Docket No. 50-461

AUG 2 2 1985

NOTE TO: File

FROM: Byron L. Siegel, Project Manager
Licensing Branch, No. 2
Division of Licensing

SUBJECT: CLINTON POWER STATION DRAFT SER SUPPLEMENT # 5

A copy of enclosed draft SER Supplement No. 5 for Clinton Power Station was provided to the applicant to apprise them of the status of remaining issues for which the staff has completed part or all of it's review.

Byron L. Siegel, Project Manager
Licensing Branch No. 2
Division of Licensing

Enclosure: As stated

Noted:
W. R. Butler

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ABSTRACT

Supplement No. 5 to the Safety Evaluation Report on the application filed by Illinois Power Company, Soyland Power Cooperative, Inc., and Western Illinois Power Cooperative, Inc. as applicants and owners, for a license to operate the Clinton Power Station, Unit No. 1, has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. The facility is located in Harp Township, DeWitt County, Illinois. This supplement reports the status of items that have been resolved by the staff since Supplement No. 4 was issued.

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1 INTRODUCTION AND GENERAL DESCRIPTION

1.1 Introduction

The Nuclear Regulatory Commission staff (referred to as the NRC staff or staff) issued its Safety Evaluation Report (SER) (NUREG-0853) in February 1982 regarding the application by Illinois Power Company, et al. (hereinafter referred to as the applicant) for a license to operate the Clinton Power Station, Unit No. 1, Docket No. 50-461. Supplement No. 1 (SSER 1) to the Clinton SER was issued in July 1982; SSER 2 was issued in May 1983; SSER 3 was issued in May 1984; and SSER 4 was issued February 1985. The purpose of this fifth supplement (SSER 5) is to further update the SER by providing results of the NRC staff's review of information submitted by the applicant to address some of the unresolved issues listed in Sections 1.9 and 1.10 and license conditions listed in Section 1.11 of the SER.

Each section and appendix of this supplement is numbered and titled so that it corresponds to the section or appendix of the SER that is relevant to the NRC staff's additional evaluation. Except where specifically noted, the material in this supplement does not replace the material in the corresponding SER section or appendix. Appendix A is a continuation of the chronology of correspondence between NRC and the applicant and updates the lists in the SER and in SSER 1 through SSER 4. Appendix B is a list of references cited in this report.* Appendix D is a list of principal staff contributors to this supplement. Appendix F corrects errors in the SER and its supplements. Appendices G and H consist of two reports prepared for the NRC which are cited in Sections 7 and 9, respectively, of this SER supplement.

Copies of this SER supplement are available for inspection at the NRC Public Document Room at 1717 H Street, N.W., Washington, D.C., and at the Warner Vespasian Library, Clinton, Illinois. Copies are also available for purchase from the sources indicated on the inside front cover.

The NRC Project Manager assigned to the operating license application for Clinton Unit 1 is Byron L. Siegel. Mr. Siegel may be contacted by calling (301) 492-8344 or by writing to

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1.9 Outstanding Issues

In SER Section 1.9, the NRC staff identified 20 outstanding issues that had not been resolved at the time the document was issued. SSER 1 reported that 4 of

*The availability of the material cited is described on the inside front cover of this report.

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those items had been satisfactorily resolved and 1 had been changed to a confirmatory status.* SSER 2 reported that 6 items had either been resolved or changed to a confirmatory status. SSER 3 reported that 4 items had been resolved. SSER 4 partially resolved 1 item and reopened another item. Therefore, 7 outstanding issues remained that had not yet been resolved after the issuance of SSER 4.

The present supplement (SSER 5) resolves _____ outstanding issues. The current status of each of the 20 original issues is tabulated below. For those items discussed in this supplement, the relevant sections in this document are indicated. Resolution of issues that are, to date, unresolved will be reported in future supplements.

Issue		Status	SSER 5 Section(s)
(1)	Transportation accidents	Resolved in SSER 3	--
(2)	Effects of Unit 2 excavation	Resolved in SSER 2	--
(3)	Seismic analysis	Became confirmatory issue 70, resolved in SSER 3	--
(4)	Internally generated missiles	Resolved in SSER 1	--
(5)	Postulated piping failures	Under review	--
(6)	Steady-state vibration acceptance criteria for balance of plant piping	Resolved in SSER 2	--
(7a)	Environmental qualification of electrical and mechanical equipment	Resolved in this SSER except for mechanical equipment, 3.11.3.2(2)	3.11
(7b)	Seismic and dynamic qualification of mechanical and electrical equipment	Under review	--
(7c)	Pump and valve operability qualification	Under review	--
(8)	Preservice (PSI) and inservice inspection (ISI) programs	PSI program: became confirmatory issue 67 in SSER 1 ISI program: became license condition 12 in SSER 2	--
(8a)	Preservice and inservice testing of pumps and valves	Became confirmatory issue 68 in SSER 1	--

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Issue		Status	SSER 5 Section(s)
(9)	Pool dynamic loads	Under review	--
(10a)	Containment purge	Became confirmatory issue 69 in SSER 2	--
(10b)	Containment isolation	Resolved in SSER 2	--
(10c)	Containment leakage testing (vent and drain lines)	Resolved in SSER 2	--
(10d)	Containment leakage testing (secondary containment)	Resolved in SSER 2	--
(10e)	Containment bypass leakage	Resolved in SSER 2	--
(11)	Control room habitability	Resolved in SSER 1	--
(12)	Engineered safety features reset controls (IE Bulletin 80-06)	Resolved in SSER 2	--
(13)	Remote shutdown system	Partially resolved in SSER 3	--
(14)	Capability for safe shutdown following loss of bus supplying power to instruments and controls (IE Bulletin 79-27)	Resolved in SSER 2	--
(15)	Control system failures resulting from high-energy-line breaks or common power source or sensor malfunctions	Under review	--
(16)	Separation of the RPS and MSIV solenoid circuits and PGCC circuits	Resolved in SSER 1	--
(17)	Organization and staffing	Under review	--
(18a)	Onsite emergency plan	Resolved in SSER 4	--
(18b)	Offsite emergency plan	Awaiting information	--
(19)	Security	Resolved in SSER 1	--
(20)	QA program	Resolved in SSER 3	--

1.10 Confirmatory Issues

In SER Section 1.10, the NRC staff identified 66 confirmatory issues for which additional information and documentation were required to confirm preliminary

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conclusions. SSER 1 reported that 28 of those items had been satisfactorily resolved. SSER 2 addressed 11 additional issues that have been resolved, as well as certain issues that still require resolution. SSER 3 addressed 9 additional issues that have been resolved. SSER 4 addressed 10 additional issues that have been totally resolved and 2 that have been partially resolved. The present supplement (SSER 5) totally resolves ______ confirmatory issues. The current status of each of the 66 original issues is tabulated below. Four issues (67, 68, 69, and 70) that previously had been outstanding issues in SSER 1 were added to the confirmatory list in SSER 2. Resolution of confirmatory issues that are, to date, unresolved will be reported in future supplements.

Issue		Status	SSER 5 Section(s)
(1)	Emergency preparedness meteorological program	Under review - Section 2.3.3 updated in SSER 3	--
(2)	Inspection program around the ultimate heat sink (UHS) and the main cooling lake dam	Resolved in SSER 1	--
(3)	Protection of UHS dam abutments against soil erosion	Resolved in SSER 1	--
(4)	Internally generated missiles - fan failures	Resolved in SSER 2	
(5)	Design adequacy of cable tray system	Resolved in SSER 1	--
(6)	Containment ultimate strength analysis	Removed from list in SSER 4	--
(7)	Structural integrity of safety-related masonry walls	Resolved in SSER 2	--
(8)	NSSS pipe break analysis using SRP criteria	Resolved in SSER 1	--
(9)	Vibration assessment of RPV internals	Resolved in SSER 4	--
(10)	Annulus pressurization loads (LOCA asymmetric loads)	Resolved in SSER 4	--
(11)	Use of SRSS for combining Mark III dynamic responses for other than LOCA and SSE	Resolved in SSER 1	--
(12)	IE Bulletin 79-02 regarding support baseplate flexibility	Resolved in SSER 2	--

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Issue		Status	SSER 5 Section(s)
(13)	Mark III hydrodynamic loads	Became part of out standing issue 9 to avoid duplication in SSER 4	--
(14)	Feedwater check valve analysis	Resolved in SSER 2	--
(15)	Seismic and LOCA loadings on fuel assemblies (LRG II Issue 2-CPB)	Resolved in SSER 4	--
(16)	Scram discharge system evaluation	Resolved in SSER 1	--
(17)	Fracture toughness data	Resolved in SSER 1	--
(18)	Subcompartment pressure analysis	Under review	--
(19)	Combustible gas control	Resolved in SSER 3	--
(20)	Containment isolation dependability	Resolved in SSER 2	--
(21)	Containment monitoring, II.F.1(1) through II.F.1(6)	Partially resolved in SSER 4 [II.F.1(1) and II.F.1(2) only remaining issues]	--
(22)	Plant-specific LOCA analysis, II.K.3.31	Resolved in SSER 3	--
(23)	High drywell pressure interlocks	Resolved in SSER 1	--
(24)	ATWS recirculation pump trip	Awaiting information	--
(25)	Response-time testing	Resolved in SSER 1	--
(26)	Analog trip modules and optical isolators	Resolved in SSER 2	--
(27)	Susceptibility of the NSPS to electrical noise	Resolved in SSER 1	--
(28)	Modification of ADS logic, II.K.3.18	Resolved in SSER 4	--
(29)	Restart of low-pressure systems, II.K.3.21	Resolved in SSER 1	--

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Issue		Status	SSER 5 Section(s)
(30)	Temperature effects on level measurements	Resolved in SSER 2	--
(31)	Containment atmosphere monitoring system	Resolved in SSER 4	--
(32)	Verification that testing is in accordance with BTP PSB-1	Removed from list in SSER 1	--
(33)	Electrical drawing review	Removed from list in SSER 1	--
(34)	Verification of diesel generator testing	Resolved in SSER 4	--
(35)	Class A supervision and power supply for fire detection system	Resolved in SSER 3	--
(36)	Circulating water system	Resolved in SSER 2	--
(37)	Initial test program	Resolved in SER	--
(38)	Human engineering aspects of control room design, I.D.1	Under review	--
(39)	Common reference for reactor vessel level instruments, II.K.3.27	Resolved in SSER 2	--
(40)	Shielding design review, II.B.2	Resolved in SSER 1	--
(41)	Short-term accident and procedures review, I.C.1, I.C.7, I.C.8	Partially resolved in SSER 4 (I.C.1 only remaining issue)	--
(42)	Training during low-power testing, I.G.1	Awaiting information	--
(43)	Review ESF values, II.K.1.5	Resolved in SSER 1	--
(44)	Operability status, II.K.1.10	Resolved in SSER 1	--
(45)	HPCI and RCIC initiation levels, II.K.3.13	Resolved in SSER 4	--
(46)	Isolation of HPCI and RCIC, II.K.3.15	Resolved in SSER 4	--
(47)	Qualification of ADS accumulators, II.K.3.28	Resolved in this SER	6.3.2.2

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Issue	Status	SSER 5 Section(s)
(48) Plant-specific analysis, II.K.3.30	Resolved in SSER 3	--
(49) ODYN analysis for River Bend as applied to Clinton	Resolved in SSER 1	--
(50) Conformance evaluation report for loose-parts monitoring system	Resolved in SSER 3	--
(51) Requirements of NUREG-0313	Resolved in SSER 1	--
(52) Control room habitability - chlorine gas	Resolved in SSER 1	--
(53) Debris screen design	Resolved in SSER 2	--
(54) Verification of adequacy of fire protection systems	Removed from list in SSER 1	--
(55) Flood-proof door	Resolved in SSER 2	--
(56) Valves in fire protection water supply system	Resolved in SSER 1	--
(57) Break in water supply piping	Resolved in SSER 1	--
(58) Test data on fire ratings	Resolved in SSER 3	--
(59) Three-hour-fire-rated penetration seals	Resolved in SSER 3	--
(60) Install fire protection equipment (emergency lighting)	Resolved in SSER 3	--
(61) Fire protection administrative controls and training	Resolved in SSER 1	--
(62) Technical Specification on fire protection	Resolved in SSER 1	--
(63) Periodic leak testing of pressure isolation values	Resolved in SSER 1	--
(64) Sedimentation in UHS	Resolved in SSER 1	--
(65) Protection against postulated piping failures	Resolved in SSER 1	--
(66) Steam bypass of the suppression pool (LRG II Issue 3-CSB)	Under review	--

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Issue		Status	SSER 5 Section(s)
(67)	Preservice inspection program	Under review	--
(68)	Preservice testing of pumps and valves	Under review	--
(69a)	Containment low-volume purge system	Partially resolved in this SSER	6.2.1.4
(69b)	Low-volume purge valve operability	Under review	--
(70)	Seismic analysis	Resolved in SSER 3	--
(71)	Humphrey concerns	Under review	--

1.11 License Conditions

In SER Section 1.11, the NRC staff identified nine potential license conditions that may be required as part of the operating license for Clinton Unit 1 to ensure that NRC requirements are met during plant operations. Two additional potential license conditions (10 and 11) were identified in SSER 1, and SSER 2 identified two additional conditions (12 and 13), as well as one (6) for which additional requirements were imposed. One condition (14) was added in SSER 3. The present supplement (SSER 5) adds two conditions (15 and 16) and eliminates the need for _____ license conditions. The current status of these issues and the sections in which they are resolved are shown below.

Issue		Status	SSER 5 Section(s)
(1)	Staffing DeWitt pumping station	Resolved in this SSER	2.2.2
(2)	New stability analysis before second cycle of operation	Awaiting information	--
(3)	Postaccident monitoring	Resolved in this SSER	7.5.3.1
(4)	Vacuum relief valve position indication	Awaiting information	--
(5)	Hydrogen management	Under review	--
(6)	Postaccident sampling, II.B.3	Resolved in this SSER	9.3.5
(7)	Diesel generator reliability	Awaiting information	--
(8)	Kuosheng-1 test program	Resolved in SSER 4	--
(9)	Visual examination of discharged fuel	Resolved in this SSER	4.2.3.9

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Issue		Status	SSER 5 Section(s)
(10)	Measurement of groundwater level	Resolved in this SSER	2.4.6
(11)	Security	Under review	--
(12)	Inservice inspection	Under review	--
(13)	Control of heavy loads	Resolved in this SSER	9.1.5
(14)	Transportation accidents	Under review	--
(15)	Fuel zone level channels	Added in this SSER	7.5.3.1
(16)	Partial feedwater heating	Added in this SSER	15.1
(17)	ERF appraisal	Added in this SSER	13.1.2.3
(18)	Emergency facilities and equipment	Added in this SER	13.3.2.8

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. Illinois Power Company has signed a contractual agreement with the Department of Energy dated July 6, 1984.

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2 SITE CHARACTERISTICS

2.2 Nearby Industrial, Transportation, and Military Facilities

2.2.2 Nearby Facilities

In the SER, the staff stated that the applicant should commit to exercise paragraph III-2(a)(2) of the formal agreement between Shell Oil Company and the applicant related to the stationing of a Shell employee at the DeWitt pumping station during shipment of propane through a pipeline that traverses the land near the station exclusion area and that this agreement should be extended to include butane shipments. This was identified as license condition 1, "Staffing DeWitt pumping station," in the SER.

By letter dated June 7, 1985, the applicant has committed to incorporate into FSAR Amendment 34 the revised wording of a modified agreement between Shell Oil Company and the applicant, dated March 2, 1982, which incorporates the shipment of butane as well as propane into the agreement.

By letter dated July 1, 1985, the applicant has committed to exercise paragraph III-2(a)(2) of the agreement between itself and Shell Oil Company and to incorporate this commitment in the next FSAR amendment.

On the basis of the commitments contained in these letters, the staff has determined that license condition 1 is no longer required.

2.4 Hydrology

2.4.6 Groundwater

In SSER 1 the staff stated that a license condition (license condition 10) would be placed on the Clinton operating license to ensure that piezometers will be installed in the vicinity of the power block before either the construction of Unit 2 continues or the backfilling of the excavation of Unit 2 commences to verify the groundwater level used for the main plant hydrostatic loading.

In FSAR Amendment 14, the applicant committed to installing piezometers under the conditions stated for the proposed licensing condition. In Amendment 14, the applicant also stated that the excavation for Unit 2 will remain open and the slopes of the backfill adjacent to Unit 1 structures will be graded. After grading, a revetment composed of a grout intrusion blanket will be placed on these slopes to protect them against erosion caused by runoff. A berm consisting of type A cohesive material will be placed and compacted around the perimeter of the excavation to divert floodwater runoff from entering the excavation. This berm material will be compacted to 90% of the maximum dry density as determined by ASTM D-1557. No berm will be placed across the construction ramp.

A drainage system will be utilized to drain any precipitation that enters the excavation. A flap gate will be used to prevent a backflow from the lake into

the excavation if the lake level rises above the invert elevation of the drainage system. In addition to the drainage system, all openings in the Unit 1 building below grade level that are exposed in the Unit 2 excavation will be closed and waterproofed.

On the basis of the commitments made by the applicant in FSAR Amendment 14, the staff has determined that license condition 10 is no longer required.

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3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

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

3.6.2 Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment

3.6.2.1 Elimination of Arbitrary Intermediate Pipe Breaks

3.6.2.1.1 Introduction and Background

In the "Background" to Branch Technical Position (BTP) MEB 3-1 as presented in SRP Section 3.6.2, the staff position on pipe break postulation acknowledged that pipe rupture is a rare event which may only occur under unanticipated conditions such as those which might be caused by possible design, construction, or operation errors, unanticipated loads, or unanticipated corrosive environments. The BTP MEB 3-1 pipe break criteria were intended to utilize a technically practical approach to ensure that an adequate level of protection had been provided to satisfy the requirements of GDC 4. Specific guidelines were developed in BTP MEB 3-1 to define explicitly how the requirements of GDC 4 were to be implemented. The guidelines in BTP MEB 3-1 were not intended to be absolute requirements but rather represent viable approaches considered to be acceptable by the staff.

The SRP provides a well-defined basis for performing safety reviews of light-water reactors. The uniform implementation of design guidelines in BTP MEB 3-1 ensures that a consistent level of safety will be maintained during the licensing process. Alternative criteria and deviations from the SRP are acceptable provided an equivalent level of safety can be demonstrated. Acceptable reasons for deviations from SRP guidelines include changes in emphasis of specific guidelines as a result of new developments from operating experience or plant-unique design features not considered when the SRP guidelines were developed.

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The SRP presents the most definitive basis available for specifying NRC's design criteria and design guidelines for an acceptable level of safety for light-water-reactor facility reviews. The SRP guidelines resulted from many years of experience gained by the staff in establishing and using regulatory requirements in the safety evaluation of nuclear facilities. The SRP is part of a continuing regulatory standards development activity that not only documents current methods of review, but also provides a basis for an orderly modification of the review process when the need arises to clarify the content, correct any errors, or modify the guidelines as a result of technical advancements or an accumulation of operating experience. Proposals to modify the guidelines in the SRP are considered for their impact on matters of major safety significance.

The staff has recently received a letter from the applicant (April 16, 1985) requesting the staff to consider an alternate approach to the existing guidelines in BTP MEB 3-1 regarding the postulation of intermediate pipe breaks. For all high energy piping systems identified in the April 16 letter, the applicant proposes to eliminate from design considerations those breaks generally referred to as "arbitrary intermediate breaks" (AIBs) which are defined as those break locations which, based on piping stress analysis results, are below the stress and fatigue limits specified in BTP MEB 3-1, but are selected to provide a minimum of two postulated breaks between the terminal ends of a piping system. The applicant has documented the benefits such as reduced radiation exposure benefits resulting from the elimination of the structures associated with the protection against the effects of pipe rupture. The applicant has further stated that all dynamic effects associated with previously postulated arbitrary intermediate pipe breaks will be excluded from the plant design basis. However, since design and construction of pipewhip restraints associated with previously postulated arbitrary intermediate pipe breaks ~~is~~ are essentially complete, it does not anticipate removing any of the installed restraints at this time. The applicant is requesting approval of alternative pipe break criteria to provide the flexibility to remove or not to shim restraints in the future, if deemed necessary. However, the applicant has stated that the elimination of AIBs will not downgrade the environmental qualification levels of Class 1E equipment. The break postulation for environmental effects is performed independently of break postulation for pipewhip and jet impingement.

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In the early 1970s when the pipe break criteria in BTP MEB 3-1 were first drafted, the advantages of maintaining low stress and usage factor limits were clearly recognized, but it was also believed that equipment in close proximity to the piping throughout its run might not be adequately designed for the environmental consequences of a postulated pipe break if the break postulation proceeded on a purely mechanistic basis using only high stress and terminal end breaks. As the pipe break criteria were implemented by the industry, the impact of the pipe break criteria became apparent on plant reliability and costs as well as on plant safety. Although the overall criteria in BTP MEB 3-1 have resulted in a viable method which ensures that adequate protection has been provided to satisfy the requirements of GDC 4, it has become apparent that the particular criterion requiring the postulation of arbitrary intermediate pipe breaks can be overly restrictive and may result in an excessive number of pipe rupture protection devices which do not provide a compensating level of safety.

At the time the BTP MEB 3-1 criteria were first drafted, high energy leakage cracks were not being postulated. In Revision 1 to the SRP (July 1981), the concept of using high energy leakage cracks to mechanistically achieve the environment desired for equipment qualification was introduced to cover areas which are below the high stress/fatigue limit break criteria and which would otherwise not be enveloped by a postulated break in a high energy line. In the proposed elimination of arbitrary intermediate breaks, the staff believes that the essential design requirement of equipment qualification is not only being retained but is being improved since all safety-related equipment is to be qualified environmentally, and furthermore certain elements of construction which may lead to reduced reliability are being eliminated.

In addition, some requirements which have developed over the years as part of the licensing process have resulted in additional safety margins that overlap the safety margin provided in the pipe break criteria. For example, the criteria in BTP MEB 3-1 include margins to account for the possibility of flaws that might remain undetected in construction and to account for unanticipated piping steady-state vibratory loadings not readily determined in the design process. However, inservice inspection requirements for the life of the plant to detect flaws before they become critical, and staff positions on the vibration monitoring of safety-related and high energy piping systems during preoperational testing, further reduce the potential for pipe failures occurring from these causes.

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Because of the recent interest expressed by the industry to eliminate the arbitrary intermediate break criteria and, particularly, in response to the detailed submittals provided by several utilities including the applicant, the staff has reviewed the BTP MEB 3-1 pipe break criteria to determine where such changes may be made.

3.6.2.1.2 Applicant's Bases for the Elimination of Arbitrary Intermediate Pipe Breaks

In a letter dated April 16, 1985, the applicant submitted a request for the elimination of arbitrary intermediate breaks and provided the technical bases for its proposal. The applicant's submittal reflects a general consensus in the nuclear industry that current knowledge and experience support the conclusion that designing for the arbitrary intermediate pipe breaks is not justified. The reasons given for this conclusion are discussed in the following paragraphs.

(1) Operating Experience Does Not Support Need for Criteria

The applicant states that the combined operating history of commercial nuclear plants (extensive operating experience in more than 80 operating U.S. plants and a number of similar plants overseas) has not shown the need to provide protection from the dynamic effects of arbitrary intermediate breaks.

(2) Piping Stresses Well Below ASME Code Allowables

Currently, AIBs are postulated to provide a minimum of two pipe breaks at the two highest stress locations between piping terminal ends. Consequently, AIBs are postulated at locations in the piping system where pipe stresses and/or cumulative usage factors are well below ASME Code allowables. Such postulation necessitates the installation and maintenance of complicated mitigating devices to afford protection from dynamic effects such as pipewhip and/or jet impingement. When these selected break locations have stress levels only slightly greater than the rest of the system, installation of mitigating devices lends little to enhance overall plant safety.

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(3) Unanticipated Thermal Expansion Stress

Unanticipated stresses from restraint of thermal expansion can be introduced into the piping system if pipe rupture protection devices come into contact with the pipes. The potential for this happening is greater than that for mechanistic failure at an arbitrary break point. To prevent a consequent decrease in the overall reliability of the pipe system, an additional as-built verification step is involved in the design process for each installed pipe whip restraint. Elimination of AIBs would significantly reduce the effort involved in designing and installing pipe rupture protection devices.

(4) Access

Access during plant operation for maintenance and inservice inspection activities can be improved by the elimination of congestion created by these pipe rupture protection devices and the supporting structural steel associated with arbitrary pipe breaks.

(5) Reduction in Radiation Exposure

In addition to the decrease in maintenance effort, a corresponding reduction in man-rem exposure can be realized from fewer man-hours spent in radiation areas, in keeping with the "as low as reasonably achievable" (ALARA) guidance.

(6) Decrease in Heat Loss

The elimination of pipewhip restraints associated with arbitrary breaks will preclude the requirements for cutback insulation or special insulating assemblies near the close-fitting restraints. This will reduce the heat loss to the surrounding environment, especially inside containment.

3.6.2.1.3 Staff Evaluation of the Bases for the Elimination of Arbitrary Breaks

The technical bases for the elimination of the AIB criteria as discussed in ~~the~~ Section ~~B~~ ~~above~~ 3.6.2.1.2 provided many arguments supporting the applicant's conclusion

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that the current SRP guidelines on this subject should be changed. However, it is not apparent that a unilateral position by the applicant concluding an unconditional deletion of the AIB criteria can be justified without a clear understanding of the safety implications that may result for the various classes of high energy piping systems involved. In this section, the bases behind the current AIB criteria from an ASME Code design standpoint will be discussed and the uncertainty factors, on which the need to postulate AIBs should be evaluated, will be put into perspective.

Although the ASME Code design requirements for Class 1 piping systems differ from those for Class 2 and 3 piping systems, there are other design considerations that are common to Class 1, 2, and 3 systems. These other design considerations (viz., (1) intergranular stress corrosion cracking, (2) water/steam hammer, and (3) thermal fatigue) can affect the safety of the systems in which AIBs are eliminated. Therefore, while evaluating the acceptability of the applicant's proposed deviation from SRP Section 3.6.2, the significance will be examined of the above three additional design considerations for the specific Clinton piping systems proposed by the applicant for eliminating AIBs.

(1) <u>ASME Code Class 1 Piping Systems</u>

In accordance with BTP MEB 3-1 (paragraph B.1.c(1)) breaks in ASME Code Class 1 piping should be postulated at the following locations in each piping and branch run:

(a) at terminal ends

(b) at intermediate locations where the maximum stress range as calculated by Equation (10) and either Equation (12) or (13) of ASME Code NB-3650 exceeds 2.4 S_m

(c) at intermediate locations where the cumulative usage factor exceeds 0.1

~~(d)~~ If two intermediate locations cannot be determined by criteria (b) and (c) above, two highest stress locations based on Equation (10) should be selected;

and a, b, and c above
this constitute
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ko(?) The AIB criteria ~~are stated in (d) above~~. It should be noted that the request for alternative criteria does not propose to deviate from the criteria in (a), (b), and (c) above. Pipe breaks will continue to be postulated at terminal ends irrespective of the piping stresses.

Pipe breaks are to be postulated at intermediate locations where the maximum stress range as calculated by Equation (10) and either Equation (12) or (13) exceeds 2.4 S_m. The stress evaluation in Equation (10) represents a check of the primary plus secondary stress intensity range due to ranges of pressure, moments, thermal gradients, and combinations thereof. Equation (12) is intended to prevent formation of plastic hinges in the piping system caused only by moments due to thermal expansion and thermal anchor movements. Equation (13) represents a limitation for primary plus secondary membrane plus bending stress intensity excluding thermal bending and thermal expansion stresses; this limitation is intended to ensure that the K_e factor (strain concentration factor) is conservative. The K_e factor was developed to compensate for absence of elastic shakedown when primary plus secondary stresses exceed 3 S_m.

With respect to piping stresses, the pipe break criteria were not intended to imply that breaks will occur when the piping stress exceeded 2.4 S_m (80% of the primary plus secondary stress limit). It is the staff's belief, however, that if a pipe break were to occur (on one of those rare occasions), it is more likely to occur at a piping location where there is the least margin to the ultimate tensile strength. insert 1/2 c

Similarly, from a fatigue strength standpoint, the staff believes that a pipe break is more likely to occur where the piping is expected to experience large cyclic loadings. Although the staff concurs with the industry belief that a cumulative usage factor of 0.1 is a relatively low limit, the uncertainties involved in the design considerations with respect to the actual cyclic loadings experienced by the piping tend to be greater than the uncertainties involved in the design considerations used for the evaluation of primary and secondary stresses in piping systems. The staff finds that the conservative fatigue considerations in the current SRP guidelines provide an appropriate margin of safety against uncertainties for those locations where fatigue failures are likely to occur (e.g., at local welded attachments).

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(2) ASME Code Class 2 and 3 Piping Systems

In accordance with BTP MEB 3-1 [paragraph B.1.c.(2)] breaks in ASME Class 2 and 3 piping should be postulated at the following locations:

(a) at terminal ends

(b) at intermediate locations selected by one of the following criteria:

 (i) at each pipe fitting, welded attachment, and valve
 (ii) at each location where the stresses exceed 0.8 (1.2 S_h + S_A) but at not less than two separated locations chosen on the basis of highest stress.

In its proposal, the applicant has not proposed changing criterion (a) above. Postulation of pipe breaks at terminal ends will not be eliminated in the proposed SRP deviation for Class 2 and 3 piping systems irrespective of piping stresses.

The AIB criterion is stated in (b)(ii) above where breaks are to be postulated at intermediate locations where the stresses exceed 0.8 (1.2 S_h + S_A) but "at not less than two separated locations chosen on the basis of highest stress." The stress limit provided in the above pipe break criterion represents the stress associated with 80% of the combined primary and secondary stress limit. Thus, a break is required to be postulated where the maximum stress range, as calculated by the sum of Equations (9) and (10) of NC/ND-3652 of the ASME Code Section III, exceeds 80% of the combined primary and secondary stress limit, when those loads and conditions are considered for which level A and level B stress levels have been specified in the system's design specification (i.e., sustained loads, occasional loads, and thermal expansion) including an operating basis earthquake (OBE) event. However, the Class 2 and 3 pipe break criteria do not have a provision for the postulation of pipe breaks based on a fatigue limit since an explicit fatigue evaluation is not required in the ASME Code for these classes of construction because of favorable service experience and lower levels of operating cyclic stresses.

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For those Class 2 and 3 piping systems which experience a large number of stress cycles (e.g., main steam and feedwater systems), the ASME Code has provisions which are intended to address these types of loads. The rules governing considerations for welded attachments in ASME Code Class 2 and 3 piping which do preclude fatigue failure are partially given in paragraph NC/ND-3645 of the ASME Code. The Code states:

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> External and internal attachments to piping shall be designed so as not to cause flattening of the pipe, excessive localized bending stresses, or harmful thermal gradients in the pipe wall. It is important that such attachments be designed to minimize stress concentrations in applications where the number of stress cycles, due either to pressure or thermal effects, is relatively large for the expected life of the equipment.

