic review team audit open items and schedule for responses to remaining open items.
September 30, 1985	Letter from applicant forwarding information about safety relief valve pool loads, bulk to local pool temperature differences, and Mark III containment, closing SER confirmatory issues 6, 13F, and 13I. FSAR Pages 6A.3-17 and 17a and figures withheld (ref: 10 CFR 2.790).
September 30, 1985	Letter from applicant forwarding results of preliminary leak testing of main steam isolation valves (MSIVs) to close SER open issue 6. Bonnet stem leakage testing is performed by pressurizing between ball valve seats. Values should be compared to acceptance criteria per November 30, 1985, letter.
October 4, 1985	Letter from applicant forwarding revised FSAR Figures 9.5-40a, 9.5-40b, 9.5-40c, and 9.5-42 showing certain Division I and II diesel generator interface piping. Figures are provided to close SER confirmatory issue 40, and will be included in next FSAR amendment.
October 7, 1985	Letter from applicant forwarding application to utilize alternative to requirements of 10 CFR 50.55a. Alternative involves transfer of authorized nuclear inspector functions for review of pipe supports and in certification process.
October 9, 1985	Letter from applicant supplementing February 7, 1985, letter transmitting summary of electrical separation analyses used by General Electric Company (GE). Applicant will evaluate October 3, 1985, suggested method of resolution for components accepted based on probability analysis.
October 10, 1985	Letter to applicant forwarding draft safety evaluation for safe and alternate shutdown scheduled to be part of next SER supplement.
October 11, 1985	Letter from applicant forwarding operator licensing examination schedule, per September 27, 1985, request.
October 11, 1985	Letter from applicant forwarding information about fire protection program. Information reconciles differences in fire protection program described in FSAR, Standard Review Plan (SRP), and SER. Activities will be discussed in October 21, 1985, meeting.

October 15, 1985	Letter from applicant forwarding updated Volume 1 of "Preservice Inspection Plan," including all nondestructive examination items required by ASME Section XI for nuclear piping system and reactor pressure vessel. Second and third parts will be submitted by November 30 and December 20, 1985, respectively.
October 17, 1985	Letter from applicant forwarding proposed revision to FSAR, providing material in response to confirmatory issue 20 about isolation of circuits. Revision should result in closure of confirmatory issue and will be incorporated into future FSAR amendment.
October 17, 1985	Letter from applicant forwarding response to equipment qualification questions transmitted in NRC letter dated July 23, 1985. Information will be included in FSAR Amendment 22.
October 18, 1985	Letter to applicant requesting remaining outstanding responses to Generic Letter 83-28, "Required Action Based on Generic Implications of Salem ATWS Events." Forwards draft technical evaluation report for Item 1.2, "Post-Trip Review: Data and Information Capabilities."
October 18, 1985	Summary issued of October 3, 1985, meeting with utility, Stone & Webster, and GE about containment system issues. Summary of responses to SER open and confirmatory issues, changes to FSAR, and list of attendees is enclosed.
October 28, 1985	Letter from applicant clarifying October 7, 1985, letter. Environmental qualification document will not be included in FSAR Amendment 22 as originally stated, since document is not considered part of FSAR.
October 28, 1985	Letter from applicant submitting results of additional studies about consideration of quantities of standing roof water due to rainfall in installation of screenwell building scupper drains before and after 6-hour probable maximum precipitation.
October 28, 1985	Summary issued of October 30-31, 1984, meetings with utility at site to review construction progress and collect data necessary for NRC to estimate resource needs, and June 13, 1985, meeting with utility to provide update of construction progress. Agenda from October 30-31, 1984, meetings are enclosed.
October 28, 1985	Letter to applicant requesting confirmation that offsite emergency plans include list of medical facilities having radiation exposure treatment capabilities and commitment to full compliance with forthcoming Commission response to enclosed May 21, 1985, GUARD remand.

October 30, 1985	Letter from applicant forwarding FSAR changes which address SER confirmatory issue 25 about low-pressure coolant injection (LPCI) and low-pressure core spray (LPCS) valve interlocks.
October 30, 1985	Letter from applicant forwarding Amendment 22 to updated FSAR and responses to questions about enhanced startup and testing program, per September 12, 1985, discussion with NRC. Test abstracts to close out SER outstanding issue 17 are also enclosed.
October 31, 1985	Letter from applicant informing that July 8, 1985, Amendment 20 to Unit 2 FSAR about updates to emergency plan and procedures also applies to Unit 1.
October 31, 1985	Letter to applicant providing review of July 26, 1985, request for approval to use NC1G-01, Revision 2, "Visual Weld Acceptance Criteria for Structural Welding...". Submittal is acceptable with listed clarifications.
November 1, 1985	Letter from applicant forwarding responses to Seismic Review Team audit open items. Remaining responses will be provided by January 1, 1986.
November 4, 1985	Letter from applicant forwarding "Control System Common Sensor Line Failure Analysis Evaluation Report" and "Control System Common Power Failures Evaluation Report," to close out SER confirmatory issues 24 and 26.
November 5, 1985	Letter to applicant forwarding draft SSER 2, Section 15.6.5, "Radiological Consequences of LOCAs," in response to applicant's request. Enclosed draft accepts proposed Technical Specifications bypass leakage limits in FSAR Table 6.2-55.
November 6, 1985	Letter to applicant informing that certain figures and information submitted on September 16 and 30, 1985, and marked "proprietary" in response to SER confirmatory issue 13 will be withheld from public.
November 6, 1985	Letter from applicant providing information to clarify status of safety-related building roofs. Concrete roofs on safety-related buildings, except reactor building, can withstand loads from water buildup up to roof parapets. Screenwell building is not wholly safety related.
November 7, 1985	Letter to applicant requesting that future amendments to FSAR list letter commitments incorporated into that supplement. Changes basis for changes and whether or not change affecting SER should be discussed in cover letter.
November 8, 1985	Letter from applicant forwarding revised response to certain FSAR questions resulting from September 13, 1985, meeting about startup and test program, FSAR Chapter 14. Information will be provided in FSAR Amendment 22.

November 14, 1985	Letter from applicant advising that instructions for diesel generators contained in Interim Operating Procedures IOP-100, IOP-100.1, and IOP-57 should resolve SER confirmatory items 35, 39, 41, and 43.
November 14, 1985	Letter from applicant forwarding additional technical data required by RG 1.84 to support invocation of ASME III Code Cases N-192 and N-192-2. Proprietary design reports are withheld (ref: 10 CFR 2.790(a)(4)).
November 14, 1985	Letter from applicant forwarding summary of incorporated changes to Amendment 21 to FSAR, including responses to SER items, editorial or typographical changes, and non-safety-related changes in design, schedule, and/or procedures.
November 15, 1985	Letter to applicant forwarding "Conformance to RG 1.97, Nine Mile Point Nuclear Station, Unit 2." Report identifies unjustified exceptions and references to unreviewed and unapproved BWR Group report.
November 18, 1985	Letter from applicant advising that completion of 90% of Unit 2 cable terminations are expected by November 30, 1985, and 90% of Category I terminations by December 31, 1985, in response to SER confirmatory issues 30 and 31.
November 18, 1985	Letter from applicant forwarding additional information to supplemental integrated reactor vessel material surveillance program about comparisons of design and operating features of four reactors.
November 19, 1985	Letter from applicant forwarding Revision 0 to "High Energy Line Break Evaluation Report (Effect on Nonsafety-Related Control Components)," per NRC Request for Additional Information 421.43 and SER confirmatory issue 27. Event is being evaluated. Supplemental report is expected by December 15, 1985.
November 19, 1985	Letter from applicant informing that on August 13, 1985, Contract DE-CR01-85RW00048 with Department of Energy (DOE) for disposal of spent reactor fuel generated at facility was executed.
November 19, 1985	Letter from applicant forwarding response to September 13, 1985, report about July 17-18, 1985, audit of safety parameter display system. Thorough design and testing program to implement enhancements is proposed. Program will be completed by end of first refueling outage.
November 19, 1985	Letter from applicant submitting additional information about operability of containment purge and vent valves, per September 10, 1985, request. Posi-Seal International will supply loss-of-coolant accident and seismic analysis report to incorporate results and recommendations.

November 20, 1985	Letter from applicant forwarding Amendment 22 to FSAR for Nine Mile Point Unit 2 and proprietary "Design Assessment Report Appendix 6A." Proprietary report is withheld (ref: 10 CFR 2.790).
November 20, 1985	Letter from applicant forwarding updated environmental qualification document, including information submitted on October 17, 1985.
November 20, 1985	Letter to applicant forwarding proof and review Technical Specifications per November 18, 1985, discussion. Review should identify areas inconsistent with FSAR or as-built plant.
November 22, 1985	Letter to applicant notifying that use of ASME Code Case N-411, "Alternative Damping Values for Seismic Analysis of Piping Section...," in lieu of Regulatory Guide 1.61 values approved for spectrum seismic analysis of piping, per October 11, 1984, and February 12, 1985, requests.
November 22, 1985	Letter to applicant forwarding Federal Register notice of receipt of additional antitrust information submitted per Regulatory Guide 9.3, on April 11, 1985, in conjunction with application for operating license.
November 27, 1985	Letter from applicant providing additional information about content of procedures generated as result of SER confirmatory issues 35 and 41 about filling fuel oil storage tanks and minimum loading of diesel generators, respectively.
November 27, 1985	Letter from applicant responding to SER confirmatory issues 9, 22, 28, 52, and 54. Topics include leak rate test limit and inservice test program for pressure isolation valves and inspection of equipment installation for reactor core isolation system.
November 27, 1985	Letter from applicant verifying that safety-related procedures meet SER confirmatory issue 51 and IE Bulletin 79-08, Items 6 and 8 requirements. Procedures about fuel loading planned by February 15, 1986. Confirmatory issue 51 is considered closed.
November 27, 1985	Letter from applicant forwarding second part of updated "Preservice Inspection Plan, Nine Mile Point Nuclear Station - Unit 2," inservice testing plan for pumps and valves. Third part will be submitted by December 20, 1985. First part was submitted on November 15, 1985.
November 27, 1985	Letter from applicant forwarding affidavit of service indicating that Amendment 22 to FSAR - OL stage was provided to appropriate parties as delineated in March 29, 1983, letter.

