DUANE ARNOLD ENERGY CENTER

SAFETY EVALUATION FOR AMENDMENT NO. 243

EXTENDED POWER UPRATE

DUANE ARNOLD ENERGY CENTER
SAFETY EVALUATION FOR EXTENDED POWER UPRATE

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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 243 TO FACILITY OPERATING LICENSE NO. DPR-49

NUCLEAR MANAGEMENT COMPANY, LLC

DUANE ARNOLD ENERGY CENTER

DOCKET NO. 50-331

1.0 OVERVIEW

1.1 Introduction

By application dated November 16, 2000[1], as supplemented April 16 (two letters[2]) and 17; May 8 (two letters), 10, 11 (two letters), 22, and 29; June 5, 11, 18, 21, and 28; July 11, 19, and 25; August 1, 10, 16, and 21; September 24; and October 17, 2001, Nuclear Management Company, LLC (NMC or the licensee), requested an amendment to Facility Operating License DPR-49 and the Technical Specifications (TS) for the Duane Arnold Energy Center (DAEC). The proposed amendment would allow an increase of the authorized operating power level from 1658 megawatts thermal (MWt) to 1912 MWt at DAEC. The change represents an increase of 15.3 percent above the current rated thermal power (CRTP) and is considered an extended power uprate (EPU).

1.2 Background

The original rated thermal power (ORTP) for DAEC was 1593 MWt. By DAEC License Amendment No. 115, dated March 27, 1985, the U.S. Nuclear Regulatory Commission (NRC) authorized an increase in power level from the ORTP to 1658 MWt. The present proposal would increase the ORTP level by 20 percent. Due to pending balance-of-plant (BOP) modifications, the licensee proposes to implement the EPU in phases. In Phase I[3], the licensee plans to increase the operating power from 1658 MWt to 1790 MWt (a 12.4-percent increase from the ORTP, or a 7.9-percent increase from the CRTP). In Phase II[4], the licensee intends to extend the rated thermal power (RTP) from 1790 MWt to 1912 MWt (a 20-percent increase from the ORTP, or a 15.3-percent increase from the CRTP).

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[1]The November 16, 2000, application is referred to hereinafter as "the EPU application."

[2]To distinguish between two letters with the same date, reference to either letter will be followed by its ADAMS Accession Number.

[3]Hereinafter referred to as EPU-Phase I.

[4]Hereinafter referred to as EPU-Phase II.

The DAEC safety analysis of the proposed EPU was provided in General Electric (GE) Nuclear Energy Licensing Topical Report (LTR) “Safety Analysis Report for Duane Arnold Energy Center Extended Power Uprate," dated November 2000 (hereinafter referred to as the Safety Analysis Report) (Reference 1). The licensee's submittal contained plant-specific information consistent with the scope and content of the NRC-approved GE LTR “Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," dated February 1999 (hereinafter referred to as ELTR1) (Reference 2). For some items, the licensee referenced the analyses and evaluations in the NRC-approved GE LTR "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," dated February 2000 (hereinafter referred to as ELTR2) (Reference 3). The licensee stated that the generic system and equipment performance and the generic transient and accident analyses presented in ELTR1 and ELTR2 are applicable to the proposed DAEC EPU.

ELTR1 and ELTR2 provide the bases for the assessment of a licensee’s request to operate at an uprated power level of up to 20 percent above the plant’s ORTP.

As part of the EPU review process, the NRC staff visited the GE facility in Wilmington, North Carolina, from March 26 to 29, 2001, to audit both GE’s adherence to the NRC-approved analytical methods in performing the safety analyses, and the DAEC safety analyses that support the proposed EPU. The audit findings and their resolutions are discussed in Section 2.6 of this safety evaluation (SE).

1.3 Approach

To accomplish the EPU, the licensee proposed to implement the maximum extended load limit line analysis (MELLLA) rod line, increasing the plant’s operating domain. The licensee plans to (1) generate higher steam flow though a more uniform (flattened) core power distribution, (2) increase the corresponding feedwater flow to match the higher steam flow, (3) operate the reactor along the higher MELLLA rod line and extend the MELLLA line to the EPU RTP, and (4) supply higher steam flow to the turbine generator through hardware modifications without a corresponding increase in the operating dome pressure and a minor increase in the maximum recirculation system flow. The increase in the maximum recirculation flow would be necessary to accommodate the higher core flow resistance. The licensee would achieve the proposed EPU by (1) revising the loading pattern of the core, (2) using larger batch sizes, and (3) introducing GE-14 fuel for EPU operation.

1.4 Evaluation of Systems, Structures, and Components

During its review of the EPU application, the NRC staff used applicable rules, regulatory guides, Standard Review Plan (SRP) sections (Reference 12), and NRC staff positions on the topics being evaluated. Additionally, the NRC staff evaluated the EPU application for conformance with the generic Boiling-Water Reactor (BWR) EPU Program as defined in ELTR1 and ELTR2. The NRC staff also used the 1998 SE for the Monticello Nuclear Generating Plant EPU as a guide for scope and depth of review. Detailed discussions of individual review topics follow.

2.0 REACTOR CORE AND FUEL PERFORMANCE

The core thermal-hydraulic (T/H) design and fuel performance characteristics are evaluated for each fuel cycle. The following sections address the effect of the proposed EPU on fuel design performance, thermal limits, power/flow map, and reactor stability.

2.1 Fuel Design and Operation

Fuel bundles are designed to ensure that (a) the fuel bundles are not damaged during normal steady-state operation and anticipated operational occurrences (AOOs), (b) any damage to the fuel bundles will not prevent control rod insertion when required, (c) the number of fuel rod failures is not underestimated during accidents, and (d) the coolability of the core is always maintained. The use by each fuel vendor of NRC-approved fuel design acceptance criteria and analysis methodologies assures that the fuel bundles perform in a manner that is consistent with the objectives of Sections 4.2 and 4.3 of the SRP and the applicable general design criteria (GDC) of 10 CFR Part 50, Appendix A. The fuel vendors perform thermal-mechanical, T/H, and neutronic analyses to ensure that the fuel system design can meet the fuel design limits during steady-state, AOO, and accident conditions.

The licensee stated that the 20-percent EPU would increase the average power density proportional to the power increase; but the increase in the power density would be within the power density of an existing GE-supplied BWR. The licensee would flatten the power distribution while limiting the absolute power in individual fuel bundles to allowable values (AVs). The increased operating power would affect operating flexibility and reactivity characteristics. Therefore, the licensee would achieve the proposed EPU by revising the loading pattern of the core, using larger batch sizes, and introducing GE-14 fuel for EPU operation.

The licensee stated that for operation at the ORTP or at the proposed EPU level, the fuel and core design limits will continue to be met. The licensee also stated that it would use NRC-approved core design methods to analyze the core performance conditions at the proposed EPU operation.

The licensee performed the EPU fuel cycle design calculations to demonstrate the feasibility of operating DAEC at the higher thermal power and rod line while maintaining the fuel design limits. Limits on the fuel rod linear heat generation rates (LHGRs) will ensure compliance with the fuel mechanical design bases. The T/H design and operating limits will ensure an acceptably low probability of boiling transition-induced fuel cladding failure in the core in the event of an AOO. The licensee stated that the EPU fuel cycle design calculations demonstrated that these fuel design limits would be maintained and the subsequent reload core designs at the proposed EPU power level would take into account these limits to ensure acceptable margins between the licensing limits and the corresponding operating values. In addition, the currently approved fuel design burnup limits will not be exceeded.

2.2 Thermal Limits Assessment

GDC 10 of 10 CFR Part 50, Appendix A, requires, in part, that the reactor core and the associated control and protection systems be designed with appropriate margins to ensure that the specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operation, including AOOs. Operating limits are established to assure that regulatory and safety limits are not exceeded for a range of postulated events (transients and accidents).

The effects of the higher MELLLA rod line and power on the thermal limits are discussed below.

2.2.1 Minimum Critical Power Ratio Operating Limit

The safety limit minimum critical power ratio (SLMCPR) protects 99.9 percent of the fuel rods from boiling transition during steady-state operation. The operating limit minimum critical power ratio (OLMCPR) assures that the SLMCPR would not be exceeded as result of an AOO.

Table 9-1 of the Safety Analysis Report provides the relative SLMCPR values based on the ORTP, the cycle-specific analysis for the CRTP, and the representative equilibrium GE-14 core at the proposed EPU power level of 1912 MWt. The table shows a slightly lower EPU SLMCPR than the SLMCPR for the current cycle. The SLMCPR is established, or confirmed every reload, based on the actual core configuration and operating conditions.

The licensee also analyzed the limiting transients for operation at the proposed EPU operating domain based on an equilibrium GE-14 core. Table 9.2 of the Safety Analysis Report provides the OLMCPR for the limiting transients. The licensee stated that the OLMCPR is not expected to change significantly from the values shown in Table 3-1 of ELTR1 and Figure 5-3 of ELTR2.

Since the DAEC EPU core would introduce GE-14 fuel, the NRC staff reviewed the experimental database used for the development of the GEXL14 critical power ratio (CPR) correlation for the GE-14 (10x10) fuel lattice design during the EPU audit. As set forth below, the resolution of the issues identified in the NRC staff’s audit ensures that the CPR correlations used to determine the minimum critical power ratio (MCPR) are benchmarked properly. The summary of the NRC staff’s findings and GE’s corrective actions to resolve the matters identified in the findings are discussed in Section 2.7 of this SE.

2.2.2 Maximum Linear Heat-Generation Rate and Maximum Average Planar Operating Limits

The maximum average planar linear heat-generation rate (MAPLHGR) operating limit is based on the most limiting design-basis accident (DBA) loss-of-coolant accident (LOCA) and ensures compliance with the emergency core cooling system (ECCS) acceptance criteria in 10 CFR 50.46. For every new fuel type, licensees perform LOCA analyses to confirm compliance with the LOCA acceptance criteria; and for every reload, licensees confirm that the MAPLHGR operating limit for each reload fuel bundle design remains applicable.

The licensee performed the LOCA evaluation for all of the DAEC resident fuel, including the limiting GE-14 fuel, assuming operation at the proposed EPU power level. The licensee revised the single-loop operation (SLO) MAPLHGR multipliers to account for SLO in the higher MELLLA region. The SLO and two-loop operation (TLO) LOCA analyses are required to account for the increased thermal power. The licensee stated that the maximum LHGR limits are fuel dependent and apply regardless of the power level, but added that the change to the advanced core methods would require the MAPLHGR and maximum LHGR limits to be monitored independently. The licensee stated that separate MAPLHGRs and maximum LHGR limits would be maintained for each GE fuel type, as described in Section 5.7.2.2 of ELTR2.

The licensee evaluated the plant's response to operation at the higher MELLLA rod line and power level based on a GE-14 equilibrium core. Although the EPU-Phase I reload analysis may not be based on the final EPU conditions, the EPU-Phase II reload analysis would be based on the MELLLA/EPU operating conditions and cycle-specific core design. The flatter power distribution may cause more fuel bundles to operate at or near the boiling transition and this could result in a slight increase in the SLMCPR. However, any SLMCPR change would constitute a TS change and the licensee would be required to submit an application for such a change for prior NRC review and approval. In addition, the audit team reviewed the GE-14 CPR correlation database used to develop the CPR correlation for the GE-14 fuel, which affects the accuracy of the SLMCPR calculations. The licensee did analyze the limiting transients based on a GE-14 equilibrium core and determined the proposed EPU OLMCPR.

In general, the licensee must ensure plant operation is in compliance with the cycle-specific thermal limits (SLMCPR, OLMCPR, MAPLHGR, and maximum LHGR) and the licensee will specify the thermal limits in the cycle-specific core operating limits reports as required by Section 5 of DAEC's TS. In addition, while EPU operation may result in a small change in fuel burnup, the licensee cannot exceed the NRC-approved burnup limits. In accordance with Section 5 of the TS, cycle-specific analyses are performed using NRC reviewed and approved methodologies. Therefore, the NRC staff finds that the licensee has appropriately considered the potential effects of the MELLLA/EPU operation on the fuel design limits, and the current thermal limits assessments show that DAEC can operate within the fuel design limits during steady-state operation, AOOs, and accident conditions.