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Code rules governing the fatigue effects associated with general bending stresses caused by thermal expansion are addressed in NC/ND-3611.2(e) and are generally incorporated into the piping stress analyses in the form of an allowable stress reduction factor.

Thus, it can be concluded that when the piping designers have appropriately considered the fatigue effects for Class 2 and 3 piping systems in accordance with NC/ND-3645, the likelihood of a fatigue failure in Class 2 and 3 piping caused by unanticipated cyclic loadings can be significantly reduced.

(3) Additional Design Considerations

In its presentation to the Advisory Committee on Reactor Safeguards (ACRS) on June 9, 1983, and in an October 5, 1983, meeting between a group of PWR near-term operating license utilities and the NRC staff, the staff indicated that the elimination of AIBs was not to apply to piping systems in which stress corrosion cracking, large unanticipated dynamic loads such as steam or water hammer, or thermal fatigue in fluid mixing situations could be expected to occur. In addition, the elimination of AIBs was to have no effect on the requirement to environmentally qualify safety-related equipment and, in fact, this requirement was to be clarified to ensure positive qualification requirements.

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(a) Intergranular Stress Corrosion Cracking

At Clinton, the applicant has taken steps to minimize the potential for intergranular stress corrosion cracking (IGSCC) in high energy lines. The IGSCC potential is likely to be reduced if the following factors are controlled: high residual tensile stresses, susceptible piping material and a corrosive environment. The NRC Piping Review Committee (NUREG-1061), Vol. 5, April 1985) has indicated the types of materials that are considered resistant to IGSCC. In addition, certain treatments given to the materials also will make them resistant to IGSCC. For example, stainless steel types 304L, 308L, and 316L are considered resistant to IGSCC. Also certain mitigating processes applied to the welds may reduce the likelihood of IGSCC.

The applicant has reported in a letter dated April 16, 1985, that, excepting the reactor recirculation piping, all austenitic stainless steel in contact with the reactor coolant is type 316L stainless steel which contains less than 0.03% carbon. In addition to using the proper~~ly~~ materials, the applicant has applied several process controls to reduce the likelihood of IGSCC. For example, the applicant purchased all austenitic stainless steel in the solution heat treated condition as per ASME and ASTM specifications. Welding heat input was restricted and interpass temperature was limited to 350°F. Inside diameter grinding of pipe welds was not allowed unless the pipe weld was subsequently solution annealed. These and similar controls were imposed to avoid severe sensitization and to comply with the intent of RG 1.44, "Control of the Use of Sensitized Stainless Steel."

Although reactor recirculation piping is fabricated primarily to type 304 stainless steel, certain portions of this piping have been changed to type 316L stainless steel that contains less than 0.03% carbon. For the remaining pipe, "corrosion-resistant cladding" has been applied near the field welds so that no heat-affected type 304 stainless steel will be in contact with the coolant. In the case of factory welding, the piping assemblies were all solution annealed after shop welding and cladding was applied ~~application of cladding~~ before the assemblies were ~~being~~ shipped to the field (letter from applicant, April 16, 1985). NUREG-1061 indicates that, in the event ~~that~~ any unanticipated severe conditions occurred, the break would most likely be located at terminal ends, at connections to components, and at other

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locations that introduce higher stress concentration or that exceed the stated threshold limits specified in SRP Section 3.6.2. Since breaks are postulated for these locations, the staff concurs with the applicant's conclusion that eliminati~~on of~~ng AIBs would not introduce adverse effects.

(b) Water/Steam Hammer

According to NUREG-0927, BWR plants report a higher frequency of water (steam) hammer events than PWR plants primarily because of two factors: line voiding and presence of steam-water interfaces in BWRs. Line voiding was the largest single cause of BWR water hammers and was responsible for at least 39 of the 69 unanticipated water hammer events in BWR plants that were reported from 1969 through mid-1981. NUREG-0927 also reports that the addition of keep-full systems to BWR systems has reduced the frequency of water hammers. Keep-full systems continuously supply water to stagnant lines to prevent voiding.

The applicant has incorporated several water hammer minimization features into piping design operations at Clinton. The discharge lines of the residual heat removal system, low-pressure core spray system, and high-pressure core spray system are maintained in a full condition. They are kept full up to the injection isolation valves by water leg pumps. Beyond the injection isolation valves, the line is not drained when the system is on standby, thus, maintaining the discharge lines full.

The steam supply line to the reactor core isolation cooling (RCIC) system turbine is built sloping downward to allow any moisture in the line to drain off to a condensing pot. The isolation valves on the steam supply line to the RCIC turbine are normally open, and automatically close on receiving an isolation signal (letter from applicant, April 16, 1985). After the isolation signal clears, the isolation valves are reopened by adopting a specific controlled procedure (which is the only way these valves can be opened after they are closed by an isolation signal). Neither isolation valve is opened automatically by an initiation signal. No interlocks exist between the isolation valves because they are powered from different sources (letter from applicant, May 24, 1985).

The applicant has reported that the main steam and feedwater systems are expected to experience steam and water hammer loadings. However, it has analyzed these loadings and designed these systems to accommodate and minimize the effects of these loadings.

As stated in the letter of May 24, 1985, the applicant has committed to conduct piping preoperational and startup testing for steam and water hammer. The staff concurs with the applicant's conclusion that the design features and operating procedures described above will minimize the potential for water hammer occurrence in several systems discussed above.

(c) Thermal Fatigue

The applicant has reported in a letter dated July 3, 1985, that it has accounted for the normal stress effects of rapid changes in temperatures of process piping in the ASME Code Section III, Class 1 fatigue analyses. Thermal mixing and stratification usually occur where fluids of significantly higher or lower temperatures are injected at branch connections. The applicant stated in the July 3, 1985, letter that temperatures are uniform at the intermediate breaks in all Class 1, 2, and 3 piping systems specified in the applicant's letter of April 16, 1985, and that no injections of fluid occur at these locations. Therefore no thermal mixing, and, consequently, no unacceptable thermal fatigue is expected to occur at such locations.

(4) Class 1 Piping Systems Evaluation

For Class 1 piping, a considerable amount of quality assurance in design, analyses, fabrication, installation, examination, testing, and documentation is provided which ensures that the safety concerns associated with the uncertainties discussed above are significantly reduced. On the basis of the staff evaluation of the design considerations given to Class 1 piping, the stress and fatigue limits provided in the BTP MEB 3-1 break criteria, and the relatively small degree of uncertainty in unanticipated loadings, the staff finds that the need to postulate arbitrary intermediate pipe breaks in ASME Code Class 1 piping in which large unanticipated dynamic loads, stress corrosion cracking, and thermal fatigue such as in mixing situations are not present and in which

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all equipment has been environmentally qualified is not compensated for by an increased level of safety. In addition, systems may actually perform more reliably for the life of the plant if the SRP criterion to postulate AIBs for ASME Code Class 1 piping is eliminated. The staff has concluded that the ~~above~~ described requirements above are present for those ASME Code Class 1 piping systems identified in the applicant's submittal of April 16, 1985.

(5) Class 2 and 3 Piping Systems Evaluation

On the basis of the staff evaluation of the design considerations given to Class 2 and 3 piping, the stress limits provided in the SRP break criterion, and the relatively small degree of uncertainty in unanticipated loadings, the staff finds that dispensing with arbitrary intermediate pipe breaks is justified for Class 2 and 3 piping in which stress corrosion cracking, large unanticipated dynamic loads, or thermal fatigue in fluid mixing situations are not expected to occur provided (a) the piping designers have appropriately considered the effects of local welded attachments per NC/ND-3645, and (b) all safety-related equipment in the vicinity of Class 2 and 3 piping systems has been environmentally qualified for the nondynamic effects of a nonmechanistic pipe break with the greatest consequences on the equipment. The staff has concluded that the above-described requirements are present for those ASME Code Class 2 and 3 piping systems identified in the applicant's letter dated April 16, 1985.

(6) Piping Systems Not Included in Proposal

For those piping systems, or portions thereof, which are not included in the applicant's submittal of April 16, 1985, the staff requires that the existing guidelines in BTP MEB 3-1 of the SRP (NUREG-0800, Rev. 1) be met. However, should other piping lines which are not specifically identified in the applicant's submittal of April 16, 1985, subsequently qualify for the conditions described above, the implementation of the proposed elimination of the AIB criteria may be used provided those additional piping lines are appropriately identified to the staff.

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3.6.3.1.4 Conclusion

The applicant has proposed a deviation from the current guidelines of the SRP by requesting relief from postulating arbitrary intermediate pipe breaks in high energy piping systems which are not susceptible to intergranular stress corrosion cracking, steam or water hammer effects, and thermal fatigue in fluid ~~corrosion cracking, steam or water hammer effects, and thermal fatigue in fluid~~ mixing. The SRP guideline which requires that two intermediate breaks be postulated even when the piping stress is low resulted from the need to ensure that equipment qualified for the environmental consequences of a postulated pipe break was provided over a greater portion of the high energy piping run. This proposal is based, in part, on the condition that all equipment in the spaces traversed by the fluid system lines, for which AIBs are being eliminated, is qualified for the environmental (nondynamic) conditions that would result from a nonmechanistic break with the greatest consequences on surrounding equipment. In addition, the applicant has committed to perform preoperational testing of all the systems identified in the April 16, 1985, submittal and also monitor those systems for vibration during preoperational and startup testing.

The staff has evaluated the technical bases for the proposed deviation from the SRP guideline with respect to satisfying the requirements of GDC 4. Furthermore, the staff has considered the potential problems identified in NUREG/CR-2136 which could impact overall plant reliability when excessive pipewhip restraints are installed. On the basis of its review, the staff finds that when those piping system conditions as stated above are met, there is a sufficient basis for concluding that an adequate level of safety exists to accept the proposed deviation from the SRP guidelines and satisfy the requirements of GDC 4.

Thus, on the basis of the piping systems having satisfied the above conditions, the staff concludes that the pipe rupture postulation and associated effects are adequately considered in the design of the Clinton Power Station, Unit No. 1, and, therefore, the deviation from the Standard Review Plan is acceptable.

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3.9 Mechanical Systems and Components

3.9.3 ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures

3.9.3.1 Loading Combinations, Design Transients, and Stress Limits

In the SER, the applicant committed to demonstrate piping functional capability for nuclear steam supply system (NSSS) and balance of plant (BOP) piping systems by using the screening criteria provided in GE Topical Report NEDO-21985. If any piping component in the piping system does not satisfy the screening criteria, the applicant has committed to demonstrate the functional capability of the components by other means.

By letter dated July 2, 1985, the applicant stated that the GE functional capability criteria are an integral part of the ASME Code Class 1, 2, and 3 piping systems design and must be satisfied.

Since each piping component satisfies the above screening criteria, no alternative means to demonstrate functional capability as stated in the SER is required.

3.10 Seismic and Dynamic Qualification of Safety-Related Mechanical and Electrical Equipment

3.10.3 Containment Purge and Vent Valve Operability [NUREG-0737, Item II.E.4.2(6)]

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

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

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Valve No.	Size (inches)
1VQ001A	24
1VQ001B	24
1VQ002	24
1VQ003	36
1VQ004A	36
1VQ004B	36
1VQ005	10
1VR001A	36
1VR001B	36

The valves are all butterfly valves manufactured by Posi-Seal International, Inc., of North Stonington, Connecticut. The 36-inch valves are ASME Class 150/150 with operator model number 45102 SR 80 supplied by MATRYX. The 24-inch valves are ASME Class 150/150 with operator model 33082 SR-80 supplied by MATRYX. The 10-inch valves are ASME Class 150 with operator model 26062 SR 80 supplied by MATRYX.

To demonstrate the purge and vent valve operability, the following five documents were submitted to the staff:

(1) Letter, November 17, 1983, from R. N. Nelson, Illinois Power Co., to A. Schwencer, NRC.

(2) Letter, October 22, 1982, from G. E. Wuller, Illinois Power Co., to C. O. Thomas, NRC.

(3) Report, "Nuclear Seismic and LOCA Analysis," issued by Posi-Seal International, Inc., October 21, 1982.

(4) ASME Code Section III, Subsection NC, 1974 Edition including Winter 1976 Addenda.

(5) "Effect of Fluid Compressibility on Torque in Butterfly Valves," F. P. Hartman, ISA 1968 Annual Conference, ISA Transactions, Vol. 8, No. 4, p. 28.

In the November 17, 1983, letter, the applicant referenced a July 20, 1983, letter from A. Schwencer, NRC, to G. E. Wuller, Illinois Power Co., which contained a technical evaluation of the containment purge and vent valve operability.

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In this technical evaluation, the staff determined the following: the applicant had adequately demonstrated the operability of the 10-inch valve; the use of the 24-inch and 36-inch valves would be acceptable during operational modes 1, 2, and 3 if they were blocked at a maximum opening angle of 50° (90° corresponds to fully open); and the applicant should confirm that the valves are in the "preferred" orientation as described by the valve manufacturer.

The applicant in that same November 17th letter committed to (1) utilize mechanical stops so that they would be in place (valves limited to 50° open) during operational modes 1, 2, and 3 and could be removed during modes 4 and 5 if increased purge flow (30,000 cfm with valves full open) is required during maintenance activities and (2) change the body-to-bracket bolt material for the 36-inch valves to the higher stress allowables material (A-354 GR BD) as recommended by Posi-Seal in the letter submitted to the NRC on October 22, 1982, and (3) confirm that the containment purge and vent valves are oriented to conform to the preferred orientation as recommended by the manufacturer and, if not, install them in the preferred orientation. The staff finds these commitments acceptable.

On the basis of the staff's evaluation in the July 20, 1983, letter and the applicant's commitments in the November 17, 1983, letter, the staff has determined that with the (1) confirmation of the limitation of the 24-inch and 36-inch valves to a 50° maximum opening angle, (2) confirmation of the purge and vent valves orientation to the manufacturer's recommendation, and (3) material change of the body-to-bracket bolt material for the 36-inch valves, the applicant has addressed the staff's concerns in these areas and has demonstrated the operability of the 24-inch and 36-inch valves. The operability of the 10-inch valve was previously addressed by the staff in the July 20, 1983, letter and found acceptable.

By the letter dated July 15, 1985 the applicant has stated these commitments will be completed before fuel load. The staff will have NRC's Region III Office verify that the applicant has satisfied these commitments before fuel load. This resolves NUREG-0737, Item II.E.4.2(6). Supply date

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3.11 Environmental Qualification of Electrical Equipment Important to Safety and Safety-Related Mechanical Equipment

3.11.1 Introduction

Equipment that is used to perform a necessary safety function must be demonstrated to be capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. This requirement--which is embodied in GDC 1 and 4 of Appendix A to 10 CFR 50 and Sections III, XI, and XVII of Appendix B to 10 CFR 50--is applicable to equipment located inside as well as outside the containment. More detailed requirements and guidance relating to the methods and procedures for demonstrating this capability for electrical equipment have been set forth in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"; NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," which supplements the Institute of Electrical and Electronics Engineers (IEEE) Std. 323-1971 and 1974; and various NRC regulatory guides and industry standards.

3.11.2 Background

NUREG-0588 was issued in December 1979 to promote a more orderly and systematic implementation of equipment qualification programs by industry and to provide guidance to the NRC staff for use in ongoing licensing reviews. The positions contained in that report provide guidance on (1) how to establish environmental service conditions, (2) how to select methods that are considered appropriate for qualifying equipment in different areas of the plant, and (3) other areas such as margin, aging, and documentation. In February 1980, the NRC staff asked certain near-term operating license (OL) applicants to review and evaluate the environmental qualification documentation for each item of safety-related electrical equipment and to identify the degree to which their qualification programs were in compliance with the staff positions discussed in NUREG-0588.

IE Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment," issued by the NRC Office of Inspection and Enforcement (IE) on January 14, 1980, and its supplements dated February 29, September 30, and October 24, 1980, established environmental qualification requirements for operating reactors. This

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bulletin and its supplements were provided to OL applicants for consideration in their reviews.

A final rule on environmental qualification of electrical equipment important to safety for nuclear power plants became effective on February 22, 1983. This rule, 10 CFR 50.49, specifies the requirements to be met for demonstrating the environmental qualification of electrical equipment important to safety that is located in a harsh environment. In conformance with 10 CFR 50.49, electrical equipment for the Clinton Power Station (Clinton) may be qualified according to the criteria specified in Category I of NUREG-0588.

The qualification requirements for mechanical equipment are principally contained in Appendices A and B to 10 CFR 50. The qualification methods defined in NUREG-0588 can also be applied to mechanical equipment.

In the SER, the staff stated that the applicant's environmental program for safety-related electrical equipment would be reviewed when submitted and a site audit of the applicant's central files would be conducted to determine if there is tangible evidence of qualification for safety-related electrical equipment. The staff further stated that the results of the review and audit would be reported in a supplement to the SER.

To document the degree to which the environmental qualification program complies with the NRC environmental qualification requirements and criteria, the applicant provided equipment qualification information by letters dated May 20, 1983, and April 4, 1985, to supplement the information in FSAR Section 3.11. The staff has reviewed the adequacy of the Clinton environmental qualification program for electrical equipment important to safety as defined in 10 CFR 50.49 and is presently reviewing the program for safety-related mechanical equipment.

The scope of this report includes an evaluation of (1) the completeness of the list of systems and equipment to be qualified, (2) the criteria they must meet, (3) the environments in which they must function, and (4) the qualification documentation for the equipment. It is limited to electrical equipment important to safety within the scope of 10 CFR 50.49 and safety-related mechanical equipment.

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3.11.3 Evaluation

The staff evaluation included an onsite examination of equipment, an audit of qualification documentation, and a review of the applicant's submittals for completeness and acceptability of systems and components, qualification methods, and accident environments. The criteria described in SRP Section 3.11 (NUREG-0800) and in NUREG-0588, Category I, and the requirements in 10 CFR 50.49 form the bases for the staff evaluation.

On March 11-14, 1985, the staff audited the applicant's qualification documentation and electrical equipment that had been installed. The audit consisted of a review of 13 files containing information regarding equipment qualification. The staff's findings from the audit are discussed in Section 3.11.4 of this SER supplement.

3.11.3.1 Completeness of Equipment Important to Safety

10 CFR 50.49 identifies three categories of electrical equipment that must be qualified in accordance with the provisions of the rule. These are

(1) safety-related electrical equipment (equipment relied on to remain functional during and following design-basis events)

(2) non-safety-related electrical equipment whose failure under the postulated environmental conditions could prevent satisfactory accomplishment of the safety functions by the safety-related equipment

(3) certain postaccident monitoring equipment (RG 1.97, Category 1 and 2 postaccident monitoring equipment)

The applicant has provided information addressing compliance with this requirement of 10 CFR 50.49.

The systems identified by the applicant for the environmental qualification program as being required to function to mitigate the consequences of loss-of-coolant accidents (LOCAs) or high-energy line breaks (HELBs) that have components

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located in a harsh environment were compared to FSAR Table 3.2-1, "Equipment Classification." The omission of systems from the harsh environment program was adequately justified by the applicant. The following systems identified as performing the safety functions of emergency reactor shutdown, containment isolation, reactor core cooling, containment heat removal, reactor heat removal, and effluent control are included in the environmental qualification programs at Clinton:

(1) reactor system
(2) main steam/nuclear boiler system
(3) reactor recirculation system
(4) control rod drive system
(5) standby liquid control system
(6) neutron monitoring system
(7) reactor protection system
(8) leak detection system
(9) process radiation monitoring system
(10) residual heat removal system
(11) low-pressure core spray system
(12) high-pressure core spray system
(13) reactor core isolation cooling system
(14) solid radwaste reprocessing and disposal system
(15) reactor water cleanup system
(16) fuel pool cooling and cleanup system
(17) local panels
(18) shutdown service water system
(19) service air and instrument air system
(20) standby gas treatment system
(21) condensate storage and transfer system
(22) ECCS equipment room HVAC
(23) auxiliary power system
(24) component cooling water system
(25) essential switchgear heat removal system
(26) containment building HVAC
(27) postaccident monitoring systems
(28) combustible gas control system

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(29) suppression pool makeup system

(30) suppression pool cleanup system

(31) MSIV leakage control system

(32) containment isolation systems

To address conformance with 10 CFR 50.49(b)(2) concerning non-safety-related equipment whose failure under postulated accident conditions could prevent the satisfactory accomplishment of safety functions, the applicant referred to compliance with IEEE Std. 384-1974 as modified by RG 1.75 to show electrical and physical separation between safety-related and non-safety-related electrical equipment. The staff has reviewed and evaluated the applicant's conformance with RG 1.75 and finds it acceptable from an equipment qualification aspect. The applicant has also conducted a study in response to the concerns addressed by the staff in IE Information Notice 79-22, "Qualification of Control Systems," issued September 19, 1979. The staff review of this study is not yet complete. Pending final staff approval of the applicant's response to the concerns addressed in IE Information Notice 79-22, the staff concludes that the applicant's conformance to 10 CFR 50.49(b)(2) is acceptable.

10 CFR 50.49(b)(3) requires that all installed RG 1.97, Category 1 and 2, instrumentation located in a harsh environment be included in the equipment qualification program unless adequate justification is provided. The applicant has indicated that all such equipment is included in the qualification program; however, in addressing conformance with RG 1.97, the applicant has identified a number of alternative methods of meeting the intent of RG 1.97. The staff will determined that these alternative methods are acceptable as part of its review for conformance with RG 1.97, which is addressed in Section 7.5.3.1 of this SER supplement.

3.11.3.2 Qualification Methods

(1) Electrical Equipment in a Harsh Environment

Detailed criteria for qualifying safety-related electrical equipment in a harsh environment are defined in NUREG-0588. These criteria are also applicable to the other equipment important to safety defined in 10 CFR 50.49.

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The staff reviewed the methods used by the applicant to demonstrate qualification to ensure that they are in compliance with NUREG-0588 and found them acceptable.

(2) Safety-Related Mechanical Equipment in a Harsh Environment

Although there are no detailed requirements for mechanical equipment, GDC 1, "Quality Standards and Records"; GDC 4, "Environmental and Missile Design Bases"; and Appendix B to 10 CFR 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants" (Sections III, "Design Control," and XVII, "Quality Assurance Records"), contain the following requirements related to equipment qualifications:

- Components shall be designed to be compatible with the postulated environmental conditions, including those associated with LOCAs.
- Measures shall be established for the selection and review for suitability of application of materials, parts, and equipment that are essential to safety-related functions.
- Design control measures shall be established for verifying the adequacy of design.
- Equipment qualification records shall be maintained and shall include the results of tests and materials analyses.

The applicant has submitted a description of the mechanical equipment qualification program for staff review. The review will determine if the environmental qualification of safety-related mechanical equipment has been adequately addressed. In addition, the staff has selected four items from the program to conduct an indepth review of the documentation associated with these items. The results of the review will be provided in an SER supplement.

3.11.3.3 Service Conditions

NUREG-0588 defines the methods to be used for determining the environmental conditions associated with LOCAs or HELBs, inside or outside the containment.

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The review and evaluation of the adequacy of these environmental conditions are described below. The staff has reviewed the qualification documentation to ensure that the qualification conditions envelop the environmental conditions established by the applicant.

(1) Temperature, Pressure, and Humidity Conditions Inside the Drywell

The applicant provided the LOCA/main steamline break (MSLB) profiles used for equipment qualification program submittals. The peak values in the drywell shown on these LOCA/MSLB profiles are as follows:

- maximum temperature, 300°F
- maximum pressure, 30 psig
- humidity, 100% (steam)

The staff has reviewed these profiles and finds them acceptable for use in equipment qualification; that is, there is reasonable assurance that the actual pressures and temperatures will not exceed these profiles anywhere within the specified environmental zone (except in the break zone).

(2) Temperature, Pressure, and Humidity Conditions Outside the Drywell

The applicant has provided the temperature, pressure, and humidity conditions associated with HELBs outside containment. The criteria used to define the location of HELBs are described in FSAR Section 3.6. The staff has used a screening criterion of saturation temperature at the calculated pressure to verify that the peak temperatures identified by the applicant are acceptable.

(3) Submergence

Flood levels for various areas have been calculated. The maximum flood level in the drywell is 735 ft 9 in. following a LOCA. The effects of flooding on equipment have been evaluated to ensure that safe shutdown can be achieved. The applicant has taken appropriate action to relocate or qualify the affected equipment.

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(4) Demineralized Water Spray

A demineralized water spray may be used inside primary containment to mitigate the effects of an accident. The applicant has evaluated the effects of spray on equipment important to safety.

(5) Aging

The aging program requirements for Clinton electrical equipment are defined in Category I of NUREG-0588. All known degrading influences must be considered and included in the aging program. Justification for excluding pre-aging of equipment in type testing must be established on the basis of equipment design and application or state-of-the-art aging techniques. A qualified life is to be established for each item of equipment.

In addition to the above, a maintenance/surveillance program must be implemented to identify and prevent significant age-related degradation of electrical and mechanical equipment. In the FSAR, the applicant committed to follow the recommendations in RG 1.33, Rev. 2, "Quality Assurance Program Requirements (Operation)," which endorses American Nuclear Society/American National Standards Institute Std. ANS 3.2/ANSI N18.1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." This standard defines the scope and content of a maintenance/surveillance program for safety-related equipment. Provisions for preventing or detecting age-related degradation in safety-grade equipment are specified and include (a) utilizing experience with similar equipment, (b) revising and updating the program as experience is gained with the equipment during the life of the plant, (c) reviewing and evaluating malfunctioning equipment and obtaining adequate replacement components, and (d) establishing surveillance tests and inspections based on reliability analyses, frequency, and type of service or age of the items, as appropriate.

In a letter dated May 20, 1985, the applicant has described a program that incorporates the above guidelines and has stated that the maintenance/surveillance program will be implemented before fuel load. The applicant has provided a description of the specific program that will be used to detect unanticipated,

age-related degradation of electrical cables inside containment. In the May 20, 1985, letter, the applicant also stated that an affiliation will be maintained with the Electric Power Research Institute to monitor the progress of this specific cable program. A staff review indicates that this program is acceptable.

(6) Radiation (Inside and Outside the Containment)

The applicant has provided values of the radiation levels postulated to exist following a LOCA. The accident radiation environments in primary containment have been defined according to NUREG-0588. For this review, the staff has assumed that the values provided have been determined in accordance with the prescribed criteria. The staff review determined that the values to which the equipment is qualified enveloped the requirements identified by the applicant.

The maximum total radiation dose specified by the applicant is 2×10^8 rads gamma both in the primary containment and in areas exposed to recirculating fluid lines in the secondary containment. These values are acceptable for use in the qualification of equipment.

3.11.3.4 Outstanding Equipment

For items not having complete qualification documentation, the applicant has provided a commitment for corrective action and a schedule for completion. All items must have full qualification before an operating license is granted.

As a result of the staff review, a number of inconsistencies and discrepancies were noted among the tables submitted in FSAR Section 3.11, specifically in the correlation and classification of equipment items in Tables 3.11-1, 3.11-2, 3.11-3, and 3.11-4. The applicant should review the information in these tables and correct any inconsistencies or omissions. The staff should be notified when this has been done.

The applicant should review the qualification files to ensure that all qualification deficiencies have been eliminated and the resolutions have been documented in an auditable form. Before an operating license is issued, the applicant must notify the staff that all equipment is qualified.

3.11.4 Environmental Qualification Audit

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The staff, with assistance from EG+G at the Idaho National Engineering Laboratory (INEL), conducted an audit of the applicant's qualification files between March 11 and 14, 1985. The purpose of the audit was to verify the bases of the information submitted by the applicant. Thirteen equipment qualification files, representing approximately 10% of the equipment items in the equipment qualification program, were selected for detailed review during the audit.

The items selected for audit were:

(1) Limitorque SMB motor operator (File EQCL-009)
(2) Rockbestos firewall III and RSS electric cable (Files EQCL-051 & EQCL-025)
(3) Rosemount 1153 B transmitter (File EQCL-021)
(4) Westinghouse 6.9-kV switchgear and breakers (File EQCL-020)
(5) BBN 424-ISO-TEC SRVM accelerometer and TEC 504 B charge converter (File EQCL-026)
(6) Okonite Okozel electric cable (File EQCL-058)
(7) Weed RTD (File EQCL-028)
(8) Conax LV power penetration (File EQCL-038)
    LV control instrument penetration (File EQCL-039)
    Airlock penetration assembly (File EQCL-032)
    MV power penetration (File EQCL-037)
(9) GE IRM detector/connector (File EQCL-034A)
    RP/LPRM detector/connector (File EQCL-034B)

These files were reviewed to determine if qualification had been demonstrated on the basis of the documents contained in the files.

With the exception of one file, adequate proof was provided to establish qualification as claimed. For the one exception (File EQCL-009), the file contained a number of deficiencies:

- The aging of internal components was not adequately addressed.
- The requirement for submergence was inaccurately listed.
- The qualification of internal components was not fully established.

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The applicant proposed acceptable corrective measures in the form of additional information and file revision to eliminate the deficiencies cited. In order to ensure that these types of deficiencies are not present in files not reviewed during the audit, the applicant should review all other qualification files and establish that the deficiencies do not apply.

As part of the audit, the equipment as actually installed was inspected during a plant walkdown. The purpose of the walkdown was to verify that the manufacturer, model number, location, and installation are consistent with the qualification documents. No discrepancies were discovered.

3.11.5 Conclusions

The staff has reviewed the Clinton program for the environmental qualification of electrical equipment important to safety and safety-related mechanical equipment. The purpose of the review was to determine the adequacy of the program, including the scope of the qualification program, the environmental conditions resulting from design-basis accidents, and the methods used to demonstrate qualification.

As identified in this supplement, the following items must be resolved before an operating license is issued:

(1) The applicant must notify the staff that the deficiencies cited during the audit have been corrected and all equipment is qualified.

(2) The acceptability of the safety-related mechanical equipment qualification program must be established.

(3) The applicant must notify the staff that the inconsistencies identified in FSAR Tables 3.11-1, -2, -3, and -4 have been corrected.

(4) The staff must give its final approval to the applicant's response to the concerns stated in IE Information Notice 79-22.

Item 4 (above) is being reviewed under outstanding issue 15 (OI 15) and therefore will not be further addressed in this section, provided OI 15 is satisfactorily resolved.

On the basis of the results of its review and subject to the acceptable resolution of the four items identified above, the staff concludes that the applicant has demonstrated conformance with the requirements for environmental qualification as detailed in 10 CFR 50.49, the relevant parts of GDC 1 and 4, and Sections II, XI, and XVII of Appendix B to 10 CFR 50, and with the criteria specified in NUREG-0588. Outstanding issue 7(a) is considered partially resolved until the four items identified have been resolved.

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4 REACTOR

4.2 Fuel System Design

4.2.3 Design Evaluation

4.2.3.9 Water-Side Corrosion

For the Clinton fuel design, the staff concluded in the SER that sipping of the discharged fuel is sufficient to meet the regulatory requirements for the issue of water-side corrosion in conjunction with the testing, inspection and surveillance plans described in Section 4.2.4 of the Clinton SER. On the basis of this conclusion, the staff has determined that license condition 9 related to visual examination of discharged fuel is not required.