December 1, 1985	Letter from applicant regarding downcomer design.
December 2, 1985	Letter from applicant forwarding response to October 28, 1985, request for information on availability of medical facilities in vicinity of unit for emergency use.
December 2, 1985	Letter from applicant informing of development of program to address TMI Action Item III.D.1.1 about leakage outside of containment per SER confirmatory issue 55. Program will begin when Technical Specification surveillance program begins.
December 3, 1985	Generic Letter 85-22 issued all licensees of operating reactors, applicants for operating licenses, and holders of construction permits about potential for loss of post-LOCA (loss-of-coolant accident) recirculation capability due to insulation debris blockage.
December 10, 1985	Letter from applicant forwarding 114 oversize drawings to assist NRC in review of previously submitted inservice testing program.
December 10, 1985	Letter from applicant forwarding summary of incorporated changes inadvertently omitted from November 20, 1985, Amendment 22 to FSAR for Nine Mile Point Unit 2.
December 10, 1985	Letter from applicant forwarding 47906-02, "Test Report on Electrical Separation Verification Testing...." Minimum allowable separation distances are listed on enclosed table and described in Sections 1.8 and 8.3.1.4 of FSAR.
December 13, 1985	Letter to applicant forwarding request for additional information about inspection program for pressure boundary welds. Request was given to utility on November 20, 1985. Relief requests for preservice inspection program are expected to be submitted by December 13, 1985, and balance of program by December 20, 1985.
December 13, 1985	Letter to applicant forwarding chronology of approved safeguards plan evaluation. Documentation will establish record of current safeguards amendments and provide assistance during inspection efforts.
December 13, 1985	Summary issued of November 18, 1985, meeting with utility in Bethesda, MD, about construction schedule and readiness for fuel load. Transcript is enclosed.
December 13, 1985	Letter to applicant forwarding BNL trip report for Seismic Qualification Review Team's July 8-12, 1985, audit at facility. Evaluation of audit results was included in SSER 2 provided on November 22, 1985, to D. Hill. Schedule for responses to issues identified in Section 3.10 of SSER 2 is requested by December 24, 1985.

December 17, 1985	Letter from applicant forwarding FSAR revision committing utility to monitor radiation damage using plant capsules and test data from LaSalle and WPPSS 2, in response to SER confirmatory issue 11. Revision will be contained in a future FSAR amendment.
December 17, 1985	Letter from applicant forwarding preservice inspection plan for nuclear piping and component supports. Enclosed report completes submittal for SER outstanding issue 3.
December 19, 1985	Letter from applicant forwarding updated response to FSAR Question F421.26 about minimum number of sensors required to monitor safety-related variables. With 214 oversize drawings.
December 20, 1985	Letter from applicant informing that portable radio demonstration performed as discussed in SER Section 9.5.2, "Communications Systems," to close confirmatory issue 33.
December 20, 1985	Letter from applicant forwarding supplement to April 10, 1984, response to Generic Letter 83-28. Topics addressed include post-trip review program description, post-trip data and information capability, equipment classification, and vendor interface about reactor trip system parts.
December 24, 1985	Letter to applicant forwarding list of items to be addressed before review of Chapter 14 of FSAR about preoperational and startup test program can be completed.
December 26, 1985	Letter to applicant requesting identification by December 31, 1985, of which changes in FSAR Amendment 23 affect Technical Specifications. NRC review of proof and review Technical Specifications is scheduled to be completed by January 24, 1986.
December 30, 1985	Letter from applicant forwarding marked-up proof and review Technical Specifications, reflecting comments based on review against current plant design. Safety Analysis Report program and Technical Specification verification program are continuing. Changes will be incorporated during branch review process.
December 31, 1985	Letter from applicant forwarding Stone & Webster proprietary calculations about design of containment downcomers discussed during December 20, 1985, meeting. Stone & Webster affidavit is enclosed. Calculations are withheld (ref: 10 CFR 2.790).
January 2, 1986	Letter from applicant forwarding Affidavit of Service indicating that Amendment 23 to FSAR - OL stage has been provided to appropriate parties, per NRC's March 29, 1983, letter. Distribution list is also enclosed.

January 2, 1986	Letter from applicant forwarding Revision 1 to "High Energy Line Break Evaluation Report (Effect on Nonsafety-Related Control Components)." Revision addresses findings of planned walkdown and closes SER confirmatory issue 27. Affidavit is also enclosed.
January 2, 1986	Letter from applicant forwarding "Process Control Program for Nine Mile Point 2 Solid Waste Management System," for solidified Class A waste, per 10 CFR 61. Production level sampling criteria are not addressed for listed reasons.
January 3, 1986	Generic Letter 86-01 issued to all BWR applicants and licensees about safety concerns associated with pipe breaks in BWR scram system.
January 6, 1986	Letter to applicant requesting revised response to FSAR Question 240.10 to include details of caulking used to maintain watertightness of diesel generator building.
January 6, 1986	Summary issued of December 20, 1985, meeting with utility and Stone & Webster about adequacy of design of downcomers at facility. List of attendees and handouts are enclosed.
January 6, 1986	Letter to applicant responding to November 27 and December 2, 1985, letters about incomplete SER confirmatory issues. Completion date of February 15, 1986, may not support February 24, 1986, fuel load date. Confirmatory issue 28 cannot be closed until functional test results are received.
January 7, 1986	Letter from applicant forwarding proprietary portion of December 19, 1985, Amendment 23 to FSAR for Nine Mile Point Unit 2 (Amendment 23 to application for operating license). Proprietary portion is withheld.
January 8, 1986	Letter to applicant discussing environmental qualification audit performed during week of December 16, 1985. Number of items are identified as needing to be completed. List of action items and mechanical engineering packages to be submitted for review are enclosed.
January 8, 1986	Letter to applicant forwarding summary of December 20, 1985, meeting about downcomer design and draft SER. Unbraced downcomer design may not fully comply with FSAR commitments to industry design codes and NRC acceptance criteria. Response is requested by January 15, 1986.
January 8, 1986	Letter to applicant requesting date for submittal of response to Question 640.35 about preoperational tests conducted after fuel load, per November 3, 1985, letter. Fuel load is scheduled for February 24, 1986.

January 9, 1986	Letter from applicant providing additional information on revision to nominal 3-inch water gap between adjacent fuel racks in spent fuel pool identified in Amendment 23 to FSAR. Change reflects as-built status of racks in spent fuel pool.
January 16, 1986	Letter from applicant notifying that environmental survey for control room human factors study is currently planned to be completed by February 21, 1986, and that supplemental report will be provided by April 18, 1986. Schedule is consistent with projected fuel load and NUREG-0700.
January 16, 1986	Letter from applicant notifying of WPPSS 2 and LaSalle 1 and 2 participation in reactor vessel material surveillance program described in September 30, November 18, and December 17, 1985, letters. Program was submitted to close SER confirmatory issue 11 about lead factors.
January 16, 1986	Letter from applicant confirming commitment to describe corrective, preventive, and maintenance action on systems outside containment, in response to January 13, 1986, conversation about SER confirmatory issue 55 (TMI Item III.D.1.1). Information will be submitted 2 months after fuel load.
January 17, 1986	Letter from applicant forwarding mechanical equipment qualification package about relief valve, spent fuel pool heat exchangers, differential pressure transmitters, and residual heat removal pressure pump, in response to NRC's January 8, 1986, request. With four oversize drawings, including one that is illegible.
January 17, 1986	Letter from applicant forwarding revisions to Sections 8.2 and 8.4 of Process Control Program, Radiation Protection Procedure RP-6, "Packaging and Transportation of Radioactive Material" and Procedure N2-CSP-14, "Solid Radwaste Chemical Surveillance at Unit 2."
January 20, 1986	Letter from applicant forwarding response to NRC's November 15, 1986, letter about conformance to Regulatory Guide 1.97. Enclosure provides information necessary to close confirmatory issue 10.
January 22, 1986	Summary issued of January 15, 1986, meeting with applicant, Stone & Webster, General Electric Co., Stevenson & Associates, and Management Analysis Co. about adequacy of downcomer design. Attendance list, agenda, and viewgraphs are enclosed.
January 22, 1986	Letter to applicant forwarding draft SER on detailed control room design review (DCRDR) and Lawrence Livermore Laboratory's "DCRDR Conducted by Niagara Mohawk Power Corporation," technical evaluation report, based on March 19-22, 1985, onsite in-progress audit. Schedule for responding to listed concerns is requested within 10 days.

January 23, 1986	Letter from applicant forwarding proprietary Stone & Webster calculations about design of facility containment downcomers and response to NRC concerns discussed in January 8, 1985, letter. Calculations supersede calculations submitted on December 31, 1985. Enclosures are withheld (ref: 10 CFR 2.790).
January 24, 1986	Letter from applicant forwarding "Review of Structural Adequacy of BWR Mark II Downcomers for Nine Mile Point 2 Nuclear Power Station."
January 24, 1986	Letter from applicant responding to NRC's December 13, 1985, request for additional information about inspection program for pressure boundary welds. Degree of compliance with Regulatory Guide 1.150 was submitted in Amendment 23 to FSAR on December 23, 1985. Reactor core isolation cooling 7.5% volumetric examination is not planned.
January 29, 1986	Letter from applicant forwarding updated seismic master list, replies to SER outstanding issues, and replies to generic open items, in response to Seismic Review Team and Pump and Valve Operability Review Team audit open items.
January 30, 1986	Letter from applicant forwarding response to request for additional information about January 23, 1986, downcomer calculations. Downcomer analysis for design chugs, GE 800 series, being carried out to govern GE 801 and 804 cases.
January 31, 1986	Summary issued of January 24, 1986, meeting with consultants to discuss adequacy of downcomer design in context of reanalysis performed by utility. Design is marginal. Recommends granting operating license with listed condition. List of attendees is enclosed.
January 31, 1986	Letter from applicant responding to January 8, 1986, request for information about utility response to Question 640.35 concerning preoperational tests conducted after fuel load. List of preoperational tests which can be deferred beyond fuel load is enclosed for review.
January 31, 1986	Letter from applicant summarizing staff's January 7, 1986, site visit in response to December 11, 1985, request to address outstanding containment system issues. Enclosed revised FSAR Table II.E.4.2-1, "Essential/Nonessential System," will be incorporated into FSAR Amendment 24.
January 31, 1986	Letter to applicant advising that based on review of recent applicant submittals, unbraced downcomer design is marginal. Although licensing criteria for upset and emergency conditions are met, design adequacy for faulted condition is inadequately demonstrated.

February 3, 1986	Letter to applicant forwarding revised schedule for review of Technical Specifications. Enclosed schedule changes proposed schedule transmitted by April 5, 1985, letter and more closely follows plant construction and testing progress.
February 4, 1986	Letter from applicant forwarding response to January 8, 1986, letter about equipment qualification for facility. For cases where final action incomplete, schedule for submitting information is provided.
February 4, 1986	Letter from applicant forwarding revisions to physical security plan. Revisions withheld (ref: 10 CFR 73.21).
February 7, 1986	Letter from applicant discussing SER confirmatory issue 17. Detailed technical assessment of methods used to establish protection system setpoints and allowable values will be submitted before startup following first refueling outage.
February 7, 1986	Letter to applicant identifying information needed to close listed SER open and confirmatory items, per January 14, 1986, discussion. Schedule for submitting balance of identified outstanding information is requested within 10 days.
February 7, 1986	Letter to applicant requesting revision to FSAR, committing provisions of October 28, 1985, NRC policy statement on engineering expertise on shift about dual position of senior technical advisor and senior reactor operator, per SSER 1.
February 10, 1986	Generic Letter 86-03 issued to all licensees of operating reactors and applicants for operating license about applications for license amendments.
February 13, 1986	Generic Letter 86-04 issued to all power reactor licensees and applicants for power reactor licenses about policy statement on engineering expertise on shift.
February 14, 1986	Letter from applicant forwarding supplemental information about revised electrical separation criteria submitted in December 10, 1985, letter. Revised criteria are incorporated into Amendment 23 to FSAR.
February 14, 1986	Letter to applicant forwarding list of concerns from review of FSAR Amendments 22 and 23. Schedule responding to concerns is requested within 10 days of letter receipt.
February 18, 1986	Letter from applicant informing of decision to seek schedular exemption to allow operation during performance of confirmatory analyses of containment downcomers. Requirements under 10 CFR 50.12 fulfilled.