2.3 Reactivity Characteristics

All minimum shutdown margin requirements that apply to cold (212 °F or less) conditions will be maintained without change. Operation at higher power could reduce the excess reactivity during the cycle. The loss of reactivity is not expected to significantly degrade the ability to manage the power distribution through the cycle to achieve the proposed EPU. The lower reactivity will result in an earlier all-rods-out condition. The TS requirements for shutdown margin will continue to be met. Therefore, the NRC staff concludes that the reactivity characteristics are acceptable for the proposed EPU.

2.3.1 Power/Flow Operating Map

To achieve the 20-percent increase from the ORTP, the licensee proposes to operate at the MELLLA rod line. The EPU operating domain would be defined by (a) the MELLLA upper boundary line extended up to the EPU RTP, (b) the maximum EPU power level corresponding to 120 percent of the ORTP, and (c) the existing 100-percent core flow line continued up to the EPU RTP. Therefore, the previously analyzed core flow range would be extended so that the RTP will correspond to the proposed EPU power level and the maximum core flow will not be increased. The EPU application contained the proposed EPU operating domain power/flow map.

The MELLLA upper boundary line replaces the extended load limit line analysis (ELLLA) upper boundary for SLO. The licensee stated that the maximum power state point for the SLO corresponding to the MELLLA upper boundary and recirculation pump speed of 102.5 percent would be to 66.8 percent of the pre-EPU RTP or 1277 MWt. The associated SLO core flow would be 53-percent core flow (25.96 Mlbm/hr). The licensee would perform the EPU SLO safety analysis based on the MELLLA state point on the SLO. The licensee stated that the proposed EPU operation at the higher rod line would also require rescaling of the associated protection system setpoints, which are discussed in Section 5.0 of this SE.

Since the licensee would implement the MELLLA rod line in conjunction with the proposed EPU, the NRC staff requested the licensee to provide additional information regarding the safety analyses that were performed to demonstrate that DAEC can operate safely at the higher MELLLA rod line for offrated and rated conditions. In its August 21, 2001, supplemental letter responding to the NRC staff's request for additional information (RAI), the licensee explained that MELLLA implementation is an integral part of the EPU implementation. The licensee's Safety Analysis Report describes the details of the analyses that were performed in support of the proposed EPU, and the licensee included in its August 21 response a list of those analyses. Based on the licensee's confirmation that the EPU safety analyses did take into account operation at the higher MELLLA rod line at offrated conditions, and the NRC staff's evaluation of the licensee's proposed operating domain, the NRC staff finds that the proposed operating domain is acceptable.

2.4 Stability

The licensee has implemented a long-term stability solution at DAEC (the "Option I-D" solution) that takes credit for unique plant characteristics that make regional mode oscillation unlikely, and provides that the existing plant instrumentation demonstrate sufficient capability for automatic detect and suppress functions for core-wide mode oscillation. This option is only applicable to plants that can demonstrate that core-wide mode instability predominates and regional mode instability is not expected to occur. Small core sizes (such as DAEC's) produce higher eigenvalue separation between oscillation modes, and tighter core inlet orifice coefficients make regional mode oscillation unlikely.

However, to qualify as an Option I-D plant, licensees are required to demonstrate analytically that regional mode oscillation is less likely to occur. The licensee has demonstrated by analysis using the approved ODYSY computer stability code that the predominant mode of oscillation for the DAEC core will be core-wide, and that regional-mode oscillations are highly unlikely. The long-term stability solutions to detect and suppress power oscillations in BWRs are discussed in GE LTR "BWR Owners' Group Stability Solutions Licensing Basis Methodology and Reload Application," dated May 1995 (Reference 7). Since the Option I-D solution is geared to respond to core-wide oscillation, the flow-biased average power range monitor (APRM) flow-biased scram is used for maintaining adequate SLMCPR protection instead of the OPRM scram available in Option III. The licensee stated that for the proposed EPU operating condition, the flow-biased APRM flux trip would provide adequate SLMCPR protection, and for each fuel cycle, the SLMCPR protection would be demonstrated.

The Option I-D long-term solution also includes an administratively controlled exclusion region. The licensee uses the ODYSY code to establish the exclusion region, which is defined by a curved line that provides a constant margin to the occurrence of anticipated reactor instability.

Decay ratios are calculated based on ODYSY stability criteria. The licensee stated that for Option I-D, the exclusion region boundary delineates those areas of the operating domain where the core decay ratio is 0.8 or greater. ODYSY calculates a best-estimate core and channel decay ratio and adds 0.15 to the core decay ratio for added conservatism. In addition, the decay ratios are calculated for state points on the power/flow map to determine the intersection of the exclusion region boundary with the natural recirculation line and the MELLLA boundary. GE LTR "ODYSY Application for Stability Licensing Calculations," dated July 2001 (Reference 13), which includes the NRC staff's SE, has been reviewed and accepted by the NRC staff.

The licensee stated that the exclusion region is core- and fuel-dependent and it is also affected by the rated core power and the corresponding operating conditions. Therefore, the exclusion region was calculated for the proposed EPU/fuel cycle conditions. The applicability of the current exclusion region would be evaluated for each subsequent fuel cycle.

The NRC staff assessed the logic information presented and has audited the licensee's implementation of the Option I-D solution for pre-EPU and EPU operations. A discussion of the audit's findings is included in Section 2.6 of this SE.

2.5 Reactivity Control

2.5.1 Control Rod Drives and Control Rod Drive Hydraulic System

The control rod drive (CRD) system controls gross changes in core reactivity by positioning neutron-absorbing control rods within the reactor. The CRD system is also required to terminate the fission process by rapidly inserting withdrawn control rods into the core. The scram, rod insertion, and withdrawal functions of the CRD system depend on the operating reactor pressure and the pressure difference between the CRD system hydraulic control unit (HCU) pressure and the reactor vessel bottom head pressure.

The licensee stated that since there is no increase in the reactor operating pressure, the CRD scram performance and compliance with the current TS scram requirements are not affected by operation at the proposed EPU power level. The CRD system was generically evaluated in Section 5.6.3 and J.2.3.3 of ELTR1 and Section 4.4 of Supplement 1 to ELTR2. The generic evaluation concluded that the CRD systems for BWR/2-6 plants are acceptable for EPU as high as 20 percent above the ORTP; no additional plant-specific calculations are required beyond confirmatory evaluation. The licensee performed confirmatory evaluations of the performance of the CRD system at EPU conditions based on a reactor dome pressure of 1025 pounds per square inch gauge (psig) with an additional 35 pounds per square inch - difference (psid) added to account for the static head of water in the vessel.

The licensee stated that for CRD insertion and withdrawals, the nominal differential pressure between the HCU and the vessel bottom head is 260 psid. The licensee evaluated the CRD pump capability and determined that the CRD pumps have sufficient capacity to provide the required pressure difference for operation at the proposed EPU conditions. The licensee also evaluated the required CRD cooling and drive flows for EPU operation and stated that the cooling and drive flows are assured by the automatic operation of the CRD system flow control valve, which would compensate for any changes in the reactor pressure. The licensee determined that the operation of DAEC's CRD system is consistent with the generic evaluations in ELTR1 and ELTR2, and that the CRD system is, therefore, capable of performing its design functions of rapid rod insertion (scram) and rod positioning (insertion/withdrawal).

In the 1985 EPU, the licensee increased the reactor dome pressure. However, this increase was not significant because the reactor pressure assists the scram function. During scrams at low reactor pressure, an accumulator provides the pressure for the scram. However, at higher power, such as during isolation events, the accumulator pressure may not be sufficient due to system losses. The CRD system is designed to use the reactor pressure to assist the scram for high-reactor-pressure scrams. In addition, scram time testing verifies the scram time for individual control rods. Therefore, the higher pressures that might occur as a result of the proposed EPU operation during isolation events would not have a significant effect on the scram function of the CRD system. The licensee has also evaluated the performance of the CRD insert, withdraw, cooling, and drive functions. For the reasons set forth above, and consistent with previous NRC staff evaluations, the NRC staff agrees with the licensee’s determination that the CRD system will perform in an acceptable fashion at the proposed EPU conditions.

2.5.2 Control Rod Drive System Integrity

The licensee indicated that the control rod drive mechanisms (CRDMs) have been designed in accordance with the code of record, the American Society of Mechanical Engineers' (ASME's) *Boiler and Pressure Vessel Code* (ASME Code), Section III, 1968 edition with addenda up to and including winter 1968. The components of the CRDMs form part of the reactor coolant pressure boundary (RCPB) and have been designed for a bottom head pressure of 1250 psig. This is higher than the analytical limit (AL) of 1100.9 psig for the reactor bottom head pressure.

The licensee’s evaluation indicated that the maximum calculated stress for the CRDMs is less than the allowable stress limit. The analysis for cyclic operation of the CRDMs resulted in a maximum cumulative usage factor (CUF) of 0.15 for the limiting CRD main flange at the proposed EPU conditions. This is less than the code-allowable CUF limit of 1.0.

On the basis of the margins described above, and consistent with previous NRC staff assessments, the NRC staff concurs with the licensee’s conclusion that the CRDM will continue to meet their design basis and performance requirements at the proposed EPU conditions.

2.6 <u>DAEC EPU ONSITE REVIEW</u>

2.6.1 Scope of Audit

During the week of March 26, 2001, four members of the NRC staff visited the GE Global Nuclear Fuel (GNF) engineering and manufacturing facility in Wilmington, North Carolina. The purpose of the visit was to perform an onsite review of the safety analyses and system and component performance evaluations used to support the proposed EPU. The areas covered by the review included:

1. Fuel performance of the 10x10 fuel lattice design (GE-12 and GE-14) fuel used for DAEC, including available post-irradiation examination (PIE) data;

2. Review of the GEXL10 and GEXL14 correlation database for GE-12 and GE-14 fuels;

3. Verification that the experimental database range covered DAEC's expected operating ranges or state points (i.e., pressures, mass fluxes, inlet subcooling) for all three axial profiles;

4. Design record files for pre-EPU and EPU DAEC LOCA analysis;

5. Review of the GE-14 fuel design compliance with the NRC-approved methodology (References 16, 17, and 18); and

6. Review of the applicability and implementation of the Option I-D long-term stability solution for the proposed EPU. The NRC staff reviewed:

   (a) the T/H compatibility of the DAEC resident fuel types in the low-flow/high power conditions with off-normal void distribution;

   (b) the applicability of DAEC Option I-D stability solution to DAEC's transition mixed core;

   (c) the application of ODYSY code in implementing the long-term stability solution - Option I-D - at DAEC.

2.6.2 Findings and Resolution

The NRC staff reviewed GE's experimental database used to develop the GEXL14 CPR correlation for the GE-14 (10x10) fuel lattice design, the Option I-D long-term instability solution, and the LOCA analysis. EPU onsite audit findings and the resolutions to identified open items are discussed below:

(1) In its CPR correlation methodology, the NRC staff found that GNF was using the COBRA G computer code to generate data instead of using experimental data obtained from their critical heat flux test facility in San Jose, CA. The use of artificial data instead of raw data affects the validity of the statistical results obtained from this methodology. The statistical results are important because they are used in the calculation of the SLMCPR for all BWRs that use GE-14 fuel. The uncertainty associated with the data points affects the uncertainty of the safety limit calculations, as well as the degree of conservatism that is used to establish the reactor operating limits.

    The NRC staff also believes that it is very difficult to predict critical power phenomena in the upper portion of the core because of the active multiple phase transitions and the part-length rods present in both the GE-12 and GE-14 fuels. This code has never been reviewed by the NRC staff for this purpose. GNF personnel indicated that COBRA G is a modified version of an original national lab version of COBRA. GE stated that COBRA G uses first principle models to predict boiling transition and the details of the flow field. To the NRC staff's knowledge, this capability is currently beyond the state of the art. Therefore, the NRC staff asked the licensee to provide a technical explanation as to how the COBRA G code predicts, from "first principles," the boiling transition phenomena in the upper portion of GE-12 and GE-14 fuels.