4.2.3.13 Channel Box Deflection

In the SER, the staff stated that a 30,000 MWd/t bundle exposure should be used as the triggering point for control rod drive settling friction tests and channel deflection measurements and not an unspecified, but higher, exposure as proposed by the applicant.

By a letter dated May 17, 1982 (D. L. Holtzscher, Illinois Power Company, to J. Faulkner, NRC), the LRG II chairman (Holtzscher) submitted a position paper (3-CPB) that applies to Clinton on channel box deflection that incorporated several of the same features as the LaSalle, Zimmer, and Grand Gulf proposals. These include the following:

(1) Records will be kept of channel locations and exposure for each operation cycle.

(2) Channels shall not reside in the outer row of the core for more than two operating cycles (because flux gradients are largest near the core periphery and, therefore, differential irradiation-induced growth and bowing will be greatest at those locations).

(3) At the beginning of each fuel cycle, the combined outer row residence time for any two channels in any control rod cell shall not exceed four peripheral cycles.

In addition, LRG II stated that channels that reside in the periphery (outer row) for more than one cycle shall be situated each successive peripheral cycle in a location that rotates the channel so that a different side faces the core edge. The NRC staff believes that (1) this should help to reduce unidirectional irradiation-induced growth, and should thus lessen channel bowing, and (2) the other measures outlined above would also help to reduce the magnitude of channel deflection.

The LRG II position statement also contains a description of a control rod drive friction test that would be performed for those core cells exceeding the above

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general guidelines or containing channels with exposures greater than 30,000 MWd/MTU (associated fuel bundle exposures). The LRG II position paper describes the control rod drive settling friction test in considerable detail.

By letter dated June 11, 1982, the applicant incorporated the LRG II position paper 3-CPB into the Clinton operating license application.

In an NRC memorandum (L. S. Rubenstein to T. Novak) dated August 19, 1982, the NRC staff accepted the LRG II position that the proposed actions would preclude excessive channel bowing in the LRG II plants. Since the applicant has endorsed this position, the NRC staff concludes that channel box deflection will not be a problem for Clinton. However, the staff is continuing its review of this phenomenon and should the review indicate that a modification to the proposed steps is necessary, the applicant will be so notified.

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5 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.2 Overpressurization Protection

NUREG-0737, Item II.D.1, requires the applicant to conduct testing to qualify the reactor coolant system relief and safety valves under expected operating conditions for design-basis transients and accidents.

In the SER, the staff provided tentative acceptance of the qualification of these valves, on the basis of a preliminary review, and stated the results of a detailed review of the BWR low-pressure test programs for verifying safety relief valve and discharge piping for compliance with NUREG-0737, Item II.D.1, requirements would be reported in an SER supplement.

5.2.2.1 Compliance With General Design Criteria and NUREG-0737 Requirements

GDC 14, 15, and 30 require that:

(1) the reactor primary coolant pressure boundary be designed, fabricated, and tested so as to have an extremely low probability of abnormal leakage

(2) the reactor coolant system and associated auxiliary, control, and protection systems be designed with sufficient margin to ensure that the design conditions are not exceeded during normal operation or anticipated transient events

(3) the components which are part of the reactor coolant pressure boundary shall be constructed to the highest quality standards practical

To reconfirm the integrity of relief and safety valve system and thereby ensure that the General Design Criteria are met, the NUREG-0578 position was issued as a requirement in a letter dated September 13, 1979, from the NRC to all operating nuclear power plants. This requirement has since been incorporated as TMI-2 Action Plan Item II.D.1 of NUREG-0737 which was issued for implementation on October 31, 1980. As stated in these NUREG reports, each boiling water reactor licensee or applicant shall satisfy the following requirements:

(1) Conduct testing to qualify reactor coolant system relief and safety valves under expected operating conditions for design-basis transients and accidents.

(2) Determine valve expected operating conditions through the use of analyses of accidents and anticipated operational occurrences referenced in RG 1.70, Rev. 2.

(3) Choose the single failures so that the dynamic forces on the safety/relief valves are maximized.

(4) Use the highest test pressures predicted by conventional safety analysis procedures.

(5) Include in the relief and safety valve qualification program the qualification of the associated control circuitry, piping and supports.

(6) Provide test data, including criteria for success or failure of valves tested, for the NRC staff review and evaluation. These test data should include data that would permit plant-specific evaluation of discharge piping and supports that are not directly tested.

(7) Submit a correlation or other evidence to substantiate that the valves tested in a generic test program demonstrate the functionability of as-installed primary relief and safety valves. This correlation must show that the test conditions used are equivalent to expected operating and accident conditions as prescribed in the Final Safety Analysis Report (FSAR). The effect of as-built relief and safety valve discharge piping on valve operability must be accounted for if it is different from the generic test loop piping.

5.2.2.2 BWR Owners Group Relief and Safety Valve Program

5.2.2.2.1 Safety/Relief Valve Test Program

To respond to the NRC requirements listed above, the BWR Owners Group (BWROG) contracted with the General Electric Company (GE) to design and conduct a Safety/Relief Valve Test Program (Waters, Sept. 17, 1980). The program describes the safety/relief valves to be tested, the test facility requirements, the test sequence, the valve acceptance criteria and the procedure for obtaining, analyzing, and reporting the test data. Before its acceptance, the test program received extensive NRC review and comment followed by responses from the GE/BWROG. Six NRC questions and BWROG responses dealing with justification of the applicability of test results to the in-plant safety/relief valves are contained in the enclosure to a BWROG letter (Waters, March 31, 1981). The NRC staff review of the response to these questions is contained in a reply to that letter (Saffell, April 23, 1981). On the basis of this review, the concerns expressed in the questions were appropriately resolved.

The early BWRs contained a combination of dual-function safety/relief valves (SRVs), power-actuated relief valves (PARVs) and single-function safety valves (SVs). However, Unit 1 of the Clinton Power Station utilizes 16 SRVs and no PARVs or SVs.

The qualification of the SRVs for steam discharge under expected operating and accident conditions has been demonstrated by vendor production tests and is confirmed routinely by in-plant startup and operability tests. On this basis, it was agreed that the valves should be tested for those events that result in liquid or two-phase flow at the SRV.

The test sequence and conditions established in the test program were based on an evaluation of expected operating conditions determined through the use of analyses of accident and anticipated operational occurrences referenced in RG 1.70, Rev. 2. Enclosure 2 to the September 17, 1980, Waters letter provides this evaluation which indicated that there is one event that is significantly likely to

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occur and can lead to the discharge of liquid or two-phase flow from the SRV. This event combined with the single-failure requirement of NUREG-0737 results in the conclusion that a test should be performed simulating the alternate shutdown cooling mode which utilizes the SRV as a return flowpath for low-pressure liquid to the suppression pool.

At a meeting on March 10, 1981 (Hodges, May 1981), BWROG presented results of a study by Science Applications, Inc. (SAI) which showed that the probability of getting liquid to the steamline, and hence to the SRV, is approximately 10^{-2} per reactor year. However, even if the water level increases to the midplane of the steamline nozzle on the vessel, which is not likely*, the fluid quality at the valve was calculated by GE to be greater than 20% (Waters, Sept. 17, 1980). Because the steamlines typically drop about 45 ft vertically from the vessel nozzles to the horizontal runs on which the SRVs are mounted, much of the liquid which gets to the steamlines would be entrained as droplets. Therefore, the two-phase mixture upstream of the SRVs should reach the level of the steamlines as a froth, droplet, annular or stratified flow and the existence of slug flow or subcooled liquid flow would be unlikely.

Even if two-phase discharge through an SRV should result in stuck-open valve, the results of the blowdown are not severe. As discussed in NUREG-0462, historically there have been a total of 53 inadvertent blowdown events from pressure relief system valve malfunctions (1969 through April 1978). These events varied in consequences from a short-duration pressure transient to a rapid depressurization and cooldown of the primary coolant system from approximately 1100 psig to a few hundred psig. No fuel failures have been reported as a result of these transients.

In a letter dated December 29, 1980, D. B. Waters (BWROG) discussed the consequences of the worst-case transient for maintaining the core covered (loss of feedwater), combined with the worst single failure (failure of the high-pressure injection system) and one stuck-open relief valve. Reference plant analyses for a BWR/4 and a BWR/5 show that the reactor core isolation cooling (RCIC) system can automatically provide sufficient inventory to keep the core covered. This capability is not a design basis for the RCIC system and not all plants have been analyzed to demonstrate this capability. If a plant should not have this capability, manual depressurization to low-pressure core cooling systems will avoid core uncovery for the case of loss of feedwater plus worst single failure plus a stuck-open relief valve. Therefore, even for the loss-of-feedwater transient with the worst single failure, a stuck-open relief valve does not uncover fuel.

At the March 10, 1981, meeting (Hodges, May 1981), BWROG presented an analysis that showed that even if a slug of subcooled water exists upstream of the SRVs, the probability of rupturing the discharge line is 7×10^{-4} per event, The staff has not reviewed the supporting analysis for this value; however, even if the failure probability is as high as 10^{-2} per event, the combined probability is no greater than for a steamline break inside the containment. In addition, since the steamline break that has been analyzed and found to be acceptable would be more severe (effects on the core and containment) than a break in a valve discharge line with a stuck-open SRV because the assumed break area is larger.

*Feedwater pumps would be tripped before the water level reached the midplane by the L8 high-level trip, the turbine vibration trip, or by operator action.

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In summary, on the basis of the BWR operating history of inadvertent SRV blowdowns, the low likelihood of severe consequences, and the bounding design-basis steamline break, the staff decided not to require high-pressure testing with saturated liquid or subcooled water.

On the basis of the above, the applicant has complied with NRC requirements 1-4 listed in Section 5.2.2.1 above. That is, an acceptable test program was established which adhered to the staff guidelines on the selection of test conditions and the maximization of system loads. That portion of requirement 5 dealing with the qualification of the associated control circuitry is considered to be satisfied as a result of the anticipated licensing action for compliance with 10 CFR 50.49.

5.2.2.2.2 Safety/Relief Valve Surveillance Program

The SER contains a requirement that the applicant participate in a safety/relief valve surveillance program. This requirement was made to establish data on the Dikkers pressure relief valves, including all abnormalities ranging from minor wear observed during normal inspection to complete failures, including failure to open or close and inadvertent operation.

In a letter dated December 3, 1981, the applicant incorporated the Licensing Review Group II BWR (LRG II) position paper on generic issue 3-RSB into the Clinton operating license application. The position is to participate in a safety/relief valve (SRV) surveillance program, the primary objective of which is to gather data to identify generic SRV problems. The Institute for Nuclear Power Operations (INPO) was asked to accept responsibility for centralized compilation of the required data. Subsequently, this LRG II issue was closed via NRC letter dated August 17, 1982, and the Perry SER (NUREG-0887, Section 5.2.3).

By letter dated June 19, 1985, the applicant has stated that participation in this surveillance program has been instituted at Clinton by Operating Procedure CPS No. 10P3831.01N, "Safety Relief Valve Report." Reporting of SRV leakage events and actuation events is performed on a quarterly basis. "Leakage events" are defined to include no leakage comments, and "actuation events" include an event requiring an SRV to lift. An SRV failing to lift when required is also considered and reported as an actuation event.

The accumulated information on Clinton SRVs will be reported to INPO by the applicant and becomes part of the data base for these valves that is contributed to by other participants in the program. This information is then provided by INPO in its annual reports on the SRV surveillance program.

5.2.2.3 BWR Owners Group Test Results and Analysis

In October 1981, the BWROG published a technical report (GE, NEDE-24988-P) documenting the results of the prototypical SRV tests conducted in accordance with the accepted test program (Waters, Sept. 17, 1980). The tests were performed by GE for the BWROG at the Wyle Laboratory in Huntsville, Alabama. The test report, which was reviewed by the staff, describes the test facility, the basis for the test conditions and valve selection, and the instrumentation and its accuracy, and analyzes the results with respect to valve operability, piping and support loads, and the applicability of the test results to the in-plant safety and relief valves.

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The generic test program required the testing of six different SRVs. Included was a Dikkers 8 x R x 10 direct acting dual function safety/relief valve, style G471-6/125.04. There are no material, dimensional, or operational differences between the in-plant valves and the tested valves. Thus, the tested valve was considered to be applicable to the in-plant valves at the Clinton Power Station, Unit No. 1.

An extensive review (Saffell, Jan. 13 and May 4, 1982) of the test results (GE, NEDE-24988-P) was conducted by NRC consultants (EG&G Idaho, Inc.) at the Idaho National Engineering Laboratory. The review addressed not only the test results but also the applicability of the test results and equipment to the Clinton Power Station, Unit No. 1, SRV systems.

As discussed in Section 5.2.2.2.1 the test conditions to envelop the expected BWR safety/relief valve events were developed in accordance with NRC guidelines. They were accepted and are presented in a letter sent to the NRC (Waters, Sept. 17, 1980). The review of the test results indicates that the actual test conditions were in accordance with the established test program.

With the completion of the testing and the submittal of the test report, compliance with requirement 6 listed in Section 5.2.2.1 was satisfied. However, the subsequent staff review of the test results generated four plant-specific questions stated in a letter NRC sent to the applicant on November 14, 1984, which required resolution. The applicant's response to the four plant-specific questions, was submitted for review on January 16, 1985, and its responses to these questions are discussed below.

The applicant's response to the first question indicates that there are SRV discharge line differences between the test configuration and the in-plant configuration. However, it is pointed out that these differences result in bounding loads on the SRVs. The first part of the response to this question addresses the segment of piping directly downstream of the SRV. The applicant has stated that the test piping is comparable to the in-plant segement (12 ft vs. 11.7 ft) which would result in a slightly higher moment at the test valve. Discharge from the "x" quencher at the end of the Clinton SRV discharge line cannot transmit loads to the valve as the test system could because the in-plant line contains an anchor between the quencher and the valve. The second part of the response to this question addressed the back pressure (dynamic, hydraulic) loads on the test and in-plant valves. The applicant addressed both transient and steady-state back-pressure loads. The steady-state back pressure for the test valve was forced to be greater than the expected in-plant pressure by installing a predetermined orifice plate in the discharge line before the ram's head and above the water line. The response also indicated that the high-pressure steam test preceding the low-pressure water test would produce the greater transient back pressures between the two tests. This would be true because of the higher pressure upstream of the SRV and the shorter valve opening time. The staff finds the applicant's response to both parts of the first question to be acceptable.

The response to the second question described the support system components in the Clinton Power Station, Unit No. 1, discharge lines indicating that spring hangers do exist at Clinton whereas the test facility piping did not include spring hangers. The basic argument defending the adequacy of the spring hangers (in fact, all supports) is that they were designed for the much larger,

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high-pressure-steam, relief valve opening loads. In this case, therefore, sufficient margin is available in the in-plant spring hangers to account for the additional load because of the dead weight in the water-filled, low-pressure event. The test results indicated significantly lower dynamic loads during the water discharge event than during the high-pressure, steam-discharge case and the point made in this response (as well as in the response to the first question) is that the test program was designed primarily to demonstrate valve and system adequacy under the prototypical water-discharge events (i.e., the alternate shutdown cooling mode).

Thus, with the in-plant SRV discharge piping and support system designed for the high-pressure steam-discharge event and with the satisfactory response of the test valves, the discharge piping and support system to the low-pressure water blowdown, the staff finds the applicant's response to the second question acceptable.

The third question requested that the applicant describe and compare expected events at Clinton with the test conditions of the generic test program. The applicant summarized the analysis procedure (Waters, Sept. 17, 1980) using RG 1.70 which arrived at 13 events that would result in liquid or two-phase flow through the SRVs and maximize the dynamic forces on the valve. As indicated in Section 5.2.2.2.1, this analysis concluded that the alternate shutdown cooling mode is the only expected event which will result in liquid at the valve inlet. To simulate this event the test program used a 15°F-50°F subcooled liquid at 20 psig-250 psig at the safety valve inlet before valve opening. The applicant indicated that the alternate cooling mode of operation at Clinton will result in a relief valve liquid discharge that would be subcooled in the pressure range 13.8 psig to 130 psig. Therefore, the test conditions envelop the expected conditions for this event should it occur in Unit 1 at the Clinton Power Station. The staff finds the applicant's response to the third question acceptable.

The applicant's response to the fourth question addressed the determination and future use of the valve flow coefficient, C_v. The response indicates that the value of the liquid flow coefficient, in itself, is not of direct interest. The flow capacity of the valves as determined during the tests is the measurement of interest. The flow capacity of the system SRVs is larger than the capacity of the coolant source pump of the residual heat removal (RHR) system and therefore sufficient to remove decay heat. The staff finds the applicant's responses to the fourth question acceptable.

Considering the above evaluations, the staff finds that the applicant has provided an acceptable response to the correlation between the generic SRV test program and the installed SRV valve concern of requirement 7 and to the piping and support concerns of requirement 5 listed in Section 5.2.2.1.

Two additional questions generated by the staff concerning (1) valve functional deficiencies encountered during invalidated test runs and (2) the effect of steam cycling on valve performance, have been addressed previously by other applicants and licensees using the Dikkers 8 x R x 10 direct acting dual function SRV. The staff accepted those responses based on the following:

(1) Previous submittals by other applicants and licensees have stated, "All the valves subjected to test runs, valid or invalid, opened and closed

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without loss of pressure integrity or damage." This statement was supported by the Wyle Laboratory test log sheet for the Dikkers valve.

(2) Although the test program did not subject the valves to steam cycling, the valve vendor has subjected the valves in question to high-pressure steam-flow cycling and no loss of valve performance has been noted.

Because of this prior acceptance, the applicant was not asked to respond to these concerns.

The applicability of the response of the SRV discharge piping system to the response of the in-plant piping system has been accepted above. In the test report (GE, NEDE-24988-P), it is indicated that (1) the analytically predicted response of the test piping and supports was compared to the measured values and (2) the maximum test piping response to liquid flow was generally less than 30% of that from test steam-flow conditions. Further, as part of the initial review, the loads on the in-plant piping and supports from steam discharge were found to be acceptable by the staff.

5.2.2.4 Evaluation and Conclusion

The applicant has provided an acceptable response to the requirements of NUREG-0737, and thereby, reconfirmed that GDC 14, 15, and 30 have been met. The rationale for this conclusion is given below.

The applicant, with concurrence by the staff, developed an acceptable relief and safety valve test program designed to qualify the operability of the prototypical valves and to demonstrate that their operation would not invalidate the integrity of the associated equipment and piping. The subsequent tests were successfully completed under operating conditions which by analysis bounded the most probable maximum forces expected from anticipated design-basis events. The generic test results showed that the valves tested functioned correctly and safely for all steam and water discharge events specified in the test program and that the pressure boundary component design criteria were not exceeded. Analysis and review of the test results and the applicant's justifications indicated the direct applicability of prototypical valve and valve system performances to the in-plant valves and systems intended to be covered by the generic test program.

Thus, the requirements of Item II.D.1 of NUREG-0737 have been satisfied (requirements 1-7 in Section 5.2.2.1 of this supplement) and, thereby, ensure that the reactor primary coolant pressure boundary will have, by testing, a low probability of abnormal leakage (GDC 14) and that the reactor primary coolant pressure boundary and its associated components (piping, valves, and supports) have been designed with sufficient margin so that design conditions are not exceeded during relief/safety valve events (GDC 15).

Further, the prototypical tests and the successful performance of the valves and associated components demonstrated that this equipment has been constructed in accordance with high quality standards (GDC 30).

In addition, the applicant's commitment to participate in the INPO SRV surveillance program and incorporation of a surveillance program by operating procedure at Clinton satisfies the staff's requirement as stated in the SER.

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6 ENGINEERED SAFETY FEATURES

6.3 Emergency Core Cooling System

6.3.2 Evaluation

6.3.2.2 Qualification of the Emergency Core Cooling System

(1) Background

NUREG-0737, Item II.K.3.28, states that safety analysis reports claim that air or nitrogen accumulators for the automatic depressurization system (ADS) valves are provided with sufficient capacity to cycle the valves open five times at design pressures. The General Electric Co. (GE) has also stated that the emergency core cooling (ECC) systems are designed to withstand a hostile environment and still perform their function for 100 days following an accident. Licensees and applicants must demonstrate that the ADS valves, accumulators, and associated equipment and instrumentation meet the requirements specified in the plant's FSAR and are capable of performing their functions during and following exposure to hostile environments, taking no credit for non-safety-related equipment or instrumentation. Additionally, air (or nitrogen) leakage through valves must be accounted for in order to ensure that enough inventory of compressed air is available to cycle the ADS valves. If this cannot be demonstrated, it must be shown that the accumlator design is still acceptable.

The commitment to satisfy the requirements of NUREG-0737, Item II.K.3.28, for Clinton Power Station, Unit No. 1, is discussed in an LRG II position paper submitted May 17, 1982, in a letter from the applicant dated June 11, 1982, and in another letter from the applicant dated November 19, 1984.

(2) Description of System and Demonstration of Operability

The automatic depressurization system (ADS) uses selected safety/relief valves (SRVs) for depressurization of the reactor. Each of the SRVs utilized for automatic depressurization is equipped with an air accumulator, a check valve, and a safety-grade backup air supply to preserve pressure. The safety-grade ADS pneumatic supply is separate for the two divisions. One supplies the ADS valves on steamlines A and C, the other supplies the ADS valves on steamlines B and D. The air supply to the ADS valves has been designed so that the failure of any one component will not result in the loss of air supply to more than one nuclear safety-related division of ADS valves. The loss of air supply to one division of ADS valves will not prevent the safe shutdown of the unit. For all BWR/6s, only three of the ADS valves in one division need to function to meet short-term demands, and the functional operability of only one ADS valve will fulfill longer term needs. The ADS accumulators are designed to provide two SRV actuations at 70% of drywell design pressure, which is equivalent to five actuations at atmospheric pressure.

The normal air supply to the accumulators for the ADS valves and non-ADS safety/relief valves is from the station instrument air (IA) system. Compressed air

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for this system is supplied at 120 psig from one of the three 100% capacity service air (SA) system compressors and processed through one of the three 100% capacity IA system filter/dryer packages. Instrument air to the ADS and non-ADS valves is processed through twelve 20% capacity air amplifiers which double the regulated supply pressure of 80 psig to 160 psig and deliver it to the valve accumulators.

If the normal air supply is not available, the safety-grade backup air supply system will preserve ADS valve accumulator pressure. This backup system has two independent air storage facilities located in separate corners of the basement of the auxiliary building. Each facility consists of eight 1.75 ft^3 bottles, pressurized to 2400 psig, and equipped with appropriate regulator valves and interconnecting piping to supply one division of ADS valves with a 7-day supply of air. Both facilities have remote makeup capability to ensure a 100-day postaccident ADS air supply.

The bottles at the air-storage facilities are manufactured to DOT Specification 3AA and are equipped with seismic Category I restraints. ADS valve accumulators, interconnecting piping back to the storage facilities, and associated valves are designed to the requirements of ASME Code Section III, Class 3, and are seismic Category I. The four motor-operated valves and controls for bringing the backup air system into service are powered from Class 1E power supplies. The valves and controls for each of the independent air-storage facilities are powered from a separate electrical division. The backup air-supply system from the air-storage facility to the ADS valve accumulators will be environmentally qualified in accordance with the requirements contained in NUREG-0588.

In the event of a normal air-supply-system problem, one or more of the following control room alarms would be activated:

- trouble with IA dryer (separate alarm for each dryer)
- trouble with SA compressor (separate alarm for each compressor)
- low pressure (70 psig) in ring header (separate alarm for each of the six ring headers)
- automatic start of standby SA compressor (80 psig)
- not available IA/SA system (separate alarm for Division I and II)
- low ADS valve accumulator pressure below 140 psig for any accumulator

These alarms would alert the operator to a problem in the normal air-supply system for the ADS valves.

The operator would verify that automatic actions to maintain the normal supply have occurred and would manually perform any that have not. If the normal air-supply system cannot be maintained and air-system pressure drops from 120 psig to below 70 psig (140 psig to ADS accumulators), then the control rod drive system scram valves will fail open, causing the associated control rods to insert and thus shut down the reactor. The control room operator places the backup air supply into service by closing the two normal air-system supply valves and opening the two backup-system supply valves.

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In the event of an accident or transient which would result in a containment isolation, the normal air system would be isolated and the backup system would automatically be placed in service.

Surveillance and testing of the compressed air-supply systems for the ADS will consist of the following activities:

(1) control room operator continual surveillance of control room alarms for SA compressors, IA dryers, IA ring header pressures, and ADS accumulator pressure

(2) auxiliary equipment operator daily inspection of backup air-storage pressure

(3) operability testing in all SRV accumulator check valves to ensure proper functioning in accordance with the requirements of ASME Code Section XI, Subsection IWV

A surveillance test will be conducted every refueling cycle under the normal plant preventive maintenance program (PPMP). For the first test, the isolation boundaries are the ADS accumulator inlet check valve and the de-energized SRV actuation solenoid. For the second test, the SRV actuation solenoid will be energized so that the SRV pneumatic operator and the solenoid valve vent port become part of the boundaries. By performing the two tests proposed, leakage from the SRV pneumatic operator can be specifically quantified. In both tests, the leakage acceptance criteria is 0.425 scfh, 85% of the expected leakage, which is obtained by subtracting the 0.5 scfh margin from the 1.0 scfh allowable leakage.

The ADS accumulator system allowable leakage criteria is 1 scfh per SRV under normal and postaccident conditions. The 1-scfh leakage rate was originally established by multiplying the 0.1-scfh GE acceptance criteria (specified to the SRV vendor for new valves) by a factor of 10 to allow for in-service deterioration between SRV overhauls. In establishing the allowable leakage criteria, actual leakage was from safety-related equipment or components. Therefore, no credit was taken for non-safety-related equipment and instrumentation when establishing the allowable leakage criteria.

Two specific calculations were performed that demonstrated the adequacy of the designed accumulator capacity with the leakage rate at the maximum allowable by the leakage criteria. The first calculation indicated that, under worst-case initial conditions, one SRV actuation can be achieved for up to 3.4 hours into a LOCA event without relying on the backup ADS air supply. The second calculation indicated that one SRV actuation can be achieved for up to nearly 8 hours into the LOCA event without relying on the backup ADS air supply. The third calculation showed that under normal (expected) initial operating conditions, accumulator to drywell differential pressure following the second actuation is above the required 95 psig for a period of at least 2 hours, if the maximum allowable leakage is assumed. Thus, two SRV actuations can be achieved under worst-case drywell pressure conditions following a small-break or intermediate-break LOCA.

To demonstrate the ability of the long-term air supply to provide sufficient air to meet the leakage criteria, a fourth calculation was performed. This

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calculation demonstrated the capability of the backup air supply to meet the ADS needs for a period of 1 week without replenishment. The calculation takes into account 100 actuations of the low setpoint SRV (also connected to this supply) and a leakage of 1 scfh for each of the five SRVs connected (per Specification 22A4622AV). At the end of this 7-day period, the pressure remaining on the air bottle is still sufficient for ADS operation. During the 7-day period, provisions can be made to bring in additional air supply to meet system demands indefinitely.

Experience from previous GE environmental qualification tests and from recent tests performed to demonstrate compliance with requirements of NUREG-0588 shows that, for well beyond the required time period for ADS SRV short-term operation, SRV pneumatic system leakage will not exceed about 0.5 scfh. These tests included seismic and environmental (temperature radiation, etc.) qualification of the SRVs.

A materials and design review was performed to ensure that these check valves would not experience a significant increase in leakage because of post-LOCA environmental and/or seismic conditions. The check valve seat and disc materials are made of stellite. Clinton's post-LOCA environmental and/or seismic conditions would not be expected to significantly increase the leakage around such materials.

On the basis of the tested rate from the ADS SRV pneumatic operators and the expected low leakage past the ADS accumulator inlet check valves, under post-LOCA environmental and/or seismic conditions, there is about 0.5-scfh margin in the 1-scfh allowable leakage criteria.

(3) Evaluation of System Operability

The applicant, in describing the normal air supply to the ADS valves, has defined and verified that the ADS accumulator system is designed to provide two SRV actuations at 70% of drywell design pressure, which is equivalent to five actuations at atmospheric pressure. Additionally, long-term capability has been verified with the safety-grade backup air-supply system. The system has two independent air-storage facilities, and both facilities have remote makeup capability. The backup air-supply system from the air-storage facility to the ADS valve accumulators will be environmentally qualified in accordance with the requirements of NUREG-0588. Therefore, the applicant has demonstrated that Clinton has the capability for long-term cooling. The staff finds this acceptable.

The allowable leakage criterion of 1 scfh is based on SRV purchase specification leak rate of 0.1 scfh multiplied by a factor of 10 to allow for in-service deterioration between SRV overhauls. This results in a margin of 0.5 scfh based on tested leakage rate from the ADS SRV pneumatic operators, from GE environmental qualification tests, and from recent tests to satisfy NUREG-0588 requirements. These tests reportedly have shown that for well beyond the required time period for ADS SRV short-term operation, SRV pneumatic system leakage will not exceed about 0.5 scfh. The staff finds this acceptable.

The applicant has developed surveillance and maintenance programs acceptable to the staff for periodic surveillance, surveillance and leak testing of the ADS accumulator system, and associated alarms and instrumentation.

The applicant has provided information to the staff confirming that

- The normal and backup air supply system, i.e., ADS valves, accumulators, interconnecting piping back to the storage facilities, and associated valves are seismic Category I.

- The accumulators and associated equipment will be capable of performing their functions during and following an accident, taking no credit for non-safety-related equipment and instrumentation. The staff finds this acceptable subject to completion and satisfactory review of the applicant's environmental qualification program in accordance with 10 CFR 50.49 which is discussed in Section 3.11 of this supplement.

(4) Conclusion

On the basis of the information provided by the applicant and summarized in Section 6.3.2.2(2) and in the evaluations in Section 6.3.2.2(3), the staff concludes that the applicant has verified qualification for the ADS accumulator systems at Clinton Unit 1 and therefore satisfies the requirements of NUREG-0737, Item II.K.3.28, resolving confirmatory issue 47.

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7 INSTRUMENTATION AND CONTROLS

7.5 Information Systems Important to Safety

7.5.3 Resolution of Issues

7.5.3.1 Conformance to Regulatory Guide 1.97, Revision 3

In Generic Letter 82-33 the applicant was asked to provide a report to the NRC describing how the postaccident monitoring instrumentation meets the guidance of RG 1.97 as applied to emergency response facilities. The applicant responded to Section 6 of the generic letter by letter dated September 9, 1983. Additional information was provided by letter dated December 11, 1984.

Subsequent to the issuance of the generic letter, the NRC held regional meetings in February and March 1983 to answer licensee and applicant questions and concerns regarding the NRC policy on RG 1.97. At these meetings, it was noted that the NRC review would only address exceptions taken to RG 1.97. Furthermore, where licensees or applicants explicitly state that instrument systems conform to the regulatory guide, it was noted that no further staff review would be necessary.