February 18, 1986	Letter from applicant advising that based on current fuel loading date, schedule for submittal of inservice inspection program plan to close SER open item 3G is changed to January 30, 1987. Revised date conforms with January 28, 1986, discussion with staff.
February 18, 1986	Letter to applicant forwarding finding of no significant antitrust changes and <u>Federal Register</u> notice about antitrust operating license review.
February 19, 1986	Letter from applicant amending commitment in December 2, 1985, letter concerning full compliance with Commission response to further requirements about 10 CFR 50.47(b)(12) to the extent of compliance within utility control, per January 29, 1986, letter.
February 19, 1986	Letter from applicant amending commitment in December 2, 1985, letter concerning full compliance with Commission response to further requirements regarding 10 CFR 50.47(b)(12) to the extent of compliance within utility control, per December 29, 1986, letter.
February 19, 1986	Letter from applicant forwarding Addendum A to physical security plan, correcting typographical errors. Addendum is withheld (ref: 10 CFR 73.21).
February 21, 1986	Letter from applicant submitting information necessary for closeout of confirmatory item 33 about portable radio demonstration. Communication equipment is not necessary for safe shutdown of reactor during design-basis event.
February 21, 1986	Letter to applicant requesting additional information by March 7, 1986, on January 31, 1986, request to defer preoperational tests beyond May 5, 1986, fuel load date. Information should include justification for not completing tests, the schedule for test completion, and exemption requests.
February 24, 1986	Letter to applicant forwarding draft reports on technical insights gained from probable risk assessments (PRAs). Reports include general insights on strengths and weaknesses gained from PRAs and modifications implemented to address problems identified during PRA. Comments are requested by March 25, 1986.
February 24, 1986	Letter to applicant requesting schedule when confirmation of items about environmental qualification of equipment will be provided, per NRC request of January 8, 1986. Response dated February 4, 1986, indicated maintenance and surveillance program and SCEW sheets would be complete before fuel load.

February 26, 1986	Letter to applicant forwarding, for information, Generic Letter 86-02, "Technical Resolution of Generic Issue B-19 - Thermal-Hydraulic Stability." Letter is being sent to all licensees of operating boiling-water reactors.
February 28, 1986	Letter from applicant forwarding schedule for response to staff's letter of February 14, 1986. FSAR Amendment 25 is currently scheduled for April 4, 1986.
February 28, 1986	Letter from applicant notifying of changes affecting correspondence distribution lists. J. A. Perry has been appointed quality assurance vice president and C. Seibert has retired. Unit 1 Technical Specification changes will be submitted. Unit 2 Technical Specification changes will be incorporated during review.
February 28, 1986	Letter from applicant advising that fuel load date has been extended by up to 10 weeks. NRC should use fuel loading date target of May 5, 1986, for planning and management of staff resources. NRC will be notified of any significant change to target date.
February 28, 1986	Letter from applicant forwarding information per NRC letter of February 7, 1986. SER open items and response dates are listed on enclosure.
February 28, 1986	Letter from applicant forwarding information on caulking diesel generator stop logs, in response to Westcott request. Information will be incorporated into Amendment 25 to FSAR.
February 28, 1986	Letter from applicant forwarding additional information for facility disconnect switches, per staff request. Disconnect switches to be used in conjunction with remote shutdown panel in event of relay room or control room fire.
February 28, 1986	Letter from applicant forwarding updated response to FSAR Question F421.26 on minimum number of sensors required to monitor safety-related variables. Information will be incorporated into FSAR amendment.
February 28, 1986	Letter from applicant forwarding revised FSAR page 9B.6-3 on evaluation of effects of postulated fire, for use and information. Page was updated to reflect NRC oral request of February 20, 1986. Revision will be incorporated into FSAR Amendment 25.
February 28, 1986	Letter from applicant responding to staff request of February 7, 1986, that utility meet Commission policy statement regarding engineering expertise on shift. Shift crew will meet requirements in policy statement of 50 FR 43621 at time of fuel load.

February 28, 1986	Letter from applicant forwarding tables describing Stone & Webster and General Electric Co. pipe class definitions, in response to request for pipe class identification key to simplify identification of pressure boundaries indicated on drawings submitted in inservice testing plan.
February 28, 1986	Letter to applicant denying request of October 7, 1985, to utilize alternative to 10 CFR 50.55a requirements on use of authorized nuclear inspectors. Proposed alternative does not provide acceptable independent verification of component quality in safety-related systems.
February 28, 1986	Letter to applicant forwarding draft SER Section 5.3.1 concerning reactor vessel material surveillance program. Proposed integrated surveillance program meets criteria in Section II.C of Appendix H to 10 CFR 50.
March 3, 1986	Letter from applicant requesting exemption from 10 CFR 50.12(a), Appendix J, Section III.C.3 and III.D.2(b)(ii) on exclusion of leakage of main steam isolation valves and relaxation of testing requirements for airlock doors, respectively.
March 3, 1986	Letter from applicant forwarding responses and commitments to staff's site visit of December 17-18, 1985. Installation of light above disconnect panels and piping supports in battery room will be completed before fuel load. Changes will be incorporated into FSAR amendment.
March 3, 1986	Letter from applicant forwarding updated responses to Seismic Review Team and Pump & Valve Operability Review Team audit of open items. Utility is currently performing compliance and verification review of seismic qualification program.
March 3, 1986	Letter from applicant forwarding additional information on temporary jumpers and lifted leads in response to SER confirmatory issue 22. Review of at-power testing is complete, including Operational Conditions 1, 2, and 3. Sixteen procedures use jumpers and lifted leads.
March 3, 1986	Letter from applicant forwarding additional information on compliance to Regulatory Guide 1.97, per telephone conversations of February 13 and 21, 1986. Information should close confirmatory issue 10. Developments in nuclear industry on neutron flux monitoring instrumentation will continue.
March 3, 1986	Letter from applicant forwarding Revision 2 to "High Energy Line Break Evaluation Report (Effect on Nonsafety-Related Control Components), Nine Mile Point Unit 2," superseding December 11, 1985, Revision 1. High-energy-line break in turbine building bounded by Chapter 15 of FSAR.

March 3, 1986	Summary issued of February 19, 1986, meeting with utility, Westinghouse, and Innovative Technologies, Inc. on Westinghouse core reloads for boiling-water reactors.
March 4, 1986	Letter from applicant discussing January 9, 1986, letter which provided detailed discussion of change made in Amendment 23 of FSAR regarding 3-inch water gap between adjacent fuel racks in spent fuel pool. No change is needed to SER conclusion on spent fuel pool.
March 6, 1986	Letter from applicant forwarding description of and reason for use of jumpers and lifted leads, per SER confirmatory issue 22. Sixteen procedures are utilized employing jumpers and lifted leads.
March 7, 1986	Letter from applicant forwarding March 3, 1986, Affidavit of Service for Amendment 24 to FSAR, operating license stage, per NRC instructions of March 29, 1983.
March 7, 1986	Letter from applicant responding to Items 6 and 8 of IE Bulletin 79-08, per SER confirmatory issue 51. Only qualified personnel may position valves under chief shift operator direction. Confirmatory issue 51 is considered closed.
March 10, 1986	Letter from applicant providing additional requested information on content of procedures generated as result of SER confirmatory issues 35 and 41. Provisions for filling diesel generator fuel oil tanks through diesel day tank connections are included in procedures.
March 10, 1986	Letter from applicant forwarding response to five concerns stated in Section 13.5.2.3.1(a) (confirmatory issue 16A) of SSER 2 about use of emergency ventpaths. Additional information on drywell spray will be submitted by April 18, 1986.
March 14, 1986	Letter from applicant forwarding revised FSAR pages on quality assurance (QA) program. Program will be fully effective for all QA activities upon completion of 100-hour warranty run. Information will be incorporated into Amendment 26 to FSAR.
March 14, 1986	Letter from applicant forwarding marked-up proof and review Technical Specifications reflecting comments on current plant design and results of meetings with staff. Technical Specifications update December 30, 1985, version. Program of safety analysis report and Technical Specification verification is continuing.
March 18, 1986	Letter from applicant responding to request for additional information about SER confirmatory issue 6 on capability of containment internal structures to withstand newly identified safety/relief valve pool loads. Tables on stresses are enclosed.

March 18, 1986	Letter to applicant forwarding draft SER and staff c sultants' reports on downcomer design issue. NRC is . viewing February 18, 1986, exemption request.
March 18, 1986	Letter to applicant requesting clarification and correction of qualified status of neutron monitoring system by March 31, 1986. Specified accident temperature is 380°F; however, stated qualification temperature is 347°F.
March 19, 1986	Letter to applicant requesting additional information about Amendment 23 to FSAR, including justification for noncompliance with Standard Review Plan Section 3.5.3 (NUREG-0800) concerning wall thickness of missile enclosure for valves 25WP, 77A, and 77B in screenwell building.
March 19, 1986	Letter from applicant advising of attempt to expedite schedule for environmental qualification of equipment. Utility's February 28, 1986, letter indicated that information would be provided by April 9, 1986.
March 20, 1986	Generic Letter 86-07 issued to all reactor licensees and applicants regarding transmittal of NUREG-1190 concerning San Onofre Unit 1 loss of power and water hammer event.
March 20, 1986	Letter to applicant forwarding request for additional information about Generic Letter 83-28, Item 1.1, "Post-Trip Review." Response is requested within 30 days of letter date.
March 21, 1986	Letter from applicant documenting topics discussed during March 14, 1986, telephone conversation between NRC and utility about SER confirmatory issue 22 concerning use of lifted leads and temporary jumpers during testing.
March 21, 1986	Letter from applicant forwarding revised schedule for review of Technical Specifications. Review has been delayed 3 weeks to allow for discussions with utility to resolve outstanding issues before issuing final draft Technical Specifications.
March 24, 1986	Letter from applicant discussing exception to Amendment 22 to FSAR Subsection NE-4452 of Section III of ASME Code regarding liquid penetrant examination of surface defects removed by grinding. Exception is one-time departure and will be deleted from amendment.
March 25, 1986	Letter from applicant forwarding updated information on fire protection at facility, per January 29, 1986, discussion with staff. FSAR changes will be included in Amendment 26.
March 26, 1986	Letter from applicant forwarding Amendment 25 to FSAR for Nine Mile Point Unit 2. Section 6A is withheld (ref: 10 CFR 2.790), per utility's request and NRC's September 21, 1983, approval.

APPENDIX B

REFERENCES

Federal Emergency Management Agency, FEMA-43, "Standard Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants."