In its July 19, 2001, response to the NRC staff's June 4, 2001, RAI, the licensee stated that GNF agreed to remove the COBRA G-generated data from the development of the GEXL correlation for the GE-12 and GE-14 fuel designs. By letter dated September 25, 2001, GE submitted LTR "GEXL14 Correlation for GE14 Fuel," Revision 2, dated September 2001 (Reference 22) and LTR "GEXL10 Correlation for GE12 Fuel," Revision 2, dated September 2001 (Reference 21), for the NRC staff's review and approval. GNF has re-correlated the 10x10 fuel design (GE-12 and GE-14) based on experimental data only and included additional GE-14 fuel design testing. The NRC staff is currently reviewing the re-correlation and the additional test data conducted by GNF. In the interim, DAEC (and other similarly situated licensees) can continue to use the revised correlation, as described in and permitted by the approved GESTAR methodology.

(2) The NRC staff was concerned that GE had not conducted sufficient testing of the new GE-14 fuel (and GE-12 fuel) to adequately test the respective CPR correlations. The NRC staff discovered that the experimental data collected to develop and validate the GEXL10 or the GEXL14 correlations did not include upskew or downskew power shapes. There are similarities between the GE-11 (9x9) fuel lattice design and the GE-12/GE-14 (10x10) fuel lattice designs, namely the presence of part-length rods. However, the NRC staff believes that there are also significant differences, such as the locations of the part-length rods relative to the water holes in the GE-12/GE-14 fuel designs. In the June 4, 2001, RAI, the NRC staff asked the licensee to provide upskew or downskew data that has been collected to validate the GEXL10 or the GEXL14 correlations used in the DAEC analyses.

In its response, the licensee stated that the GEXL10 correlation for GE-12 fuel was based on the full-scale ATLAS test points, all of which were cosine power shape. The licensee also discussed the design similarities between the GE-11 and GE-12 fuel lattice designs that affect the CPR performance of the two fuel designs and concluded that the GEXL10 correlation can be considered to be based upon test data points for both the GE-11 and GE-12 designs. The NRC staff evaluated the licensee's justification that the similarity between the GE-11 and GE-12 fuel lattice designs was sufficient to accept the GE-11 database as representative of the GE-12 fuel in the development of the GEXL10 correlations. Based on the above, the NRC staff has accepted GE's basis for the development of the GEXL10 correlation in the upskew and downskew power profiles.

The licensee also stated that the GEXL14 correlation for GE-14 fuel was based on full-scale ATLAS test points with only a cosine axial power shape. Since the original GE-14 testing was performed, GE has performed additional testing in the ATLAS facility for the GE-14 fuel design for both cosine and inlet-peaked power shape. Additional test points were obtained for a cosine axial power shape and for an inlet-peaked power shape. The NRC staff is currently reviewing the re-correlation and the additional test data conducted by GNF. In the interim, DAEC (and other similarly situated licensees) can continue to use the revised correlation, as described in and permitted by the approved GESTAR methodology.

(3) The NRC staff, in a GE-11 compliance audit (Team Audit of GE-11 Fuel Design Compliance with Amendment 22 of NRC-approved GE LTR "General Electric Standard Application for Reactor Fuel," dated June 2000 (Reference 5), asked GE to establish a procedure for implementing Amendment 22 criteria for developing new correlations. GNF implemented the procedure as recommended in GNF Technical Design Procedure (TDP)-0117, Revision 2, page 8. However, GNF did not appear to have followed the procedure in the

development of the GEXL10 and GEXL14 correlation with respect to criteria 3 and 4 of the procedure because there was no raw experimental data for upskew and downskew power profiles for the GE-14 fuel design. In the June 4, 2001, RAI, the NRC staff asked the licensee to provide a justification for not meeting the Amendment 22 process for these criteria. This issue applies to plants with GE-12 and GE-14 fuels.

The licensee stated that TDP-0117, Revision 2, Sections 5.3 and 5.4, describe the test matrix for the ATLAS testing in the development of GEXL correlations. This process was used as described in Reference 14, which also provides the process that was used to develop the uncertainties for GEXL14 using the COBRA G code to simulate the upskew and downskew power shape effects. GNF added that the GEXL correlation would be reevaluated based on test data alone, including the data characterizing the trend of the correlation with axial power shape. GNF also opened a Corrective Action Request (CAR) to track the proposed resolution of the GEXL correlation issue and stated that implementation of these corrective actions would ensure that the GEXL correlations for the 10x10 fuel design would be in full compliance with the Amendment 22 process. Since GNF has performed additional testing and re-correlated the 10x10 fuel design lattice in accordance with Amendment 22, the NRC staff is satisfied that GE and the licensee have conformed with previously approved methods and NRC staff evaluations.

(4) LOCA analyses of off-rated conditions (specifically SLO) assume that the statistical adders developed for SAFER at rated conditions will apply. The NRC staff asked GE to provide justification for the use of these adders for SLO. GE responded that the SLO peak cladding temperature (PCT) is first-peak limited and the two-loop PCT is second-peak limited. There is less uncertainty in the first peak PCT calculation than the second peak PCT calculation. The first peak PCT is governed primarily by the steady-state stored energy in the fuel rod and the time-of-boiling transition. The phenomena governing the second peak PCT are more complex. These uncertainties are reflected in the upper bound adder terms used for the first- and second-peak upper bound PCT calculations. Since the uncertainty is less for the first-peak PCT, the first-peak upper bound adders are smaller. Because the early boiling transition occurs throughout the bundle for SLO conditions, this reduces the uncertainty associated with the first-peak PCT calculation for SLO. Therefore, the assumption that the upper bound adder terms used in the two-loop calculation are bounding for SLO is valid and the two-loop upper bound PCT is bounding for SLO conditions. As described above, the NRC staff found this explanation logical, defensible, and thus, acceptable.

(5) In reviewing the applicability of the long-term solution, Option I-D, the NRC staff questioned whether the generic DIVOM curve for core-wide mode and regional mode stabilities was applicable for EPU operation. "DIVOM" stands for Delta critical power ratio over initial minimum critical power ratio (IMCPR) Versus Oscillation Magnitude. The DIVOM curves are normalized curves of CPR performance versus the hot bundle oscillation magnitude. Two generic curves are used to specify core-wide oscillation and regional mode oscillation. The regional curve is used to determine the Option III trip setpoints against regional mode instability. The core-wide curve is used for Option I-D plants to confirm that the flow-biased APRM trip setpoint provides adequate SLMCPR in the event of core-wide instability.

The NRC staff reviewed the EPU application and Cycle 18 design record files to determine the applicability of the generic curves for EPU operation. GE provided the NRC staff with a February 19, 2001, "Interim Corrective Action Request," which indicated that the for a 20-percent EPU, the generic DIVOM curve may not be bounding for regional mode oscillations. The interim corrective action report stated that the generic DIVOM curves are acceptable for a 5-percent power uprate. On June 29, 2001, GE issued a 10 CFR Part 21 report on the potential nonconservatisms and provided a figure of merit which confirmed the validity of the DIVOM curves for DAEC. This response resolved the NRC staff's questions regarding the applicability of the generic DIVOM curves for EPU operations (see Section 2.4 of this SE).

2.6.3 Conclusion - DAEC Audit

The NRC staff performed an audit of the above-mentioned issues related to the proposed EPU. The audit identified a number of areas of concern related to the application of the approved analysis methodologies, but in all cases, the licensee and GNF successfully responded to the issues with timely and appropriate corrective actions, or explanations, which have resolved the NRC staff's concerns, as relevant to the requested amendment. Therefore, the NRC staff finds that these audit issues are closed.

3.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

3.1 Nuclear System Pressure Relief

The safety/relief valves (SRVs) and safety valves (SVs) provide overpressure protection for the nuclear steam supply system (NSSS), preventing failure of the RCPB. The SRV setpoints are established to provide the overpressure protection function while ensuring that there are adequate pressure differences (simmer margin) between the reactor operating pressure and the SRV actuation setpoints. The SRV setpoints are also selected to be high enough to prevent unnecessary SRV actuations during normal plant maneuvers.

Table 5-1 of the Safety Analysis Report listed the ALs of the SRVs and SVs, using an upper tolerance limit of 3 percent. DAEC has six SRVs and two SVs, with one SRV set to actuate at 1110 psig, a second SRV set to actuate at 1120 psig, two SRVs set to actuate at 1130 psig, and two SRVs set to actuate at 1140 psig. The two SVs are set to actuate at 1240 psig, 10 psig below the vessel design pressure of 1250 psig.

The licensee evaluated the capabilities of the SRVs and SVs to provide overpressure protection based on the existing TS setpoints and tolerances for operation at the proposed EPU power level. The licensee determined that sufficient capability exists for overpressure protection. The licensee also stated that the EPU evaluation is consistent with the generic evaluations and discussions provided in Section 5.6.8 of ELTR1 and Section 4.6 of ELTR2. Because the maximum operating dome pressure would not change for the proposed EPU operation, the licensee would not change the SRV and SV setpoints.

Since the licensee performed the limiting ASME Code overpressure analyses (discussed in Section 3.2 below) based on 102 percent of the proposed EPU power level, and the current SRV/SV setpoints and upper tolerance limits would not change, the NRC staff accepts the licensee's assessment that the SRVs will have sufficient capacity to handle the increased steam flow associated with operation at the proposed EPU power level. The ASME Code overpressure situation is evaluated during each cycle-specific reload analysis. Therefore, the capabilities of the SRVs and SVs to ensure ASME Code overpressure protection will be confirmed in subsequent reload analyses.

3.2 ASME Code Overpressure Protection

The ASME Code allowable peak pressure for the reactor vessel and the RCPB is 1375 psig (110 percent of the design pressure of 1250 psig). This is also the acceptance limit for pressurization events. Section 5.5.1.4 and Appendix E of ELTR1 evaluated the ASME overpressure analysis in support of a 20-percent power increase, stating that the limiting pressurization transient events are (1) the main steam isolation valve closure (MSIVC) with failure of the valve position scram and (2) the turbine trip with bypass failure (TTNBP). The licensee analyzed both events based on an initial dome pressure of 1055 psia, 102 percent of the EPU RTP, and a representative equilibrium core. The licensee determined that MSIVC with valve position scram failure was more limiting than the TTNBP, with a 40 psid higher dome pressure. The MSIVC event resulted in a maximum reactor dome pressure of 1286 psig, which corresponds to vessel bottom head pressure of 1313 psig. Therefore, the peak calculated dome pressure (1286 psig) remains below the TS safety limit of 1335 psig and the peak reactor pressure vessel (RPV) pressure (1313 psig) remains within the ASME Code limit of 1375 psig. The licensee concluded that there is no decrease in safety margin, and the EPU overpressure protection analysis (given in Figure 3-1 of the Safety Analysis Report) is consistent with the generic analysis in Section 3.8 of ELTR2.

Therefore, for the current equilibrium core overpressure analysis, the maximum calculated pressure meets both the ASME Code and the TS pressure limits. In addition, the most limiting pressurization transient is analyzed on a cycle-specific basis and this approach would not change for the subsequent EPU reload cycle. Therefore, the NRC staff agrees that the licensee has demonstrated an acceptable analysis of the plant response to overpressure conditions.

3.3 Reactor Vessel and Internals

3.3.1 Reactor Vessel Fracture Toughness

The NRC staff had technical issues with the methodology used to derive the fluence values used in the pressure-temperature (P-T) limits evaluation. The NRC staff reviewed the P-T limits in the SE issued with DAEC License Amendment No. 238, dated April 30, 2001. The fluence methodology is the subject of GE LTR "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluations" dated August 2000 (Reference 19). The fluence issues were discussed with the licensee in a teleconference on December 14, 2000. The NRC staff concluded that these issues must be resolved in order to justify applying the fluence values for a full 32 effective full power years (EFPYs). As an interim solution, the licensee proposed that NRC approve the P-T limits for a shorter, more defensible period. Specifically, by letter dated December 22, 2000 (which supplemented the licensee's original license amendment application dated October 16, 2000), the license requested interim approval for the P-T curves until September 1, 2003, and the NRC staff approved this request by Amendment No. 238, dated April 30, 2001. Further discussion of the P-T limits evaluation is contained in Section 3.3.3 of this SE.