A detailed review and technical evaluation of the applicant's submittals was performed by EG&G Idaho, Inc., under contract to the NRC, with general supervision by the NRC staff. This work is reported by EG&G in its Technical Evaluation Report (TER), "Conformance to Regulatory Guide 1.97, Clinton Power Station, Unit No. 1," dated May 1985 which is contained in Appendix G to this supplement to the SER. As previously mentioned, the review performed and reported by EG&G only addressed exceptions to RG 1.97. This safety evaluation addresses the applicant's submittals based on the review policy described in the NRC regional meetings and the conclusions of the review as reported by EG&G.

The staff has reviewed the evaluation performed by its consultant contained in the TER (Appendix G of this supplement) and concurs with its bases and findings. The applicant either conforms to, or has provided an acceptable justification for deviations from the guidance of, RG 1.97 for each postaccident monitoring variable except for fuel zone level instrumentation. The two redundant channels of fuel zone range level instrumentation do not presently comply with the Category I requirement of RG 1.97. Both fuel zone level channels are powered from the same 120-V ac non-Class 1E power sources and are not environmentally qualified (see Section 4 of Appendix G). The applicant committed to provide separate Class 1E power for those instruments before power ascension following the first refueling outage. The staff finds this commitment acceptable.

On the basis of its review of the enclosed TER (see Appendix G) and the applicant's submittals, the staff finds that the Clinton Power Station, Unit No. 1, design is acceptable with respect to conformance to the guidelines of RG 1.97, Rev. 3, and therefore license condition 3 is no longer required.

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Since the fuel zone instrumentation currently does not conform to the requirements of RG 1.97, the following condition (license condition 15) will be added:

> Prior to startup following the first refueling outage, the applicant shall install and have operational separate Class 1E power sources on the fuel zone level channels and inform the staff that the fuel zone level instrumentation has been environmentally qualified in accordance with the requirements of 10 CFR 50.49

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9 AUXILIARY SYSTEMS

9.1 Fuel Storage Facility

9.1.5 Overhead Heavy Load Handling System

As a result of Generic Task A-36, "Control of Heavy Loads Near Spent Fuel," NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," was developed. Following the issuance of NUREG-0612, a generic letter dated December 22, 1980, was sent to all operating plants, applicants for operating licenses, and holders of construction permits requesting that responses be prepared to indicate the degree of compliance with the guidelines of NUREG-0612. As indicated above, in accordance with the generic letter dated December 22, 1980, the applicant was asked to review its provisions for handling and control of heavy loads at Clinton to determine the extent to which the guidelines of NUREG-0612 are satisfied and to commit to mutually agreeable changes and modifications that would be required in order to fully satisfy these guidelines. By letters dated September 25, 1981; February 10, 1982; March 18, July 28, December 21, 1983; and January 26 and February 21, 1985, the applicant responded to this request.

The staff and its consultant, the Idaho National Engineering Laboratory (INEL), have reviewed the applicant's submittals for the Clinton Power Station. As a result of its review, EG&G has issued a Technical Evaluation Report (TER) which is contained in Appendix H to this supplement. The staff has reviewed the TER and concurs with its findings that the guidelines in NUREG-0612, Section 5.1.1 (Phase I), have been satisfied. The NRC staff established in NUREG-0612, Article 5.3, interim protection guidelines for operating plants. Since Clinton Power Station is not operational, these guidelines are not applicable.

Two commitments made by the applicant associated with the guidelines that remain to be completed before fuel loading have been identified. They are

(1) Documentation of the safe load paths for each heavy load handled shall be developed, complete with drawings or sketches and risks identified.

(2) Procedures for all overload handling systems, including the single-failure-proof cranes shall be completed.

The information associated with these commitments should be available at the site for staff confirmation.

On the basis of its review of the applicant's submittals and the INEL TER the staff concludes that Phase I of NUREG-0612 for Clinton Power Station is acceptable.

In Supplement 2 to the Clinton Power Station SER, license condition 13 regarding compliance with the criteria of Phases I and II (Section 5.1.2 through 5.1.6) of NUREG-0612 was added. On the basis of the applicant's compliance with the criteria of Phase I, and the reviews of Phase II to date, license condition 13 is no longer needed.

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9.3 Process Auxiliaries

9.3.5 Postaccident Sampling Capability (NUREG-0737, Item II.B.3)

Introduction and Background

Subsequent to the TMI-2 incident, the need was recognized for an improved post-accident sampling system (PASS) to determine the extent of core degradation following a severe reactor accident. Criteria for an acceptable sampling and analysis system are specified in NUREG-0737, Item II.B.3. The system should have the capability to obtain and quantitatively analyze reactor coolant and containment atmosphere samples without radiation exposure to any individual exceeding 5 rem to the whole body or 75 rem to the extremities (GDC 19) during and following an accident in which there is core degradation. Materials to be analyzed and quantified include certain radionuclides that are indicators of severity of core damage (e.g., noble gases, isotopes of iodine and cesium, and nonvolatile isotopes), hydrogen in the containment atmosphere, and total dissolved gases or hydrogen, boron, and chloride in reactor coolant samples.

To comply with NUREG-0737, Item II.B.3, the applicant should (1) review and modify its sampling, chemical analysis, and radionuclide determination capabilities as necessary and (2) provide the staff with information pertaining to system design, analytical capabilities, and procedures in sufficient detail to demonstrate that the criteria are met.

In the SER, the staff identified 11 criteria that had to be satisfied by the applicant for compliance with the requirements of NUREG-0737, Item II.B.3. The staff evaluated the applicant's submittals against these criteria and determined that additional information was required before this item could be resolved. In SSER 2, the staff approved the applicant's plant-specific core-damage estimate procedure on an interim basis. However, the staff stated that final approval was required before fuel load and identified additional information that should be incorporated into the procedure. In addition, SSER 2 contained an evaluation of the Licensing Review Group II (LRG II) positions endorsed by the applicant.

Evaluation

By FSAR Amendment 33 and letters dated April 19, 1985, and June 11, 1985, the applicant provided additional information and consolidated all the previous information provided on the postaccident sampling system. The staff's evaluation of the applicant is submittals against the 11 acceptance criteria for compliance with the requirements of NUREG-0737, Item II.B.3, follows.

Criterion 1:

> The licensee [applicant] shall have the capability to promptly obtain reactor coolant samples and containment atmosphere samples. The combined time allotted for sampling and analysis should be 3 hours or less from the time a decision is made to take a sample.

The applicant has provided sampling and analysis capability to promptly obtain and analyze reactor coolant, suppression pool (from RHR loop), containment sump, and containment atmosphere samples within 3 hours from the time a decision is

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made to take a sample. During loss of offsite power, alternate power sources are available for both gas and liquid sampling systems that can be energized in sufficient time to meet the 3-hour sampling and analysis time limit. The staff finds that these provisions meet Criterion 1 and are, therefore, acceptable.

Criterion 2:

> The licensee [applicant] shall establish an onsite radiological and chemical analysis capability to provide, within the 3-hour time frame established above [in Criterion 1], quantification of the following:
>
> (a) certain radionuclides in the reactor coolant and containment atmosphere that may be indicators of the degree of core damage (e.g., noble gases, iodines and cesiums, and non-volatile isotopes);
>
> (b) hydrogen levels in the containment atmosphere;
>
> (c) dissolved gases (e.g., H_2), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids.
>
> (d) Alternatively, have inline monitoring capabilities to perform all or part of the above analyses.

The PASS provides grab sample and/or in-line analysis capability for pH, chloride, boron, radionuclide analysis and dissolved hydrogen and oxygen in the reactor coolant, and grab and/or in-line monitoring of hydrogen, oxygen, and gamma spectra in the containment atmosphere. The PASS provides the capability to collect diluted or undiluted liquid reactor coolant and gaseous grab samples. The applicant provided a plant-specific core damage estimation procedure based on the BWR Owners Group procedure which is incorporated in the Site Emergency Plan. This procedure includes core damage estimates based on reactor water and containment atmosphere radionuclide concentrations, reactor vessel water level indications, containment hydrogen levels, and drywell radiation levels.

The staff finds that these provisions meet Criterion 2 by establishing an onsite radiological and chemical analysis capability and are, therefore, acceptable.

Criterion 3:

> Reactor coolant and containment atmosphere sampling during post-accident conditions shall not require an isolated auxiliary system [e.g., the letdown system, reactor water cleanup system (RWCUS)] to be placed in operation in order to use the sampling system.

Reactor coolant and containment atmosphere sampling during postaccident conditions does not require an isolated auxiliary system to be placed in operation in order to perform the sampling function. The PASS valves which are not accessible after an accident are environmentally qualified for the conditions in which they need to operate. These provisions meet Criterion 3 and are, therefore acceptable.

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Criterion 4:

> Pressurized reactor coolant samples are not required if the licensee [applicant] can quantify the amount of dissolved gases with unpressurized reactor coolant samples. The measurement of either total dissolved gases or H_2 gas in reactor coolant samples is considered adequate. Measuring the O_2 concentration is recommended, but is not mandatory.

The PASS system provides the capability to take pressurized or unpressurized reactor coolant samples for dissolved gas analysis. The hydrogen concentration is measured by gas chromatography and the oxygen concentration is measured by an Orbisphere in-line. Dissolved oxygen concentrations of less than 0.1 ppm can be verified by measurement of a dissolved hydrogen residual of >10 cc/kg. Alternately, dissolved oxygen can be obtained by gas chromatography. The staff has determined that these provisions meet Criterion 4 of Item II.B.3 in NUREG-0737, and are, therefore, acceptable.

Criterion 5:

> The time for a chloride analysis to be performed is dependent upon two factors: (a) if the plant's coolant water is seawater or brackish water and (b) if there is only a single barrier between primary containment systems and the cooling water. Under both of the above conditions the licensee [applicant] shall provide for a chloride analysis within 24 hours of the sample being taken. For all other cases, the licensee shall provide for the analysis to be completed within 4 days. The chloride analysis does not have to be done onsite.

Chloride analysis is performed on a diluted sample within 96 hours of sampling by using an ion chromatograph. Chloride analysis accuracy by this technique is <0.1 ppm. An undiluted sample will also be obtained and stored on site for analysis within 30 days. These provisions meet Criterion 5 and are, therefore, acceptable.

Criterion 6:

> The design basis for plant equipment for reactor coolant and containment atmosphere sampling and analysis must assume that it is possible to obtain and analyze a sample without radiation exposures to any individual exceeding the criteria of GDC 19 (Appendix A, 10 CFR Part 50) (i.e., 5 rem whole body, 75 rem extremities). (Note that the design and operational review criterion was changed from the operational limits of 10 CFR Part 20 (NUREG-0578) to the GDC 19 criterion (October 30, 1979, letter from H. R. Denton to all licensees).

The applicant has performed a study to ensure that operator exposure while obtaining, transporting, and analyzing a PASS sample is within the acceptable limits. This operator exposure includes entering and exiting the sample panel area, operating sample panel manual valves, positioning the grab sample into the shielded transfer casks, transporting casks, and performing sample analyses. Radiation exposures to PASS personnel from reactor coolant and containment atmosphere sampling and analysis are within 5 rem whole body and 75 rem extremities, which meet the requirements of GDC 19 and Criterion 6 and are, therefore, acceptable.

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Criterion 7:

> The analysis of primary coolant samples for boron is required for PWRs. (Note that Revision 2 of Regulatory Guide 1.97 specifies the need for primary coolant boron analysis capability at BWR plants.)

A diluted grab sample of the reactor coolant will be analyzed for boron by ion chromatography in the range of 0 to 1000 ppm with an accuracy of 8%. This provision meets the recommendations of Regulatory Guide 1.97, Rev. 2, and Criterion 7 and is, therefore, acceptable.

Criterion 8:

> If inline monitoring is used for any sampling and analytical capability specified herein, the licensee [applicant] shall provided backup sampling through grab samples, and shall demonstrate the capability of analyzing the samples. Established planning for analysis at offsite facilities is acceptable. Equipment provided for backup sampling shall be capable of providing at least one sample per week until the accident condition no longer exists.

In-line monitoring is used to determine containment atmosphere hydrogen and oxygen levels and radionuclide analysis and reactor coolant dissolved hydrogen and oxygen, pH, and conductivity. The PASS can obtain both diluted and undiluted reactor coolant, dissolved gas, and containment atmosphere samples for either onsite or offsite analyses. Prior arrangements have been made for a shipping container and for an offsite facility for sample analysis. The staff finds that these provisions meet Criterion 8 and are, therefore, acceptable.

Criterion 9:

> The licensee's [applicant's] radiological and chemical sample analysis capability shall include provisions to:
>
> (a) Identify and quantify isotopes of the nuclide categories discussed above to levels corresponding to the source term given in Regulatory Guide 1.3 or 1.4[,] and 1.7. Where necessary and practicable, the ability to dilute samples to provide capability for measurement and reduction of personnel exposure should be provided. Sensitivity of onsite liquid sample analysis capability should be such as to permit measurement of nuclide concentration in the range from approximately 1 μCi/g to 10 Ci/g.
>
> (b) Restrict background levels of radiation in the radiological and chemical analysis facility from sources such that the sample analysis will provide results with an acceptably small error (approximately a factor of 2). This can be accomplished through the use of sufficient shielding around samples and outside sources, and by the use of a ventilation system design which will control the presence of airborne radioactivity.

The radionuclides in both the primary coolant and the containment atmosphere will be identified and quantified. Provisions are available for diluted reactor coolant samples to minimize personnel exposure. The PASS can perform radioisotope analyses at the levels corresponding to the source term given in Regulatory

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Guide 1.3, Rev. 2, and 1.7. Radiation background levels will be restricted by shielding. Ventilated radiological and chemical analysis facilities are provided to obtain results with an acceptably small error (approximately a factor of 2). The staff finds that these provisions meet Criterion 9 and are, therefore, acceptable.

Criterion 10:

> Accuracy, range, and sensitivity shall be adequate to provide pertinent data to the operator in order to describe radiological and chemical status of the reactor coolant systems.

The accuracy, range, and sensitivity of the PASS instruments and analytical procedures consistent with the recommendations of Regulatory Guide 1.97, Rev. 3, and July 27, 1983, clarifications of NUREG-0737, Item II.B.3, "Post-Accident Sampling Capability." Therefore, they are adequate for describing the radiological and chemical status of the reactor coolant. The analytical methods and instrumentation were selected for their ability to operate in the postaccident sampling environment. The standard test matrix and radiation effect evaluation indicated no interference in the PASS analyses. Technician requalification training will occur every 2 years, as a minimum. Refresher training of technicians will occur on a semiannual basis through the use of PASS for routine analyses and drills. Analytical and sampling instrumentation are calibrated routinely as prescribed in the vendor manual. The staff determined that these provisions meet Criterion 10 of Item II.B.3 in NUREG-0737, and are, therefore, acceptable.

Criterion 11:

> In the design of the postaccident sampling and analysis capability, consideration should be given to the following items:
>
> (a) Provisions should be made for purging sample lines, for reducing plateout in sample lines, for minimizing sample loss or distortion, for preventing blockage of sample lines by loose material in the RCS or containment, for appropriate disposal of the samples, and for flow restrictions to limit reactor coolant loss from a rupture of the sample line. The postaccident reactor coolant and containment atmosphere samples should be representative of the reactor coolant in the core area and the containment atmosphere following a transient or accident. The sample lines should be as short as possible to minimize the volume of fluid to be taken from containment. The residues of sample collection should be returned to containment or to a closed system.
>
> (b) The ventilation exhaust from the sampling station should be filtered with charcoal adsorbers and high-efficiency particulate air (HEPA) filters.

The applicant has addressed provisions for purging and recirculation back to containment to ensure samples are representative, and the small size of the sample line serves to limit reactor coolant loss from a rupture of the sample line. To limit iodine plateout, the containment atmosphere sample line is heat traced. A dedicated charcoal adsorber and HEPA filtration system are provided for the sampling station ventilation system. Reactor coolant samples will be

obtained from the jet pump instrumentation system when the system is at pressure to obtain a representative sample under accident conditions.

At power levels of less than 1%, a sample that is representative of core conditions would be obtained by increasing the reactor water level by 18 inches. This will fully flood the standpipes of the moisture separators and will provide a thermally induced recirculation flowpath for mixing.

A single sample line is also connected to both loops in the RHR system. This provides a means of obtaining a reactor coolant sample when the reactor is depressurized and at least one of the RHR loops is operated in the shutdown cooling mode. Similarly, a suppression pool liquid sample can be obtained from the RHR loop lined up in the suppression pool cooling mode. The staff determined that these provisions meet Criterion 11 of Item II.B.3 of NUREG-0737, and are, therefore, acceptable.

Conclusion

On the basis of the above evaluation, the staff concludes that the postaccident sampling system meets the requirements of Item II.B.3 of NUREG-0737 and is, therefore, acceptable. License condition 6 is no longer required.

13 CONDUCT OF OPERATIONS

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During the period May 6 to June 24, 1985, the staff reviewed FSAR Chapter 13 through Amendment 33 against the July 1981 version of the Standard Review Plan (SRP) (NUREG-0800).

The staff also met with a representative of Illinois Power Company (the applicant) on June 13 and 19, 1985, to clarify matters addressed in FSAR Chapter 13, Amendment 33.

The material that follows provides the results of those meetings and reviews.

13.1 Organizational Structure of Applicant

13.1.1 Management and Technical Support Organizations

The corporate organization and lines of responsibility for management and technical support of Clinton are shown on revised Figure 13.1 of this supplement. The basic difference affecting Clinton between this support organization and the one accepted in the Clinton SER is the addition of three departments under the Vice President responsible for nuclear projects. A brief description of the new departments is provided below.

The Startup Department is responsible for preoperational and acceptance testing and for providing assistance to the Clinton plant manager for startup testing.

The Nuclear Planning and Support Department is directly responsible for Clinton budgets and accounting, schedule coordination and integration, personnel (including fitness for duty program), nuclear records, information and computer systems, procurement, and short- and long-term planning.

The Nuclear Training Department is responsible for the development and implementation of the Clinton training program. This program is intended to

ensure safe and efficient operation of the station by developing and maintaining a plant staff which is fully trained and qualified to safely operate, maintain and support the plant and technical aspects of Clinton.

In addition to adding these three new departments, modifications have also been made to the Nuclear Station Engineering Department (NSED). However, the overall responsibilities and reporting authority of this department remain essentially the same. The Manager of the NSED is the designated "Engineer in Charge" described in Section 4.6.1 of ANSI Std. 3.1-1978. The Manager - NSED meets the qualifications for that position as described in ANSI Std. 3.1-1978.

The applicant has described the organization for the management and technical support of the Clinton Power Station staff during operation of the facility. This organization has been reviewed and the staff concludes that the applicant has an organization and staff acceptable to meet the requirements expressed in SRP Section 13.1.1.

13.1.2 Operating Organization

13.1.2.1 Organization

(1) Plant Operating Staff

The organization of Clinton is shown on revised Figure 13.3 of this supplement. The applicant has modified the Clinton organization from that originally reviewed and reported in the SER, NUREG-0853. The most significant change is the establishment of a separate organization for radiation protection. A brief description of the radiation protection group responsibilities follows.

The Radiation Protection Department is responsible for the planning and development of the operational aspects of radiation protection and radiological monitoring at Clinton. The Supervisor of Radiation Protection reports to the Plant Manager of Clinton.

The applicant's current plant organization was reviewed against criteria expressed in the SRP and was judged acceptable.

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(2) Plant Staff Levels and Qualifications

The applicant has indicated the current 1985 approved staffing levels are as shown below.

CPS Plant Manager's Office	12
Operations Department	148
Maintenance Department	147
Technical Department	44
Radiation Protection Department	43
Plant Services Department	31
Compliance and Configuration Control	12
Total Plant Staff	437

The applicant has stated that, as of April 1985, there were 70 open positions against the 1985 approved staffing levels. None of these open positions were for required control room operators, assistant shift supervisors, or shift supervisors.

The applicant is still planning to use five operating shift crews for normal operation. The normal shift complement will be as follows:

Shift Supervisor (SRO)	1
Asst. Shift Supervisor (SRO)	2
Control Room Operator (RO)	3
Unit Attendant	1
Auxiliary Operator	1
Radwaste Operator	1
Radiation Protection Technician	1
Shift Technical Advisor	1

This shift complement may vary, but will not be less than the minimum specified in the Technical Specifications.

Except as noted in FSAR Chapter 1, the applicant has committed to meeting personnel qualifications as stated in ANS Std 3.1-1978. Two of the exceptions were discussed with the applicant's representative.

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(1) The Supervisor of Chemistry shall possess qualifications as required by ANS Std. 3.1-1981, not ANS Std. 3.1-1978. The requirements of ANS Std. 3.1-1981 specify that individuals filling this position must have a bachelor's degree in chemistry, or related science, and 2 years of experience in chemistry, of which 1 year shall be nuclear power plant experience in radiochemistry. ANS Std. 3.1-1978 does not require a degree, but does require 5 years of chemistry experience, of which 1 year shall be in radiochemistry at an operating nuclear power plant. The present individual incumbent in the Chemistry Supervisor position has a B.A. and M.S. in chemistry, an M.S. in management, and 10 years of chemistry experience, of which ~~two~~ 2 have been at Clinton. The applicant has committed to provide this individual specific nuclear training by an assignment in a chemistry section of an operating nuclear power plant for a period of 3 months (the plant must be above 20% power for at least 2 of these months), and the successful completion of the NSSS vendor chemistry and radiochemistry training program. This training is to be in addition to the onsite experience at Clinton.

The staff has reviewed the applicant's exception to the qualifications of the Chemistry Supervisor and judges that the individual possesses an adequate background, which when augmented by the additional training committed to by the applicant, will make the exception acceptable. Future assignments of individuals to the position of Supervisor of Chemistry will be reviewed and judged on a case-by-case basis.

(2) The qualifications required by ANS Std. 3.1-1978 for the individual assigned as Supervisor of the Instrument and Control (I&C) group includes 1 year of nuclear I&C experience at an operating nuclear plant. The applicant has requested an exception for the 1 year of nuclear I&C experience at an operating nuclear plant for the Clinton Supervisor of Control and Instrumentation. The individual currently incumbent in this position has extensive electrical experience and specialized instrument and control training. The following examples were provided by the applicant to support the requested exception.

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Training:

GE Process Instrumentation and Control Course
GE Nuclear Instrumentation and Control Course
GE Rod Control and Information Systems Course
Electronics Circuits Course, Lewis and Clark Community College

Experience:

Three years as journeyman level electrician at Olin Corporation after completing required 4-year apprenticeship with 576 hours of classroom training in ac/dc circuit theory, algebra, trigonometry, and advanced circuit analysis, in addition to 8000 hours of on-the-job training on repair and maintenance of motors, circuit breakers, transformers, and control circuits.

Five years as journeyman level electrician at a fossil fuel power station. Performed trouble shooting and repair of electrical equipment, motors, breakers, control circuits and solid-state equipment.

Five years as control and instrumentation supervisor or assistant supervisor at Clinton. Directed I&C personnel during preoperational and startup activities, including testing, trouble-shooting, and repairing of all installed plant control and instrumentation equipment.

The staff has reviewed the applicant's request for exception and judges that the individual's experience and training is acceptable in lieu of the 1 year of experience at an operating plant.

(3) Plant Operator Experience

Dialogue with the industry was begun in late 1983 to find a way of ensuring that each operating shift at a newly licensed plant had at least one senior operator with previous hot operating experience. On February 24, 1984, an Industry Working Group, representing utilities with nuclear power plants under construction or ready for operation, presented a proposal to the staff on the amount of previous operating experience considered to be the minimum desirable

on each shift and how that experience could be obtained. On June 14, 1984, the staff accepted the industry proposal with certain clarifications. Information regarding this action was forwarded to the industry as Generic Letter 84-16, dated June 27, 1984. The objective is that, at the time of fuel load (or, at the latest, at least 1 week before initial criticality), each operating shift will have at least one senior operator with a minimum of 6 months of hot participation experience on a same type plant, including startup/shutdown experience and at least 6 weeks above 20% power. Hot participation experience is defined as direct involvement in review and discussions leading to decisions relative to operation of a commercial nuclear plant, or direct hands-on operation as a trainee at a commercial nuclear power plant. For prospective on-shift SROs at the Clinton Power Station, this includes:

- on-shift duty as a licensed operator at a large commercial BWR

- direct hands-on operation as a licensed operator trainee on shift at a large commercial BWR

- direct involvement as an on-shift observer in review and discussions at the licensed operator level at a large commercial BWR

Information from the applicant regarding the hot participation experience of license candidates is contained in FSAR Chapter 13 and in an Illinois Power Company submittal dated May 10, 1985 ("Summary of Training and Experience of Operations for Clinton Power Station"). The May 10 submittal contains experience summaries for 64 license candidates, including five Shift Supervisors and 12 Assistant Shift Supervisors who will staff the on-shift senior operator positions. Two of the Shift Supervisors currently satisfy Generic Letter 84-16 requirements based on previous licensed-operator experience at large commercial BWRs (Cooper and Brunswick).

In order to meet the guidelines of Generic Letter 84-16 on all operating shift crews, the applicant has established a Supervisory Operating Plant Experience (SOPE) program. Under this program, selected supervisory personnel (including selected Shift Supervisors and Assistant Shift Supervisors) either have been or will be assigned to Commonwealth Edison Company's LaSalle plant for at least

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6 months. The Clinton personnel work on shift under the direction of LaSalle SROs and become directly involved in reviews and discussions that lead to operating decisions. Details of the SOPE program are contained in Nuclear Training Department Procedure 2.1, which outlines the objectives and overall conduct of the program. The staff concludes that prospective Clinton SROs who complete the SOPE program will also satisfy the requirements of Generic Letter 84-16.

To ensure that the applicant will have Senior Reactor Operators on shift who meet the generic guidelines for hot operating experience, the staff will condition the license (license condition 17) as follows to require such experience until the applicant's operators have accumulated the requisite hot operating time on their own plant.

5 At the time of fuel load, the licensee shall have a licensed senior operator on each shift who has had at least 6 months of hot operating experience on a same type plant, including at least 6 weeks at power levels greater than 20% of full power, and who has had BWR startup and shutdown experience. This license condition shall be effective for a period of 1 year from fuel load or until the attainment of a nominal 100% power level, whichever occurs later. 5

13.3 Emergency Preparedness Evaluation

13.3.2 Evaluation

13.3.2.8 Emergency Facilities and Equipment (NUREG-0737, Item III.A.1.2)

Supplement 4 to the SER (SSER 4) stated that the applicant's emergency response facilities (ERFs) meet the requirements of the specific planning standard of 10 CFR 50.47(b), the requirements of 10 CFR 50, Appendix E, and the guidance criteria of NUREG-0654 on an interim basis for licensing. The staff further stated that the adequacy of the applicant's final ERFs will be confirmed in accordance with the requirements of NUREG-0737, Item III.A.1.2 (Supplement 1 of NUREG-0737), on a schedule to be developed between the applicant and the NRC.

By letter dated May 29, 1985, the applicant requested that the NRC staff perform the appraisal of the Clinton ERFs after fuel load. The applicant also stated that the specific date for this appraisal will be determined following the 2-week NRC emergency preparedness implementation appraisal scheduled for October 1985.

The staff has evaluated the applicant's request and finds it acceptable. However, a license condition (license condition 18) associated with the NUREG-0737, Item III.A.1.1.2, will be required which states that the applicant shall commit to a date (for appraisal of the Clinton ERFs after fuel load) that is acceptable to the staff.

13.4 Review and Audit

The applicant has established an acceptable safety review and audit program. The applicant has committed to implement this program in accordance with the Clinton Technical Specifications, Section 6.5.

13.5 Administrative Procedures

The applicant has committed to establish procedures in accordance with RG 1.33. All activities affecting nuclear safety will be conducted according to these written and approved procedures. The applicant has established a policy governing overtime usage and working hours. This policy is in compliance with the guidance provided in Generic Letter 82-12 and is, therefore, acceptable. Section 6.2.2.f of the Clinton Technical Specifications will be used as the acceptable minimum standard for implementation of the Clinton overtime control policy.

13.6 Operating and Maintenance Procedures

13.6.3 Reanalysis of Transients and Accidents; Development of Emergency Operating Procedures

In the SER, the staff stated it would confirm the applicant's commitment to have the nuclear steam supply system (NSSS) vendor review low-power, power-ascension, and emergency operating procedures (EOPs). Because the applicant's Procedure Generation Package of EOPs is based on generic owners group guidelines that the staff has reviewed and approved, the vendor's review of the EOPs is not required. By letter dated May 16, 1985, the applicant described the administrative controls which require the NSSS vendor representative to review and approve low-power and power-ascension procedures as directed by the Clinton Power Station Startup Manual and attachment to the Startup Administrative Procedure.

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The staff considers these actions sufficient to satisfy NUREG-0737, Item I.C.7, partially resolving confirmatory issue 47.