---, Memorandum to E. L. Jordan, NRC, from R. W. Krimm, Subject: "Post-Exercise Assessment of the November 13, 1985, Exercise at the Nine-Mile Point Nuclear Generating Station," March 19, 1986.

Lawrence Livermore National Laboratory, "Pipe Ruptures in BWR Plants."

Reddy, B. D., "An Experimental Study of the Plastic Buckling of Circular Cylinders in Pure Bending," Journal of Solids Structures, Vol. 15, Pergamon Press, Ltd., 1979.

Reiter, Leon, "Uses of Probabilistic Estimates of Seismic Hazard and Nuclear Power Plants in the U.S.," in Proceedings of Second CSNI Specialist Meeting on Probabilistic Methods in Seismic Risk Assessment for Nuclear Power Plants, Livermore, California, May 16-19, 1983.

U.S. Nuclear Regulatory Commission, NUREG-75/014 (formerly WASH-1400), "Reactor Safety Study - An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," October 1975.

---, NUREG-0261, "Natural Convection in Horizontal Fluid Layers," June 1977.

---, NUREG-0484, Rev. 1, "Methodology for Combining Dynamic Responses," May 1980.

---, NUREG-0487, Suppl. 1, "Mark II Containment Lead Plant Program Load Evaluation and Acceptance Criteria: Generic Technical Activities A-8 and A-39," September 1980.

---, NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," January 1980; Revision 1, November 1980.

---, NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," May 1980; Revision 1, July 1980.

---, NUREG-0700, "Guidelines for Control Room Design Reviews," September 1981.

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

---, NUREG-0763, "Guidelines for Confirmatory Inplant Tests of Safety Relief Valve Discharges for BWR Plants," May 1981.

---, NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Section 18.1, Appendix A, "Evaluation Criteria for Detailed Control Room Design Reviews," September 1984.

---, NUREG-0802, "Safety/Relief Valve Quencher Loads: Evaluation for BWR Mark II and III Containments," October 1982.

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

---, NUREG-1061, Vol. 2, "Report of the U.S. Nuclear Regulatory Commission Piping Review Committee: Evaluation of Seismic Designs - A Review of Seismic Design Requirements for Nuclear Power Plant Piping," April 1985.

---, NUREG/CR-3028, "A Review of the Limerick Generating Station Probabilistic Risk Assessment," February 1983.

---, NUREG/CR-3085, "Analysis of the Millstone Point Unit 1 Nuclear Power Plant," May 1983.

---, NUREG/CR-3600, "Probability of Pipe Failure in the Reactor Coolant Loops of Westinghouse PWR Plants," July 1985.

---, Office of Inspection and Enforcement (IE), IE Bulletin 79-22, "Possible Leakage of Tubes of Tritium Gas Used in Timepieces for Luminosity," September 5, 1979.

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

---, IE Circular 79-02, "Failure of 120 Volt Vital AC Power Supplies," January 16, 1979.

---, IE Information Notice 84-37, "Use of Lifted Leads and Jumpers During Maintenance or Surveillance Testing," May 10, 1984.

---, IE Inspection Report 50-410/85-14.

---, IE Inspection Report 50-410/85-18, November 20, 1985.

---, IE Inspection Report 50-410/85-28.

APPENDIX D

ACRONYMS AND INITIALISMS

AIM	analog isolation module
ANSI	American National Standards Institute
APRM	average power range monitor
ARD	Advanced Resource Development Corporation
ARI	alternate rod injection
ASME	American Society of Mechanical Engineers
ASSS	Assistant Station Shift Supervisor
ATWS	anticipated transient without scram
AWS	American Welding Society
BNL	Brookhaven National Laboratory
BOP	balance of plant
BTP	branch technical position
BWR	boiling-water reactor
BWROG	Boiling Water Reactor Owners Group
CFR	Code of Federal Regulations
CO	condensation oscillation
CPR	critical power ratio
CRB	control rod block
CUF	cumulative usage factor
DAR	design assessment report
DBA	design-basis accident
DBMS	database management system
DCRDR	Detailed Control Room Design Review
DOE	U.S. Department of Energy
DRMS	digital radiation monitoring system
EA	engineering assurance
EAP	engineering assurance program
ECCS	emergency core cooling system
E&DCR	Engineering and Design Change Report
EOF	Emergency Operations Facility
EOP	emergency operating procedure
EPG	emergency procedures guideline
EQEDC	equipment qualification environmental design criteria
ERF	emergency response facility
FEMA	Federal Emergency Management Agency
FSAR	Final Safety Analysis Report
GDC	General Design Criterion(a)
GE	General Electric Company
GEMS	gaseous effluent monitoring system

HED	human engineering discrepancy
HELB	high-energy line break
HEO	human engineering observation
HP	Hewlett-Packard
HPCS	high-pressure core spray
HVAC	heating, ventilation, and air conditioning
ICS	isolation cooling system
ICU	indicating control unit
ID	internal diameter
IE	Office of Inspection and Enforcement, NRC
IEEE	Institute of Electrical and Electronics Engineers
IOP	interim operating procedure
IRM	intermediate range monitor
ISMG	Instrumentation Setpoint Methodology Group
IST	inservice testing
KWU	Kraftwerk Union
LER	licensee event report
LLNL	Lawrence Livermore National Laboratory
LOCA	loss-of-coolant accident
LPCI	low-pressure coolant injection
LPCS	low-pressure core spray
MCF	maximum credible fault
MOV	motor-operated valve
MSIV	main steam isolation valve
NCIG	Nuclear Construction Issues Group
N&D	nonconformance and disposition
NMP-2	Nine Mile Point Nuclear Station, Unit 2
NMPC	Niagara Mohawk Power Corporation
NMS	neutron monitoring system
NRC	U.S. Nuclear Regulatory Commission
NSSS	nuclear steam supply system
NTD	Nuclear Technology Division
OBE	operating basis earthquake
OL	operating license
PCP	process control program
PIV	pressure isolation valve
QA	quality assurance
RHR	residual heat removal
RHRS	residual heat removal system
RMCS	reactor manual control system
RPS	reactor protection system
RPT	recirculation pump trip
RPV	reactor pressure vessel
RRCS	redundant reactivity control system

SER	Safety Evaluation Report
SFTA	system function and task analysis
SIM	safety isolation module
SLCS	standby liquid control system
SPDS	safety parameter display system
SRDI	safety-related display instrumentation
SRM	source range monitor
SRMS	safety-related monitoring system
SRP	Standard Review Plan
SRSS	square root of the sum of the squares
SRV	safety/relief valve
SSE	safe shutdown earthquake
SSER	supplement to Safety Evaluation Report
SWEC	Stone and Webster Engineering Corporation
TER	Technical Evaluation Report
TMI-2	Three Mile Island, Unit 2
TSC	Technical Support Center
VWAC	visual weld acceptance criteria
WNP-2	Washington Nuclear Plant No. 2
WPPSS	Washington Public Power Supply System

APPENDIX E

NRC STAFF CONTRIBUTORS AND CONSULTANT

This supplement to the Safety Evaluation Report is a product of the NRC staff and its consultant. The NRC staff members listed below were principal contributors to this report.

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*Reflects the new organization of NRC's Office of Nuclear Reactor Regulation since SSER 2 was issued.

APPENDIX J

ADDITIONAL INFORMATION ON THE DEMONSTRATION OF CONTAINMENT PURGE AND VENT VALVE OPERABILITY

NINE MILE POINT NUCLEAR STATION, UNIT 2
DOCKET NO. 50-410

DEMONSTRATION OF CONTAINMENT PURGE AND VENT VALVE OPERABILITY

1.0 Requirement

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 assure containment isolation. This demonstration of operability is required by BTP CSB 6-4 and SRP 3.10 for containment purge and vent valves which are not sealed closed during operational conditions 1, 2, 3, and 4.

2.0 Description of Purge and Vent Valves

The valves identified as the containment isolation valves in the purge and vent system are as follows:

Valve Tag No.	Valve Size (Inches)	Operator Type	Valve Location
AOV-104	14	Air-Open, Spring-Close	Outside Containment
AOV-106	14	Air-Open, Spring-Close	Inside Containment
AOV-108	14	Air-Open, Spring-Close	Inside Containment
AOV-110	14	Air-Open, Spring-Close	Outside Containment
AOV-105	12	Air-Open, Spring-Close	Outside Containment
AOV-107	12	Air-Open, Spring-Close	Inside Containment
AOV-109	12	Air-Open, Spring-Close	Inside Containment
AOV-111	12	Air-Open, Spring-Close	Outside Containment

All the valves are butterfly valves manufactured by Posi-Seal International (PSI) of North Stonington, Connecticut and are furnished with Bettis (air-open, spring-close) Model Number N721C-SR80-M3HW actuators.

3.0 Demonstration of Operability

3.1. Niagara Mohawk Power Corporation (NMPC) has provided purge and vent valve operability demonstration information for the 12-inch and 14-inch purge and vent valves at the Nine Mile Point Nuclear Station, Unit 2 in their letters of January 25, 1985 and March 29, 1985 from C. V. Mangan (NMPC) to A. Schwencer (NRC) and the following reports.

Reference A - Posi-Seal International Report No. 33375SL-001 entitled "LOCA and Seismic Analysis."

Reference B - Posi-Seal International Seismic Functional Test 19157ST-01.

Reference C - Posi-Seal International Nuclear Seismic Analysis 19157SQ-01.

Reference D - Niagara Mohawk Power Corporation letter from C. V. Mangan to W. Butler (NRC), dated November 19, 1985.

3.2 Enclosure 3 of Reference A describes model testing performed by PSI on valve sizes from 1-1/2 inch through 14 inch for both preferred and nonpreferred flow to obtain hydrodynamic torque factors that are used in calculating dynamic torques for all sizes and classes of trunnion valves. Based upon the flow testing performed at PSI, the following general observations concerning hydrodynamic torque of trunnion valves can be made:

1. For preferred flow, the hydrodynamic torque will always act to close the valve.

2. For nonpreferred flow, the hydrodynamic torque will oppose valve closure from the 90° full open position through 70° to 80° open (the exact location varies with valve class). Beyond this point to 0° (closed), the hydrodynamic torque will act to close the valve.

3. Except for the 90° valve opening where the hydrodynamic torque factors are of equal magnitude for both preferred and nonpreferred flow, but of opposite sign, the nonpreferred hydrodynamic torque factors are considerably less in magnitude than those for preferred flow.

Posi-Seal International in Reference A derives aerodynamic torque equations for steam and water using the data from the hydrodynamic model testing program.

A constant peak containment pressure during the postulated LOCA of 45 psig is assumed for all the valves for conservatism since the larger the pressure drop, the larger the aerodynamic torques acting on the valve. Actually, with valve (drywell) closure within 5 seconds the containment pressure will have increased only to approximately 6 psig based on the LOCA containment pressure response curve. Single valve closure is assumed for conservatism since simultaneous valve closure would reduce the aerodynamic torque and flow.

3.3 Flow conditions as the valves close against the buildup of pressure in containment due to a LOCA, are analyzed in Appendix B to Reference A "Determination of Flow Conditions."