3.3.2 Reactor Vessel Internals and Pressure Differentials

The licensee evaluated the reactor vessel and internal components in accordance with the current design basis. The loads considered in the evaluation include reactor internal pressure difference, LOCA, annulus pressurization (AP), jet reaction, acoustic, thermal, seismic, and fuel lift loads. The licensee indicated that the load combinations for normal, upset, and faulted conditions were considered consistent with the current design-basis analyses. In the evaluation, the licensee compared the proposed EPU conditions (pressure, temperature, and flow) against those used in the design basis. For cases where the proposed EPU conditions are bounded by the design-basis analyses, no further evaluation is performed. If the proposed EPU conditions are not bounded by the design-basis analyses, new stresses are determined by scaling up the existing design-basis stresses in proportion to the proposed EPU conditions. The resulting stresses are compared against the applicable AVs, consistent with the design basis. The NRC staff finds that the methodology used by the licensee is consistent with the NRC-approved methodology in Appendix I of ELTR1, and is therefore acceptable.

The stresses and CUFs for the RPV components were evaluated by the licensee in accordance with the codes of record at DAEC. These codes include the ASME Code, Section III, 1965 edition with addenda to and including summer 1967, the 1968 edition with addenda to and including summer 1969, and the 1977 edition with addenda to and including summer 1977, with certain exceptions and modifications as specified in the DAEC Updated Final Safety Analysis Report (UFSAR). Although the DAEC reactor internal components are not ASME Code components, the ASME Code requirements have been used as guidelines in the design-basis documents. The assessment is performed consistent with the current design basis. The NRC staff finds that the licensee’s use of the ASME Code for this purpose is acceptable. The NRC staff also finds that the licensee’s assessment is in compliance with the codes of record at DAEC, and are, therefore, acceptable.

The licensee provided the calculated maximum stresses and CUFs for the RPV components at critical locations in Table 3-2 of the Safety Analysis Report. The RPV components not listed in Table 3-2 have maximum stresses and CUFs that are either not affected by the proposed EPU or are already bounded by the those listed in Table 3-2. The maximum calculated stresses shown in Table 3-2 are within the allowable limits, and the CUFs are less than the code limit of unity. The licensee summarized the maximum stresses for critical components of the reactor internals for the proposed EPU conditions in Table 2 of its supplemental letter dated April 16, 2001 (ADAMS Accession No. ML011140328). The calculated stresses are less than the allowable code limits shown in the table.

In its assessment of the potential for flow-induced vibration (FIV) on reactor vessel internal components other than the steam dryers and separators, the licensee presented that the evaluation was performed based on the vibration data recorded during startup testing at DAEC and operating experience from similar GE BWR plants. The vibration levels for the requested EPU were calculated by extrapolating the recorded vibration data to the conditions expected to be experienced and comparing the extrapolation to the plant allowable limits at the proposed EPU rating. The licensee concluded that the vibration levels of all evaluated components are within GE’s acceptance limit (10.0 ksi). The NRC staff finds the licensee's evaluation acceptable since it is below the ASME Code endurance limit of 13.6 ksi for the peak vibration stress.

The licensee indicated in its supplemental letter dated August 1, 2001 (ADAMS Accession No. ML012190116), that the steam dryers and separators are not safety-related components; however, their failure may lead to an operational concern. The licensee also presented that, although the design-basis criteria do not require evaluation of FIV or determination of cumulative fatigue usage for the steam separators and dryers, the maximum vibration level for the shroud/separators is small in comparison to the allowable limit. The licensee also presented that the dynamic pressure loads, which may induce vibration for the dryers, are small in comparison to loads for the design-basis-faulted condition. Hence, the design-basis loads are bounding and the dryer's structural integrity will be maintained for the proposed EPU. In addition, the dryers will be visually inspected during their removal in each refueling outage, and any significant cracking can be detected and repaired. The design basis for the steam dryers specifies that the dryers maintain their structural integrity when subjected to a steamline break (SLB) occurring beyond the MSIVs. Since the dome pressure is not changed, the current steam dryer analysis remains bounding for the proposed EPU conditions. On the basis of the above information provided by the licensee, the NRC staff concludes that the licensee has reasonably demonstrated that the steam dryers and separators will meet their design-basis requirements and continue to perform their designated functions following the proposed EPU.

Based on its review of the licensee's evaluation of the RPV and internals as set forth above, the NRC staff finds that the maximum stresses and fatigue usage factors for safety-related components are within the code-allowable limits. The NRC staff also concurs with the licensee's conclusion that the RPV and internal components will continue to maintain their structural integrity for the proposed EPU conditions.

3.3.3 Reactor Vessel Integrity

In Sections 3.3.1 and 3.5 of the Safety Analysis Report, the licensee assessed the effects of the proposed EPU on the RPV and RCPB piping. With regard to the RPV, the licensee provided an assessment of (1) the impact of the proposed EPU on the adjusted reference temperature (ART[5]) of the limiting RPV materials; (2) the need to revise the P-T limit curves; and (3) the validity of previously approved equivalent margins analyses. For the RCPB piping, the licensee provided an assessment of changes in the potential for flow-accelerated corrosion (FAC) damage due to the proposed EPU.

For analyzing the RPV, the licensee examined the effect on the RPV fluence of operating DAEC at a power of 1912 MWt until end-of-license (i.e., February 21, 2014). The analysis addressed the expected RPV material embrittlement since it is directly related to the RPV neutron fluence, which is in turn related to the reactor operating power. The licensee stated that the estimated fluence for the proposed EPU is conservatively increased above the UFSAR end-of-license value, and the higher fluence was used to evaluate the RPV against the requirements of 10 CFR Part 50, Appendix G. The results of the licensee's evaluation indicate that:

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[5]The ART is defined as the sum of the initial (unirradiated) reference temperature (initial RT_{NDT}, the mean value of the adjustment in reference temperature caused by irradiation (ΔRT_{NDT}), and a margin (M) term.

(1) The upper shelf energy (USE) remains bounded by the equivalent margins analysis (EMA) for the design life of the vessel and maintains the margin requirements of 10 CFR Part 50, Appendix G. The EMA percent drop in USE for the beltline materials for the limiting plate is 18 percent (less than 21 percent) and the limiting weld is 12 percent (less than 34 percent) for 32 EFPYs.

(2) The P-T curves contained in the current TS remain bounding for the proposed EPU operation up to 25 and 32 EFPYs. However, the licensee has chosen to adopt ASME Code Case N-640, which requires a license amendment to modify the P-T curves. The required license amendment application was submitted on October 16, 2000. (This amendment request was reviewed and approved by the NRC staff via Amendment No. 238, dated April 30, 2001.)

(3) The 32-EFPY shift is increased, and consequently requires a change in the ART.

(4) The maximum operating dome pressure for EPU RTP operation is unchanged from that for CRTP operation. Therefore, the current hydrostatic and leakage test pressures are acceptable for the proposed EPU.

The licensee concluded that the vessel would remain in compliance with the regulatory requirements during proposed EPU conditions.

The licensee’s evaluation of the reactor coolant piping confirmed that changes in flow parameters associated with the proposed EPU would have no significant effects on the potential for FAC in those systems that might be susceptible to the phenomenon (e.g., feedwater or main steam (MS) systems).

As mentioned in Section 3.3 of this SE, the NRC staff had technical issues with the methodology used to derive the fluence values used in the P-T limits evaluation. The fluence issues were discussed with the licensee in a teleconference on December 14, 2000. As a result of the teleconference, the licensee requested interim approval for the P-T curves until September 1, 2003. The details of the NRC staff’s review are contained in the SE issued with DAEC License Amendment No. 238, dated April 30, 2001.

In evaluating the effect of the proposed EPU on the shift in ART, the NRC staff applied the methodology found in NRC Regulatory Guide (RG) 1.99, "Radiation Embrittlement of Reactor Vessel Materials," Revision 2, dated May 1988, for evaluation of radiation embrittlement. The licensee submitted ART calculations and P-T limit curves valid for up to 25 and 32 EFPYs. For the RPV, the licensee determined that the most limiting material at the 1/4T and 3/4T locations is the lower intermediate shell plate (1-21) that was fabricated using plate heat number B0673-1. Based on the information in surveillance capsule report GE-NE-B1100716-01, the licensee chose to apply the data from the testing of the DAEC surveillance plate toward the determination of the chemistry factors (CFs) for all plates in the RPV. The licensee adopted the ratio procedure from RG 1.99, Revision 2, when applicable. The ratio procedure is only required to be applied to welds if the chemistry of the surveillance weld differs from the vessel weld.

The conservative application of the ratio procedure to the limiting plate resulted in an adjusted CF value of 165 °F. The ART values at the 1/4T location for up to 25 and 32 EFPYs are 127.3 °F and 137.6 °F, respectively. The neutron fluence used in the ART calculation is 2.33×10^{18} n/cm^2 at the 1/4T location for 25 EFPYs and 2.98×10^{18} n/cm^2 at the 1/4T location for 32 EFPYs. The ΔRT_{NDT} values at the 1/4T locations for up to 25 and 32 EFPYs are 100.3 °F and 110.6 °F, respectively. The initial RT_{NDT} for the limiting plate is 10 °F. The margin term used in calculating the ART for the limiting plate is 17 °F at up to 25 and 32 EFPYs as permitted by Position 2 of RG 1.99, Revision 2. The NRC staff has confirmed the licensee's ART by performing an independent assessment and verification of the licensee's values. The licensee also developed nonbeltline P-T limits curves. Individual temperature limits for the bottom head of the RPV were established. In addition, upper vessel curves were developed to allow monitoring of the upper vessel independent of the beltline and bottom head.

BWR Owners Group (BWROG) LTR "10 CFR 50 Appendix G Equivalent Margin Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels," Revision 1, dated February 1994 (Reference 20), describes a fracture mechanics analysis which demonstrates that there are margins of safety against fracture which are equivalent to those required by Appendix G of the ASME Code, Section XI, for the beltline materials having USE values below 50 ft-lbs. The BWROG statistically derived the initial USE values for materials that originally did not have documented USE values. The data source used in the analysis was the BWROG's database with USE test data from approximately 31 BWR reactor vessels. The BWROG predicted the minimum permissible end-of-license USE value for each type of material and determined the values in accordance with RG 1.99, Revision 2. Individual BWR licensees assessed the applicability of the BWROG LTR to their vessels by demonstrating that the predicted end-of-license percent drop in USE for their subject materials was smaller than the AVs documented in the BWROG LTR. The end-of-license percent drop in USE values applicable to the beltline materials at DAEC are 21 percent for the limiting plate and 34 percent for the limiting weld. The DAEC-specific numbers that resulted from the EPU analysis are 18 percent and 12 percent for the limiting plate and weld, respectively. These percent drops in USE values are less than the values in the LTR. Therefore, the licensee has demonstrated that the DAEC RPV materials retain margins of safety equivalent to those required by Appendix G of the ASME Code, Section XI. The NRC staff has confirmed the licensee's percent drop in USE by performing an independent verification of the licensee's values.

For the reasons set forth above, the NRC staff has determined that the licensee's proposed P-T limit curves are acceptable for the interim period (i.e., until September 2003) since they meet the requirements of 10 CFR 50.60 and Appendix G of 10 CFR Part 50. The EMA USE evaluation also meets the requirements of Appendix G of 10 CFR Part 50. The proposed EPU does not necessitate a change in the DAEC 10 CFR Part 50, Appendix H, RPV surveillance program. DAEC is included in the BWR vessel and internals project (BWRVIP) integrated surveillance program (ISP), which is currently under review by the NRC staff. The BWRVIP ISP was developed in order to integrate surveillance data for the benefit of those BWR vessels that do not have unirradiated baseline data. The BWRs that are part of the ISP will be able to use baseline and irradiated surveillance data to measure changes in RPV material embrittlement.

In BWRs, FAC mostly affects components made of carbon steel that are exposed to single- or two-phase flowing water at high temperature and low oxygen concentration. The proposed EPU at DAEC would affect some of the plant's operating parameters, and thus change the rates of corrosion of the components subjected to FAC.

The licensee evaluated the effect of the proposed EPU on FAC in the following systems: recirculation, MS and associated piping, feedwater, RCIC, RPV head vent and bottom head drain, reactor water cleanup (RWCU), and portions of the residual heat removal (RHR) system.