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Figure 13.1 Management and technical support organization for Clinton power station (revised from SER)

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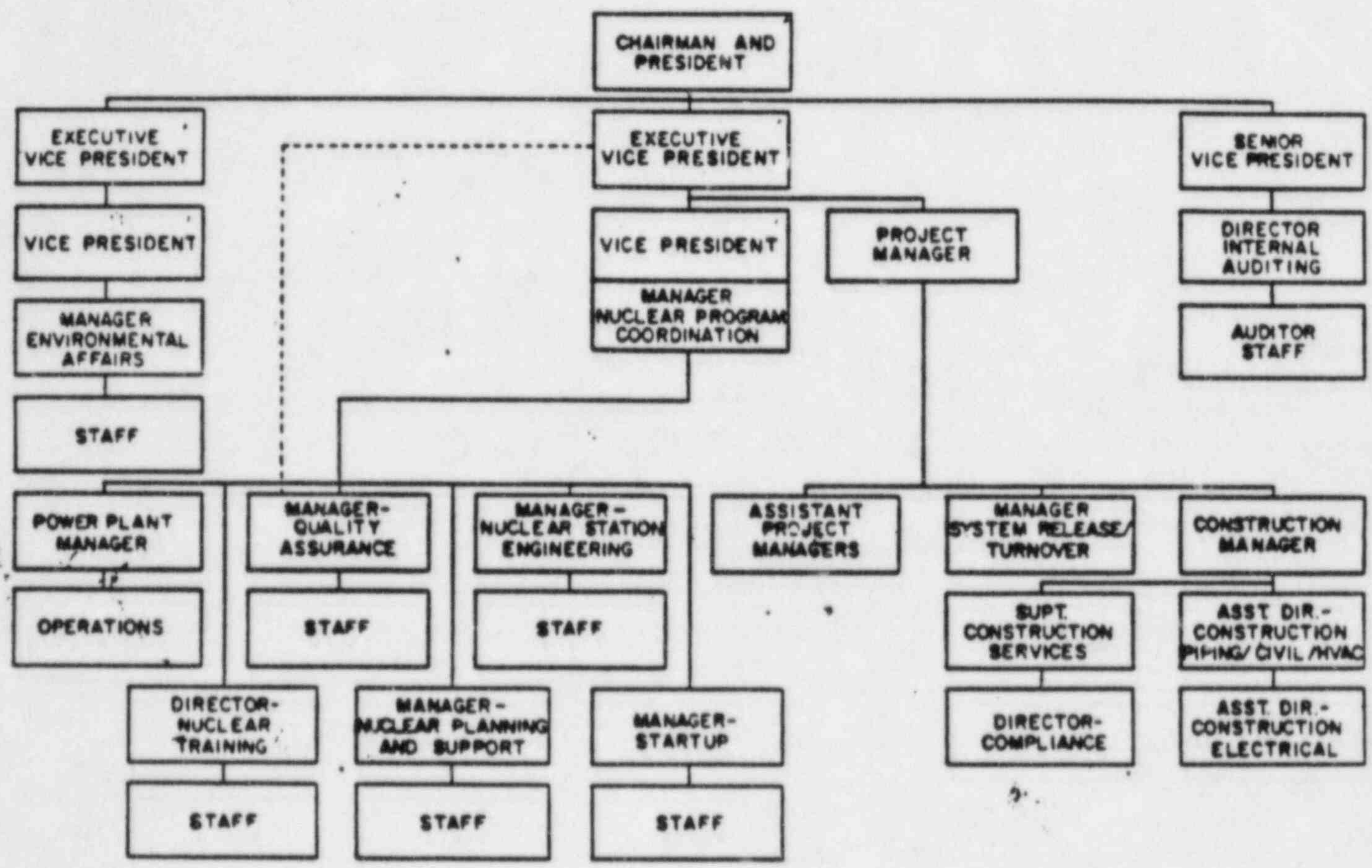

FIGURE 13.1 2

MANAGEMENT AND TECHNICAL SUPPORT
ORGANIZATION FOR CLINTON POWER STATION (revised from SER)

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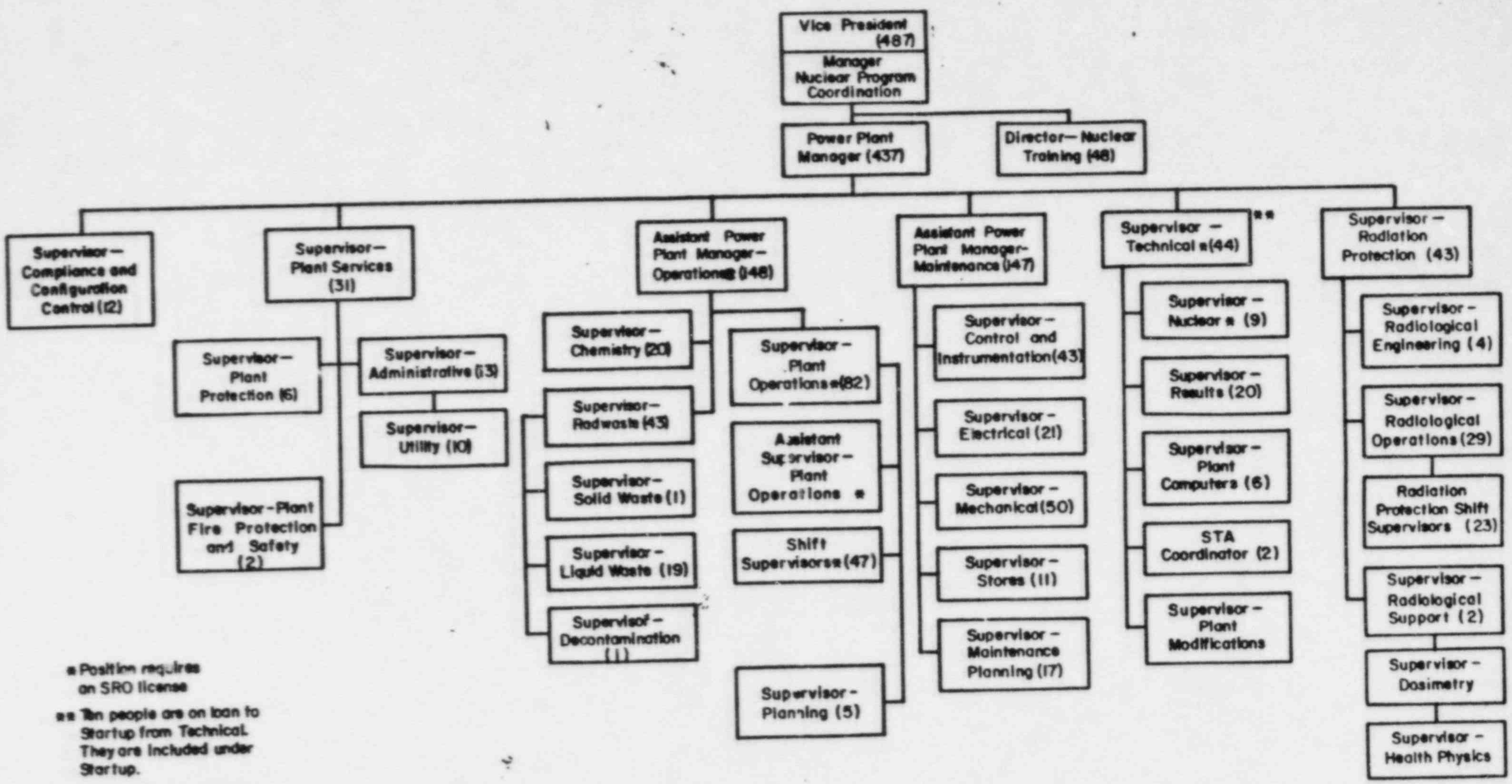
Figure 13.3 Plant organization for Clinton Power Station (revised from SER)



* Position requires an SRO license

** Ten people are on loan to Startup from Technical. They are included under Startup.

Note: This chart was accurate as of March 1985. The staffing is controlled by a nuclear organization transition plan that is updated quarterly.

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FIGURE 13.~~1~~ 3 [2]

PLANT ORGANIZATION FOR CLINTON POWER STATION (revised from SER)

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15 SAFETY ANALYSIS

15.1 Anticipated Operational Occurrences

The SER stated that the applicant performed preliminary analyses to show that partial feedwater heating (lower feedwater temperatures) does not result in a reduction in minimum critical power ratio. In addition, the SER stated that the applicant indicated that further analyses will be prepared before any operation at lower feedwater temperatures for the purpose of extending the normal fuel cycle.

By letter dated July 2, 1985, the applicant has stated that the partial feedwater heating mode of operation at Clinton will be restricted to those periods forced by equipment malfunction and will not be used for the purpose of extending the fuel cycle.

To limit operation in this mode, the staff will condition the operating license (license condition 16) as follows: "The facility shall not be operated with partial feedwater heating for the purpose of extending the normal fuel cycle."

15.2 Accidents

15.2.2 Salem Anticipated Transients Without Scram (Generic Letter 83-28)

On February 25, 1983, both of the scram circuit breakers at Unit 1 of the Salem Nuclear Power Plant failed to open upon an automatic reactor trip signal from the reactor protection system. This incident occurred during the plant startup and the reactor was tripped manually by the operator about 30 seconds after the initiation of the automatic trip signal. The failure of the circuit breakers has been determined to be related to the sticking of the undervoltage trip attachment. Before this incident, on February 22, 1983, at Unit 1 of the Salem Nuclear Power Plant, an automatic trip signal was generated based on steam generator low-low level during plant startup. In this case, the reactor was tripped manually by the operator almost coincidentally with the automatic trip. Following these incidents, on February 28, 1983, the NRC Executive Director for Operations (EDO), directed the NRC staff to investigate and report on the generic implications of these occurrences at Unit 1 of the Salem Nuclear Power Plant. The results of the staff's inquiry into the generic implications of the Salem unit incidents are reported in NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant." As a result of this investigation, the Commission (NRC) requested (by Generic Letter (GL) 83-28 dated July 8, 1983) all licensees of operating reactors, applicants for an operating license, and holders of construction permits to respond to certain generic concerns. These concerns are categorized into four areas: (1) Post-Trip Review, (2) Equipment Classification and Vendor Interface, (3) Post-Maintenance Testing, and (4) Reactor Trip System Reliability Improvements.

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15.2.2.1 Post-Trip Review

Program Description and Procedures, Action Item 1.1

Post-Trip Review consists of Action Item 1.1 (GL 83-28), "Program Description and Procedure," and Action Item 1.2 (GL 83-28), "Data and Information Capability." This supplement only addresses Action Item 1.1.

The following review guidelines, developed after initial evaluation of the various utility responses to Action Item 1.1, incorporate the best features of these submittals. As such, these review guidelines, in effect, represent a "good practices" approach to post-trip review. The staff has reviewed the applicant's response to Action Item 1.1 against the following guidelines:

A. The licensee or applicant should have systematic safety assessment procedures established that will ensure that the following restart criteria are met before restart is authorized.

- The post-trip review team has determined the root cause and sequence of events resulting in the plant trip.
- Near-term corrective actions have been taken to remedy the cause of the trip.
- The post-trip review team has performed an analysis and determined that the major safety systems responded to the event within specified limits of the primary system parameters.
- The post-trip review has not resulted in the discovery of a potential safety concern (e.g., the root cause of the event occurs with a frequency significantly larger than expected).
- If any of the above restart criteria are not met, then an independent assessment of the event is performed by the Plant Operations Review Committee (PORC), or another designated group with similar authority and experience.

B. The responsibilities and authorities of the personnel who will perform the review and analysis should be well defined.

- The post-trip review team leader should be a member of plant management at the shift supervisor level or above and should hold or should have held an SRO (Senior Reactor Operator) license on the plant. The team leader should be charged with overall responsibility for directing the post-trip review, including data gathering and data assessment and the leader should have the necessary authority to obtain all personnel and data needed for the post-trip review.
- A second person on the review team should be an STA (Shift Technical Advisor) or should hold a relevant engineering degree and should have special transient analysis training.
- The team leader and the STA (engineer) should be responsible to concur on a decision/recommendation to restart the plant. A nonconcurrence from either of these persons should be sufficient to prevent

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restart until the trip has been reviewed by the PORC or an equivalent organization.

C. The licensee or applicant should indicate that the plant response to the trip event will be evaluated and a determination made as to whether the plant response was within acceptable limits. The evaluation should include:

- a verification of the proper operation of plant systems and equipment by comparison of the pertinent data obtained during the post-trip review to the applicable data provided in the FSAR

- an analysis of the sequence of events to verify the proper functioning of safety-related and other important equipment. Where possible, comparisons with previous similar events should be made

D. The licensee or applicant should have procedures to ensure that all physical evidence necessary for an independent assessment is preserved.

E. Each licensee or applicant should provide in its submittal, copies of the plant procedures which contain the information required in items A through D. As a minimum, these should include the following:

- the criteria for determining the acceptability of restart

- the qualifications, responsibilities, and authorities of key personnel involved in the post-trip review process

- the methods and criteria for determining whether the plant variables and system responses were within the limits as described in the FSAR

- the criteria for determining the need for an independent review

By letter dated October 1, 1984, the applicant provided information regarding its post-trip review program and procedures. The staff has evaluated the applicant's program and procedures against the review guidelines developed as described above. A brief description of the applicant's response and the staff's evaluation of the response against each of the review guidelines is provided below:

(1) The applicant has established the criteria for determining the acceptability of restart. On the basis of its review, the staff, finds that the applicant's criteria conform to the guidelines as described under item A above and, therefore, are acceptable.

(2) The qualifications, responsibilities, and authorities of the personnel who will perform the review and analysis have been clearly described. The staff has reviewed the applicant's chain of command for responsibility for post-trip review and evaluation and finds it acceptable.

(3) The applicant has described the methods and criteria for comparing the event information with known or expected plant behavior. On the basis of its review, the staff finds them to be acceptable.

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(4) The applicant has established criteria for determining the need for independent assessment of an event. On the basis of its review, the staff finds them acceptable. In addition, the applicant has established procedures to ensure that all physical evidence necessary for an independent assessment is preserved. This action taken by the applicant conforms with the guidelines as described in items A and D above.

(5) The applicant has provided for staff review a systematic safety assessment program to assess unscheduled reactor trips. On the basis of its review, the staff finds that this program is acceptable.

On the basis of its review, the staff concludes that the applicant's post-trip review program description and procedures in response to Action Item 1.1 of Salem ATWS events (Generic Letter 83-28) for Clinton Power Station, Unit No. 1, are acceptable.

15.2.2.3 Post-Maintenance Testing

Post-Maintenance Testing (Reactor Trip System Components); Action Items 3.1.1 and 3.1.2

The review criteria for these items require that the applicant submit a statement indicating that it has reviewed plant test and maintenance procedures and Technical Specifications to ensure that post-maintenance operability testing of safety-related components in the reactor trip system (RTS) is required. Also, the applicant's statement should contain a verification that vendor-recommended test guidance has been reviewed, evaluated, and where appropriate, included in the test and maintenance procedures or the Technical Specifications.

The staff has evaluated the applicant's June 14, 1985, letter and has determined that the information provided adequately confirms that the requirements identified under Action Items 3.1.1 and 3.1.2 of the Salem ATWS Events Generic Letter 83-28, for Clinton Power Station, Unit No. 1, have been implemented.

Post-Maintenance Testing (All Other Safety-Related Components); Action Items 3.2.1 and 3.2.2

The review criteria for these items require that the applicant submit a statement indicating that it has reviewed plant test and maintenance procedures and Technical Specifications to ensure that post-maintenance operability testing of safety-related components is required. Also, a statement is required that contains a verification that vendor-recommended test guidance be reviewed, evaluated, and where appropriate, included in the test and maintenance procedures or the Technical Specifications.

The staff has evaluated the applicant's June 14, 1985, submittal and has determined that the information provided adequately confirms that the requirements identified under Action Items 3.2.1 and 3.2.2 of the Salem ATWS Events Generic Letter 83-28, for Clinton Power Station, Unit No. 1, have been implemented.

15.2.2.4 Reactor Trip System Reliability Improvements

Reactor Trip System Reliability (System Functional Test Description); Action Item 4.5.1

The review criteria for this item require that the applicant submit a statement committing to independent, on-line functional testing of the diverse trip features. The staff has evaluated the applicant's October 1, 1984, submittal for this item, committing to on-line testing of the scram pilot solenoid valves and initiating circuitry, and has determined that the commitment provided satisfies the requirement contained in Action Item 4.5.1 of the Salem ATWS Events Generic Letter 83-28 for Clinton Power Station, Unit 1.

17 QUALITY ASSURANCE

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17.5 Independent Design Verification

17.5.1 Background

Bechtel Power Corporation (Bechtel) was engaged by the Illinois Power Company (applicant) to conduct an independent design review (IDR) of the Clinton Power Station, Unit No. 1 (Clinton). The purpose of the IDR was to assess the adequacy of the Clinton design through a review of the design process employed. Specifically, evaluation of plant design work measured the adequacy of

(1) implementation of design commitments and criteria
(2) technical adequacy of design
(3) structure and implementation of the design process, particularly with regard to compliance with the applicant's commitments to the provisions of RG 1.64 and ANSI Std. N45.2.11.

A program plan was proposed by Bechtel and commented on by the staff in a letter sent to the applicant on August 6, 1984. Other interested parties including the Illinois Power Company ~~, the applicant,~~ and the Attorney General of the State of Illinois commented, too. A revised program plan was subsequently submitted and approved by the NRC. Bechtel issued a final IDR report on this program in January 1985. ?

Bechtel commenced the IDR in August 1984. The NRC closely monitored conduct of the IDR including:

(1) attendance at public meetings in Rosemont, Illinois, on September 16, 1984, and November 13, 1984, to review IDR progress

(2) inspection of IDR activities at Bechtel ~~BPC~~ headquarters in San Francisco, California, on October 18 and ~~,~~19, 1984 (preceded by a tour of the Clinton site on October 17, 1984) [The NRC's report of this inspection was provided in a letter to the applicant dated November 16, 1984. Bechtel replied to the NRC

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inspection report in a letter dated November 12, 1984 (for programmatic items), and in the final IDR report (for technical items).]

(3) monitoring of a large number of telephone conversations between Bechtel, the applicant, and Sargent & Lundy Engineers (S&L), during which observations or other technical matters were discussed

(4) attendance at a public meeting in Chicago, Illinois, on March 7, 1985, where a presentation on the final IDR report was given by Bechtel

(5) followup inspections at Bechtel after issuance of the final IDR report (March 26 through 28, 1985) and at S&L (May 6 through 9, 1985):

   (a) at Bechtel, documentation supporting Bechtel's conclusions was reviewed and evaluated

   (b) at S&L, adequacy and status of corrective actions were reviewed and evaluated

17.5.2 Bechtel Design Review Program

Bechtel performed two types of reviews, vertical and horizontal. The vertical review examined the design of the shutdown service water (SSW) system, the portion of the high-pressure core spray (HPCS) system inside containment, and the Class 1E ac electrical distribution system. The vertical review also went beyond these systems in evaluating various common design requirements such as high-energy-line break, fire protection, and seismic interactions. The horizontal review was based on applicable findings from design audits of other stations including Byron, LaSalle, and Fermi, as well as prior applicant audits of Clinton.

Bechtel reviewed more than 2900 documents in a period of more than 6 months, expending approximately 31,000 man-hours in the process. Where problems or concerns were identified, a potential observation report was issued. A total of 84 potential observation reports were issued, of which 76 were determined to be valid and 8 were classified as invalid. The final IDR report provided technical details on each observation report (both valid and invalid), including resolutions and in certain cases, planned corrective actions. The IDR report

also analyzed trends which appeared to be generic to the design process, drawing conclusions as to the significance of each identified trend.

17.5.3 Bechtel Conclusions

Bechtel reached conclusions about the adequacy of the design and design process at Clinton relative to both the systems reviewed and the overall plant. The IDR report set forth Bechtel's conclusions in considerable detail, including the bases for these conclusions. The IDR conclusions assumed successful completion of work committed to in resolving issues raised by the review. Contingent on completion of the work, Bechtel concluded that there was reasonable assurance that the overall design of Clinton was technically adequate and met FSAR commitments. Furthermore, Bechtel stated that more review work would, in all likelihood, produce similar results to those from the IDR, i.e., there would be more observations, but they would be of comparable number and significance.

17.5.4 Assessment by the NRC Staff

The NRC staff has assessed the results of the IDR including a detailed review of the subsequent corrective actions, both completed and in progress. As a part of the staff's assessment, two inspections were conducted, one at the Bechtel offices in San Francisco to review the documentation supporting the conclusions of the IDR team and the other at the S&L offices in Chicago to review S&L implementation of corrective actions. The inspection at Bechtel focused on the review of documentation submitted to it by S&L that formed the basis for the IDR team's agreement that an observation report required no corrective action. In addition to reviewing documentation connected with specific observation reports, the review sheets in the areas of fire protection and seismic Category II/I were inspected. Both of these reviews appeared to be comprehensive and well documented. The Appendix R (10 CFR 50) safe shutdown analysis prepared by S&L was also reviewed. Although this analysis was out of date, the staff concurs with the conclusion of the IDR team that the methodology used by S&L could ensure the safe shutdown capability would be maintained in the event of fire.

Through inspection of Bechtel, the staff found the IDR to be well documented. It was also evident by reviewing the check sheets prepared by the individual

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reviewers that the IDR team had reviewed in detail the S&L documentation. On the basis of its review of the IDR report and subsequent inspection of the supporting documentation, the staff concurs in the findings of the IDR team and concludes that observation reports that were subsequently found acceptable by the IDR team based on review of additional information provided by S&L are closed. The observation reports in this category are: OR-6, 8, 15, 16, 18, 22, 23, 25, 26, 27, 31, 32, 36, 37, 38, 40, 44, 45, 47, 50, 52, 53, 56, 58, 60, 61, 62, 65, 66, 76, and 77. OR- ~~Observation report~~ 51 was closed by the Bechtel IDR team. This will remain an NRC open issue and is further discussed in Section 17.5.4.2 under the heading "Mechanical Discipline."

The purpose of the staff's inspection at S&L was to review the implementation of corrective actions agreed to with Bechtel to resolve concerns generated during the IDR. Of the observation reports requiring corrective actions, 21 of these resulted in changes to the FSAR and are addressed ~~below~~ in Section 17.5.4.1. The corrective actions associated with the remaining observation reports were reviewed during this inspection. At the time of the staff's inspection, the corrective actions associated with 11 observation reports were still in progress. However, these had progressed to a point where the staff was able to review them in sufficient detail to conclude that they would be completed as agreed with Bechtel. Therefore, no further reinspection of S&L is necessary. The corrective actions for these 11 observation reports (OR-5, 9, 13, 54, 55, 57, 64, 73, 74, 80, and 81), all in the mechanical discipline, are discussed in Section 17.5.4.2. The corrective actions for the observation reports that were completed at the time of staff inspection were reviewed and appeared to have been completed as agreed with the IDR team.

Observation reports requiring corrective actions will be held open pending receipt of a confirmatory letter from the applicant that the corrective actions are completed and adequately resolve the concerns of the IDR team. Detailed discussions of the staff's assessment of the individual observation reports and the trends noted by Bechtel are discussed below.

17.5.4.1 FSAR Changes

Twenty-one observation reports involved commitments from the applicant to submit proposed FSAR changes to the NRC. (The observation reports in this category

are: OR-4, 7, 12, 14, 17, 24, 30, 43, 46, 48, 55, 57, 63, 64, 69, 70, 72, 73, 75, 79, and 83). Proposed FSAR changes constitute open licensing issues to be resolved between the applicant and the staff. Since these items will be individually resolved as licensing issues, they will be considered closed for purposes of the IDR when they are formally submitted to the staff. Of the 21 observation reports that included proposed FSAR changes only the following 9 ~~observation reports~~ remain open: 24, 43, 55, 57, 64, 69, 70, 73, and 79.

These observation reports remain open because either the applicant has not yet submitted the proposed FSAR change to the staff or the applicant has not yet confirmed that other corrective action associated with these observation reports has been completed. Twelve observation reports were closed on the basis of letters from the applicant to the staff dated May 29 and June 7, 1985, which forwarded proposed FSAR changes to be included in FSAR Amendment 34.

17.5.4.2 Technical Assessments

The following is the NRC staff's technical assessment of the valid observation reports.

Mechanical Discipline

There were 9 valid observation reports in the mechanical systems area and another 27 valid observation reports in the area of mechanical components. These 36 observation reports can be further broken down into three categories: (1) those which were closed by the IDR team based on the response by S&L and which required no action by S&L; (2) those observation reports requiring corrective action by S&L for which corrective action appeared to be completed; and (3) the observation reports for which the corrective actions accepted by the IDR team were still in progress. The following NRC staff comments are provided on these observations.

OR-5 identified that the equipment qualification packages for two active valves had not addressed valve operability under seismic loadings. Also, S&L calculations were needed to demonstrate that the vendor's allowable deflections would not be exceeded under the seismic loadings. In addition, engineering judgments associated with S&L's review of equipment qualification packages needed to be

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documented. To resolve this issue and the generic equipment qualification concern, S&L developed a new updated checklist and committed to include it in all the equipment qualification packages. At the S&L offices, the staff was informed that 75% of the 510 total equipment qualification packages had been completed. The staff reviewed the completed checklist and was satisfied that the aforementioned concerns were being adequately resolved by use of the updated checklist. This observation report remains open pending confirmation by the applicant that all the equipment qualification packages have been completed and revised.

OR-9 identified that specific piping support weld sizes did not comply with the requirements of ASME Code Section III and AWS Std. D1.1 which are committed to in the Clinton FSAR. Specifically, the subject pipe support weld sizes were smaller than the weld sizes required by the two aforementioned codes based upon the thicker of the two parts being joined. S&L has initiated a request for a Code case to allow weld sizes less than those as required in Appendix XVII, paragraph XVII-2452.1 of ASME Code Section III. Also, a review of the weld procedure qualification is being made to ensure that all welds were made in accordance with qualified welding procedures. The staff verified at the S&L offices in Chicago that the welding procedure qualification had been completed for full and partial penetration welds which were not prequalified per AWS Std. D.1.1. However, this issue remains an open licensing issue pending NRC acceptance of the Code case and confirmation by the applicant that all associated welds have been made in accordance with approved welding procedures, and that the associated design documents have been updated accordingly.

OR-13 identified a concern regarding whether an adequate program was in place to verify pipe rupture restraint hot gaps. At S&L, the staff reviewed a draft Preoperation Test Procedure and verified that this procedure, if properly implemented, would present an adequate program for verification of rupture restraint hot gaps. This draft procedure applies to all rupture restraints including those designed by S&L as well as by General Electric. The staff also verified that the draft procedure includes an adequate reconciliation aspect for hot gaps that are too large. This observation report remains open pending the applicant's confirmation that a hot gap verification program has been established.

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OR-19 addressed a concern regarding the replacement of specific snubbers with rigid restraints (i.e., rods, struts, or structural steel) and the resulting impact on equipment nozzles and pipe supports. S&L performed an evaluation which documented that the effect of snubber replacement and thermal movements on equipment nozzle allowables was acceptable. During an inspection at Bechtel from March 26 through 28, 1985, the staff verified Bechtel had reviewed the aforementioned calculations and had appropriately assessed the observation. Also, during an inspection at S&L from May 6 through 9, 1985, the staff reviewed the snubber replacement program. Of the 375 snubbers in the original design of Clinton, 227 snubbers had been replaced with rigid restraints to date. The staff also found that S&L's snubber replacement program was developed with Region III's involvement and is documented in Welding Research Council Bulletin 300 under the paragraph entitled "Zero Deflection Criteria." The staff concluded that the program properly addresses the replacement of snubbers with rigid restraints. However, this observation report remains open pending confirmation from the applicant that all affected stress reports have been updated to reflect snubber replacement.

OR-25 questioned whether the modeling of motor- or air-operated valves with extended masses resulted in a more rigid representation of the valve because of improper consideration of amplification through the valve superstructure. At the time the IDR was being conducted, there were no flexible valves identified. As indicated by the applicant in its March 21, 1985, letter, there are approximately 30 flexible valves. The staff reviewed the S&L program for qualifying these valves during its inspection of S&L in May 1985. The staff concluded that S&L has an adequate program in effect, based on staff review of an S&L-conducted generic study. Representative piping systems were analyzed using detailed finite element models of the valves which accounted for flexibility. The results of the study were compared with similar cases in which the valves were modeled as rigid in the piping analysis. Amplification factors resulting from this comparison were used to evaluate the flexible valves. S&L used the results of this study to qualify the flexible valves. The staff concurs with the process in use by S&L to qualify flexible valves, and considers this observation report to be closed. While reviewing the corrective action associated with this observation report, the staff noted that the S&L stress analysis group is not addressing the effects of valve flexibility in its mathematical model for calculating pipe stress. This issue has been identified as a deviation from a licensing commitment and will be assessed by the staff.

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(1) OR-27 identified that the bus tie dimension between the battery racks (Division 1, 125-V dc) is greater than what was specified on the design drawings. Consequently, the seismic qualification of the batteries did not address the as-built bus tie length. To address this concern, S&L performed a calculation. The staff reviewed this calculation and verified that it supported the seismic qualification of the batteries. The staff was also concerned about the generic implication that the as-built configuration, in general, did not agree with the design documents. To address this as-built/design discrepancy, the staff reviewed "Environmental/Seismic Qualification Field Verification Program," PI-CP-050, Revision 0, dated April 19, 1984, and verified that the applicant's program would have probably identified the aforementioned specific concern had it not been otherwise identified. Thus, the staff was satisfied that the specific resolution for the batteries had been properly analyzed and that a program is in place to adequately resolve similar discrepancies.

OR-36 questioned the program in effect for the Clinton project relative to protection of safety-related equipment from damage due to interactions with other equipment, safety related or not safety related, during seismic events. Although the IDR accepted the specific resolution to the questions raised, the staff was concerned with broader questions in this area. During the staff's inspection at S&L on May 6 through 9, 1985, it reviewed the key calculation and project instruction documents of the Clinton design relative to the subject of seismic interaction analysis. The staff is satisfied that the program for seismic interaction analysis at Clinton is satisfactorily structured to adequately satisfy requirements in this area. No further action is required. This observation report is considered closed.

(II) OR-51 resulted from the field walkdown which discovered 1½-inch gaps between Division I and Division II batteries and the battery rack end rails. S&L performed a calculation which demonstrated that the battery cells would not impact the end rails during a seismic event. However, there is enough uncertainty in some assumptions of the calculation to raise questions about the margin in the calculation. In view of these uncertainties, the staff considers it prudent to eliminate the gaps altogether. This observation report remains open pending the applicant's corrective action.

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OR-54 expressed a concern that the documentation package used to accept qualification of the diesel generators appeared to lack adequate justification for seismic qualification. However, Bechtel accepted the S&L response which demonstrated that S&L had been involved in an ongoing qualification program for the diesel generators. At S&L, the staff reviewed an S&L calculation that confirmed the validity of assumption made by the diesel generator manufacturer regarding anchor bolt modeling. The staff was satisfied with the approach being taken regarding diesel generator qualification, but this observation report will remain open pending confirmation from the applicant that the subject qualification has been satisfactorily completed.

ORs-55, 57, 64, and 73 all involve design considerations relative to high-energy-line break (HELB) and moderate-energy-line break (MELB) effects. In each of these observation reports, the IDR basically determined that the S&L documentation was not sufficient to enable the IDR team to conclude that HELB/MELB effects had been adequately considered in all cases. Since publication of the IDR report, S&L has done a substantial amount of work to document its efforts in these areas. During its inspection of S&L on May 6 ~~to~~ through May 9, 1985, the NRC staff reviewed a portion of the preliminary information prepared by S&L and determined that this documentation was sufficiently complete to permit meaningful evaluation. Subsequently, the applicant agreed to have an independent review performed relative to the HELB/MELB design at Clinton and to provide the results of the review to the NRC staff. Consequently, these observation reports remain open pending the applicant's submittal of the above review to the staff. Further NRC review of this area of design will be addressed as part of the normal licensing process.

OR-74 represented a concern that calculations or analyses confirming the ability of certain check valves to operate during and after a seismic event were not available. S&L provided a deflection analysis which justifies operability of the valves based on certain actuator deflections. The valve supplier stated that the check valve would remain operable regardless of the deflections. S&L committed to obtaining documentation in the form of a seismic analysis of the valve from the vendor in order to document this position. This observation report remains open pending receipt of a confirmatory letter from the applicant to NRC regarding receipt and approval of the vendor documentation.

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OR-80 identified a concern that the FSAR commitment to design pressure-retaining components in the ESF systems to include a corrosion allowance had not been fully implemented. In resolving this concern, Bechtel concluded that S&L's response provided adequate justification that the FSAR commitment had been implemented. However, two valves were identified that needed their Code Data Package sheets updated to properly document that the Code minimum wall thickness requirements had been met. During the staff's inspection at the S&L offices, it was verified that S&L had initiated the corrective action by requesting the valve manufacturer to update the subject data sheets. This observation report will remain open pending confirmation by the applicant that the associated Code Data Package sheets have been corrected.