Since the makeup of the media is not known, three different conditions are analyzed to determine which condition results in the largest aerodynamic torques. This condition is then used in the remainder of the analysis. The three conditions investigated are as follows:

Condition	Media	Temperature (°F)
1	Air	135
2	Air	340
3	Steam	292 (Saturated)

Condition 2 results in the largest aerodynamic torques and is assumed in the analysis as worst case.

3.3 Stress analysis results for the valve critical parts are shown on p. 7 of Reference A. Calculated stresses for the actuator bolt, bracket bolt, bracket, valve neck, stem and disc pin are compared to Section III ASME Boiler and Pressure Code allowable stresses.

3.4 Appendices C, D and E to Reference A entitled "Determination of Closing Times" presents the results of a closure time analysis based on the equation shown below:

$$T_{TTO} = T_{flow} + T_{air} + T_{spring} + T_{packing\ and\ seal} + T_{bearing}$$

where:

- T_{TTO} = The net torque tending to open the valve (equals zero when the valve starts to close).
- T_{flow} = The torque due to aerodynamic flow caused by the LOCA.
- T_{air} = The torque exerted by the actuator as a result of the air acting on the actuator piston tending to open the valve.
- T_{spring} = The torque exerted by the actuator spring tending to close the valve.
- $T_{packing\ and\ seal}$ = Torque of the packing and the seal resisting the closing motion of the valve. The seal torque does not take effect until the disc begins to seal which occurs at approximately 3° from fully closed. The running torque of the packing is approximately 0.6 times the break away torque.
- $T_{bearing}$ = Torque due to the ΔP acting across the valve which forces the stem/disc assembly into the bearings.

Closing times are calculated for each valve for opening angles of 90° and 70° to closure. For those valves installed in the nonpreferred direction, the closure times are also determined for the preferred direction of installation.

3.5 Seismic qualification analysis and seismic functional test data are provided by PSI in Reference B and Reference C.

3.6 Posi-Seal recommends, Reference A, based on their analysis that valve numbers AOV-105, -104, and -110 presently installed in the nonpreferred direction either be reoriented in the preferred direction with the stem side of the disc upstream and the retaining ring downstream or be mechanically limited to a 70° maximum valve opening. The reason for this is that the LOCA-induced dynamic loads oppose closure for these valves installed in the nonpreferred direction and exceed the actuator spring capability to close the valve. Also recommended for valve number AOV-111 is a reorientation to the preferred direction and a 70° limitation on valve opening to preclude overstressing the disc pin.

3.7 Based on Posi-Seal recommendations and the NRC Safety Evaluation Report Supplement 2, dated November 1985, the following modifications have been made or will be implemented prior to fuel load:

Valve AOV-104. Valve will be oriented in the preferred direction.

Valves AOV-105 and -110. Both of these valves will be reoriented in the preferred direction and restricted to an opening angle of 70° (90° is equal to full open). With these modifications the allowable shear stress of 21,120 psi for the disc pin will not be exceeded.

Valve AOV-107. By orienting this valve in the preferred direction, the torque will be reduced from 3,998 to 3,237 in-lb. This results in a disc pin stress less than the allowable stress of 21,120 psi.

Valve AOV-111. By reorienting the valve in the preferred direction and restricting the opening angle to 60°, the allowable shear stress of 21,120 psi for the disc pin will not be exceeded.

4.0 Evaluation

4.1 Posi-Seal's approach to dynamic torque predictions for the 12-inch and 14-inch purge and vent valves at Nine Mile Point, Unit 2 is based on torque factors derived from hydrodynamic model tests coupled with torque equations (Reference A) that determine the aerodynamic torques under LOCA conditions. Conservative assumptions used by PSI for dynamic torque predictions include a constant peak containment pressure during closure, selection of worst case media (air at 340° F), single valve closure (other valve failed open) and no credit taken for downstream pressure drops in piping. The staff's findings from the previous review and the evaluation for each valve are summarized below. (All modifications are to be implemented prior to fuel load):

Valve Number AOV-104 (14 inch). Operability for this valve was demonstrated pending implementation of PSI recommendations to reorient the valve in the preferred direction or limit the opening angle to 70°. The licensee will orient the valve in the preferred direction prior to fuel load. This addressed the staff's concerns.

Valve Numbers AOV-106 and -108 (14 inch). Operability has been demonstrated for both valves as installed.

Valve Numbers AOV-110 (14 inch) and AOV-105 (12 inch). The staff previously concurred with PSI's recommendations to reorient the valve in the preferred direction or limit the opening to 70° in order not to exceed the actuator spring torque capability. As a result of the reanalysis by Posi-Seal, these valves will be reoriented in the preferred direction and be restricted to an opening angle of 70°. This is based on using an allowable shear stress of 21,120 psi (see Section 4.3 for details).

Valve Number AOV-107 (12 inch). The previous disc pin calculated shear stress at the 80° opening angle exceeds the allowable shear stress. By orienting the valve in the preferred direction, the licensee reports that the torque will be reduced from 3,998 to 3,237 in-lbs. This results in a disc pin stress less than the allowed 21,120 psi (see Section 4.3 for details).

Valve Number AOV-109 (12 inch). Operability has been demonstrated for this valve as installed.

Valve Number AOV-111 (12 inch). The staff previously concurred with PSI's recommendations to reorient the valve in the preferred direction and limit the opening to 70° in order not to exceed the actuator spring torque capability. However, the calculated shear stress at 70° exceeds the allowable shear stress. The results of the reanalysis led to reorienting the valve and restricting it to 60°. This results in the disc pin stress being less than the code allowable stress of 21,120 psi (see Section 4.3 for details).

4.2 The largest LOCA induced valve torque of 9,584 in-lbs occurs at a valve closure angle of 80° for 14-inch valve number AOV-110 and compared to the Bettis N721C-SR80 actuator maximum allowable torque of 22,500 in-lbs provides an adequate structural margin.

4.3 The results of the valve critical parts stress analysis performed by PSI were shown in Table 2 of Reference A. For the valve openings and flow directions analyzed, the allowable stresses shown in References A and D are not exceeded by the calculated stresses. Previously the staff found the stress analysis methodology acceptable for each critical part analyzed. However, the staff did not accept the values of the allowable shear stress used for the disc pin. The allowable shear stress used by PSI was 31,680 psi which is unacceptably high compared to the 21,120 psi determined by the staff using the ASME Boiler and Pressure Vessel Code. (Using Table I-7.2 for Class 2, 3 components from the ASME Boiler and Pressure Vessel Code, Section III Appendix I, the allowable stress in tension (S) at 400° F for the SA564 GR630 H1075 disc pin material is 35,200 psi. The allowable stress in shear therefore is 0.6 x 35,000 or 21,120 psi and is exceeded by the calculated disc pin stresses for valve numbers AOV-110, -107, -105 and -111.)

The licensee has concurred with the staff's findings regarding a stress allowable of 21,120 psi for the disc pin material. In the reanalysis performed by Posi-Seal and summarized by Niagara Mohawk, Reference D, for valves AOV-105, -107, -110 and 111, this value was utilized. The result of this reanalysis, summarized and discussed in Sections 3.7 and 4.1, are the basis for reorienting and restricting the open angle of the valve, when applicable, all of which satisfactorily address the staff's previous concerns. Additionally, the remaining valves were evaluated using the proper value for the code allowable stress, and were still found acceptable.

4.4 Seismic qualification of the 12-inch and 14-inch purge and vent valves at the Nine Mile Point Nuclear Station, Unit 2 is addressed in References B and C. Reference C demonstrates by analysis that the valves are seismically qualified, with natural frequencies greater than 33 Hz, stresses smaller than the allowable stresses, and small actuator deflections. Reference B contains test information that demonstrates that the valves retain the ability to operate in the intended manner when subjected to a static force equivalent in magnitude to the seismic load and applied at the actuator center of gravity.

5.0 Summary

We have completed our review of the information submitted to date concerning the operability of the 12-inch and 14-inch valves used in the containment purge and vent system at the Nine Mile Point Nuclear Station, Unit 2. We find that the information submitted and with the incorporation of the proposed modifications, demonstrates the ability of valves AOV-104, -105, -107, -110 and -111 to close against the rise in containment pressure in the event of a DBA/LOCA. Operability of valves AOV-106, -108 and -109 has been demonstrated previously.

APPENDIX K

TECHNICAL EVALUATION REPORT OF THE NINE MILE POINT, UNIT 2
DETAILED CONTROL ROOM DESIGN REVIEW
CONDUCTED BY NIAGARA MOHAWK POWER CORPORATION

TECHNICAL EVALUATION REPORT

OF THE

NINE MILE POINT, UNIT 2

DETAILED CONTROL ROOM DESIGN REVIEW

CONDUCTED BY

NIAGARA MOHAWK POWER CORPORATION

L. Rolf Peterson

Lawrence Livermore National Laboratory

November 15, 1985

TABLE OF CONTENTS

TECHNICAL EVALUATION REPORT OF THE NINE MILE POINT, UNIT 2 DETAILED CONTROL ROOM DESIGN REVIEW CONDUCTED BY NIAGARA MOHAWK POWER CORPORATION

1. BACKGROUND

Licensees and applicants for operating licenses shall conduct a Detailed Control Room Design Review (DCRDR). The objective is to "improve the ability of nuclear power plant control room operators to prevent accidents or cope with accidents if they occur by improving the information provided to them" (NUREG-0660, Item I.D.1). The need to conduct a DCRDR was confirmed in NUREG-0737 and Supplement 1 to NUREG-0737. DCRDR requirements in Supplement 1 to NUREG-0737 replaced those in earlier documents. Supplement 1 to NUREG-0737 requires each applicant or licensee to conduct a DCRDR on a schedule negotiated with the Nuclear Regulatory Commission (NRC).

NUREG-0700 describes four phases of the DCRDR and provides applicants and licensees with guidelines for its conduct. The phases are:

1. Planning
2. Review
3. Assessment and Implementation
4. Reporting

Supplement 1 to NUREG-0737 requires that the DCRDR include the following elements:

1. Establishment of a qualified multidisciplinary review team.
2. Function and task analyses to identify control room operator tasks and information and control requirements during emergency operations.
3. A comparison of display and control requirements with a control room inventory.
4. A control room survey to identify deviations from accepted human factors principles.
5. Assessment of human engineering discrepancies (HEDs) to determine which are significant and should be corrected.
6. Selection of design improvements.
7. Verification that selected design improvements will provide the necessary correction and do not introduce new HEDs.
8. Coordination of control room improvements with changes from other programs such as the safety parameter display system (SPDS), operator training, Reg. Guide 1.97 instrumentation, and upgraded emergency operating procedures (EOPs).

Licensees are expected to complete Element 1 during the DCRDR's planning phase, Elements 2 through 4 during the DCRDR's review phase, and Elements 5 through 7 during the DCRDR's assessment and implementation phase. Completion of Element 8 is expected to cut across the planning, review, and assessment and implementation phases.

A summary report is to be submitted at the end of the DCRDR. As a minimum it shall:

1. Outline proposed control room changes.

2. Outline proposed schedules for implementation.

3. Provide summary justification for HEDs with safety significance to be left uncorrected or partially corrected.

The NRC staff evaluates the organization, process, and results of the DCRDR. Results of the evaluation are documented in a Safety Evaluation Report (SER).