The components in the recirculation system are made from stainless steel and are resistant to FAC; therefore, they would not be affected by the proposed EPU. However, the other systems contain carbon steel components that are exposed to single- and two-phase flowing water. The change of velocity of flow caused by the proposed EPU would have some effect on FAC. The licensee evaluated the potential damage caused by this change, including the worst-case limiting feedwater and MS piping flow increases. The licensee found that the change in flow would not exhibit a significant effect on FAC. In addition, the fluid temperature change due to increased subcooling and reduced heat exchanger effectiveness in the RWCU system is small and does not exhibit a significant effect on FAC. The licensee also indicated that it has a program (consistent with the Maintenance Rule and other parts of the facility’s licensing bases) that monitors the systems where FAC is expected to occur. If any significant FAC is detected, inspection frequency will be adjusted to ensure repair or replacement of the defective components prior to reaching minimum allowable wall thickness. The NRC staff reviewed the licensee’s evaluations regarding the effects of the proposed EPU on FAC. Based on the licensee’s discussion of the impact of the proposed EPU on the flow and on the temperatures of fluid in carbon steel components, the NRC staff has concluded that the proposed EPU will have an insignificant effect on FAC at DAEC. In addition, any changes in FAC will be detected by the licensee’s FAC program, and appropriate corrective actions will be taken.

Based on the information presented above, the NRC staff has concluded that for the systems described above, FAC issues have been adequately addressed in the EPU application.

3.4 Reactor Recirculation System

The primary function of the reactor recirculation system is to vary the core flow and power during normal operation. The recirculation system also forms part of the RCPB.

The licensee evaluated the changes at DAEC in the system operating pressure and temperature at the proposed EPU conditions and determined that the changes are small and result in conditions less severe than the current rated conditions.

The proposed EPU will not involve any increase in the steady-state dome pressure and DAEC is currently licensed to operate at up to a maximum core flow of 100 percent of the rated flow. However, operation at the proposed EPU RTP level would increase the two-phase flow resistance, requiring a slight increase in the recirculation system drive flow. The licensee indicated that this increase in the demand on the motors would cause the pump motors to exceed their current and horsepower nameplate rating by a small amount. The licensee stated that the DAEC recirculation system and its components are capable of providing the core flow required for operation at the proposed EPU RTP conditions. According to the licensee, the pump motor limitations are operational issues and do not affect plant safety.

The NRC staff reviewed the potential impact that the recirculation pumps trip would have on plant safety in order to ensure that the recirculaiton pump motor limitations are an operational issue and not a safety issue. A loss of recirculation pumps would result in a decrease in the reactor core flow and the plant is analyzed for decreases in the reactor core coolant flow rate.

The transient events in this category are (a) single and multiple recirculation pump trips, (b) recirculation flow controller failure malfunction, (c) recirculation pump shaft seizure (SLO and TLO), and (d) recirculation pump shaft break. In these events, core flow would be reduced, resulting in a corresponding decrease in the reactor power. For DAEC, these transients are considered to be nonlimiting in terms of thermal limits and are not reanalyzed during the reload analysis, except for the single-recirculation-loop pump seizure event. There are no physical phenomena associated with the proposed EPU operation to make these transients limiting.

Chapter 15.3 of the DAEC UFSAR states that a pump seizure event during SLO is analyzed for each reload to determine the impact on the MCPR, specifically to ensure that this event does not violate the SLMCPR for the cycle. DAEC is licensed to operate with SLO, and the licensee stated that SLO operation would be limited to 66.8 percent of the proposed EPU power level. The EPU application did not originally include the SLO pump seizure in the list of transients analyzed for the MELLLA/EPU operation. In its August 16, 2001, supplemental letter, the licensee confirmed that the SLO recirculation pump seizure event was analyzed in support of the proposed EPU operation.

The licensee evaluated the impact of the proposed EPU on the required and available net positive pump suction head (NPSH) for the recirculation system pumps and the jet pumps. The licensee concluded that the proposed EPU conditions would not increase the NPSH required or reduce the NPSH margin for the recirculation pump and jet pump. Therefore, the licensee stated its intent to maintain the flow cavitation protection interlock at the current setpoints in terms of actual feedwater flow rate. The cavitation interlock (shown in the lower portion of the power/flow map) ensures that sufficient subcooling is available to prevent cavitation of the recirculation pumps. This evaluation is consistent with the evaluation in Section F.4.2.6 of ELTR1. The NRC staff reviewed the licensee's evaluations and accepts the licensee's assessment.

The licensee will not change the values (in percent) of the recirculation pump flow mismatch specification in the TS, but to be consistent with the power increase, the licensee's proposed TS change reflects the adjustment of the mismatch power basis point from 80 percent of the current rated power to 69 percent of the proposed EPU RTP (80 percent x 1658/1912).

The DAEC TS allow jet pump performance surveillance to be deferred for 24 hours upon reaching 25 percent RTP. The basis for the 25-percent power is for the reactor to reach stable power and flow conditions that would allow collection of meaningful data. The licensee stated that since the absolute thermal power and flow necessary for obtaining meaningful data are not changed by the proposed EPU, the actual power level will remain the same, with 25 percent of the CRTP corresponding to 21.7 percent of the proposed EPU RTP.

Based on the licensee's reasoning, as set forth above, the NRC staff finds the licensee's assessment of the changes to the cavitation interlock, the recirculation pump mistmatch power basis, and the jet pump SR power level acceptable.

The NRC staff considered the impact on the safety function of the recirculation system discussed in Section 4.5.3 of Supplement 1 to ELTR2 for the proposed EPU. The supplement stated that the proposed EPU affects the safety functions of the recirculation system by affecting (a) closure of the discharge valve during low-pressure coolant injection (LPCI),

(b) pump trip in transients and ATWS, and (c) measurement of the drive flow used in the APRM flow-biased setpoint and rod blocks.

For LOCA, one recirculation system discharge valve must close to ensure LPCI injection into the core. Since the proposed EPU does not involve an increase in the operating pressure, the discharge valve closure permissive pressure would not be changed.

The recirculation system drive flow is measured and used as an input to the APRM for the flow-biased APRM scram and rod blocks. According to Supplement 1 to the ELTR2, the recirculation system fast transient analysis is necessary to support EPU operation for plants that have adopted the APRM/Rod Block Monitor TS (ARTS) feature to ensure adequate protection during the transient. The ARTS program replaces the flow-biased APRM trip setdown during operation at offrated conditions. Under these conditions, ARTS plants like DAEC use power and flow-dependent MCPR, MAPLHGR, and LHGR values for operation at offrated conditions. Table 9.2 of the Safety Analysis Report provided the changes in the MCPR for the fast recirculation flow transient, and indicated that the ARTS multipliers used to develop the power-dependent MCPR(P) remained bounding.

In support of the proposed EPU conditions, the licensee also reanalyzed the ATWS and the transient analyses that assume recirculation pump trips. Therefore, the NRC staff concludes that the impact on the recirculation systems safety functions discussed in Supplement 1 to ELTR2 were adequately considered for the proposed EPU operation.

3.5 Reactor Coolant Piping and Components

The licensee evaluated the effects of the proposed EPU conditions, including temperature, pressure, higher flow rate, and fluid transients on the RCPB and the BOP piping systems and components. The piping interfaces with equipment nozzles, anchors, guides, penetrations, pumps, valves, flange connections, and pipe supports (including snubbers, hangers, and struts). The licensee indicated that the original codes of record (as referenced in the original and existing licensing basis) and analytical techniques were used in the evaluation. The applicable codes are the American National Standards Institute (ANSI) B31.1, ANSI B31.7, and ASME Code, Section III, Subsections NB and NC/ND, as specified in the DAEC UFSAR. The specific codes and code editions for all piping evaluated for the proposed EPU are provided in the licensee's August 10, 2001, supplemental letter. The NRC staff agrees that these are the appropriate codes of record and the use of the above codes is acceptable.

The RCPB piping systems evaluated include the MS piping, reactor recirculation piping, feedwater piping, RWCU piping, reactor vessel head vent line, reactor core isolation cooling (RCIC) piping, core spray piping, high-pressure coolant injection (HPCI) piping, standby liquid control (SLC), RHR, safety/relief valve discharge line (SRVDL) piping and CRD piping. The licensee indicated that the evaluation follows the process and methodology defined in Appendix K of ELTR1 and in Section 4.8 of Supplement 1 of ELTR2. The licensee compared the pressure, temperature, and increased flow rate due to the proposed EPU against the same parameters used as input to the original design-basis analyses. The comparison resulted in bounding percentage increases in stress for affected limiting piping systems. The bounding percentage increases are compared to the design margin between calculated stresses and the ASME Code allowable limits. From the comparison, the licensee concluded that there are sufficient design margins to justify operation at the proposed EPU conditions while continuing to satisfy regulatory requirements. This approach was approved by the NRC in Supplement 1 to ELTR2 (Reference 4) and its use is conservative and acceptable to the NRC staff.

In its August 10, 2001, supplemental letter, the licensee provided (a) the maximum calculated stresses and the stress ratios compared to those allowed by the ASME Code, (b) ASME Code and code edition, and (c) the CUFs (if applicable) for the piping systems evaluated for the proposed EPU. The licensee indicated that the codes and editions provided in the table are the current licensing basis codes of record. On the basis of information provided by the licensee, all calculated stresses and CUFs are within the allowable limits. The licensee also concluded that the evaluation showed compliance with all appropriate code requirements for the piping systems evaluated and that EPU will not have an adverse effect on the reactor coolant piping system design. The NRC staff reviewed relevant portions of the evaluation provided by the licensee in its August 10, 2001, supplemental letter, agrees that the appropriate code requirements are satisfied, and therefore, finds the licensee's conclusion acceptable.

Based on the above review, the NRC staff concurs with the licensee's conclusion that the piping, components, and their supports are designed to maintain their structural and pressure boundary integrity at the proposed EPU conditions.

3.6 Main Steam Flow Restrictors

Regarding the assessment of the MS flow restrictor, the licensee stated that the proposed EPU will have no impact on the structural integrity of the restrictor. In Section 3.2 of the Safety Analysis Report, the licensee indicated that a higher peak RPV transient pressure of 1286 psig dome pressure results from the proposed EPU conditions, but this value remains below the ASME Code limit of 1375 psig. Therefore, the main steamline (MSL) flow restrictor would maintain its structural integrity following implementation of the proposed EPU since the restrictor was designed for a differential pressure of 1375 psig, which exceeds that for the proposed EPU conditions.

3.7 Main Steam Isolation Valves

The main steam isolation valves (MSIVs) are part of the RCPB and perform a safety function (steamline isolation). The MSIVs must be able to close within the specified time limits at all design and operating conditions upon receipt of a closure signal. They are designed to satisfy leakage limits set forth in the plant's TS. The licensee indicated that the MSIVs have been generically evaluated, as discussed in Section 4.7 of ELTR2 (including Supplement 1, Volumes I and II). This evaluation covers both the effects of the changes to the structural capability of the MSIV to meet pressure boundary requirements and the potential effects of EPU-related changes to the safety functions of the MSIVs. The generic evaluation in ELTR2 is based on (1) a 20-percent thermal power increase, (2) an increased operating reactor dome pressure to 1095 psia, (3) a reactor temperature increase to 556 °F, and (4) steam and feedwater increases of about 24-percent. The licensee stated that the conditions for DAEC are bounded by those in the generic analysis. Although the dome pressure would not increase with the proposed EPU, the increase in flow rate assists MSIVC, which results in a slightly faster MSIVC time. The actual in-plant settings will be adjusted such that the closure speed will be maintained within the required range. Therefore, the MSIVs remain acceptable for EPU operation.

Based on the NRC staff's review of the licensee's rationale and evaluation, the NRC staff concurs with the licensee's conclusion that EPU operation, as indicated above, would remain bounded by the conclusion of the generic evaluation in Section 4.7 of ELTR2, and that the plant operations at the proposed EPU level will not affect the ability of the MSIVs to perform their isolation function.

3.8 Reactor Core Isolation Cooling System

The RCIC system provides core cooling when the RPV is isolated from the main condenser and the RPV pressure is greater than the pressure at which the low-pressure core cooling systems can supply water to the core. The licensee has assessed the RCIC system consistent with the bases and conclusions of Section 3 of ELTR2 and concluded that the current RCIC system will maintain adequate water level for the proposed EPU conditions, with one exception. The exception is related to the operational criteria for the Level 1 setpoint margin, as discussed in the following paragraph.