OR-81 expressed a concern that the seismic equipment qualification for the shutdown service water system pumps did not adequately demonstrate pump operability during a seismic event. In response, S&L stated that it had evaluated the pump vendor's seismic analysis and determined that the effects were insignificant. However, to confirm and document its initial assessment, S&L performed a calculation which Bechtel subsequently accepted as resolving the specific concern. To ensure that all similar concerns are adequately addressed, S&L is updating all seismic qualification reports to include a new equipment qualification (EQ) checklist. The new EQ checklist requires that equipment deflections at critical sections be compared against allowables for active components for which analysis is used as a basis of qualification. During its inspection of S&L, the staff reviewed S&L's confirmatory calculation as well as S&L's new EQ checklist and was satisfied that both were adequate. However, this observation report remains open pending confirmation by the applicant that all associated EQ packages have been updated to include the new EQ checklist and to document engineering judgments.

The remaining 20 observation reports in the mechanical discipline were not specifically addressed in this supplement because they either required no corrective action or were generally deemed to be of lesser safety significance and corrective actions appeared to be completed. The staff concurs that those 13 which were resolved by the IDR team based on the S&L response and which required no corrective action are closed. These 13 observation reports are: OR-16, 18, 22, 23, 26, 40, 44, 45, 47, 52, 53, 56, and 58. The remaining 7 observation reports in the mechanical discipline that required S&L corrective actions were

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reviewed by the NRC staff and the staff concurs that the corrective actions when completed will adequately resolve the concerns of the IDR team. Although the corrective actions for these observation reports appeared to have been completed during the staff's May inspection of S&L, these reports will be held open pending a confirmatory letter from the applicant verifying that the corrective actions have in fact been acceptably completed and resolve the concerns of the IDR team. The remaining 7 observation reports in the mechanical discipline requiring confirmatory action are: OR-20, 21, 39, 43, 67, 69, and 84.

Electrical Discipline

There were 17 valid observation reports in the electrical power and instrumentation and controls areas. Some of these have been resolved by the IDR team based on the S&L response, the remaining required corrective action. The following NRC staff comments are provided on these observations.

OR-6 involved starting voltages at the terminals of continuous-duty motors and MOV operators during simultaneous start of non-running engineered safety feature loads on offsite power when a LOCA occurred. Since starting voltages had not been calculated, the IDR team was concerned that motors and MOVs could stall and draw high inrush current that could cause the thermal overload protection to trip. S&L performed confirmatory calculations to verify the ESF motors required to function upon actuation by a safety signal would perform their safety function. These calculations were reviewed and accepted by the IDR team. In addition, the IDR team performed an independent calculation to verify the 460-V motor acceleration. This was identified as the most restrictive condition. The IDR team calculation provided an additional level of confidence in the S&L calculation. During the inspection of IDR documentation at Bechtel on March 26, 1985, the staff reviewed the S&L confirmatory calculation. The staff verified that the S&L calculation confirmed that the 460-V ESF motors will not be tripped by their respective circuit breakers during the acceleration period. In view of the S&L calculation, the IDR team's independent calculation, and the staff's review of the entire matter, the staff concurs that the functionality of the ESF motors has been adequately demonstrated and concurs with the IDR's conclusion that this item be closed.

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OR-10 was initiated because certain noncritical diesel generator trip circuits were not bypassed during a LOCA condition (coincident with a loss of offsite power) for a 10-second interval. This observation resulted in the modification to the diesel generator bypass circuitry to provide a noninterruptible power supply to the bypass relays. Although the concern violated an FSAR commitment, the IDR concluded this was not a safety-significant condition because the non-critical trips were Class 1E devices, therefore failure of one trip could only affect one diesel generator, and hence the diesel generators met the single-failure criterion. Nevertheless, S&L proceeded to review 102 additional auxiliary relay circuits to determine whether similar problems existed in other circuits. This review questioned whether noninterruptible power should be provided to relays used to shed a small number of non-Class 1E loads from the Class 1E buses during the transition from offsite to onsite power. S&L performed a calculation which demonstrated that the design was adequate since these loads would be shed within approximately 5 cycles of reenergizing the buses with onsite power and a faulted condition of one of the non-Class 1E loads did not have an adverse effect on the bus. The staff reviewed the calculation and found it acceptable. The staff considers the work done in this area to be sufficient; however, the observation report is held open pending a confirmatory letter from the applicant.

OR-11 raised questions of electrical separation, including questions relative to bundling of Class 1E cables with non-Class 1E cables in several panels in General Electric's (GE's) design scope. In each instance within S&L's scope of design responsibility, S&L provided documentation or justification that resolved the IDR team's concern. With regard to separation in the GE panels, this item was referred to GE for review. Subsequently, GE determined that no safety hazard existed based upon a probabalistic analysis and a failure-modes-and-effects analysis. During the inspection of S&L on May 10, 1985, the staff reviewed the GE analysis. The staff concluded that the GE analysis satisfactorily demonstrated that an electrical fault in these panels would be cleared by the circuit protection device with no degradation to Class 1E circuitry. The staff considers this observation report open pending confirmation of closure by the applicant.

OR-33 and OR-34 both involved inconsistencies within equipment qualification packages between vendor qualification information and S&L's certification of

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the components for service in extreme environments. In resolving these issues, the applicant committed to reviewing the section of the environmental qualification checklists for all Class 1E packages to ensure that these particular areas were properly addressed. During its inspection at S&L in May 1985, the NRC staff reviewed the work performed in regard to this commitment and found it to be satisfactory. The staff considers these items to be open pending confirmation from the applicant that the corrective action has been completed.

OR-60 involved several potential deficiencies relative to the voltage of various components of the SSW system. The IDR team raised the concerns that the stall time on MOV actuators might not be adequate for overload protection of thermal magnetic breakers; the "hammer-blow" effect for MOV operation might not be as effective for MOV operation during the reduced voltage condition; and that there was a possibility ~~of~~ that would trip~~ping of~~ the offsite power supply breakers ~~by~~ the source side undervoltage relay. S&L subsequently provided analyses and calculations which, together with the response to OR-6 (described above), satisfied the IDR team's technical adequacy concerns. During the review of IDR documentation at Bechtel headquarters on March 26, 1985, and the review of S&L on May 9, 1985, the staff reviewed these calculations and associated matters. As a result of the review of OR-60 and OR-6, the staff concurs with the IDR team's conclusion that the question of technical adequacy of the design has been fully resolved. This item is considered closed.

OR-76 noted that the maximum calculated momentary symmetrical short-circuit current that could exist at the 4160-V, Class 1E switchgear, when the reserve auxiliary transformer is supplying LOCA loads, exceeded the ANSI-rated capacity. The observation report represented a concern that the rated momentary duty of the switchgear did not meet design requirements under short-circuit conditions. S&L provided a Westinghouse-certified test result which demonstrated that the momentary duty of the switchgear was greater than the calculated value and therefore, even though the ANSI rating was exceeded, the breaker capacities were suitable for use at Clinton. The IDR team accepted this response and considered the item closed. During the visit to Bechtel in March 1985, the staff reviewed the documentation supporting the IDR team's conclusion and concurred with the IDR that the adequacy of the switchgear had been satisfactorily demonstrated. This item is considered ~~to be~~ closed.

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OR-77 involved the fast transfer of power source from one offsite source to the second offsite source at the Class 1E, 4160-V buses. The IDR team's concern was that the length of bus dead time was excessive and the degradation of bus voltage could possibly cause the application of more than normal starting forces to coil ends and other components of Class 1E motors, possibly resulting in motor trip under certain faulted conditions. S&L subsequently provided an analysis which demonstrated that the motors were not overstressed during the transfer. The results of the analysis were accepted by the IDR team. During the visit to Bechtel in March 1985, the staff reviewed the file of documentation relating to this observation report. As a result of its review, the staff concluded that Bechtel had sufficient technical basis to accept the resolution presented by S&L. This item is considered ~~to be~~ closed.

The nine remaining observation reports in the electrical discipline were not specifically addressed in this supplement because they either required no corrective action or were generally deemed to be of lesser safety significance and corrective actions appeared to be completed. The staff concurs that those four which were resolved by the IDR team based on the S&L response and required no corrective action are closed. These four observation reports are ORs-8, 31, 32, and 50. The remaining five observation reports in the electrical discipline that required S&L corrective action were reviewed by the staff and the staff concurs that the corrective actions when completed should adequately resolve the concerns of the IDR team. Although the corrective actions for these observation reports appeared to have been essentially completed at the time of the staff's May inspection of S&L, these observation reports will be held pending a confirmatory letter from the applicant verifying that the corrective actions have in fact been acceptably completed and resolve the concerns of the IDR team. The remaining five observation reports in the electrical discipline requiring confirmation by the applicant regarding completion of corrective actions are ORs-1, 28, 29, 59, and 78.

Structural Discipline

There were eight valid observation reports in the structural area. All of these observation reports were resolved by the IDR team based on the S&L response and required no corrective action. The following NRC staff comments are provided on these observations.

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OR-15 identified a discrepancy in tornado pressures between the structural design criteria and the calculations for the circulating water screenhouse structure. Investigation of this matter revealed the design criteria had been incorrectly changed in 1984 and that the calculation was correct. The staff has reviewed this matter and concurs with the IDR team's conclusion that the design is adequate. This item is considered closed.

OR-38 involved a discrepancy between the calculations and drawings related to pipewhip restraint FWR11. The drawings indicated there were two 1½-inch-diameter rods; the calculation, however, considered two 1-inch-diameter rods. The results of the calculation indicated a total strain of 85% of ultimate strain which was considered excessive compared with the structural design criteria on strain of 50% of ultimate. A corrected calculation using the installed 1½-inch-diameter rods indicated a strain of 19% of the ultimate strain. The staff considers the technical resolution of this item ~~to be~~ satisfactory. This problem appears to have been random in nature and the staff does not consider additional action ~~to be~~ warranted. This item is considered closed.

OR-61 was related to use of the square root of the sum of the squares (SRSS) method for combining dynamic soil pressures with other seismic effects. If the SRSS method were not applied, a safety factor below 1.1 would be calculated. S&L considered the SRSS method to be valid because of a comparison of frequencies of the structure and a soil column which S&L indicated were out of phase. The IDR team did not agree with S&L's position but noted conservatisms such as soil resistance from the pond side of the structure were neglected in the calculation and inside hydrodynamic pressure was assumed to act on the structure at the opening to the pond. The staff has reviewed this matter and concurs with the position taken by the IDR team that the overall calculation is conservative. The staff considers the design to be adequate and no further action is required on this item. This item is considered closed.

OR-71 involved discrepancies in the circulating water screenhouse design between a design calculation and the requirements of ACI Code 318-71. The observation report represented a concern that the foundation design of the screenhouse did not meet Code requirements. S&L provided the IDR team with documentation substantiating the adequacy of the screenhouse basemat reinforcing steel layout and demonstrating that the basemat design satisfied all Code requirements.

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Subsequently, after review of additional documentation, the IDR team accepted the S&L resolution. During the visit to Bechtel in March 1985, the staff reviewed the documentation supporting the IDR team's acceptance of the resolution. The staff considers this observation report to have been largely a matter of interpretation of ACI Code requirements and considers that S&L has demonstrated compliance with the Code. OR-71 is considered to be open pending confirmation by the applicant that the structural design criterion has been updated.

With regard to the four remaining observation reports (OR-37, 62, 65, and 66) in the structural discipline, the staff concurs with the IDR team's acceptance of the resolution of these items. The staff considers these items closed. These reports were not specifically addressed because no corrective actions were required and these are deemed to be of lesser safety significance.

17.5.4.3 Invalid Observation Reports

~~There were~~ eight observation reports (OR-2, 3, 35, 41, 42, 49, 68, and 78) were classified by the IDR team as invalid. The staff has reviewed these observations and concurs with the IDR classification.

OR-49 and OR-68 were classified as invalid because they were beyond the scope of the IDR. Specifically, these items resulted from the plant walkdown but were determined to be construction deficiencies as opposed to design deficiencies. The IDR report indicates that these items have been turned over to the applicant for correction or resolution. During the public meeting in Chicago on November 13, 1984, an Illinois Power Company (applicant) representative stated for the public record that construction deficiencies of this nature were included in the applicant's tracking system for correction or resolution. Consequently, these two observations are left for verification by NRC Region III personnel, on a selected basis, in accordance with their normal procedures for verifying correction of construction deficiencies.

17.5.4.4 Common Design Aspects

In addition to the specific systems reviewed by the IDR team, the IDR team evaluated the design and design process of certain common design aspects, such as high-energy-line break (HELB), moderate-energy-line break (MELB), seismic

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interactions (Seismic II/I), and fire protection. In the areas of seismic Category II/I and fire protection, the IDR team concluded that although the design work in these areas was still in progress at the time of review, the portion of work completed was acceptable. The IDR team further concluded that the design basis for fire protection and seismic Category II/I were well documented by S&L and that procedures would ensure that these design aspects were adequately completed. During the staff's followup inspection of Bechtel on March 26 through 28, 1985, the documentation in the areas of seismic Category II/I and fire protection was found to fully support the IDR team's conclusion regarding the design process and design adequacy for these design attributes. ~~The~~ Bechtel's conclusions for these common design aspects does not suggest the need for further review in this area, except as noted below for HELB/MELB. When specifically questioned by NRC staff at the public meeting in Chicago on March 7, 1985, the Bechtel engineer responsible for the review of common design aspects stated for the public record that these design aspects had generally been performed in a satisfactory manner and that the number of observation reports in this area was not unusual.

In the case of HELB/MELB, Bechtel observed that a significant amount of work had been performed but the documentation of the work was insufficient to allow Bechtel to arrive at definitive conclusions regarding the adequacy of the HELB/MELB design. The IDR team generated four observation reports, ORs-55, 57, 64, and 73, dealing with different aspects of the HELB/MELB issue. These are:

initial ops? Are these titles of reports?

(1) the effects of pipewhip and jet impingement on safety-related equipment located outside the drywell, OR-55

(2) the spray effects on safety-related equipment caused by a postulated piping failure, OR-57

(3) the flooding effects on safety-related equipment caused by a postulated piping failure, OR-64

(4) the effect of pipewhip and jet impingement on safety-related equipment located inside the drywell, OR-73

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To resolve these observation reports, S&L has committed to:

(1) provide a documented analysis in each of the four areas that will contain enough detail to allow an effective independent review of design adequacy

(2) revise the FSAR to update commitments and reflect the results of all analyses

(3) implement an effective design change control program to ensure that future design changes will be evaluated for their effects on safe shutdown

Since the IDR team was unable to reach a conclusion regarding design adequacy in the four HELB/MELB areas noted above, the applicant has committed to provide an independent assessment of these areas to the NRC staff.

The FSAR changes addressing OR-55, 57, and 73 have been submitted to the staff for review. During ~~our~~ its inspection of S&L corrective actions, the staff noted design change control procedures in place to ensure that future design changes will be evaluated for their effects on safe shutdown. The staff review of the independent HELB/MELB assessment and the FSAR changes will be conducted as part of the licensing process.

With the applicant's commitment to independently review the HELB/MELB design, the staff finds that the subject of common design aspects has been thoroughly reviewed and is considered closed for purposes of the IDR. There is sufficient confidence that, with exception of HELB/MELB, the common design requirements have been adequately addressed in the plant design. The HELB/MELB assessment will remain as an open licensing item to be resolved between the applicant and the staff.

17.5.4.5 Trend Analysis

The IDR report identified a number of trends which appeared to be generic to the design process at Clinton. The IDR concluded that these trends were of a nature so as to not alter the judgment that the design process at Clinton was adequate. Nevertheless, in a letter dated March 21, 1985, the applicant committed

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to certain actions to eliminate these trends. The NRC staff reviewed these corrective action programs during its inspection at S&L in May 1985. The staff determined that the corrective action committed to by the applicant was being implemented in a satisfactory manner. The staff will monitor the programs to rectify trends on a continuing basis. The nature of these trends does not suggest the need for further review and, as such, the corrective actions indicated below are being applied on a forward-fit basis. The following paragraphs provide the staff's specific comments on these trends.

Documentation of Engineering Judgment

The IDR team found a significant number of situations where it believed S&L judgments were not appropriately documented, or where documentation left some doubt about the ability of an independent reviewer to reach the same conclusions as S&L. In these cases, S&L was usually requested to perform additional checking of the design or perform check calculations to confirm the design concept and intent and otherwise more fully document the design process.

Sargent and Lundy has recognized the need for improvements in the area of documentation of design work, especially documentation of engineering judgment. By revising ~~the~~ "QA Procedure on Design Calculations" and three "Departmental Standards on Design Calculations," S&L has strengthened the requirements for proper documentation of design bases, including assumptions, formulas, steps used in the design, and the appropriate use and documentation of engineering judgment.

On the basis of evaluation of the individual observations and its review of the S&L design process, the IDR team believed that similar use of judgment by qualified, experienced engineers would produce results similar to those found in the IDR for other safety-related systems, structures, and components.

The staff reviewed the S&L documents, ~~on~~ "QA Procedure on Design Calculations" and three "Departmental Standards on Design Calcuations" and concurs with the modifications. The staff verified that these changes would apply on a companywide basis and that the changed procedures adequately addressed the problems identified. The staff also observed evidence of training of personnel in the new procedures. The staff considers the action taken to be sufficient.

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Document Change Control

Documents are changed to reflect design changes and design evolution. Important design documents like design criteria should be updated if design requirements are changed, and relevant design information must then be properly communicated to others affected by the design change. Lack of rigorous control in this activity contributed to the discrepancies in 15 observation reports.

A new project instruction has been issued by S&L to ensure that, when a field design change is made, the affected documents are identified and the incorporation of the change into these documents is monitored. In addition, the effect of the change on the FSAR, the calculations, the Technical Specifications, and any other design documents is identified. This procedure supplements the procedures that are already in place.

A revised design change control procedure in the form of a new project instruction is also being implemented by S&L which provides the requirements for the preparation of design change packages. These packages will be prepared whenever a major design change is identified. The packages will then be reviewed to determine when and how they will be implemented. This procedure provides improved control of design changes.

The staff reviewed the following S&L documents: (1) signoff sheets showing design criteria are being maintained current, (2) signoff sheets showing project personnel training in the new project instructions, (3) procedure for preparing design change packages and by which changes will be incorporated into interfacing documents, and (4) procedures for review of all physical changes against all design bases. The staff had certain comments or suggestions regarding these documents but in general found them acceptable in addressing the problems identified in this area.

FSAR Control

The IDR team identified a number of discrepancies between the FSAR and design documents. In each case, resolution of the discrepancy required a modification of the FSAR rather than a design change. Although S&L could have implemented

tighter FSAR control, the IDR team does not believe that this group of observations indicates an adverse trend which could result in a serious deficiency. That is, other discrepancies between the FSAR and design documents would be resolved in a manner similar to those found in the IDR.

The staff reviewed the results of the FSAR certification program. This program, which had been initiated by the applicant before the IDR, consists of a line-by-line review of the FSAR to verify that commitments were being incorporated in the appropriate design documents. The staff observed substantial evidence that the program was well under way, along with evidence that the personnel involved were trained in the details of the program. The staff feels that this is an effective on-going program which would have uncovered many, if not all, FSAR control problems revealed by the IDR.

Design Communications

The IDR team found that, in some cases, there was doubt that the design intent would always be properly communicated to affected design groups. For the most part, some of the various discipline design procedures required changes to remove ambiguities or inconsistencies which, if uncorrected, could add confusion to the design process.

Overall, where this situation seems to have been the cause of an observation, close examination of the context of each item by the IDR team revealed that the overall design process was functioning properly and that the specific design condition was adequate and in conformance with the design criteria and licensing commitments. The IDR team did not consider this group to constitute a trend which is likely to have adverse effects on the adequacy of the systems and structures not reviewed.

S&L has taken actions to enhance the design communication process in specific areas through the additional documentation requirements detailed in the responses to individual observations.

In addition, S&L has issued a new procedure on design information transmittal which formalizes the transmittal of design information between project team members in the various disciplines. This procedure covers the transmittal of

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design input which is not already addressed in existing standards or procedures. It requires documentation of the basis for design information, including identification of preliminary design inputs.

The staff reviewed this procedure on design information transmittals (DITs) and considers it acceptable to resolve this concern.

Vendor Document Review

In six cases, the IDR team found that vendor document review was not complete or accurate. This condition appeared to be a generic problem from the number of instances identified. Accordingly, S&L has committed to a comprehensive review of equipment qualification documentation. In each case, however, additional qualification data were provided by the vendor or developed by S&L to support the qualification of the equipment.

In the March 21, 1985, letter, the applicant indicated that, of the six instances of incomplete vendor review identified by the IDR, several were in packages not yet reviewed by the Seismic Qualification Review Team (SQRT) audit using revised checklists. Nevertheless, the applicant committed to taking further steps to upgrade vendor document review. This commitment involved further reviews of vendor packages and training of personnel. The staff observed evidence of both the further review and training in this area. The staff finds the applicant's response and action to be sufficient.

Code Compliance

With regard to Code compliance issues, these items largely involved questions of Code interpretation. The IDR team concluded that the design was adequate in each instance of possible Code violation and that the conditions were random in nature. The applicant concluded that there was no trend identified at Clinton and no corrective action was necessary. The staff concurs with the applicant's conclusion for the following reasons:

(1) There were six issues raised of the hundreds, and perhaps thousands, of Code applications.

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(2) One of the six had a previous Code case initiated.

(3) Of the remaining five items, the design was found adequate in each instance.

17.5.5 NRC Staff Conclusions

The applicant contracted with Bechtel Power Corporation to undertake an independent design review of the design activities of Clinton Unit No. 1. The review involved a substantial effort which evaluated more than 2900 documents and expended approximately 31,000 man-hours. The NRC staff closely monitored the review at all stages of its activities, including subsequent corrective actions. In view of monitoring performed by the staff (as detailed in this supplement), the staff concludes that the IDR provides additional confidence that the design of Clinton is in accordance with design requirements and published regulations. This conclusion is contingent upon successful completion of certain on-going corrective actions as described here. At this time, the staff has reason to believe that these corrective actions will be successfully accomplished. In addition, the staff concurs with the IDR conclusion that further review work would, in all likelihood, produce results similar to the IDR. Further independent design review of Clinton Unit No. 1, other than that indicated in this supplement, is not considered warranted.

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APPENDIX A

CONTINUATION OF CHRONOLOGY

February 1, 1985	Letter from applicant clarifying Appendix D, TMI Item II.K 3.18, "Automatic Depressurization System Actuation Logic" (SER Confirmatory Issue 28). Automatic depressurization system initiates on low reactor pressure vessel water level signal alone when bypass timer and 105 S timer are out.
February 5, 1985	Letter from applicant forwarding preliminary design assessment human engineering discrepancies evaluation, including Sections B-3 through B-9 previously omitted from September 28, 1984 submittal, per SER Confirmatory Issue 38.
February 8, 1985	Letter from applicant notifying of completion of actions identified in December 21, 1984 letter regarding safety parameter display system action plan. Meeting requested with NRC on February 20, 1985 to discuss systems, evaluations, proposed changes, and schedules for implementation and audit.
February 8, 1985	Letter to applicant forwarding NRC and Science Applications Inc., safety parameter display system design verification audit reports, handouts provided by utility for audit presentations, and plant emergency procedure guideline. Meeting is scheduled for February 20, 1985 regarding safety parameter display system action plan.
February 8, 1985	Letter from applicant providing quarterly update on construction schedule. Critical path schedule analysis shows

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that limiting system schedule and containment building ventilation system are approximately 56 days behind schedule. Target date for fuel load remains at January 1, 1985.

February 13, 1985	Letter from applicant forwarding "Results of Quality Programs for Construction of Clinton Power Station." Report demonstrates with reasonable assurance that facility can be operated without endangering public health and safety.
February 13, 1985	Letter to applicant forwarding Federal Register notice of environmental assessment and finding of no significant impact regarding extension of construction completion permit date for facility.
February 14, 1985	Letter from applicant notifying that safety parameter display system hardware/software installation, per emergency response capability implementation plan schedule, will not be completed on February 3, 1985 because of hardware delays, electrical construction, and isolator procurement.
February 20, 1985	Letter from applicant forwarding percent complete profile, utility nuclear power program key events and system turnover schedule tracking charts for period ending December 31, 1984, per request. Quarterly updates will be provided.
February 21, 1985	Letter from applicant responding to concerns identified in July 1984 letter regarding compliance to NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants" (Phases I and II). Information on methods of physically marking safe load paths and load drop analysis is discussed.
February 21, 1985	Summary issued of February 20, 1985 meeting with utility regarding corrective actions for proposed safety parameter display system to resolve concerns identified in preimplementation audit.

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February 28, 1985	Letter from applicant forwarding February 11, 1985 letter reflecting agreement reached between utility and State of Illinois Attorney General regarding protocol under which independent design review is conducted. Protocol will no longer be in effect after March 7, 1985 public meeting.
March 1, 1985	Letter to applicant forwarding preliminary assessment of independent design review report of facility. Specific corrective actions regarding future design activities, including followup audits by utility, are necessary.
March 4, 1985	Letter from applicant forwarding February 1985 detailed preservice inspection program, superseding February 1982 version. Class 1 and Class 2 component lists, replacing pages 47-470 of Volume 1 (final plan) submittal, is enclosed.
March 6, 1985	Summary issued of February 27, 1985 meeting with utility in Bethesda, MD, regarding detailed control room design review. Applicant's presentation addressed NRC concerns. Conformance to NUREG-0737, Supplement 1 requirements for proposed task analysis methodology is questioned.
March 6, 1985	Letter to applicant forwarding February 28, 1985 telephone conversation record informing utility and Bechtel of subject areas in independent design review report which NRC wishes to discuss at March 7, 1985 meeting.
March 6, 1985	Letter from Hydrogen Control Owners Group forwarding additional information regarding CLASIX-3 computer code, per NRC request. Information should not be used for evaluation of any specific plant unless endorsed by appropriate utility.
March 8, 1985	Letter to applicant forwarding SSER 4 (NUREG-0853).

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March 8, 1985	Letter to applicant forwarding order extending construction completion date specified in CPPR-137 to October 1, 1986, in response to August 22, 1984 request. Safety evaluation is also forwarded.
March 13, 1985	Letter from applicant advising that bimonthly updates of equipment seismic qualification and installation status to assist in scheduling of Seismic Qualification Review Team audit are unnecessary, per NRC statement. Update 6 weeks before July 1985 audit is sufficient.
March 13, 1985	Letter from Hydrogen Control Owners Group documenting final selection of hydrogen release histories for use in 1/4-scale test program, based on discussions which have occurred since August 1984 meeting. Final 1/4-scale test matrix is also documented. Revised final test matrix is enclosed.
March 14, 1985	Letter from applicant discussing emergency operations facility power supply. Backup emergency operation facility is being equipped and readied to provide continuation of key functions. Power supply meets requirements of NUREG-0737, Supplement 1.
March 18, 1985	Letter from applicant forwarding "Clinton Nuclear Station Ventilating Duct Flame Guard" final report. Report closes out April 4, 1983 commitment to provide results of fire test conducted on insulation wrap for ductwork, per SER Confirmatory Issue 58.
March 19, 1985	Letter to applicant acknowledging agreement reached with State of Illinois regarding conduct of independent design review contained in Schiff, Hardin, & Waite's February 11, 1985 letter forwarded by utility's February 28, 1985 letter. NRC agreement is contingent on documentation being available for NRC inspection.

March 19, 1985	Letter to applicant forwarding request for additional information regarding Generic Letter 83-28, Items 2.1, 2.2.1, 2.2.2, 3.1.3, 3.2.3, 4.5.2, and 4.5.3. Response is requested within 60 days for Items 2.1, 2.2.1, 2.2.2, 3.1.3, and 3.2.3, and within 90 days for Items 4.5.2 and 4.5.3.
March 20, 1985	Letter from applicant requesting authorization to implement spectral shifting and damping recommendations per ASME Code Cases N-397 and N-411, as alternatives to Regulatory Guides 1.122 and 1.61, respectively.
March 21, 1985	Letter from applicant forwarding response to initial NRC assessment regarding independent design review. Utility and Sargent & Lundy will follow closeout of identified commitments to ensure quality and completeness. Corrective action will be implemented.
March 21	Letter from applicant regarding valves trend analysis.
April 3, 1985	Letter from applicant requesting approval to use ASME Code Case N-413, "Minimum Size of Fillet Welds for Linear Type Supports, Section III." Use of fillet welds smaller than sizes listed in Subsection NF, Table NF-3324.5(d)-1 is allowed.
April 3, 1985	Letter from applicant forwarding outline of preliminary analysis for hydrogen control, endorsing Hydrogen Control Owners group hydrogen control program plan. Final analysis will be submitted by May 31, 1985.
April 3, 1985	Letter from applicant endorsing Hydrogen Control Owners Group March 6, 1985 generic responses to September 14, 1985 request for additional information on CLASIX-3 computer code. Utility will utilize heat transfer option discussed in generic response to Question 1.
April 4, 1985	Letter from applicant forwarding four mechanical environmental qualification packages.

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April 5, 1985	Letter to applicant advising of completion of review of utility's March 20, 1985 request for authorization to use ASME Code Cases N-397 and N-411 regarding spectral shifting and damping. Use of code cases is acceptable.
April 10, 1985	Letter from applicant forwarding Change 2 to Volume 1 of "Illinois Plan for Radiological Accidents."
April 11, 1985	Letter from applicant forwarding "SPDS: NRC Preimplementation Audit Results/CPS Response," per February 20, 1985 meeting commitment. Safety parameter display system primary and secondary display formats, report of SPDS Parameter Selection Task Force, and related information are enclosed.
April 12, 1985	Letter from applicant forwarding Revision 5 to physical security plan. Revision is withheld (refer to 10 CFR 73.21).
April 12, 1985	Letter from applicant forwarding Revision 4 to security force qualification and training program. Revision represents clarification and reorganization of document. Revision is withheld (refer to 10 CFR 73.21).
April 15, 1985	Letter to applicant forwarding notice of preparation of environmental assessment and finding of no significant impact regarding August 22, 1984 request for modifications to Section 3E of CPPR-137.
April 16, 1985	Generic Letter 85-06 issued to all PWR licensees and all applicants for operating licenses regarding quality assurance guidance for anticipated transient without scram equipment not safety-related.
April 16, 1985	Letter from applicant forwarding request for exemption from current NRC piping design criteria regarding arbitrary intermediate pipe breaks. Alternative criteria

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to provide flexibility to remove or retain shim restraints are requested.

April 18, 1985	Letter to applicant forwarding first draft of Technical Specifications. Draft document will be basis for May 28, 1985 meeting in Bethesda, MD to discuss areas where additional information may be required to ensure that final Technical Specifications documented in FSAR reflect as-built plant design.
April 19, 1985	Letter from applicant forwarding proprietary "Post-Accident Sampling System Evaluation Report," addressing 11 criteria of NUREG-0737, TMI Action Plan Item II.B.3, per SER (NUREG-0853) License Condition 6. Affidavit is enclosed. Report is withheld (refer to 10 CFR 2.790).
April 22, 1985	Letter from applicant committing to perform drywell low-pressure leakage test, per SRP Section 6.2.1.1.C, Appendix A, Revision 5, every 18 months or during each refueling outage. Commitment is based on reevaluation of SER Confirmatory Issue 66 regarding low pressure leakage testing.
April 24, 1985	Letter from applicant forwarding "Line-by-Line Evaluation/ Response to NRC Staff Review of Clinton Power Station Detailed Control Room Design Review program," per comments during February 28, 1985 meeting.
April 29, 1985	Letter from applicant forwarding nonproprietary and proprietary GE report, "Clinton Plant-Unique Encroachments Final Test Report," resolving Confirmatory Issue 71. Proprietary report is withheld (refer to 10 CFR 2.790).
April 30, 1985	Letter to applicant advising of completion of review of utility's April 3, 1985 request for authorization to use ASME Code Case N-413, "Minimum Size of Fillet Welds for Linear-Type Supports, Section III, Division 1, Subsection NF." Code case is acceptable.