2. DISCUSSION

The Niagara Mohawk Power Corporation (NMPC) submitted a Detailed Control Room Design Review (DCRDR) Program Plan for its Nine Mile Point, Unit 2 Plant (NMP-2) to the Nuclear Regulatory Commission by letter dated June 29, 1984. The DCRDR Program Plan was reviewed against the requirements of Supplement 1 to NUREG-0737 by the NRC Division of Human Factors Safety (DHFS) and consultants from Lawrence Livermore National Laboratory (LLNL).

The NRC Human Factors Engineering Branch (HFEB) and consultants from LLNL conducted a DCRDR In-Progress Audit at NMP-2 on March 19-22, 1985. The NRC audit team's observations, findings, and conclusions resulting from this on-site audit were documented in the In-Progress Audit Report of the NMP-2 DCRDR that was submitted to DHFS by LLNL on May 16, 1985.

NMPC submitted the Detailed Control Room Design Review Final Summary Report Program Implementation for NMP-2 to the NRC in September 1985.

The evaluation of the NMP-2 DCRDR provided in this Technical Evaluation Report is based upon a review of the NMP-2 DCRDR Program Plan, the findings of the NRC DCRDR In-Progress Audit at NMP-2, and a review of the NMP-2 DCRDR Summary Report.

2.1 DCRDR REVIEW TEAM

2.1.1 Requirement

Supplement 1 to NUREG-0737 requires the establishment of a qualified multidisciplinary review team. Guidelines for review team selection are found in NUREG-0700 and NUREG-0800, Appendix A to SRP Section 18.1. NUREG-0700 guidelines state that support of the applicant's management is needed to provide to the DCRDR team all of the information, equipment, and categories of manpower needed to conduct a control room design review.

2.1.2 Findings

The NMP-2 Review Team was directed and coordinated by Niagara Mohawk Power Company (NMPC) Team Leader, and included the following personnel:

- Team Leader/Project Engineer--NMPC
- Human Factors Engineers--Advanced Resource Development Corp. (ARD)
- Balance of Plant (BOP) Systems Engineer Coordinator--Stone and Webster Engineering Corp. (SWEC)
- Nuclear Steam Supply System (NSSS), Systems Engineer Coordinator--General Electric Company (GE)

- Station Operations Coordinator—NMPC
- Training Department Coordinator—NMPC
- Licensing Coordinator—NMPC
- Safety Parameter Display System (SPDS) Coordinator—SWEC
- Emergency Operating Procedures (EOP) Coordinator—NMPC

The NMP-2 DCRDR Review Team was supported by additional human factors specialists from ARD Corp. and by additional NMP-2 operations personnel.

The NMP-2 DCRDR Review Team has a diverse set of knowledge, skills, and nuclear power plant experience. The NMP-2 DCRDR Summary Report provided detailed resumes of all review team members and describes their participation.

The DCRDR was directed at the corporate level by a management team composed of the NMPC Vice President for Nuclear Generation and the NMP-2 Project Director. The DCRDR Review Team reported to a plant project level Management Team that provided management support to the DCRDR Review Team and reviewed their work. The review team had management support in providing records, facilities, and services needed to conduct the DCRDR.

The NMP-2 review team members were given an orientation in human factors at the start of the DCRDR.

2.1.3 Conclusions

Based on NRC audit team observations during the NRC in-progress audit, the NRC audit team concluded that NMPC management had made a firm commitment to support the DCRDR. The documentation provided in the NMP-2 DCRDR Summary Report confirms this conclusion.

NMPC has satisfied the requirement of Supplement 1 to NUREG-0737 to establish a multidisciplinary review team to conduct the NMP-2 DCRDR.

2.2 FUNCTION AND TASK ANALYSES

2.2.1 Requirement

Supplement 1 to NUREG-0737 requires the applicant to perform systems function and task analyses (SFTA) to identify control room operator tasks and to identify control room operator information needs during emergency operations. Supplement 1 to NUREG-0737 recommends the use of function and task analyses that have been used as the basis for developing emergency operating procedures technical guidelines and plant-specific emergency operating procedures to define these needs.

2.2.2 Findings

NMPC used the Boiling Water Reactor Owners Group (BWROG) Emergency Procedure Guidelines (EPGs), Revision 3, to prepare the NMP-2 plant specific Emergency Operating Procedures (EOPs). The NMP-2 plant specific EOPs were used as the basis for their task analyses and the determination of information and control needs.

The BWROG EPGs consist of four guidelines and seven contingencies which are designed to:

1. Maintain reactor pressure vessel (RPV) inventory

2. Maintain the integration of primary and secondary containments through adequate heat rejection

3. Control and minimize radioactive releases to the environment

The BWROG EPGs identified generic information and control needs.

NMPC procedures N2-EOP-1, Emergency Operating Procedure Development; N2-EOP-2, Emergency Operating Procedure Verification; N2-EOP-3, Emergency Operating Procedure Validation; and N2-EOP-4, Emergency Operating Procedures Writers Guide; were used to make the transition from generic EPGs to the NMP-2 plant specific EOPs.

The NMP-2 DCRDR Task Analysis identified operator functions from the generic EPGs and the plant specific EOPs, identified operator tasks associated with the operator functions for each EOP, and assigned unique tasks numbers to each operator task. For each unique task, a human factors specialist working with NMP-2 reactor operators and senior reactor operators identified and recorded the detailed information and control needs and their characteristics.

During the task analysis, data was initially recorded on NMP-2 Task Description Forms and NMP-2 Task Analysis Forms. Then this data was entered into a computerized database management system (DBMS). The task analysis data collection was conducted at the Nine Mile Point Training Center. NMPC made a conscious effort to ensure that operator information and control needs and their characteristics were based on the task definitions and were derived independently from the existing control room equipment.

In response to the NRC In-Progress Audit of the NMP-2 DCRDR, NMPC reviewed the task analysis and identified tasks and task action steps that branched into non-EOP procedures. The review resulted in additions to the identified EOP tasks and identification of additional operator information and control needs.

NMPC states in the NMP-2 DCRDR Summary Report that Niagara Mohawk Administrative Procedure, APN-2, will be revised to require that all new or revised EOPs be reviewed for impact on the SFTA in accordance with guidance provided in the NMPC Human Factors Manual.

2.2.3 Conclusions

Based upon the NRC audit team observations and discussions during the DCRDR In-Progress Audit and upon our review of the NMP-2 DCRDR Summary Report, we conclude that NMPC has conducted a systems function and task analysis that identifies operator information and control needs independently from the existing control room equipment design. The NMP-2 SFTA satisfies the task analysis requirement of Supplement 1 to NUREG-0737.

2.3 COMPARISON OF CONTROL AND DISPLAY REQUIREMENTS WITH A CONTROL ROOM INVENTORY

2.3.1 Requirement

Supplement 1 to NUREG-0737 requires the applicant to make a control room inventory and to compare the operator display and control requirements determined from the task analyses with the control room inventory to determine missing controls and displays. Guidance in NUREG-0700 also calls for a review of the human factors suitability of instruments and controls used to satisfy operator information and control requirements.

2.3.2 Findings

Human factors specialists from ARD Corp. inventoried the NMP-2 control room controls, displays, and annunciators. The inventory was based on the SWEC Engineering Design Base of January 1985 using SWEC arrangement drawings. These drawings were also being used for design configuration control by GE to implement hardware changes. Hardware implementation of the design base would not be accomplished until late 1985.

In the inventory, each piece of equipment was identified by a unique code that included location and physical characteristics of each component. Characteristics noted were those that would be used to determine human factors suitability and usefulness of the component for performance of operator tasks.

The component characteristics data included component label name and subname, color, type of display, parameter/variable measured, units range, scale divisions or graduations, type of switch and switch action, switch position, type of equipment controlled, valve control mode, and the SWEC tag number identification.

The inventory data was entered and stored in the NMP-2 computerized database management system.

NMPC and ARD performed an on-site verification of the control room inventory by direct observation in the control room. This verification was performed by ARD human factors specialists with assistance from NMP Operations and Engineering personnel as needed. It was done to check the accuracy of database entries, to detect discrepancies between the arrangement drawings and the control boards, and to gather additional information about component characteristics that was not available from front panel drawings.

NMPC compared the operator information and control needs derived from the NMP-2 SFTA with the control room equipment inventory by conducting a verification of task performance capabilities. This process was performed in two steps; verification of availability and verification of suitability. Separate verifications were performed for controls, indicators, annunciators, and for back panels and other control room equipment whose characteristics were not fully described in the NMP-2 inventory database. The methodology and evaluation criteria NMPC used for the verification process were based upon the guidance of NUREG-0700, Sections 3.7 and 6.0.

Where the task analysis and inventory databases were compatible, the comparison was automated. Manual follow-up verification was performed where data was not compatible or where possible discrepancies were identified. The NMPC automated verification checks included appropriate criteria to flag potential human factors suitability discrepancies for review team evaluation.

NMPC conducted control room validation walk-throughs and talk-throughs to evaluate the suitability of control room equipment and to validate emergency operating procedures. NMP-2 operators performed walk-throughs of five event based emergency operating procedures at the NMP-2 Simulator. Walk-throughs were observed by an observation team and were videotaped. The walk-through videotapes were analyzed by human factors specialists at ARD Corp.

Talk-throughs for all tasks identified in the NMP-2 DCRDR task analysis were performed in the NMP-2 Control Room. The talk-throughs were performed by NMP-2 operators and were observed, recorded, and analyzed by human factors specialists.

Eighty (80) NMP-2 human engineering observations (HEOs) of discrepancies with human factors criteria were identified by the NMP-2 control room verification process. Twenty-one (21) NMP-2 HEOs were identified by the NMP-2 control room validation process.

2.3.3 Conclusions

The NMPC inventory of control room equipment and comparison of the inventoried control room equipment characteristics with the operator information and control needs derived from the SFTA satisfies the requirement of Supplement 1 to NUREG-0737.

Prior to NMP-2 reactor start-up, NMPC should confirm that changes made since June 1985 in operator information and control requirements resulting from changes in the NMP-2 EOPs and SFTA, and changes in control room equipment resulting from changes in control room design and equipment specifications have been appropriately compared and reviewed.

2.4 CONTROL ROOM SURVEY

2.4.1 Requirement

Supplement 1 to NUREG-0737 requires that a control room survey be conducted to identify deviations from accepted human factors principles. NUREG-0700 provides guidelines and criteria for conducting a control room survey. The objective of the control room survey is to identify, for assessment and possible correction, characteristics of displays, controls, equipment, panel layout, annunciators and alarms, control room layout, and control room ambient conditions that do not conform to good human engineering practices.