Section 3 of ELTR2 provided an evaluation of the RCIC system design basis. The report states that for BWR 4, 5, and 6 plants, the RCIC system (the smaller of the two high-pressure supply systems) should maintain the reactor water level so that the very low level trip setpoint (Level 1) for the low-pressure ECCS, would not trip, and the MSIVs would not close. ELTR2 also reports that the operational aspects will be evaluated for the Level 1 setpoint for each plant and documented in the plant-specific licensing report. Contrary to the model plant in ELTR2, the licensee does not currently maintain the RCIC system reactor water level above the Level 1 trip setpoint and will not maintain it above the Level 1 trip setpoint for EPU operation. Since this is an operational issue and would not affect the RCIC system's ability to provide core cooling and maintain the water level above the top of active fuel (TAF), the NRC staff accepts the licensee's assessment.

Section 4.2.3 of Supplement 1 to ELTR2 discusses the potential for turbine overspeed of the steam-driven RCIC and HPCI pumps. The supplement stated that startup transients for the HPCI and the RCIC systems at a potentially higher steam inlet pressure may result in an increased initial turbine acceleration rate, increasing the peak initial speed and the probability of system trip. The HPCI and RCIC startup transients are dependent on the reactor pressure and Supplement 1 to ELTRA 2 recommended that the modifications described in GE's Services Information Letter (SIL) 377, "RCIC Startup Transient Improvement with Steam Bypass," be implemented to assure RCIC and HPCI availability for EPUs that involve a reactor pressure increase. The licensee has decided not to implement this recommendation on the basis that the proposed EPU would not increase the steady-state reactor pressure and the SRV safety setpoints and tolerance would also not change. Because there is no increase in the potential for peak transient speeds during startup, and no increase in the potential for an overspeed trip, there is no need to implement the modifications.

The RCIC system's performance evaluation depends on the system's capability to inject the designed flow rate for the range of EPU reactor pressures during isolation transients, without overspeeding of the turbine. Therefore, the startup transient for the RCIC pumps depends upon when the relief valves lift to depressurize the reactor, the capacity of the relief valves, and the corresponding reactor pressure at the time the RCIC pumps start to inject. For the LOFW event, the operators inhibit the ADS as long as the level is steady or rising, delaying reactor depressurization. Because the licensee has analyzed the LOFW transient for the proposed

EPU operation, evaluated the performance of the RCIC system, and determined the RCIC system would inject as designed without RCIC turbine overspeed, the NRC staff accepts the licensee's assessment.

The licensee determined that the RCIC system has been evaluated for the LOFW transient event and the licensee's evaluation is consistent with the conclusions of Section 4.2 of ELTR2, with the exceptions of (a) not complying with the operational criteria for water level margin for Level 1, (b) not implementing the turbine control modification discussed in SIL 377, and (c) using a different RCIC design-basis maximum operating pressure than that assumed in ELTR2. Based on the above discussion, the NRC staff assessed the plant-specific differences between the proposed DAEC EPU and the evaluation in ELTR2 and finds that the RCIC response for an LOFW transient is acceptable.

3.9 Residual Heat Removal System

The RHR system is designed to (1) restore and maintain the coolant inventory in the reactor vessel and (2) remove sensible and decay heat from the primary system and containment following reactor shutdown for both normal and post-accident conditions. The RHR system operates in the LPCI mode, shutdown cooling (SDC) mode, suppression pool cooling (SPC) mode, containment spray cooling (CSC) mode, and fuel pool cooling assist mode.

3.9.1 Shutdown Cooling Mode

The operational objective of normal shutdown is to reduce the bulk reactor temperature after scram to 125 °F within approximately 20 hours using two RHR loops. RG 1.139, "Guidance for Residual Heat Removal," dated May 1978, provides an alternative approach to demonstrate SDC capability, which is that the RHR system can reduce the reactor coolant temperature to 200 °F within 36 hours.

The licensee stated that with the proposed EPU operation, the decay heat would be increased proportionally. Therefore, the time required to reach shutdown temperature would increase by about 10.5 hours. The SDC evaluation at the proposed EPU conditions demonstrated that the plant can be brought to a temperature that would allow refueling operations to proceed (125 °F in 27.1 hours). This meets the RG 1.139 acceptance guidelines. Therefore, the NRC staff finds the proposed change acceptable.

3.9.2 Residual Heat Removal System - Suppression Pool Cooling Mode

The SPC mode of the RHR system is designed to remove heat discharged into the suppression pool to maintain pool temperature below the TS limit during normal plant operation and below the suppression pool design temperature limit after an accident. The proposed EPU would increase the reactor decay heat, which increases the heat input to the suppression pool during a LOCA, and results in a higher peak suppression pool temperature. The affect of the proposed EPU on SPC after a design-basis LOCA is addressed in Section 4.1.1 of this SE.

3.9.3 Residual Heat Removal System - Containment Spray Cooling Mode

The CSC mode is designed to spray water from the suppression pool via spray headers into the containment airspace to reduce the long-term containment pressure and temperature during post-accident conditions. The proposed EPU would slightly increase the containment spray water temperature. This increase would have a negligible effect on the use of the CSC mode to maintain the containment pressure and temperature within their design limits as the peak pressure and temperature are reached well before the use of the RHR system in the CSC mode is assumed to occur.

Based on the NRC staff's review of the licensee's rationale and evaluation, the NRC staff concurs with the licensee that plant operation at the proposed EPU level will have an insignificant impact on the CSC mode.

3.9.4 Residual Heat Removal System - Fuel Pool Cooling Assist Mode

For plant operation at the proposed EPU level, the decay heat load for any specific fuel discharge scenario would increase. In the rare event that the spent fuel pool (SFP) heat load exceeds the heat removal capability of the SFP cooling system (i.e., during full-core offload events), the RHR system will be operated in the fuel pool cooling assist mode to provide supplemental cooling to the SFP, and to maintain the SFP temperature within acceptable limits. Section 6.3 of this SE addresses the adequacy of the combined heat removal capability of the SFP cooling system and the RHR system operating in the fuel pool cooling assist mode to meet the increases in SFP heat loads resulting from the proposed EPU.

3.10 Reactor Water Cleanup System

Evaluation of the RWCU system is included in Sections 3.3.3 and 3.5 of this SE. The system functional design basis for water chemistry is described in the DAEC UFSAR, Section 5.4.8. RWCU is also discussed in Section 10.1.1.5 of this SE.

3.11 Main Steam and Feedwater Piping

The MS and feedwater piping evaluation is addressed along with reactor coolant piping in Sections 3.3.3 and 3.5 of this SE.

3.12 Balance-of-Plant Piping and Supports

The licensee evaluated the stress levels for BOP piping and appropriate components, connections, and supports in a manner similar to the evaluation of the RCPB piping and supports based on increases in temperature, pressure, and flow from the design-basis analyses input. The evaluated BOP systems include lines which would be affected by the proposed EPU, but not evaluated in Section 3.5 of ELTR1, such as feedwater heater piping, main steam bypass lines, and portions of the MS, feedwater, RCIC, HPCI, and RHR systems outside the primary containment. The existing design analyses of the affected BOP piping systems were reviewed against the uprated power conditions. The licensee concluded that in all cases, there is a sufficient margin between the calculated stresses and the code-allowable limits to accommodate the increase in stresses due to the increase in pressure, temperature, and flow as a result of the proposed EPU. The NRC staff finds that the stress ratios provided by the licensee are within the code-allowable limits and are, therefore, acceptable.

The licensee evaluated pipe supports such as snubbers, hangers, struts, anchorages, equipment nozzles, guides, and penetrations by evaluating the piping interface loads due to the increases in pressure, temperature, and flow for affected limiting piping systems. The licensee indicated that there is an adequate margin between the original design stresses and code limits for the supports to accommodate the load increase and therefore, all evaluated pipe supports were within the code-allowable limits. The licensee reviewed the original postulated pipe break analysis and concluded that the existing pipe break locations would not be affected by the proposed EPU and that no new pipe break locations were identified. The NRC staff reviewed the information provided by the licensee and found the licensee's conclusions to be reasonable and acceptable.

The licensee indicated that the FIV levels for the safety-related MS and feedwater piping systems will increase in proportion to the increase in the fluid density and the square of the fluid velocity following the proposed EPU. To ensure that the vibration level will be below the acceptable limit, the licensee will perform a piping vibration startup test program, as outlined in Section 10.4.3 of the Safety Analysis Report. The startup testing would include monitoring and evaluating the FIV during plant startup for proposed EPU operation. Vibration data will be collected at 50 percent, 75 percent, and 100 percent of the ORTP, and every 5-percent step increase in power level above 100 percent of ORTP up to the final proposed EPU power level. The vibration at the new higher EPU level may be determined based on extrapolation of the vibration data taken at the lower power levels. The measured vibration level would be compared against the acceptance criteria set by the design fatigue endurance stress limits established by GE for stainless and carbon steels. The NRC staff finds the licensee's methodology in assessing the FIV acceptable.

4.0 ENGINEERED SAFETY FEATURES

4.1 Containment System Performance

The DAEC UFSAR provides the results of analyses of the containment response to various postulated accidents that constitute the design basis for the containment. Operation with a 15.3-percent EPU from 1658 MWt to 1912 MWt would change some of the conditions and assumptions of the containment analyses. Section 5.10.2 of ELTR1 provides that applicants for EPUs show the acceptability of the effect of the uprate power on containment capability. These evaluations consider containment pressures and temperatures, LOCA containment dynamic loads, SRV containment dynamic loads, and subcompartment pressurization. Appendix G of ELTR1 prescribes the generic approach for this evaluation and outlines the methods and scope of plant-specific containment analyses to be done in support of an EPU. Appendix G of ELTR1 states that applicants will analyze short-term containment pressure and temperature response using the previously applied GE code, the M3CPT code. These analyses will cover the response through the time of peak drywell pressure throughout the range of power/flow operating conditions with EPU.

Appendix G of ELTR1 also requires applicants to perform long-term containment heatup (suppression pool temperature) analyses for the limiting UFSAR events to show that pool temperatures will remain within limits for suppression pool design temperature, ECCS NPSH, and equipment qualification temperatures. These analyses can be performed using the GE computer code SHEX. The SHEX computer code has been used by GE on all BWR EPUs.

The NRC staff requested the assistance of Information Systems Laboratories, Inc. (ISL), in performing audit calculations of both the short-term and long-term responses of the DAEC containment to a double-ended guillotine break of a recirculation line. These calculations used mass and energy input values and plant description values furnished by the licensee, which were obtained from the DAEC UFSAR. The NRC staff used conservative assumptions in performing these calculations. The results of the NRC staff's calculations for both the short-term (peak pressure and drywell temperature) and long-term (peak suppression pool temperature) calculations agree well with the licensee's results for the trend and timing of important parameters. The numerical values of two calculations are close and can be explained by small changes in any one of several input values. The results of ISL's audit calculations are contained in ISL Technical Evaluation Report, "Duane Arnold Energy Center Extended Power Uprate Containment Analysis Audit Calculation," dated July 2001 (ADAMS Accession No. ML012620344).

4.1.1 Containment Pressure and Temperature Response

Short-term and long-term containment analyses results following a large break inside the drywell are documented in the DAEC UFSAR. The short-term analysis was performed to determine the peak drywell and wetwell pressure response during the initial blowdown of the reactor vessel inventory into the containment following a large break inside the drywell (DBA-LOCA), while the long-term analysis was performed to determine the peak pool temperature response considering decay heat addition.

The licensee indicated that the containment analyses were performed in accordance with NRC guidelines using GE codes and models. The M3CPT code was used to model the short-term containment pressure and temperature response. The licensee also indicated that the SHEX code was used to model the long-term containment pressure and temperature response for the proposed EPU. These calculations were also done for the proposed EPU. They were done to demonstrate compliance with equipment environmental qualification criteria.

4.1.1.1 Long-Term Suppression Pool Temperature Response

(a) Bulk Pool Temperature

The licensee indicated that the long-term bulk suppression pool temperature response with the proposed EPU was evaluated for the DBA-LOCA. The bounding analysis was performed at 102 percent of EPU RTP and assumes that no offsite power is available following the LOCA with only minimum diesel power available. This results in only one RHR loop with one RHR pump, its heat exchanger, two RHR service water pumps, and one core spray pump being available. No credit is taken for use of containment spray. The analysis was performed using the SHEX code and the more realistic decay heat model (ANS/ANSI 5.1-1979 + two sigma) with a core average exposure of 31.7 GWD/Short Ton (corresponding to a core average time of 3.5 years at power), rather than the May-With decay heat model used in the current licensing basis. The decay heat model used in the SHEX code is less conservative than the current decay heat model and has been approved by the NRC in many different SEs. The use of this decay heat model was approved for GE containment analyses in ELTR1. Therefore, the NRC staff has determined the use of the ANS/ANS 5.1-1979 decay heat model with an uncertainty adder of two sigma is acceptable.