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May 2, 1985	Generic Letter 85-07 issued to all operating reactor licensees regarding implementation of integrated schedules for plant modifications.
May 3, 1985	Letter from applicant certifying compliance to 10 CFR 50.49 regarding environmental qualification of electric equipment important to safety, per Generic Letter 84-24. Program is in place which controls IE bulletins and information notices from receipt to closeout.
May 6, 1985	Letter to applicant forwarding comments on revised safety parameter display system design based on February 20, 1985 meeting. Comments are listed according to utility's responses to NRC/Science Applications International, Inc. audit findings described in February 20, 1985 briefing book.
May, 7, 1985	Letter from applicant forwarding percent complete profile, key events, and system turnover schedule tracking charts, per July 1984 request. Chart updates will be sent on a quarterly basis.
May 9, 1985	Letter from applicant submitting quarterly update on construction schedule, per NRC May 9, 1981 request. Limiting system schedule is 53 days behind. Delay is addressed through partial system turnovers to allow concurrent construction and testing. Fuel load is scheduled for January 3, 1986.
May 10, 1985	Letter to applicant responding to utility's April 3, 1985 request for evaluation of proposed scope of preliminary analysis for hydrogen control for compliance with 10 CFR 50.44. Scope of proposed submittal is acceptable with listed modifications.
May 10, 1985	Letter from applicant forwarding "Summary of Training and Experience of Operations Personnel." Report summarizes

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	experience of individuals and shift crews as of December 1984 and projects data to December 1985.
May 14, 1985	Letter from applicant forwarding final draft of "Environmental Protection Plan," for review. Response is requested by August 1, 1985.
May 15, 1985	Letter to applicant forwarding agenda for July 23 and 24, 1985 Caseload Forecast Panel site visit and list of panel representatives.
May 16, 1985	Letter from applicant confirming GE review of emergency operating procedures, per NUREG-0737, TMI Item I.C.7. Resolution of GE comments is expected by July 1985. Implementation processes are reviewed and approved by NRC per SER (NUREG-0853, Section 13.6.3).
May 16, 1985	Letter from applicant providing supplemental information in response to request for additional information regarding SER (NUREG-0978) Outstanding Issue 9 concerning LOCA-related pool dynamic loads. Issue is resolved.
p.13-2 May 16	Letter from applicant describing administrative controls
May 20, 1985	Letter from applicant affirming that utility will implement Regulatory Guide 1.33, "Surveillance Requirements," before fuel load. EPRI affiliation will be contained to monitor progress of cable study being performed by University of Connecticut.
May 20, 1985	Letter from applicant submitting list of Sargent & Lundy drawings being sent to NRC to enable completion of technical review of listed licensing issues, per staff request.
May 22, 1985	Letter from applicant requesting approval by June 21, 1985 to use ASME Code Case N-71-13, "Additional Materials for Subsection NF, Classes 1, 2, 3, and MC Component Supports Fabricated by Welding, Section III, Division 1."

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May 23, 1985	Generic Letter 85-08 issued to all holders of construction permits and operating licenses regarding 10 CFR 20.408 termination reports and formats.
May 23, 1985	Letter from applicant forwarding updated draft of Technical Specifications for review. Changes constitute plant-specific changes to setpoints resulting from review of design documents and as-built information, per May 25, 1985 meeting.
May 24, 1985	Letter from applicant requesting approval for alternate method of meeting Section C.2.a of Revision 1 to Regulatory Guide 1.108 for periodic testing of diesel generator units by running either 24-hour test or running diesel at 100% power. Approval is requested by June 21, 1985.
May 24, 1985	Letter from applicant forwarding clarification of April 16, 1985 request for exemption from piping design criteria regarding arbitrary pipe breaks. Provisions minimize steam and water hammer effects.
May 29, 1985	Letter from applicant requesting NRC appraisal of emergency response facilities after January 3, 1986 fuel load. Date can be determined after emergency preparedness implementation appraisal in October 1985.
May 29, 1985	Letter from applicant forwarding advance copies of FSAR changes requested, per May 9, 1985 agreements. Enclosed changes will be incorporated into FSAR Amendment 34 scheduled for issuance in July 1985. Status report of observation reports already committed to are also enclosed.
May 30, 1985	Letter from applicant forwarding Revision 2 to security contingency plan. Revision is withheld (refer to 10 CFR 73.21).

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June 7, 1985	Letter from applicant advising that FSAR Section 2.2.2.3 regarding pipelines crossing utility property will be revised in Amendment 34 to incorporate response to Question 311.5 concerning safety measures with revised wording of March 2, 1982 agreement between utility and Shell Oil Co.
June 7, 1985	Letter from applicant forwarding draft proposed FSAR revision regarding effects of jet impingement and justification for exceptions to SRP, per SER Outstanding Issue 5. NUREG/CR-2913 is used for certain jet analyses.
June 11, 1985	Letter from applicant submitting information to provide clarification regarding fire protective signaling system. Proprietary protective signal system designated as Class A and local protective signaling system used to actuate and/or monitor water suppression system is designated as Class B.
June 11, 1985	Letter from applicant forwarding revisions to FSAR Sections 1.8, 7.1, 7.2, 8.1, and 8.3, and responses to Questions 430.119 and 430.131. Revisions are made to clarify statements in FSAR regarding electrical separation and flexible conduit. Changes will be incorporated in Amendment 34.
June 11, 1985	Letter from applicant forwarding Emergency Plan Implementing Procedure EC-13, "Reactor Core Damage Estimation." Procedure was revised to include third core damage class, referred to as fuel overheat per TMI Item II.B.3.
June 11, 1985	Letter from applicant forwarding additional accident monitoring instrumentation, per NUREG-0737, TMI Item II.F.1. Information is complete and adequate to provide confirmation that TMI item and SER Confirmatory Issue 21 are implemented.
June 12, 1985	Letter from applicant confirming April 23, 1985 telephone conversation regarding revised response to Question 430.135

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of FSAR and to reduce scope of voltage verification test required on listed bases. Proposed change to FSAR and description of EASY computer code are enclosed.

June 12, 1985	Letter from applicant forwarding responses to NRC comments on revised safety parameter display system (TMI Action Plan Item I.D.2) for review. Scheduling of design validation audit requested in mid-October to support final closure.
June 12, 1985	Letter from applicant endorsing Containment Issues Owners Group May 15, 1985 submittal regarding Confirmatory Issue 71 concerning flow momentum comparisons between clean and encroached pool areas.
June 12, 1985	Letter from applicant forwarding list of selected operating events to be used in systems function and task analysis, per April 24, 1985 responses to NRC comments on Detailed Control Room Design Review program plan. Plan process fulfills Supplement 1 to NUREG-0737 requirements.
June 12, 1985	Letter from applicant forwarding "Offsite Dose Calculation Manual" for approval. Table 2.6-1, "Input Parameters for Calculating Rapj," will be completed and forwarded by October 1, 1985. ?
June 14, 1985	Letter from applicant responding to NRC request for clarification of utility's October 1, 1984 response to Generic Letter 83-28. Utility process uniquely determines post-maintenance testing required for each maintenance evolution on safety-related equipment.
June 19, 1985	Letter from applicant requesting NRC acceptance of station-specific fire protection halon concentration (6% for 10 minutes), as described in NEDO-10466A, Addendum 1. Request is based on recent acceptance of report. Utility plans refer to report in September 1, 1985 FSAR amendment.
p. 5-6 June 19	Letter from applicant regarding CPS No. [illegible] ?

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June 19, 1985	Letter from applicant providing information on compliance with requirements of SER (NUREG-0853), dated February 1982, regarding safety-relief valve surveillance program, for use by NRC to close issue. Procedures instituted to detect valve condition are listed.
June 24, 1985	Letter from applicant requesting that limitation of ASME Code Case N-411 for seismic loads only be removed and approved for applications and conditions as stated in March 20, 1985 request.
June 25, 1985	Letter from applicant forwarding proposed schedule for meeting requirements of 10 CFR 50.44, Paragraphs (c)(3)(iv), (v), and (vi). Scheduled simplified summary of detailed generic schedule was recently prepared by Hydrogen Control Owners Group.
June 25, 1985	Letter to applicant approving use of ASME Code Case N-71-13, "Additional Materials for Subsection NF, Classes 1, 2, 3 and MC Component Supports Fabricated by Welding, Section III, Division 1," with limitations stated in inquiry and reply section of code case.
June 25, 1985	Letter to applicant approving May 29, 1985 request for NRC appraisal of emergency response facilities after fuel load, recommendation for determining date for appraisal, and proposal to discuss preparation and conduct of evaluation before appraisal.
July 1, 1985	Letter from applicant confirming Shell Oil Co. commitment to station and maintain one employee at Dewitt Pumping Station during shipments of propane/butane on Shell pipeline upon request of utility. Commitment will be included in FSAR Amendment 34.
? July 2, 1985	Letter from applicant regarding partial feedwater heating mode of operation

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July 3, 1985	Letter from applicant submitting additional justification to support April 16 and May 24, 1985 requests for exemption from current piping design criteria regarding arbitrary intermediate pipe breaks.

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APPENDIX B

REFERENCES

Bechtel Power Corp., "Independent Design Review for Illinois Power Company," Final Report, 6 Vols., January 1985.

---, Nov. 12, 1984, Letter to NRC [reply to NRC inspection report (for programmatic items)]

General Electric Co., NEDE-24988-P, "Analysis of Generic BWR Safety Relief Valve Operability Test Results," Oct. 1981.

---, NEDO-21985, "Functional Capability Criteria for Essential Mark II Piping," Sept. 1978.

Hartman, F. P., "Effect of Fluid Compressibility on Torque in Butterfly Valves," ISA Transactions, 8(4):28.

Hodges, M. W. (NRC), May 1981, Memorandum to T. P. Speis, "Summary of March 10 Meeting With General Electric To Discuss BWR Liquid Overfill Events."

Operators?

Illinois Power Co., "Summary of Training and Experience of Operations for Clinton Power Station," May 10, 1985.

Novak, T. M. (NRC), August 17, 1982, Letter to J. E. Booker (Gulf States Utilities), "Status of LRG II Issues."

Posi-Seal International, Inc., "Nuclear Seismic and LOCA Analysis," Oct. 21, 1982.

Rubenstein, L. S. (NRC), Aug. 19, 1982, Memorandum to T. Novak, "Resolution of LRG-II Channel Box Deflection Issue (LRG-II Issue 3-CPB)."

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Saffell, B. F. (INEL), April 23, 1981, Letter to R.E. Tiller (DOE), "Comments on BWR Owners' Group Responses to NRC Questions on Safety/Relief Valve Low Pressure Program," Saff-95-81.

---, Jan. 13, 1982, Letter to R. E. Tiller (DOE), "Review of BWR/GE Safety Relief Valve Test Report (A6356)," Saff-14-82.

---, May 4, 1982, Letter to D. E. Solecki (DOE), "Open Questions--BWR/GE Safety/Relief Valve Test Report, BWR Owners' Safety/Relief Submittals (A6356)," Saff-178-82.

Sargent & Lundy Engineers, "Standard on Design Calculations," SAS-22, May 11, 1984; MAS-22, June 25, 1984; ESI-253, Aug. 6, 1984.

---, "QA Procedure on Design Calculations," GQ-3.08, Jan. 31, 1985.

---, "Procedure for Incorporating Changes Into Affected Documents," PI-CP-071, March 1, 1985.

---, "Procedure for Preparation of Design Change Package," PI-CP-073, _______. date ?

---, "____________," GQ-3.17, May 1, 1984. ? title ?

U.S. Nuclear Regulatory Commission, NUREG-0462, "Technical Report on Operating Experience With BWR Pressure Relief Systems," July 1978.

---, NUREG-0578, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations," July 1979.

---, NUREG-0588, "Interim Staff Position on Environment Qualification of Safety-Related Electrical Equipment, Nov. 1979.

---, NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants, " July 1980.

---, NUREG-0737, "Clarification of TMI Action Plan Requirements, " Nov. 1980; Suppl. 1, Dec. 1982.

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---, NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," LWR Edition, July 1981.

---, NUREG-0867, "Safety Evaluation Report Related to the Operation of Perry Nuclear Power Plants, Units 1 and 2," May 1982.

---, NUREG-0927, "Evaluation of Water Hammer Occurrence in Nuclear Power Plants," Rev. 1, March 1984.

---, NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant," Vol. 1, April 1983; Vol. 2, Aug. 1983.

---, NUREG/CR-2136, "Effect of Postulated Event Devices on Normal Operation of Piping Systems in Nuclear Power Plants," May 1981.

Waters, D. B. (BWROG), Sept. 17, 1980, Letter to R. H. Vollmer (NRC), "NUREG-0578 Requirement 2.1.1--Performance Testing of BWR and PWR Relief and Safety Valves."

---, Dec. 29, 1980, Letter to D.G. Eisenhut, "BWR Owners' Group Evaluation of NUREG-0737 Requirements," BWROG-80-12.

---, March 31, 1981, Letter to D.G. Eisenhut (NRC), "Responses to NRC Questions on the BWR S/RV Test Program," BWROG-81-35.

? Title ? Date

cited in 17.5.4.2 Welding Research Council, "________________," Bulletin 300, ____________.

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APPENDIX D

NRC STAFF CONTRIBUTORS AND CONSULTANTS

This SER supplement is a product of the NRC staff and its consultants. The NRC staff members listed below were principal contributors to this report. A list of consultants follows the list of staff members.

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M. Schoppman	Management Systems Engineer	Licensee Qualification
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APPENDIX F

ERRATA TO CLINTON POWER STATION SAFETY EVALUATION REPORT

<u>SER (NUREG-0853, February 1982)</u>

Page ix and page 3-41:	Change title of Section 3.11 from "Environmental Qualification of Safety-Related Electrical Equipment" to "Environmental Qualification of Electrical Equipment Important to Safety and Safety-Related Mechanical Equipment."
Page 6-27, line 12:	Change "condensate" to "RCIC."
Page 6-33, line 32:	Change "$\geq$ 1/4 in." to "$\geq$ 1/8 in."
Page 16-1, item (2):	Delete item 2.
Page 16-1, item (6):	Delete everything after "core flow checked" and insert "at least once per 24 hours."
Page C-8, line 3:	Delete word "all."

<u>SSER 2 (NUREG-0853, May 1983)</u>

Page 3-4, Section 3.10.1, line 11:	After words "program before fuel load." insert the following sentence: "The applicant's program for the aging degradation aspects of equipment qualification will be addressed by the staff as part of the environmental qualification of electrical equipment important to safety and safety-related mechanical equipment (see Section 3.11 of this SER and its supplements)."
Page 6-3, item(6)	Change "Section 3.10" to "Section 3.11."

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APPENDIX H
CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS
CLINTON POWER STATION - UNIT 1
(Phase I)
Docket No. [50-461]

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FIN No. A6457

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ABSTRACT

The Nuclear Regulatory Commission (NRC) has requested that all nuclear plants, either operating or under construction, submit a response of compliancy with NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." EG&G Idaho, Inc., has contracted with the NRC to evaluate the responses of those plants presently under construction. This report contains EG&G's evaluation and recommendations for Clinton Power Station Unit 1.

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EXECUTIVE SUMMARY

Illinois Power Company has presented information and made commitments to show that Clinton Power Station Unit 1 is consistent with the intent of NUREG 0612 Article 5.1.1.

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CONTENTS

TABLES

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Control of Heavy Loads at Nuclear Power Plants

Clinton Power Station Unit 1

(Phase I)

1. INTRODUCTION

1.1 Purpose of Review

This technical evaluation report documents the EG&G Idaho, Inc., review of general load-handling policy and procedures at Clinton Unit 1. This evaluation was performed with the objective of assessing conformance to the general load-handling guidelines of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants" [1], Section 5.1.1.

1.2 Generic Background

Generic Technical Activity Task A-36 was established by the U.S. Nuclear Regulatory Commission (NRC) staff to systematically examine staff licensing criteria and the adequacy of measures in effect at operating nuclear power plants to assure the safe handling of heavy loads and to recommend necessary changes to these measures. This activity was initiated by a letter issued by the NRC staff on May 17, 1978 [2], to all power reactor applicants, requesting information concerning the control of heavy loads near spent fuel.

The results of Task A-36 were reported in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." The staff's conclusion from this evaluation was that existing measures to control the handling of heavy loads at operating plants, although providing protection from certain potential problems, do not adequately cover the major causes of load-handling accidents and should be upgraded.

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In order to upgrade measures for the control of heavy loads, the staff developed a series of guidelines designed to achieve a two-phase objective using an accepted approach or protection philosophy. The first portion of the objective, achieved through a set of general guidelines identified in NUREG-0612, Article 5.1.1, is to ensure that all load-handling systems at nuclear power plants are designed and operated such that their probability of failure is uniformly small and appropriate for the critical tasks in which they are employed. The second portion of the staff's objective, achieved through guidelines identified in NUREG-0612, Articles 5.1.2 through 5.1.5, is to ensure that, for load-handling systems in areas where their failure might result in significant consequences, either (a) features are provided, in addition to those required for all load-handling systems, to ensure that the potential for a load drop is extremely small (e.g., a single-failure-proof crane) or (b) conservative evaluations of load-handling accidents indicate that the potential consequences of any load drop are acceptably small. Acceptability of accident consequences is quantified in NUREG-0612 into four accident analysis evaluation criteria.

The approach used to develop the staff guidelines for minimizing the potential for a load drop was based on defense in depth and is summarized as follows:

- Provide sufficient operator training, handling system design, load-handling instructions, and equipment inspection to assure reliable operation of the handling system

- Define safe load travel paths through procedures and operator training so that, to the extent practical, heavy loads are not carried over or near irradiated fuel or safe shutdown equipment

- Provide mechanical stops or electrical interlocks to prevent movement of heavy loads over irradiated fuel or in proximity to equipment associated with redundant shutdown paths.

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Staff guidelines resulting from the foregoing are tabulated in Section 5 of NUREG-0612.

1.3 Plant-Specific Background

On December 22, 1980, the NRC issued a letter [3] to Illinois Power Company, the applicant for Clinton Unit 1 requesting that the applicant review provisions for handling and control of heavy loads at Clinton Unit 1, evaluate these provisions with respect to the guidelines of NUREG-0612, and provide certain additional information to be used for an independent determination of conformance to these guidelines. On June 22, 1981, Illinois Power provided an initial response [4] to this request; related discussions have resulted in the following additional correspondence:

September 25, 1981 [5]
February 10, 1982 [10]
March 18, 1983 [11]
July 28, 1983 [12]
December 21, 1983 [13]
January 26, 1984 [14]
February 21, 1985 [15].

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2. EVALUATION AND RECOMMENDATIONS

2.1 Overview

The following sections summarize Illinois Power Company's review of heavy load handling at Clinton Unit 1 accompanied by EG&G's evaluation, conclusions, and recommendations. The applicant has indicated the weight of a heavy load for this facility (as defined in NUREG-0612, Article 1.2) as 1000 pounds.

2.2 Heavy Load Overhead Handling Systems

This section reviews the applicant's list of overhead handling systems which are subject to the criteria of NUREG-0612 and a review of the justification for excluding overhead handling systems from the above mentioned list.

2.2.1 Scope

"Report the results of your review of plant arrangements to identify all overhead handling systems from which a load drop may result in damage to any system required for plant shutdown or decay heat removal (taking no credit for any interlocks, technical specifications, operating procedures, or detailed structural analysis) and justify the exclusion of any overhead handling system from your list by verifying that there is sufficient physical separation from any load-impact point and any safety-related component to permit a determination by inspection that no heavy load drop can result in damage to any system or component required for plant shutdown or decay heat removal."

A. Summary of Applicant's Statements

The applicant's review of overhead handling systems identified the cranes and hoists shown in Table 2.1 as those which handle heavy loads in the vicinity of irradiated fuel or safe shutdown equipment. The remaining cranes shown in

TABLE 2.1. NON EXEMPT HEAVY LOAD HANDLING SYSTEMS "CRANES WHICH HANDLE HEAVY LOADS IN THE VICINITY OF IRRADIATED FUEL OR SAFE SHUTDOWN EQUIPMENT--CLINTON UNIT 1"

	Crane	Building	Capacity (tons)
(1)	Containment Polar Crane	Containment	100/10
(2)	Refueling Platform	Containment	0.5
(6)	Fuel Building Crane	Fuel	125
(7)	Fuel Handling Platform	Fuel	0.5
(8)	Fuel Transfer Tube Shield PLate Jib Crane	Fuel	0.5
(9)	Spent Fuel Pool Jib Crane	Fuel	0.5
(16)	Auxiliary Platform	Containment	5
(17)	Fuel Bundle Jib	Fuel	0.5

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Table 2.2 are exempt from satisfying the general guidelines of NUREG-0612. Cranes 2, 7 and 9 of Table 2.1 are also exempt as the loads transported by these cranes do not qualify as "heavy loads" per the NUREG-0612 definition. They are listed in Table 2.1 due to the irradiated fuel loads transported by them. Originally Table 2.1 listed hoists by numbers 3, 4, 5, 10, 11, 12, 13, 14, and 15. The July 1983 submittal justified removal of each of these to Table 2.2 where they are now listed.

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The applicant has also indicated that all the cranes listed in Table 2.1 that are capable of transporting loads over an open reactor vessel or the spent fuel pool were designed to be single failure proof. The Fuel Building Crane is single failure proof with the exception of the hook, which is not redundant. This crane is equipped with permanent mechanical stops that prevent crane travel over the spent fuel pool, and upper limit switches that prevent the cask bottom from clearing the upper walls of the pool.

B. EG&G Evaluation

The applicant provided drawings with overhead handling systems clearly marked. The initial correspondence listed 20 hoisting systems in Table 2.1; three were not qualified as handling heavy loads. Three were still under consideration. In the July 1983 submittal justification, from careful analysis, was provided to relocate nine hoistings systems to Table 2.2 and delete the three that were under consideration.

C. EG&G Conclusions and Recommendations

Based on the information provided, EG&G concludes that the applicant has included all applicable hoists and cranes in

TABLE 2.2. CLINTON UNIT 1, MONORAILS, HOISTS AND CRANES EXCLUDED FROM FURTHER CONSIDERATION

Crane	Location/Impact Area	Loads[a]	Elevation	Safety-Related Equipment Location	Hazard Elimination Category
	Containment Building Column Rows				
MSIV Monorail	AB-AE 109-116	MSIV--11,700 lb	767.75 ft	Under load	Site-specific considerations[b]
Containment Equipment Hatch--Hoist Beam 35	AH-AF 105-112	Equipment Hatch--18,500 lb	712 ft	Under load	Site-specific consideration[b]
Recirculation Pump/Motor Removal Monorail	Containment Building (Drywell)	Recirculation pump motor--51,000 lb	737 ft	Under load	Site-specific consideration[b]
HPCS Pump Removal Beam 69	AE-AH 102-105	HPCS pump motor 14,500 lb[d]	707.5 ft	Under load	Redundant systems
Fuel Pool Waste Filter Demineralizer Beam 33	Radwaste Building P-H.9 122-124	Shield plugs--4.5 tons	737 ft	Under load	Site-specific consideration[c]
RHR Pump Removal Beams 38, 39, 40	Auxiliary Building Beam 38-- V-Z 102-105 Beam 39-- V-Z 105-107 Beam 40-- V-Z 105-107	RHR pump motor--5,400 lb[d]	712 ft	Under load	Redundant systems
RCIC pump removal beams 41 and 13	S-U 112-117	RCIC pump motor--5,275 lb[d]	712t	Under load	Redundant systems
LPCS pump removal Beam 42	V-Z 121-124	LPCS pump motor--7,600 lb[d]	712 ft	Under load	Redundant systems
MSIV Steam Tunnel Bridge Crane	U-F 110-114	MSIV--11,700 lb	755 ft	Under load	Site-specific considerations[b]

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TABLE 2.2. (continued)

Crane	Location/Impact Area	Loads[a]	Elevation	Safety-Related Equipment Location	Hazard Elimination Category
Auxiliary Roof Gantry Crane	--	--	--	--	Use only during shutdown[b]
Fuel Channeling Hoist	--	--	--	--	Will not lift heavy loads
Screenhouse Trash Basket Hoist	--	--	--	--	Cancelled

a. Includes hook, load block, and lifting devices as applicable.

b. Crane used only during plant shutdown.

c. Equipment hatch only opened during plant shutdown.

d. Worse Scenario: Bringing in new motor before decommissioning.

e. Each filter is isolated if access is required. Therefore, a load drop would not affect pool inventory.

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their list of handling systems which must comply with the requirements of the general guidelines of NUREG-0612.

2.3 General Guidelines

This section addresses the extent to which the applicable handling systems comply with the general guidelines of NUREG-0612, Article 5.1.1. EG&G's conclusions and recommendations are provided in summaries for each guideline.

The NRC has established seven general guidelines which must be met in order to provide the defense-in-depth approach for the handling of heavy loads. These guidelines consist of the following criteria from Section 5.1.1 of NUREG-0612:

- o Guideline 1--Safe Load Paths
- o Guideline 2--Load-Handling Procedures
- o Guideline 3--Crane Operator Training
- o Guideline 4--Special Lifting Devices
- o Guideline 5--Lifting Devices (not specially designed)
- o Guideline 6--Cranes (Inspection, Testing, and Maintenance)
- o Guideline 7--Crane Design.

These seven guidelines should be satisfied for all overhead handling systems and programs in order to handle heavy loads in the vicinity of the reactor vessel, near spent fuel in the spent-fuel pool, or in other areas where a load drop may damage safe shutdown systems. The succeeding paragraphs address the guidelines individually.

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2.3.1 Safe Load Paths [Guideline 1, NUREG-0612, Article 5.1.1(1)]

"Safe load paths should be defined for the movement of heavy loads to minimize the potential for heavy loads, if dropped, to impact irradiated fuel in the reactor vessel and in the spent-fuel pool, or to impact safe shutdown equipment. The path should follow, to the extent practical, structural floor members, beams, etc., such that if the load is dropped, the structure is more likely to withstand the impact. These load paths should be defined in procedures, shown on equipment layout drawings, and clearly marked on the floor in the area where the load is to be handled. Deviations from defined load paths should require written alternative procedures approved by the plant safety review committee."

A. Summary of Applicants Statement

Information showing how Illinois Power Co. is meeting or plans to meet Guideline 1 is contained in parts of four submittals. The actions and commitments show:

1. Two sets of drawings are provided, General Arrangements M01-1100 series and Equipment Removal M01-1400 series. Color codes and numbers are used to help locate load handling devices and equipment.

2. Generic safe load paths are planned for two specific areas. Load drop analysis made (6 below) on the Fuel Building and will be made for lifts of the Polar Crane. Load handling limitations will be covered in operating procedures.

3. Safe load paths for each heavy load handled will be developed, complete with drawings or sketches, and risks identified. Documentation will be provided to NRC six months prior to fuel loading.

4. Safe load paths will be clearly marked on the floor before fuel loading.

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5. Administrative controls will be provided for deviations and supported by written approval in plant records.

6. Load drop analysis was performed to show the floor below can sustain a drop in areas where new fuel shipping containers will be handled.

7. Safe load paths will be physically marked, or a second member of the load handling party will assure the safe load path is followed. Any change will require special approval by a trained person.

8. The pending load drop analysis will be completed and safe load paths modified accordingly.

B. EG&G Evaluation

The actions taken and commitments made indicate that Illinois Power Co. will be consistent with Guideline 1.

C. EG&G Conclusions and Recommendations

Clinton 1 is consistent with Guideline 1.

2.3.2 Load-Handling Procedures [Guideline 2, NUREG-0612, Article 5.1.1(2)]

"Procedures should be developed to cover load-handling operations for heavy loads that are or could be handled over or in proximity to irradiated fuel or safe shutdown equipment. At a minimum, procedures should cover handling of those loads listed in Table 3-1 of NUREG-0612. These procedures should include: identification of required equipment; inspections and acceptance criteria required before movement of load; the steps and proper sequence to be followed in handling the load; defining the safe path; and other special precautions."

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A. Summary of Applicant's Statements

Procedures for handling equipment at Clinton Unit 1 are assigned to the Plant Staff for preparation and implementation. The Procedures for all overhead handling systems, including the single failure proof cranes will be completed and available at the site, before fuel loading.

B. EG&G Evaluation

The Illinois Power Co. plans and commitments indicate Clinton Unit 1 will be consistent with Guideline 2 before fuel loading.

C. EG&G Conclusions and Recommendations

Clinton Unit 1 is consistent with the intent of Guideline 2.

2.3.3 Crane Operator Training [Guideline 3, NUREG-0612, Article 5.1.1(3)]

"Crane operators should be trained, qualified, and conduct themselves in accordance with Chapter 2-3 of ANSI B30.2-1976, 'Overhead and Gantry Cranes' [6]."

A. Summary of Applicant's Statements

Illinois Power Co. takes no exceptions to ANSI B30.2 for crane operator training, and intends to comply with it for training.

B. EG&G Evaluation

Completion of the plans to comply with ANSI B30.2 for crane operator training will show consistency with Guideline 3.

C. EG&G Conclusions and Recommendations

Clinton Unit 1 is consistent with Guideline 3.

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2.3.4 Special Lifting Devices [Guideline 4, NUREG-0612, Article 5.1.1(4)]

"Special lifting devices should satisfy the guidelines of ANSI N14.6-1978, 'Standard for Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or More for Nuclear Materials' [7]. This standard should apply to all special lifting devices which carry heavy loads in areas as defined above. For operating plants, certain inspections and load tests may be accepted in lieu of certain material requirements in the standard. In addition, the stress design factor stated in Section 3.2.1.1 of ANSI N14.6 should be based on the combined maximum static and dynamic loads that could be imparted on the handling device based on characteristics of the crane which will be used. This is in lieu of the guideline in Section 3.2.1.1 of ANSI N14.6 which bases the stress design factor on only the weight (static load) or the load and of the intervening components of the special handling device."

A. Summary of Applicant's Statements

Originally three special lifting devices were planned and covered in submittals. Subsequently one has been deleted from plans. The two provided are discussed below.

The steam Dryer/Separator Strongback is handled by the Polar Crane. The device was supplied by General Electric Co. who terms the strongback "Single Failure Proof." The strongback is attached to the redundant dual hook of the crane through the use of a hook box on top of the strongback and two six inch diameter link pins. The ANSI N14.6, 1978 standard as amended by NUREG 0612 Sec. 5.1.1.(4) was used for making a thorough evaluation of the design. The information obtained supports that they were designed to industry standards. The design load was 54.5 tons which includes a 15% dynamic allowance. It provides safety factors of greater than 3 with respect to yield and greater than 5 with respect to ultimate strength of the material.