2.4.2 Findings

NMPC conducted a human factors engineering survey of the NMP-2 control room and remote shutdown panel. The NMP-2 DCRDR Summary Report states that the survey used a NMP-2 Human Factors Engineering Checklist that was based on the checklist illustrated in Section 6 of NUREG-0700. The NRC In-Progress Audit Team noted that the control room review followed NUREG-0700 guidelines and that the checklists used appeared to be derived directly from NUREG-0700. NMPC recorded any instances of noncompliance with the criteria provided by the NMP-2 Human Factors Engineering Checklist as HEOs. The NMP-2 Summary Report states that the checklist survey identified 191 HEOs.

The NRC audit team noted weaknesses in the portions of the control room review that had been performed prior to the time of the audit in March 1985. The NRC In-Progress Audit Report recommended that NMPC critically review the control room survey that had been conducted to that date to evaluate whether there were areas of weakness and to determine whether additional surveys were needed. NMPC conducted a resurvey of the control room in April and May 1985 using the NMP-2 Human Factors Engineering Checklist. That resurvey identified eleven (11) new HEOs and "...numerous equipment additions to existing generic HEOs."

A checklist survey of the remote shutdown panel was included in the April-May 1985 survey. Twenty-eight (28) HEO's were identified on the remote shutdown panel.

Better definition of the specific human factors criteria used for the NMP-2 control room checklist survey is needed. The nine topic areas of the NMP-2 human Factors Engineering Checklist that are described in the summary report correspond to the general topics and subtopics of NUREG-0700, Section 6. However, the NMP-2 DCRDR Summary Report does not state definitely whether all of the specific human factors criteria of NUREG-0700 were used, whether some NUREG-0700 criteria were dropped, or whether other specific criteria were used to supplement or replace NUREG-0700 criteria.

A number of checklist survey items were incomplete at the time the NMP-2 DCRDR Summary Report was submitted because construction was still in progress. These included control room environmental measurements to be obtained by a sound survey; a lighting survey of normal ambient lighting and emergency lighting; humidity and temperature measurements; and an air velocity survey. NMPC planned to collect this data in October 1985 following procedures that were outlined in the summary report.

Appendix K to the NMP-2 DCRDR Summary Report also lists incomplete checklist items from the topic areas of control room layout, workstation design, emergency equipment, communications, annunciators, controls, visual displays, labels, and control-display integration. NMPC stated that it expects to complete these incomplete checklist survey items by December 1985.

In addition to the human factors engineering checklist review of the NMP-2 control room and remote shutdown panel, NMPC conducted a historical document review of Licensee Event Reports (LERs) from the past five years at five similar GE BWR-5 plants with operating experience. This review analyzed 253 LERs and identified events related to both human factors and the control room. Four (4) HEOs for NMP-2 were identified from this operating experience survey.

NMPC conducted a control room operators survey by written questionnaires that were completed by twenty four (24) operators and by follow-up interviews with twenty (20) of the operators who responded to the questionnaires. The interviewees had a wide range of operating experience. They included Operations Supervisors, Shift Supervisors, Operators, Trainees, and Engineers. The interviews were conducted by human factors specialists from ARD Corp. Confidentiality was maintained.

Negative items from the operator survey were written as HEOs or presented as general reference information for NMPC review team and management consideration in the later stages of the NMP-2 DCRDR. Positive items were also presented as reference information to suggest control room features that should not be compromised in the course of correcting other HEOs. Ninety-five (95) HEOs were identified from the operator survey.

NMPC identified a total 290 HEOs from the historical, operator, and control room checklist surveys.

2.4.3 Conclusions

While identifying the general human factors topics and subtopics included in the NMP-2 control room survey, the NMP-2 DCRDR Summary Report does not positively identify the specific human factors criteria used to conduct the control room checklist survey. It is implied that the criteria of NUREG-0700, Section 6 were used. NMPC should confirm to the NRC that the specific criteria of NUREG-0700 were used, if that is the case. NMPC should identify any topics where NUREG-0700 criteria were not used and any topic areas where other human factors criteria were used. NMPC should justify deviations from use of the NUREG-0700 criteria to the NRC and should specifically identify any other human factors criteria that were used.

NMPC should report to the NRC, in a supplement to the DCRDR Summary Report, completion of incomplete control room survey items and the disposition of human engineering discrepancies identified by those survey items.

When completed and reported to the NRC, the NMP-2 survey activities are expected to satisfy the control room survey requirement of Supplement 1 to NUREG-0737, provided NMPC confirms that suitable specific human factors engineering criteria were used throughout the DCRDR control room survey.

2.5 ASSESSMENT OF HEDs

2.5.1 Requirement

Supplement 1 to NUREG-0737 requires that HEDs be assessed to determine which HEDs are significant and should be corrected.

2.5.2 Findings

The assessment process for the NMP-2 DCRDR consisted of placing each of the 391 HEOs identified during the DCRDR into one of four categories of risk.

Category 1 – HEOs associated with documented errors in similar plants included in the operating experience review

Category 2 – HEOs associated with potential errors

Category 3 – HEOs associated with low probability errors of serious consequence

Category 4 – HEOs not associated with errors.

Then within each one of these four individual categories the HEOs were assigned one of five levels of adverse effects.

Level A – Includes those HEOs for which the related documented (in similar plants) error was associated with a safety-related function, and resulted in unsafe plant operation.

Level B – Includes those HEOs for which the related documented (in similar plants) error was associated with a safety-related function, and resulted in violation of a technical specification.

Level C – Includes those HEOs for which the related potential error is associated with a safety-related function, and could result in unsafe operation or the violation of technical specification.

Level D – Includes those HEOs for which the related potential error is associated with a nonsafety-related function, but could result in a plant outage or significant financial loss.

Level E – Includes those HEEs for which the related potential error is associated with either a safety-related function or a nonsafety-related function, but could not result in unsafe operation, the violation of technical specification, a plant outage, or a significant financial loss.

The NMP-2 DCRDR Review Team reviewed and discussed each HEO. They assigned a category of risk and a level of adverse effects to each HEO. NMPC states that where there was disagreement among team members, the highest category and level of those chosen by the team members was assigned to the HEO by the team leader.

After the categories of risk and the levels of adverse effect were assigned to HEOs, the review team reviewed each HEO to determine the significance of the HEO and to select a corrective action. Those HEOs that were determined to be significant were defined as NMP-2 human engineering deficiencies (HEDs). The NMP-2 HEDs were HEOs that were potential sources of operator error that could compromise plant safety or that could affect plant operability or availability in a manner unacceptable to management. NMPC states that all significant HEOs that have been defined as NMP-2 HEDs will be corrected.

The 74 HEOs designated 1A, 1B, 1D, 2C, and 2D became HEDs. All of the 145 Category 3 HEOs were assessed by the review team to make a concensus judgment of their significance. The review team classified 126 of the Category 3 HEOs as HEDs.

NMPC will need to apply this assessment process to any additional HEOs that may result from the completion of unfinished portions of the DCRDR.

2.5.3 Conclusions

The NMP-2 DCRDR Summary Report provides satisfactory responses to the concerns about the classification system and the assessment process that were stated in the NRC DCRDR In-Progress Audit Report for NMP-2.

NMPC should summarize the assessment and disposition of all HEOs identified during completion of unfinished portions of the DCRDR in a supplement to the NMP-2 DCRDR Summary Report.

The NMPC assessment process performed to date partially fulfills the requirement of Supplement 1 to NUREG-0737. It is expected that continued application of this process to assess discrepancies identified during completion of the unfinished DCRDR items will fully satisfy the NUREG-0737 requirement for HED assessment.

2.6 SELECTION OF DESIGN IMPROVEMENTS

2.6.1 Requirement

Supplement 1 to NUREG-0737 requires the selection of control room improvements that will correct significant HEDs. It also states that improvements that can be accomplished with an enhancement program should be done promptly.

2.6.2 Findings

The NMP-2 DCRDR Review Team reviewed all discrepancies classified as HEDs and determined whether they should be corrected by enhancement techniques or by a separate design effort. Recommendations for enhancements were developed by the review team. Corrections that involved a design change were approached as a separate design effort. The review team made preliminary design change recommendations that included design objectives and a scope of work for HED corrections that required a design effort.

After the review team completed assessment and categorization of NMP-2 HEOs, determination of HEDs that should be corrected, and selection of recommended enhancements or design changes to correct NMP-2 HEDs, the NMP-2 DCRDR Review Team findings and recommendations were submitted to the NMP-2 DCRDR Management Team.

The management team reviewed all HEOs and HEDs. It assigned an implementation schedule for correction of all HEDs.

The management team DCRDR HEO/HED package, including their recommended implementation schedule, was submitted to the NMPC Executive Team for corporate level approval. After executive team approval, all of the HEDs requiring corrective actions were sent to the parties responsible for implementing the correction. Enhancement and design fixes went to SWEC for implementation, training fixes went to the NMPC Training Department, and procedural changes went to the NMPC Operations or Engineering Departments, as appropriate.

The NMP-2 DCRDR Summary Report also states that NMPC was conducting seven (7) special corrective action studies to satisfactorily complete the corrective actions that resulted from the DCRDR findings. These corrective action studies were:

1. Center Desk Study
2. Annunciator Study
3. Inventory Discrepancy Study
4. Zone Banding Study
5. Labeling Study
6. Follow-Up to Solution Packages
7. Human Factors Design Manual

The completion status of these correction studies was not specific. The summary report states, "These studies have either been completed of are presently being performed".

The follow-up role of the NMP-2 DCRDR Review Team in the final design and implementation of HED corrective actions that have been turned over to SWEC is not clear. The NMPC process to monitor and control human factors aspects of design changes during implementation of HED corrections is not provided. Human factors evaluation of the implementation of any final design changes that differ substantially from the review team's preliminary design recommendations is of particular concern.

2.6.3 Conclusions

The NMPC process to select control room improvements that will correct significant HEDs meets the intent of NUREG-0737. Corrective actions for significant HEDs that are identified during completion of unfinished DCRDR activities will be needed.

Completion of the special corrective action studies and final determination and human factors evaluation of design changes that will satisfactorily correct HEDs requiring a design effort are also needed.

NMPC should report the results of corrective action studies, final determination of design changes, and corrective actions resulting from the completion of unfinished DCRDR activities to the NRC in a supplement to the DCRDR Summary Report. These DCRDR activities should be completed on a schedule acceptable to the NRC.

NMPC should describe the actions taken to monitor and control the development and implementation of HED corrective actions that require design changes. NMPC should ensure that the human factors aspects of the final design to correct each HED conforms to the DCRDR Review Team's preliminary design recommendations or to good human factors practice.

Upon completion of unfinished actions and after satisfactorily addressing the concerns about monitoring and controlling implementation of design changes, the NMP-2 program to select and implement HED corrections is expected to satisfy the requirement of Supplement 1 to NUREG-0737.

2.7 VERIFICATION THAT DESIGN IMPROVEMENTS PROVIDE NECESSARY CORRECTION AND DO NOT INTRODUCE NEW HEDs

2.7.1 Requirement

Supplement 1 to NUREG-0737 requires verification that selected design improvements will provide the necessary correction and will not introduce new HEDs into the control room.

2.7.2 Findings

The NMP-2 DCRDR Summary Report states the NMPC will verify and validate the final results of design efforts initiated after the completion of the DCRDR using the same methods that were used earlier in the DCRDR. The NMP-2 control room verification and validation processes are summarized in Section 2.3.2 of this report.