The peak bulk suppression pool temperature was calculated to be 215.3 °F for the proposed EPU, which is an increase of 15.3 °F in peak pool temperature from 200 °F over the current licensing basis. The peak suppression pool temperature remains below the wetwell structure design temperature of 281 °F.

Based on the NRC staff's containment calculations for DAEC, the NRC staff concludes that the peak bulk suppression pool temperature response remains acceptable for the EPU.

(b) Net Positive Suction Head

The licensee indicated that the containment analysis for the NPSH for peak suppression pool temperature with minimum available wetwell pressure was performed for the DBA-LOCA at 102 percent of EPU RTP, using the ANS/ANSI 5.1-1979 + two sigma decay heat with finite fuel exposure. The analysis assumed the limiting case of one RHR pump and one core spray pump operating at rated flows. Unlike the bulk suppression pool analysis, the containment analysis for NPSH took credit for the operation of the containment sprays. This is conservative since the use of containment sprays reduces the containment pressure available. The analysis calculated the peak suppression pool temperature of 209.2 °F at the corresponding wetwell pressure of 13.3 psig as compared to 202.7 °F and 10.6 psig for the current licensing basis. The wetwell pressure includes consideration of containment leakage. The effects of the proposed EPU on NPSH for pumps taking suction from the suppression pool are discussed in Section 4.2.5 of this SE.

(c) Local Pool Temperature with SRV Discharge

The maximum local pool temperature (200 °F) for SRV discharge is identified in NUREG-0783, “Suppression Pool Temperature Limits for BWR Containment,” based on concerns resulting from unstable condensation observed at high pool temperatures in plants without quenchers. NUREG-0783 provided acceptance criteria for the BWR suppression pool temperature limit during SRV discharges to meet the requirements of GDC 16 and GDC 29. This maximum temperature was required as part of the Mark I containment LTP analyses. The EPU analysis shows that the peak local suppression pool temperature exceeds 200 °F as specified in NUREG-0783. Exceeding 200 °F for plants with quenchers on the SRVDLs is justified in GE LTR "Elimination of Limit on BWR Suppression Pool Temperature for SRV Discharge with Quenchers" (Reference 15). In an SE dated August 29, 1994, the NRC staff approved elimination of the maximum local pool temperature limit for plants with quenchers on the SRVDLs, provided the ECCS suction strainers are below the quencher elevation. The licensee indicated that for DAEC, certain portions of the SRV quenchers are located below the suction strainers. However, the SRV quenchers and RHR and CS pump suction strainers are located in different sections (i.e., bays) in the torus and are separated from each other horizontally. Based on this horizontal separation, the 200 °F limit for local suppression pool temperature is not governing.

Based on the NRC staff's review of the licensee's rationale and evaluation (including the horizontal separation of the SRV quenchers and RHR and CS pump suction strainers), the NRC staff agrees with the licensee's conclusion that the local pool temperature with SRV discharge will remain acceptable after implementation of the proposed EPU.

4.1.1.2 Containment Gas Temperature Response

The licensee indicated that the limiting DBA with respect to peak drywell temperature involves SLBs. The SLBs produce a higher drywell temperature response than the DBA-LOCA (liquid line break) because the steam has a higher specific energy content than liquid at the same pressure. The analyses calculated the peak drywell gas temperature of 331 °F at the EPU level, and this remains below the drywell airspace design temperature of 340 °F. The current licensing basis analysis had calculated a temperature of 335 °F. The licensee indicated that the current licensing basis for SLBs did not credit heat sinks in the containment (i.e., drywell shell and vents). The EPU analysis removed the extra conservatism and included these heat sinks to ensure that the existing environmental qualification (EQ) peak temperature in the drywell remains bounding. The NRC staff finds the inclusion of the above heat sinks in the containment acceptable. The licensee calculated the maximum drywell shell temperature of 275.5 °F, which also remains below the shell design temperature of 281 °F.

The analyses calculated a peak wetwell air space temperature of 236.5 °F, which occurs during the blowdown period and a long-term peak wetwell temperature of 215.3 °F, which occurs near the time of the peak suppression pool temperature at the EPU level. The peak calculated long-term wetwell airspace temperature of 215.3 °F remains below the wetwell airspace design temperature of 281 °F. Therefore, the wetwell airspace temperature response also remains acceptable.

The NRC staff reviewed the licensee's rationale and evaluation as set forth above, and based on that rationale and evaluation, the NRC staff agrees with the licensee's conclusion that the drywell and wetwell air temperature response will remain acceptable after implementation of the proposed EPU.

4.1.1.3 Short-Term Containment Pressure Response

The licensee indicated that the short-term containment response analyses were performed for the limiting DBA-LOCA, which assumes a double-ended guillotine break of a recirculation suction line, to demonstrate that operation at the proposed EPU level does not result in exceeding the containment design pressure limits. The short-term analysis covers the blowdown period during which the maximum drywell pressures and maximum differential pressures between the drywell and wetwell occur. These analyses were performed at 102 percent of the EPU RTP per RG 1.49, "Power Levels of Nuclear Power Plants," dated December 1973, using the M3CPT code with the break flow calculated by the homogeneous equilibrium model. These methods were reviewed and accepted by the NRC during the Mark I Containment Long-Term Program (LTP). These analyses calculated a peak drywell pressure of 45.7 psig at EPU, which remains below the containment design value of 56 psig.

The current value of P_a used for containment testing is 43.0 psig and the licensee has proposed a TS change to increase this value to 45.7 psig based on the above pressure response for the

EPU per 10 CFR Part 50, Appendix J. The NRC staff finds the proposed change is in accordance with the definition of P_a in Appendix J, and is acceptable.

Based on the NRC staff's review of the licensee's evaluation as set forth above, the NRC staff agrees with the licensee's conclusion that the short-term containment pressure response following a postulated LOCA will remain acceptable after implementation of the proposed EPU.

4.1.2 Containment Dynamic Loads

4.1.2.1 LOCA Containment Dynamic Loads

The licensee indicated that the LOCA containment dynamic loads analysis for the proposed EPU is based primarily on the short-term recirculation suction line break DBA-LOCA analyses. These analyses were performed in a manner similar to the ones described above in Section 4.1.1.3; however, the initial conditions were consistent with Mark I Containment LTP analyses. These analyses provide calculated values for the controlling parameters for the dynamic loads throughout the blowdown. The key parameters are the drywell and wetwell pressures, vent flow rates, and suppression pool temperature. The LOCA dynamic loads are pool swell, condensation oscillation (CO), and chugging and are included in the proposed EPU. For Mark I plants like DAEC, the vent thrust loads are also evaluated.

The licensee stated that the short-term containment response conditions with the proposed EPU are within the range of test conditions used to define the pool swell and CO loads for the plant. The long-term response conditions with the proposed EPU for times beyond the initial blowdown period in which chugging would occur are within the conditions used to define the chugging loads. Therefore, the pool swell, CO, and chugging loads at the proposed EPU conditions are bounded by existing data.

The licensee indicated that the vent thrust loads with the proposed EPU are calculated to be up to 5 percent higher than the plant-specific values calculated during the Mark I Containment LTP. While the controlling load combinations are influenced by more than the vent thrust loads, it was conservatively assumed that the resultant stresses and displacements increase linearly with the vent thrust loads. Additionally, the resultant stresses and displacement were conservatively assumed to increase 10 percent (twice the calculated increase in vent thrust loads). The licensee stated that the stress and displacement ratio due to applied loads divided by the acceptance criterion at the proposed EPU conditions remain less than one and, therefore, the increased vent thrust loads are acceptable.

Based on the licensee's rationale and evaluation of LOCA containment loads at the proposed EPU conditions, the NRC staff agrees with the licensee's conclusion that the LOCA containment dynamic loads will remain acceptable after the implementation of the proposed EPU.

4.1.2.2 Safety/Relief Valve Loads

The SRV air-clearing loads include SRVDL loads, suppression pool boundary pressure loads, and drag loads on submerged structures. These loads are influenced by the SRV opening setpoint pressure, the initial water leg height in the SRVDL, the SRVDL geometry, and suppression pool geometry. For the first SRV actuations, the only parameter change which can affect the SRV loads that could be introduced by the proposed EPU is an increase in the SRV opening setpoint pressure. Since the proposed EPU does not include an increase in the SRV opening setpoint pressures, it would have no effect on the loads from the first SRV actuations.

The licensee indicated that to mitigate the effects of subsequent SRV actuations, low-low set logic has been implemented at DAEC, which extends the time between the SRV closure and subsequent reopening, and therefore ensures that the water column height during subsequent actuations has been reduced to its initial condition. The proposed EPU has an insignificant impact on the time intervals between SRV openings, and therefore, it has an insignificant impact on the loads from subsequent SRV actuations.

The NRC staff reviewed of the licensee's rationale and evaluation. Based on the licensee's evaluation, the NRC staff agrees with the licensee's conclusion that with the low-low set logic implementation of the proposed EPU will have insignificant or no impact on the SRV containment loads.

4.1.2.3 Subcompartment Pressurization

The licensee indicated that the calculations to determine the asymmetrical loads on the vessel, attached piping, and biological shield wall due to postulated pipe break in the annulus between the reactor vessel and the biological shield wall have been updated to treat the break flow as subcooled liquid. This conservative change in methodology reduces the design margin more than the effect of the proposed EPU. It was also found that the original analysis had not been updated during the previous EPU. For the limiting case of the recirculation outlet nozzle shield plug, the pressurization transient inside the shield wall increases peak pressure from 16.5 psi in the original analysis to 18.98 psi, including all the above changes, and remains below the design pressure of 20 psi. The results of the updated calculations, including the effects of the proposed EPU indicate that the biological shield wall and component designs remain adequate because there is sufficient pressure margin available.

Based on the licensee's use of conservative break-flow assumptions as indicated above, the NRC staff concurs with the licensee's conclusion that the subcompartment pressurization will remain acceptable after implementation of the proposed EPU.

4.1.3 Containment Isolation

The licensee indicated that the system designs for containment isolation will not be affected by the proposed EPU. The capability of the actuation devices to perform with the higher flow and temperature during normal operations and under post-accident conditions has been determined to be acceptable.

Most containment isolation systems are independent of reactor power. For the MSIVs, the affect of the increase in steam flow must be considered. This was done generically as discussed in Section 4.7 of ELTR2 and described in the Safety Analysis Report.

4.1.4 Generic Letter 89-16

The licensee indicated that in response to Generic Letter (GL) 89-16, "Installation of a Hardened Wetwell Vent," dated September 1, 1989, it installed a hardened wetwell vent system at DAEC. The criterion specified in GL 89-16 for the hardened wetwell vent was the ability to exhaust energy equivalent to 1 percent RTP at a pressure of 56 psig. The design of the hardened wetwell vent was based on the current power level of 1658 MWt. Based on the as-built design, the hardened wetwell vent will exhaust approximately 0.91 percent of the proposed EPU RTP of 1912 MWt.

The licensee indicated that the primary objective of the hardened wetwell vent is to preclude primary containment failure due to overpressurization, given a loss-of-decay-heat-removal event. The NRC staff considers the new value of 0.91 percent RTP to be a change to the design basis. However, this change is acceptable since there is still adequate margin between the 0.91 percent RTP criterion and the fraction of RTP at the time the licensee would initiate venting.

Based on the above, the NRC staff agrees with the licensee’s conclusion that the hardened wetwell vent system will remain acceptable for preventing containment overpressure for plant operation at the proposed EPU level with the revised design-basis value of 0.91 percent RTP.

4.2 Emergency Core Cooling System

The ECCS is designed to provide protection in the event of a LOCA due to a rupture of the primary system piping.

The ECCS for DAEC includes the HPCI, the LPCI mode of the RHR, the low-pressure core spray system, and the ADS.

4.2.1 High-Pressure Coolant Injection System

The HPCI system (with other systems that make up ECCS as backup) is designed to maintain reactor water level inventory during a small- and intermediate-break LOCA, isolation transients, and LOFW. For a large-break LOCA, the reactor will depressurize rapidly, thereby rendering the HPCI system inoperable.