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The largest load, (the separator) is 44.5 tons; the strongback weight is 4 tons. The combined weight of 48.5 tons differs by ~2% from the General Electric Co. calculation basis (47.4 tons). It is considered negligible considering the margin between the 15% dynamic allowance used in calculations and actual dynamic load imposed on the handling system (1/2% of load per foot per minute of hoisting speed per CMAA 70, i.e. 1/2% of 5 ft/min = 2.5%).

The load test performed was 55.625 tons (125% of rated load).

The RPV Head Strongback is rated at 100 tons. Its largest single load is the Drywell Head of 65 tons. The maximum load is the RPV head plus the strongback, nut tray, nuts and washers of 25 tons. General Electric Co. used design estimates of 86.7 tons plus a 15% dynamic allowance of 13 tons. Resultant safety factors were greater than 3 with respect to yield and greater than 5 with respect to ultimate strength of material. Actual weight maximums are less than 1% from estimate and is considered negligible considering the 15% dynamic load allowance when crane speed is at 5 ft/min. Or, as allowed by CMAA 70, 1/2% of 5 ft/min equals 2.5% allowance.

The load test performed was at 125 tons (125% of 100 tons rated capacity).

B. <u>EG&G Evaluation</u>

The submittal information presents data confirming major design features of the two special lifting devices. The minor deviations from technical requirements are discussed also. Differences are within the purview of the NRC consistent approaches provided in their letter, "Synopsis of Issues Associated with NUREG-0612." The special lifting devices, when used with the crane at maximum speed of 5 ft/min are consistent with the intent of Guideline 4.

C. EG&G Conclusions and Recommendations

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The two special lifting devices for Clinton Unit 1 are consistent with the intent of Guideline 4.

2.3.5 Lifting Devices (Not Specially Designed) [Guideline 5, NUREG-0612, Article 5.1.1(5)]

"Lifting devices that are not specially designed should be installed and used in accordance with the guidelines of ANSI B30.9-1971, 'Slings' [8]. However, in selecting the proper sling, the load used should be the sum of the static and maximum dynamic load. The rating identified on the sling should be in terms of the 'static load' which produces the maximum static and dynamic load. Where this restricts slings to use on only certain cranes, the slings should be clearly marked as to the cranes with which they may be used."

A. Summary of Applicant's Statements

It will be demonstrated that all slings used for heavy loads lifts meet the applicable requirements of ANSI B30.9-1971 as amended by NUREG-0612 Section 5.1.1(5). Any dedicated slings at Clinton Unit 1 will be used in accordance with Guideline 5.

B. EG&G Evaluation

Since compliance with ANSI B30.9 is indicated, only two other requirements are specified. These are the NUREG-0612 specification to select the slings on static plus dynamic load and special identification of a sling used in a dedicated service. Illinois Power Co. has committed to meet these requirements so, the Clinton Unit 1 will be consistent with Guideline 5.

C. EG&G Conclusions and Recommendations

The actions taken and commitments show that Clinton Unit 1 is consistent with Guideline 5.

2.3.6 Cranes (Inspection, Testing, and Maintenance) [Guideline 6, NUREG-0612, Article 5.1.1(6)]

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"The crane should be inspected, tested, and maintained in accordance with Chapter 2-2 of ANSI B30.2-1976, 'Overhead and Gantry Cranes,' with the exception that tests and inspections should be performed prior to use where it is not practical to meet the frequencies of ANSI B30.2 for periodic inspection and test, or where frequency of crane use is less than the specified inspection and test frequency (e.g., the polar crane inside a PWR containment may only be used every 12 to 18 months during refueling operations, and is generally not accessible during power operation. ANSI B30.2, however, calls for certain inspections to be performed daily or monthly. For such cranes having limited usage, the inspections, test, and maintenance should be performed prior to their use)."

A. Summary of Applicant's Statements

Procedures for crane inspections, testing, and maintenance will be developed in accordance with Chapter 2-2 of ANSI B30.2-1976 with the exception of the Polar Crane which will be inspected at each refueling outage.

B. EG&G Evaluation

The procedures to be taken are consistent with the guidelines. The exception for the Polar Crane is within the NRC "Synopsis of Issues Associated with NUREG-0612," due to infrequent use and impracticality of testing and inspection during reactor operations.

C. EG&G Conclusions and Recommendations

The commitments and handling of one exception show that Clinton Unit 1 is consistent with the intent of Guideline 6.

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2.3.7 Crane Design [Guideline 7, NUREG-0612, Article 5.1.1(7)]

"The crane should be designed to meet the applicable criteria and guidelines of Chapter 2-1 of ANSI B30.2-1976, 'Overhead and Gantry Cranes,' and of CMAA-70, 'Specifications for Electric Overhead Traveling Cranes' [9]. An alternative to a specification in ANSI B30.2 or CMAA-70 may be accepted in lieu of specific compliance if the intent of the specification is satisfied."

A. Summary of Applicant's Statements

"Crane contract reviews and contracts with Clinton crane manufacturers verified that the requirements of CMAA 70 and ANSI B30.2-1976 were imposed during the design and manufacture of the Clinton lifting devices. No exception is taken to these requirements."

B. EG&G Evaluation

The applicant states that contracts for the Clinton Unit 1 cranes required adherence to the specified guidelines. Also, it is stated that reviews have verified adherence. The submittals indicate there is consistency with Guideline 7.

C. EG&G Conclusions and Recommendations

Information provided indicates that Clinton Unit 1 is consistent with Guideline 7.

2.4 Interim Protection Measures

The NRC staff has established (NUREG-0612, Article 5.3) for interim protection guides to operating plants. Since Clinton Unit 1 is not operational these guidelines do not apply.

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3. CONCLUDING SUMMARY

3.1 Applicable Load-Handling Systems

The list of cranes and hoists supplied by the applicant as being subject to the provisions of NUREG-0612 is apparently complete (see Section 2.2.1).

3.2 Guideline Recommendations

Commitments or compliance with the seven NRC guidelines for heavy load handling (Section 2.3) are satisfied at Clinton Unit 1. This conclusion is represented in tabular form as Table 3.1. Guideline actions are shown in the summary below:

Guideline	Action or Recommendation
1. Section 2.3.1 Safe Load Paths	The actions taken and commitments made indicate that Clinton Unit is consistent with Guideline 1.
2. Section 2.3.2 Load Handling Procedures	Clinton Unit 1 is consistent with Guideline 2.
3. Section 2.3.3 Crane Operator Training	Clinton Unit 1 is consistent with Guideline 3.
4. Section 2.3.4 Special Lifting Devices	The two special lifting devices for Clinton Unit 1 are consistent with Guideline 4.

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Guideline	Action or Recommendation
5. Section 2.3.5 Lifting Devices, Not Specially Designed	The actions taken and commitments made show that Clinton Unit 1 is consistent with Guideline 5.
6. Section 2.3.6 Cranes Inspection Testing and Maintenance	The commitments and the handling of one exception show that Clinton Unit 1 is consistent with Guideline 6.
7. Section 2.3.7 Crane Design	Information provided indicates that Clinton Unit 1 is consistent with Guideline 7.

3.3 Interim Protection

These requirements do not apply to plants under constructicn.

3.4 Summary

Illinois Power Co. has shown that Clinton Unit 1 is consistent with the intent of NUREG 0612 Article 5.1.1 requirements.

TABLE 3.1. CLINTON POWER STATION UNIT 1, NUREG 0612 SECTION 5.1.1 COMPLIANCE MATRIX

No.	Handling System Identification	Load Rating (tons)	Safe Loads Paths	Load Handling Procedures	Crane Operator Training	Special Lifting Devices	Lifting Devices Not Special Design	Crane Inspection Test Maintenance	Crane Design
1.	Containment Polar Crane	100/10	C	C	C	C	C	C	C
6.	Fuel Building Crane	125	C	C	C	C	C	C	C
8.	Fuel Transfer Tube Shield Plate Jib Crane	10	C	C	C	--	C	C	C
16.	Auxilary Platform	5	C	C	C	--	C	C	C
17.	Fuel Bundle Jib	0.5	C	C	C	--	C	C	C

C = Applicant action complies with NUREG 0612 Guideline.
NC = Application action does not comly with NUREG 0612 Guideline.
R = Applicant has proposed revision/modifications designed to comply with NUREG 0612 Guidelines.
I = Insufficient information provided by the applicant.

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4. REFERENCES

1. NUREG-0612, Control of Heavy Loads at Nuclear Power Plants, NRC.

2. V. Stello, Jr. (NRC), Letter to all applicants. Subject: Request for Additional Information on Control of Heavy Loads Near Spent Fuel, NRC, 17 May 1978.

3. USNRC, Letter to Illinois Power Co. Subject: NRC Request for Additional Information on Control of Heavy Loads Near Spent Fuel, NRC, 22 December 1980.

4. G. E. Wuller, Illinois Power Co. to Darrell G. Eisenhut, NRC. Subject: December 22, 1980 letter on "Control of Heavy Loads. Docket 50-461, June 22, 1981.

5. G. E. Wuller, Illinois Power Co. to Darrell G. Eisenhut, NRC. Subject: Clinton Power Station Units 1 and 2. Docket 50-461, September 25, 1981.

6. ANSI B30.2-1976, "Overhead and Gantry Cranes."

7. ANSI N14.6-1978, "Standard for Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or more for Nuclear Materials."

8. ANSI B30.9-1971, "Slings".

9. CMAA-70, "Specifications for Electric Overhead Traveling Cranes."

10. J. D. Geier, Illinois Power Co. to A. Schwencer, NRC. Subject: Clinton Power Station Unit 1, Control of Heavy Loads, Docket 50-461. February 10, 1982.

11. G. E. Wuller, Illinois Power Co. to A. Schwencer, NRC. Subject: Clinton Power Station Unit 1, Control of Heavy Loads, Docket 50-461 March 18, 1983.

12. G. E. Wuller, Illinois Power Co. to A. Schwencer, NRC, Subject: Clinton Power Station Unit 1 Control of Heavy Loads, Docket 50-461, July 28, 1983.

13. J. D. Geier, Illinois Power Co. to A. Schwencer, NRC, Subject: Clinton Power Station Unit 1 Control of Heavy Loads, Docket 50-461, December 21, 1983.

14. J. D. Geier, Illinois Power Co. to A. Schwencer NRC, Subject: Clinton Power Station Unit 1 Control of Heavy Loads, Docket 50-461, January 26, 1984.

15. F. A. Spangenberg, Illinois Power Co., to A. Schwencer, NRC. Subject: Clinton Power Station Unit 1 Control of Heavy Loads, Docket 50-461, February 21, 1985.

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APPENDIX G

CONFORMANCE TO REGULATORY GUIDE 1.97
CLINTON POWER STATION, UNIT NO. 1

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ABSTRACT

This EG&G Idaho, Inc., report reviews the Clinton Power Station, Unit No. 1 submittal for Regulatory Guide 1.97 and identifies areas of nonconformance. Exceptions to the guidelines are evaluated and those areas where sufficient basis for acceptability is not provided are identified.

FOREWORD

This report is supplied as part of the "Program for Evaluating Licensee/Applicant Conformance to RG 1.97," being conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of Systems Integration, by EG&G Idaho, Inc., NRC Licensing Support Section.

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CONFORMANCE TO REGULATORY GUIDE 1.97

CLINTON POWER STATION UNIT NO. 1

1. INTRODUCTION

On December 17, 1982, Generic Letter No. 82-33 (Reference 1) was issued by D. G. Eisenhut, Director of the Division of Licensing, Nuclear Reactor Regulation, to all licensees of operating reactors, applicants for operating licenses, and holders of construction permits. This letter included additional clarification regarding Regulatory Guide 1.97, Revision 2 (Reference 2), relating to the requirements for emergency response capability. These requirements have been published as Supplement No. 1 to NUREG-0737, "TMI Action Plan Requirements" (Reference 3).

The Illinois Power Company, applicant for the Clinton Power Station, Unit No. 1, provided a response to the generic letter on September 9, 1983 (Reference 4) and provided additional information on December 11, 1984 (Reference 5). This report provides an evaluation of these submittals.

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2. REVIEW REQUIREMENTS

Section 6.2 of NUREG-0737, Supplement No. 1, sets forth the documentation to be submitted in a report to the NRC describing how the applicant complies with Regulatory Guide 1.97 as applied to emergency response facilities. The submittal should include documentation that provides the following information for each variable shown in the applicable table of Regulatory Guide 1.97:

1. Instrument range
2. Environmental qualification
3. Seismic qualification
4. Quality assurance
5. Redundance and sensor location
6. Power supply
7. Location of display
8. Schedule of installation or upgrade.

The submittal should identify deviations from the guidance in the regulatory guide and provide supporting justification or alternatives.

Subsequent to the issuance of the generic letter, the NRC held regional meetings in February and March 1983, to answer licensee and applicant questions and concerns regarding the NRC policy on this subject. At these meetings, it was noted that the NRC review would only address exceptions taken to Regulatory Guide 1.97. Where licensees or applicants explicitly state that instrument systems conform to the regulatory guide, it was noted that no further staff review would be necessary. Therefore,

this report only addresses exceptions to Regulatory Guide 1.97. The following evaluation is an audit of the applicant's submittals based on the review policy described in the NRC regional meetings.

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3. EVALUATION

The applicant provided responses to Section 6.2 of NRC Generic Letter 82-33 on September 9, 1983 and December 11, 1984. This evaluation is based on the information provided within the applicant's submittals.

3.1 Adherence to Regulatory Guide 1.97

The applicant has committed within his submittal to the requirements of Revision 3 to Regulatory Guide 1.97 (Reference 6). The applicant has identified the post-accident monitoring instrumentation that provides indication of the regulatory guide variables and has identified the deviations from Regulatory Guide 1.97, Revision 3, and has given the supporting justification or alternatives for these deviations. We conclude that the applicant has provided an explicit commitment on conformance to Regulatory Guide 1.97. Exceptions to and deviations from the regulatory guide are noted in Section 3.3.

3.2 Type A Variables

Regulatory Guide 1.97 does not specifically identify Type A variables, i.e., those variables that provide information required to permit the control room operator to take specific manually controlled safety actions. The applicant classifies the following instrumentation as Type A:

1. Primary containment and drywell hydrogen concentration

2. Reactor pressure vessel (RPV) pressure

3. RPV water level

4. Suppression pool bulk average water temperature

5. Suppression pool water level

6. Drywell pressure.

The above variables either meet, or will be modified to meet, the Category 1 requirements consistent with the requirements for Type A variables.

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3.3 Exceptions to Regulatory Guide 1.97

The applicant identified exceptions and deviations from Regulatory Guide 1.97, Revision 3. These are discussed in the following paragraphs.

3.3.1 Neutron Flux

The applicant has identified a deviation from Regulatory Guide 1.97 for the neutron flux measurement. A Category 1 classification is recommended by Regulatory Guide 1.97 for this measurement. The applicant has not provided Category 1 instrumentation, indicating that the neutron monitoring detectors are powered from a Class 1E power source, but the SRM/IRM drive mechanisms and all neutron monitoring displays are powered from station power. The justification provided by the applicant for this deviation is that the Clinton neutron flux monitoring system is of a similar design to those used in most BWRs. A Category 1 neutron flux system that meets all of the criteria of Regulatory Guide 1.97 is an industry development item. The applicant commits to following the industry developmental activities and will upgrade or replace the existing system when a fully qualified and proven neutron flux monitoring system becomes available.

Based on the applicant's present neutron flux instrumentation being state-of-the-art, and the applicant's commitment to upgrade or replace this instrumentation with Category 1 neutron flux instrumentation when qualified instrumentation becomes available, we find the existing instrumentation acceptable on an interim basis.

3.3.2 Reactor Pressure Vessel Water Level

Regulatory Guide 1.97 recommends Category 1 instrumentation for this variable with a range from the bottom of the core support plate to the

lesser of the top of the vessel or the centerline of the main steamline. For the Clinton reactor, the range should be from 197.6 to 636.5 in. above the vessel bottom.

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There are five ranges of reactor vessel water level instrumentation provided in the Clinton design. These ranges and the associated control room indications are: (a) shutdown range; one indicator; (b) upset range; one recorder (this is a dual pen recorder which also displays a narrow range channel); (c) narrow range; three indicators and one recorder (the recorder is shared with the upset range channel as noted above); (d) wide range; one indicator and two recorders; and (e) fuel zone range; one indicator and one recorder. These ranges are shown in FSAR Figure 7.7-1 and are discussed in FSAR Section 7.7.1.1.3.1.2.

The wide range level instrumentation (i.e., the indicator 1B21-R604 and recorders 1B21-R623A and 1B21-R623B, and their associated transmitters 1B21-N081A, B, and C) complies with the Category 1 requirements of Regulatory Guide 1.97. The safety related wide range instrumentation monitors reactor coolant level from approximately 360 to 580 in. with respect to the vessel bottom. This range covers from just above the top of the active fuel (TAF) to near the top of the steam dryer skirt. Thus, the Regulatory Guide 1.97 recommended range for reactor vessel coolant level, except for the upper 56 in. (between the top of the dryer skirt and the centerline of the main steamlines) and the lower 162 in. (between the bottom of the core support plate and the TAF) is covered by the three safety related channels of wide range level instrumentation.

The fuel zone range extends from approximately 208 to 408 in. with respect to the vessel bottom. Thus, there is some overlap (about 48 in.) between the wide range and the fuel zone range. The fuel zone range level instrumentation covers all but approximately the lower 10 in. of the lower portion of Regulatory Guide 1.97 recommended range. The bottom of the active fuel (BAF) is at 208.56 in. Therefore, the Clinton water level instrumentation extends to the BAF at the lower end. The purpose for prescribing the bottom of the core support plate as the lower end of the recommended reactor coolant level range in Regulatory Guide 1.97 is to

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ensure that the operators are provided with a reliable indication of core coverage (and therefore capability for heat removal from the fuel). The level instrumentation at Clinton complies with the intent of Regulatory Guide 1.97 in this regard.

The two redundant channels of fuel zone range level instrumentation (indicator 1B21-R610 and recorder 1B21-R615), however, do not presently comply with the Category 1 requirements of Regulatory Guide 1.97. The applicant has committed to provide redundant qualified fuel zone range level instrumentation. The present fuel zone instrumentation is seismically qualified from a reactor coolant pressure boundary standpoint (i.e., the transmitters and sensing lines will remain intact during and following a seismic event); however, its operability (including control room indication) following a seismic event cannot be assured. In addition, both fuel zone level channels are powered from the same 120 Vac non-Class 1E power source, and are not environmentally qualified. The NRC staff has determined that the degree of seismic qualification provided for the fuel zone range instrumentation is acceptable. The basis for this is that all manual and automatic initiated safety functions occur in the range monitored by the redundant safety related wide range level instrumentation. Based on the applicant's commitment to provide qualified fuel zone range level instrumentation, the use of non-Class 1E power sources for the fuel zone instrumentation is acceptable on an interim basis.

Subsequent to the issuance of Generic Letter 82-33, the NRC issued the environmental qualification rule, 10 CFR 50.49. The rule requires qualification of all equipment in Categories 1 and 2 of Regulatory Guide 1.97, as stated in the statement of considerations accompanying the final rule. The equipment specified must be qualified in accordance with the subsection (g) schedule. The fuel zone range reactor vessel level instrumentation at Clinton would be required to be qualified prior to operation under this schedule since their operating license is not scheduled to be issued until after March 31, 1985. It is concluded that the guidance of Regulatory Guide 1.97 has been superseded by a regulatory requirement. Any exception to the rule is beyond the scope of this review, and therefore, will not be addressed here. The equipment qualification

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review for Clinton is scheduled to be completed by the NRC's Equipment Qualification Branch (EQB) by the end of 1985. Therefore, with the exception of the interim use of a common power supply, we conclude that the fuel zone range level instrumentation is acceptable.

The remaining portion of the recommended reactor coolant range to be discussed is the upper 56 in. between the upper end of the wide range level instrumentation and below the centerline of the main steamline. This portion of the range is not monitored by redundant instruments. The upset range recorder which displays level between approximately 520 in. (this is instrument zero near the bottom of the steam dryer skirt) and 700 in. (below the vessel head flange; about 64 in. above the centerline of the main steamlines) provides the only control room level indication over this range. A shutdown range indicator also covers this range, but can only be used during cold shutdown conditions (the shutdown range channel is calibrated for 0 psig and 120°F). The upset range channel, like the fuel zone range channels, is seismically qualified from a pressure boundary standpoint, but is not environmentally qualified or powered from a Class 1E source.

The upset range instrument reference leg uses the reactor vessel head vent as a penetration. In order to comply with the single failure requirement of Regulatory Guide 1.97, an additional vessel penetration would be needed for a redundant reference column for a second upset range channel. The centerline of the main steamlines is used as the upper end of the Regulatory Guide 1.97 recommended range in order to provide the operator with an indication of whether the reactor coolant has reached, and spilled into, the main steamlines. We conclude that a single upset range channel is sufficient to provide this information. As previously stated, all manual and automatic safety functions are initiated in the range covered by the safety related wide range level instrumentation. The applicant has concluded that the existing reactor coolant level instrumentation meets the intent of the regulatory guide and that only a marginal improvement in plant safety would be achieved by installing a redundant upset range channel. We concur that a second upset range

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instrument channel would not result in a significant increase in plant safety. Based on the above, we conclude that the single non-Class 1E upset range level instrument channel is acceptable.

In conclusion, based on our review of the reactor coolant level instrumentation at Clinton for compliance with Regulatory Guide 1.97, this instrumentation is acceptable with the exception of the redundant fuel zone level channels which are powered from a common supply, and the environmental qualification for the fuel zone range instrumentation that should be addressed in accordance with 10 CFR 50.49. The applicant has committed to provide separate power supplies for these instruments prior to power ascension following the first refueling outage.

3.3.3 Drywell Sump Level
Drywell Drain Sumps Level

Exception has been taken by the applicant to Regulatory Guide 1.97 for the Drywell Sump Level and the Drywell Drain Sumps Level measurements. The applicant's position is that the Drywell Sump Level and Drywell Drain Sumps Level instrumentation should not be implemented as Regulatory Guide 1.97 parameters. In lieu of this instrumentation, the applicant proposes the use of the drywell sump flow and drywell drain sump flow instrumentation. This instrumentation is Category 3 instead of the recommended Category 1. The supporting justification given by the applicant for providing the alternate Category 3 instrumentation is that:

1. the drain sumps level can be a direct indication of breach of the reactor coolant system pressure boundary; however, the indication is ambiguous because of existing water in the sumps during normal operation,

2. the drywell pressure and temperature along with the primary containment area radiation (Category 1 or 2) instrumentation can be used to indicate leakage in the drywell,

3. the drywell sump systems are isolated for an accident condition, and

4. the drywell sump flow and drywell drain sump flow instrumentation will provide continuous indication in the reactor control room and will actuate alarms for excessive flow rates.

We conclude that the alternate instrumentation provided by the applicant will provide appropriate monitoring of the parameters of concern. Based on (a) for small leaks, the alternate instrumentation is not expected to experience harsh environments during operation, (b) for larger breaks, the sumps fill promptly and the sump drain lines isolate due to the increase in drywell pressure, thus negating the drywell sump flow and drywell drain sumps flow instrumentation, (c) the drywell pressure and temperature as well as the primary containment area radiation instrumentation can be used to detect leakage in the drywell, and (d) this instrumentation neither automatically initiates nor alerts the operator to initiate operation of a safety-related system in a post-accident situation, we find the alternate Category 3 instrumentation provided acceptable.

3.3.4 Radioactivity Concentration or Radiation Level in Circulating Primary Coolant

The applicant indicates that the Post-Accident Sampling System (PASS) provides a means of obtaining samples of reactor coolant and primary containment atmosphere and that radiation monitors in the steam jet air ejector and main steamlines provide information on the status of fuel cladding when the plant is not isolated.

Based on the alternate instrumentation provided by the applicant, we conclude that the instrumentation supplied for this variable is adequate, and therefore, acceptable.

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3.3.5 Effluent Radioactivity

Exception has been taken by the applicant to Regulatory Guide 1.97 for this measurement. The guide specifies that the range should be 10^{-6} µCi/cc to 10^{3} µCi/cc. The applicant has instrumentation to monitor effluent radioactivity that is qualified to Category 2 with a low range of 10^{-4} µCi/cc. The applicant states that it is not practical or feasible from the standpoint of functional need to implement Category 2 instrumentation with a lower range of 10^{-6} µCi/cc. The justification is that any indication below 10^{-4} µCi/cc is not applicable to accident scenarios. The applicant has Category 3 instrumentation which provides a lower range capability of 10^{-7} µCi/cc; therefore, the applicant concludes that the Clinton design meets the intent of Regulatory Guide 1.97 for this parameter.

We conclude that the applicant's design using Category 2 instrumentation in combination with Category 3 instrumentation will monitor the ranges of concern and is, therefore, acceptable.

3.3.6 Drywell Atmosphere Temperature

Exception has been taken by the applicant to Regulatory Guide 1.97 for this measurement. Regulatory Guide 1.97 specifies that the range should be 40 to 440°F. The applicant's monitoring instrumentation range is 40 to 350°F. The applicant states that the implemented range exceeds the Design-Basis Accident (DBA) limit of 330°F and to extend the upward bound would introduce greater departures from linearity.

Since the applicant's implemented design range exceeds the plant DBA limit, this deviation from Regulatory Guide 1.97 is acceptable.

3.3.7 Main Steamline Isolation Valves Leakage Control System Pressure

Exception has been taken by the applicant to Regulatory Guide 1.97 for this measurement. Regulatory Guide 1.97 specifies that the range should be

0 to 15 in. of water (narrow range) and 0 to 5 psid (wide range). The applicant's design monitors both the inboard and outboard system pressures and the instrumentation's ranges are 0 to 90 in. of water. The applicant states that system differential pressure can be ascertained from the existing instrumentation. Therefore, the applicant concludes that the Clinton design meets the intent of Regulatory Guide 1.97 for this parameter.

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We conclude that the applicant's design is adequate to monitor the operation of this variable and is acceptable.

3.3.8 Standby Liquid Control System (SLCS) Flow

Exception has been taken by the applicant to Regulatory Guide 1.97 for the SLCS Flow measurement. The applicant states that the SLCS Flow can be adequately monitored by (a) the decrease in the level of the boric acid storage tank, (b) the reactivity change in the reactor as measured by neutron flux and concentration of boron, (c) the SLC pump motor contactor indicating lights (or motor current), or (d) the squib valve continuity indicating lights.

We final that the applicant's alternate means of monitoring SLCS flow adequate and acceptable.

3.3.9 Standby Liquid Control System (SLCS) Storage Tank Level

Exception has been taken by the applicant to Regulatory Guide 1.97 for the SLCS storage tank level measurement. Regulatory Guide 1.97 specifies that the instrumentation be qualified to Category 2 criteria. The applicant states that the SLCS instrumentation is assigned a Category 3 status because the instrumentation will be operating in a mild environment and the current design basis for the SLCS recognizes that the system has a classification less than the reactor protection system and engineered safeguards systems.

The applicant conforms to all the criteria (power supply, range, etc.) identified under Category 2 instrumentation, except for equipment qualification, and the SLCS tank level instrumentation is in a mild environment; therefore, this justification is acceptable.

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3.3.10 Cooling Water Flow to ESF System Components

Regulatory Guide 1.97 specifies a range of 0 to 110 percent design flow for this variable. The applicant states that, for Division 1 and Division 2 cooling water, Clinton will utilize the flow transmitters on the shutdown service water supply to the Division 1 and Division 2 RHR heat exchangers, in conjunction with proper valve alignment, as indication of flow to the Division 1 and Division 2 ESF system components. For Division 3, Clinton will utilize shutdown service water pump discharge pressure, in conjunction with the shutdown service water pump performance curves and proper valve alignment, as indication of flow to the Division 3 ESF system components. The applicant concludes that the Clinton design meets the intent of Regulatory Guide 1.97. We find the instrumentation provided by the applicant for this variable acceptable.

3.3.11 Radiation Exposure Meters

Exception has been taken by the applicant to Regulatory Guide 1.97 for the radiation exposure meter Type E measurement. The applicant's position is that Regulatory Guide 1.97 states it is unlikely that a few fixed-station area monitors could provide sufficiently reliable information to be of use in detecting releases from unmonitored containment release points and that decision to install such a system is left to the licensee.

The applicant has chosen not to implement the measurement. Based on the applicant's full implementation of the Area Radiation Exposure Rate instrumentation, which provides detection of significant releases, and the Containment Area Radiation instrumentation, which provides an identical means of measurement, the applicant's decision to not implement fixed Radiation Exposure meters for detecting releases from unmonitored

containment release points is acceptable. The requirement for variable radiation exposure meters has been removed from Revision 3 of Regulatory Guide 1.97.

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3.3.12 Primary Containment Isolation Valve Position

The applicant states that with the exception of some check, pressure relief and test valves, all containment isolation valves have position indication. Check valves are specifically excluded from this variable by the regulatory guide. The test valves are under administrative control, and their position is known. The effect of the pressure relief valves can be observed on drywell and containment pressure instruments which are Category 1. Therefore, we find that the instrumentation supplied for this variable is acceptable.

3.3.13 Status of Standby Power

The instrumentation for this variable meets the requirements of Regulatory Guide 1.97 except for the Division 3 DC bus current. This is monitored outside of the control room, in an accessable area, with control room alarms. We find this instrumentation acceptable for monitoring this bus current.

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4. CONCLUSIONS

Based on our review, we find that the applicant either conforms to or is justified in deviating from Regulatory Guide 1.97, with the following exception:

1. Reactor Pressure Vessel Water Level--the environmental qualification for the fuel zone range instrumenation should be addressed in accordance with 10 CFR 50.49 (Section 3.3.2).

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5. REFERENCES

1. NRC letter, D. G. Eisenhut, to all licensees of operating reactors, applicants for operating licenses, and holders of construction permits, "Supplement No. 1 to NUREG-0737--Requirements for Emergency Response Capability (Generic Letter No. 82-33)," December 17, 1982.

2. Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, Regulatory Guide 1.97, Revision 2, U.S. Nuclear Regulatory Commission (NRC), Office of Standards Development, December 1980.

3. Clarification of TMI Action Plan Requirements, Requirements for Emergency Response Capability, NUREG-0737 Supplement No. 1, NRC, Office of Nuclear Reactor Regulation, January 1983.

4. Illinois Power Company letter to NRC, P. M. Nelson to A. Schwencer, Chief, Division of Licensing, "Clinton Power Station, Unit 1--Compliance Report--Regulatory Guide 1.97," September 9, 1983.

5. Illinois Power Company letter to NRC, F. A. Spangenberg to A. Schwencer, Chief, Division of Licensing, "Clinton Power Station Unit 1 Response to Conformance Report--Regulatory Guide 1.97," December 11, 1984.

6. Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, Regulatory Guide 1.97, Revision 3, U.S. Nuclear Regulatory Commission (NRC), Office of Nuclear Regulatory Research, May 1983.