NMPC stated that the objective of the task verification process was to assure that operator tasks can be performed in the existing control room with minimum potential for human error. The NMP-2 verification process addressed availability and suitability of control room equipment.

NMPC stated that the objective of the validation process was to determine if the functions allocated to the control room operating crew can be accomplished effectively within the structure of the established emergency procedures and the design of the control room.

NMPC has not provided information about how and when these verification and validation techniques will be used to confirm that HED corrective actions provide acceptable improvements and do not introduce new HEDs.

2.7.3 Conclusions

The verification and validation methods that NMPC used earlier in the DCRDR can be used to satisfy the NUREG-0737 requirement to verify that selected design improvements will provide the necessary correction of HEDs and will not introduce new HEDs.

However, NMPC has not supplied enough information to determine that these methods will be used appropriately to evaluate selected HED corrective actions and design changes. NMPC should describe this process to the NRC and should provide a schedule of when this evaluation will be made. Completion of the verification and validation of HED corrective actions should be reported to the NRC in a supplement to the DCRDR Summary Report.

The NMP-2 DCRDR has not satisfied the requirement of Supplement 1 to NUREG-0737 to verify that selected design improvements will provide the necessary correction of HEDs and will not introduce new HEDs.

2.8 COORDINATION OF THE DCRDR WITH OTHER PROGRAMS

2.8.1 Requirement

Supplement 1 to NUREG-0737 requires that control room improvements be coordinated with changes from other programs: e.g., Safety Parameter Display System (SPDS); operator training, Regulatory Guide 1.97 (R.G. 1.97) instrumentation, and upgraded emergency operating procedures (EOPs).

2.8.2 Findings

NMPC states that a coordinated program headed by NMPC Project Engineering addressed each of the NUREG-0737, Supplement 1, initiatives. This program provided coordination and support to ensure that a systematic approach was used to integrate design changes resulting from the control room improvement activities. The coordinated program was also used to optimize the interfaces within the control room network.

NMPC states that Regulatory Guide 1.97 post accident monitoring instrumentation displays were incorporated into the control room hardware prior to commencing the DCRDR and were reviewed during the DCRDR.

The NMP-2 plant specific EPGs were used to perform he DCRDR task analysis. NMPC states that the lead author of the NMP-2 EPGs and EOPs was a key DCRDR participant.

NMPC states that training department personnel were involved at both the DCRDR Review Team and DCRDR Management Team levels to assure proper retraining of operators and upgrading of procedures to reflect physical changes made in the control room.

The SPDS System Engineer was a member of the DCRDR Review Team and coordinated SPDS design information to DCRDR concerns.

NMPC states that corrective action modifications resulting from the DCRDR will be evaluated for their effects on NUREG-0737, Supplement 1, initiatives. Review of future design changes in accordance with the NMP-2 Human Factors Design Manual will be incorporated as a requirement in the NMPC Engineering Procedures.

2.8.3 Conclusions

The NMP-2 DCRDR was coordinated with other control room improvement programs. It satisfies the requirement of Supplement 1 to NUREG-0737 that control room improvements be coordinated with changes from other programs.

3. CONCLUSIONS

The NMP-2 DCRDR partially fulfills the DCRDR requirements of Supplement 1 to NUREG-0737. We recommend that NMPC take the following actions to complete a satisfactory DCRDR of NMP-2.

- Prior to NMP-2 reactor startup, NMPC should confirm that:

  1. changes made since June 1985 in operator information and control requirements resulting from changes in the NMP-2 EOPs and SFTA, and

  2. changes in control room equipment resulting from changes in control room design or equipment specifications

  have been appropriately compared and reviewed for human factors suitability.

- NMPC should identify any topics where NUREG-0700 criteria were not used for the NMP-2 control room checklist review and any topic areas where other human factors criteria were used. NMPC should justify deviations from the NUREG-0700 criteria to the NRC and should specifically identify other human factors criteria used.

- NMPC should report to the NRC in a supplement to the NMP-2 DCRDR Summary Report:

  - Completion of incomplete control room survey items

  - Assessment and disposition of all HEOs identified during completion of unfinished portions of the DCRDR

  - Results of the special corrective action studies

  - Final determination and human factors evaluation of design changes to correct HEDs that required a design effort

  - Implementation plans for corrective actions that result from the completion of unfinished DCRDR activities.

  These DCRDR activities should be completed on a schedule acceptable to the NRC.

- NMPC should describe the actions taken to monitor and control the development and implementation of HED corrective actions that require design changes. NMPC should to ensure that the human factors aspects of the final design to correct each HED conforms to the DCRDR Review Team's preliminary design recommendations or to good human factors practice.

- The NMP-2 DCRDR has not satisfied the requirement of Supplement 1 to NUREG-0737 to verify that selected design improvements will provide the necessary correction of HEDs and will not introduce new HEDs. NMPC has not supplied enough information to determine that the verification and validation methods used earlier in the DCRDR will be used appropriately to evaluate implementation of selected HED corrective actions and design changes. NMPC should describe this process to the NRC and should provide a schedule of when this evaluation will be made. The verification and validation of HED corrective actions should be reported to the NRC in a supplement to the NMP-2 DCRDR Summary Report.

After NMPC completes unfinished DCRDR activities and provides to the NRC satisfactory responses to the open items noted above, it is expected that the NMP-2 DCRDR will fully satisfy the DCRDR requirements of Supplement 1 to NUREG-0737.

4. REFERENCES

1. NUREG-0600, "NRC Action Plan Developed as a Result of the TMI-2 Accident, May 1980," Revision 1, August 1980.

2. NUREG-0737, "Clarification of the TMI Action Plan Requirements," November 1980.

3. NUREG-0737, "Clarification of TMI Action Plan Requirements," Supplement 1, December 1982.

4. NUREG-0700, "Guidelines for Control Room Design Reviews," September 1981.

5. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Section 18.1, Appendix A, "Evaluation Criteria for Detailed Control Room Design Reviews," September 1984.

6. Program Plan Report, Detailed Control Room Design Review Nine Mile Point Nuclear Power Station—Unit 2, Niagara Mohawk Power Corporation, June, 1984.

7. "Staff Comments on the Nine Mile Point Nuclear Station Unit 2 Detailed Control Room Design Review Program," letter from A. Schwencer to B.G. Hooten, February 6, 1985.

8. In-Progress Audit Report of the Nine Mile Point, Unit 2, Detailed Control Room Design Review, May 16, 1985.

9. Nine Mile Point Unit 2 Detailed Control Room Design Review, Final Summary Report Program Implementation, September 1985.

APPENDIX L

FEDERAL EMERGENCY MANAGEMENT AGENCY FINDING ON STATE AND LOCAL EMERGENCY PLANS AND PREPAREDNESS FOR THE NINE MILE POINT NUCLEAR STATION

Federal Emergency Management Agency

Washington, D.C. 20472

February 1, 1985

Mr. William J. Dircks
Executive Director for Operations
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Dircks

In accordance with the Federal Emergency Management Agency (FEMA) rule 44 CFR 350, the State of New York submitted its State and associated local plans for radiological emergencies related to the Nine-Mile Point/ James A. Fitzpatrick Nuclear Power Generating Stations to the Regional Director of FEMA Region II for FEMA review and approval. The Regional Director forwarded his evaluation of the New York State and local plans to me on September 28, 1984, in accordance with section 350.11 of the rule. His submission included an evaluation of the full-scale exercises conducted September 15, 1981, August 11, 1982, and September 28, 1983, as well as a report of the public meeting held on November 4, 1981, for the Nine-Mile Point/James A. Fitzpatrick Nuclear Power Generating Stations which explained the site-specific aspects of the State and local plans.

Based on an overall evaluation, I find and determine that the State and local plans and preparedness for Nine-Mile Point/James A. Fitzpatrick Nuclear Power Generating Stations are adequate to protect the health and safety of the public in that there is reasonable assurance that the appropriate protective measures can be taken offsite in the event of a radiological emergency. The adequacy of the public alerting and notification system has also been verified by FEMA in accordance with the criteria in FEMA 44 CFR 350 and in Appendix 3 of NUREG-0654/FEMA-REP-1, Rev.1, and in the "Standard Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants" (FEMA-43).

The enclosed report entitled "Nine-Mile Point/Fitzpatrick Nuclear Power Plants Site-Specific Offsite Radiological Emergency Preparedness Alert and Notification System Quality Assurance Verification" summarizes the engineering design review, incorporates the results of the telephone survey of the public conducted immediately following the alert and notification system activation on November 16, 1984, and includes the results of the review of the other applicable evaluative criteria from NUREG-0654/FEMA-REP-1, Rev. 1, and FEMA-43.

Sincerely,

Samuel W. Speck

Samuel W. Speck
Associate Director
State and Local Programs
and Support

Enclosure

NRC FORM 335 (2-84) NRCM 1102, 3201, 3202 U.S. NUCLEAR REGULATORY COMMISSION **BIBLIOGRAPHIC DATA SHEET** SEE INSTRUCTIONS ON THE REVERSE.	1. REPORT NUMBER (Assigned by TIDC, add Vol. No., if any) NUREG-1047 Supplement No. 3
2. TITLE AND SUBTITLE Safety Evaluation Report related to the operation of Nine Mile Point Nuclear Station, Unit No. 2	3. LEAVE BLANK
	4. DATE REPORT COMPLETED MONTH: July YEAR: 1986
5. AUTHOR(S)	6. DATE REPORT ISSUED MONTH: July YEAR: 1986
7. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code) Division of BWR Licensing Office of Nuclear Reactor Regulation U. S. Nuclear Regulatory Commission Washington, D. C. 20555	8. PROJECT/TASK/WORK UNIT NUMBER
	9. FIN OR GRANT NUMBER
10. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code) Same as 7. above	11a. TYPE OF REPORT Supplement No. 3 to the Safety Evaluation Report
	b. PERIOD COVERED (Inclusive dates)
12. SUPPLEMENTARY NOTES Pertains to Docket No. 50-410	

13. ABSTRACT (200 words or less)

This report supplements the Safety Evaluation Report (NUREG-1047, February 1985) for the application filed by Niagara Mohawk Power Corporation, as applicant and co-owner, for a license to operate the Nine Mile Point Nuclear Station, Unit No. 2 (Docket No. 50-410). It has been prepared by the Office of Nuclear Reactor Regulation of the U. S. Nuclear Regulatory Commission. The facility is located near Oswego, New York.

Supplement 1 to the Safety Evaluation Report was published in June 1985 and contained the report from the Advisory Committee on Reactor Safeguards as well as the resolution to a number of outstanding issues from the Safety Evaluation Report. Supplement 2 was published in November 1985 and contained the resolution to a number of outstanding and confirmatory issues.

Subject to favorable resolution of the issues discussed in this report, the NRC staff concludes that the facility can be operated by the applicant without endangering the health and safety of the public.

14. DOCUMENT ANALYSIS – a. KEYWORDS/DESCRIPTORS	15. AVAILABILITY STATEMENT Unlimited
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