The licensee stated that the HPCI system is designed to inject with a maximum reactor pressure of 1120 psig and this is consistent with the current DAEC licensing basis, which allows for an increase of the as-found SV and SRV safety mode setpoint from +/- 1 percent to +/-3 percent. The HPCI system is required to start and operate reliably over its design operating range. The licensee stated that since there are no increases in the SRV setpoint pressures for the proposed EPU operation, no changes are required to the HPCI system startup transient or system reliability from the currently licensed pre-EPU conditions. During the LOFW event and isolation transients, the HPCI and/or RCIC systems maintain water level above the TAF. The SRVs would open and close as required to control pressure and the HPCI or RCIC system will eventually restore water level.

The licensee has implemented the turbine control modifications recommended by SIL 480. According to the licensee, these modifications minimize the impact of reactor pressure increases on: (a) the magnitude of the turbine peak initial speed, (b) the initial pump discharge pressure, and (c) the pump discharge flow rate. The modifications described in the SIL hydraulically limit the opening of the control valves during the initial startup period, thereby minimizing the potential for turbine overspeed. Since the HPCI turbine has been modified as recommended in SIL 480, which increases the availability of the HPCI system during isolation transients including LOFW, the NRC staff accepts the licensee's assessment regarding HPCI turbine overspeed.

The licensee evaluated the capability of the HPCI system for operation at the proposed EPU power level to provide core cooling to the reactor: (a) to prevent excessive fuel PCT following a small- and intermediate-break LOCA, and (b) maintain core coverage up to the TAF in isolation transients and LOFW transients. The licensee stated that the HPCI evaluation is applicable to and consistent with the evaluation in Section 4.2 of ELTR2, except for the DAEC HPCI system design-basis maximum system pressure.

The licensee evaluated the capability of the HPCI system to perform as designed and analyzed its performance at the proposed EPU conditions. The licensee's analysis concluded that the HPCI system can start and inject the required amount of coolant into the reactor for the range of reactor pressures associated with a LOCA and isolation transients. The NRC staff agrees with the licensee's assessment.

4.2.2 Low Pressure Coolant Injection

The LPCI mode of the RHR is automatically initiated in the event of a LOCA, and in conjunction with other ECCS the LPCI mode is required to provide core cooling for ECCS events.

The licensee stated that, as indicated in the ECCS performance discussion in Section 4.3 of this SE, the calculated LOCA PCT would increase slightly for the proposed EPU. However, the existing LPCI system combined with other ECCS provide adequate long-term post-LOCA core cooling. The licensee added that the existing RHR hardware has the capability to perform the design injection function of the LPCI mode for operation at the proposed EPU conditions and the generic evaluation in Section 4.1 of ELTR2 bounds the DAEC LPCI system performance. Since the licensee's ECCS-LOCA analysis (see Section 4.3 of this SE) based on the current LPCI capability demonstrated that the system provides adequate core cooling, the NRC staff finds the licensee's evaluation acceptable.

4.2.3 Core Spray System

The core spray system initiates automatically in the event of a LOCA and in conjunction with other ECCS, the core spray system provides core cooling for all ECCS events.

The licensee stated that, as indicated in the ECCS performance discussion in Section 4.3, the calculated LOCA PCT would increase slightly at the proposed EPU power level. However, the existing core spray system, combined with other ECCS systems, will provide adequate long-term post LOCA core cooling. The licensee added that the existing core spray system hardware has the capability to perform its design injection function at the proposed EPU conditions and that the generic evaluation in Section 4.1 of ELTR2 bounds the DAEC core spray system performance. Since the licensee's ECCS-LOCA analysis (see Section 4.3 of this SE) based on the current core spray system capability demonstrated that the system provides adequate core cooling, the NRC staff finds the licensee's evaluation acceptable.

4.2.4 Automatic Depressurization System

The ADS uses the SRVs to reduce reactor pressure after a small-break LOCA with HPCI system failure, allowing LPCI and core spray to provide cooling flow to the vessel. The ADS actuates on low water level and the licensee stated that the ability of the ADS to initiate on appropriate signals will not be affected by the proposed EPU. However, the proposed EPU decay heat is higher, increasing the required flow capacity. The licensee stated that the increase in the required flow capacity is within the current system design capability. Since the built-in ADS capacity is sufficient to provide the required blow down flow rate and the licensee did perform the LOCA analysis for the proposed EPU conditions in accordance with NRC-approved methods, the NRC staff accepts the licensee's evaluation.

4.2.5 Net Positive Suction Head

The licensee indicated that the available and required NPSH for the HPCI pump will not be changed for the proposed EPU. The available NPSH is based on the TS limit of 120 °F for the suppression pool temperature that requires depressurization of the RPV. This TS limit is not changed and there are no physical changes being made in the HPCI system.

The licensee also indicated that the NPSH requirements for the RHR and core spray ECCS pumps are calculated from the EPU long-term suppression pool temperature response. The most limiting case for NPSH occurs at the peak long-term suppression pool temperature of 209.2 °F and the wetwell pressure of 28.0 psia (13.3 psig) with one RHR pump and one core spray pump operating at rated flows. The results of this calculation establish that a containment pressure of 20 psia is adequate to ensure NPSH is available to the low pressure ECCS pumps post-LOCA during EPU operation.

During the initial review of the DAEC operating license, the NRC staff concluded that a limited amount of containment overpressure was required to ensure adequate NPSH for one core spray and one RHR pump during the long-term transient following the design-basis LOCA. In an SE dated September 2, 1998, regarding GL 97-04, "Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal Pumps, dated October 7, 1997, the NRC staff noted that the design did not meet the guidelines of RG 1, "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps, dated November 1970, but a containment pressure margin of 2.7 psi would exist to ensure adequate NPSH. This margin was depicted in UFSAR Figure 5.4-15. In the current licensing basis, containment pressure necessary (i.e., containment overpressure) to maintain minimum NPSH for the core spray pumps is 17.8 psia (25.3 psia available) at the peak suppression pool temperature of 202.7 °F. Thus, implementation of the proposed EPU will require an increase of 2.2 psi in containment overpressure for NPSH over the current conditions. According to the licensee, there is sufficient containment pressure available for post-LOCA conditions to establish the margin between the 20.0 psia needed and the 28.0 available to satisfy the 2.7 psid margin specified by the current licensing basis. Therefore, the licensee concluded that adequate NPSH will be ensured under the proposed EPU conditions. The licensee also indicated that the maximum containment overpressure for NPSH will be needed after approximately 8 hours after a DBA-LOCA. Reliance on containment overpressure decreases as the temperature of the suppression pool decreases, if all other factors are held constant.

The NRC staff requested that DAEC provide NPSH curves which depict the amount of time the peak containment overpressure must be relied upon. This information is important to demonstrate that the risk associated with the limited time the containment overpressure is required is low relative to the potential loss of containment integrity during the same time period. The licensee stated that an overpressure margin is an acceptable criterion for adequate available NPSH. This means that as long as the margin is maintained, the absolute amount of overpressure can be increased. The NRC staff discussed its position in a letter to the licensee dated September 25, 2001. As described in the September 25, 2001, letter, and as set forth above, the NRC staff finds that sufficient overpressure will be available for the proposed EPU.

4.3 ECCS Performance Evaluation

The ECCS is designed to provide protection against postulated LOCAs caused by ruptures in the primary system piping. Although DBAs are not expected to occur during the lifetime of a plant, plants are designed and analyzed to ensure that the radiological dose from a DBA will not exceed the limits set by 10 CFR 50.67 or 10 CFR Part 100. For a LOCA, 10 CFR 50.46 specifies design acceptance criteria based on: (a) the PCT, (b) local cladding oxidation, (c) total hydrogen generation, (d) coolable core geometry, and (e) long-term cooling. The LOCA analyses consider a spectrum of break sizes and locations, including a rapid circumferential rupture of the largest recirculation system piping. Assuming a single failure of the ECCS, the LOCA analyses identify the break sizes that most severely challenge the ECCS systems and the primary containment. The MAPLHGR operating limit is based on the most limiting LOCA analysis, and licensees perform LOCA analyses for each new fuel type. ECCS performance under all LOCA conditions and the analysis models must satisfy the requirements of 10 CFR 50.46 and 10 CFR Part 50, Appendix K.

The licensee performed the LOCA analysis at 102 percent of the EPU RTP, for all resident fuel including the limiting GE-14 fuel. The ECCS-LOCA analysis was based on an NRC-approved methodology (SAFER/GESTR) and the results are summarized in Table 4-3 of the Safety Analysis Report. The licensee determined the licensing-basis PCT at the rated core operating conditions with an adder to account for the uncertainties. For the proposed EPU conditions, the licensing-basis PCT based on the limiting GE-14 fuel design is less than 1510 °F at rated flow in comparison with the pre-EPU PCT of 1500 °F. The estimated upper bound PCT for the limiting GE-14 fuel is less than 1350 °F for the proposed EPU conditions, which is below the 1600 °F limit, which is included as a condition in the NRC SE for the SAFER/GESTR methodology.

For SLO, the licensee applied a multiplier to the TLO MAPLHGR limits. The licensee stated that the multiplier to the MAPLHGR for the SLO operation ensures that the SLO nominal PCT is less than the PCT for the nominal TLO. Section 2.6 of this SE discussed the findings from the NRC staff's audit of these calculations and the licensee’s response.

Table 4-3 of the Safety Analysis Report indicates that long-term decay heat removal requirements can be satisfied for the proposed EPU conditions either by having the core reflooded above the TAF or by having the core reflooded to the top of the jet pumps with one core spray pump in service. The licensee determined that the ECCS performance under LOCA conditions, and the analysis models, satisfy the requirements of 10 CFR 50.46 and Appendix K.

As part of the EPU review process, the NRC staff audited the DAEC LOCA analysis. The NRC staff focused on the GNF's use of the LOCA codes and their applicability to DAEC. The NRC staff examined the design record files describing the LOCA, which contained both the pre-EPU and the proposed EPU analyses, and made the following observations:

1. The analyses were based on the NRC approved SAFER/GESTR methodology, and GNF followed NRC-approved processes in performing the ECCS-LOCA analysis.

2. The licensee worked closely with GNF and was involved in the development of the plant-specific information required in developing the model.

3. The ECCS-LOCA analyses support compliance with the requirements of 10 CFR 50.46.

4. The GNF method for SLO uses statistical adders derived from RTP operation. The NRC staff questioned this approach and GNF responded that any uncertainty introduced by using these values will be compensated for by the conservative nature of the SLO application procedure. This procedure leads analysts to derive conservative SLO multipliers. The NRC staff accepts this explanation and concurs with the GNF conclusion.

The NRC staff agrees with the licensee that the DAEC ECCS-LOCA performance complies with 10 CFR 50.46 and 10 CFR Part 50, Appendix K, requirements and the analyses conform to NRC-approved methods and codes.

4.4 Standby Gas Treatment System

The standby gas treatment system (SGTS) processes the secondary containment atmosphere to limit the release of radioisotopes to the environment that may leak from the primary containment under DBA conditions. The SGTS provides a negative differential pressure between the secondary containment and the outside air. The licensee stated that this capability will not be affected by the proposed EPU.

The licensee stated that the charcoal filter bed removal efficiency for iodine would be unaffected by the proposed EPU. As a result of the application of alternate source terms (ASTs) derived from RG 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," dated July 2000, the post-DBA-LOCA total iodine loading is well below the value specified by RG 1.52, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered Safety Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants," dated June 2001, which is 2.5 mg/gm of charcoal. The system, therefore, contains sufficient charcoal to ensure iodine removal efficiencies greater than the current design provision of 99 percent, as stated in the UFSAR.

In its supplemental letter dated June 21, 2001, in response to an RAI from the NRC staff, the licensee explained that a large decrease in charcoal filter loading was related to the change in the assumed chemical form of the iodine associated with the AST (i.e., 95 percent of the DBA-LOCA iodine source term is assumed in the particulate form). The large increase in the particulate iodine species, which is filtered by mechanical filters, results in significantly decreased loadings on the charcoal filters to values "well below" the RG 1.52 value.

In addition, the licensee's evaluation of fission product accumulation within the SGTS filter train, consistent with AST assumptions, shows that both the increase in component operating temperature due to decay heating and the increase in loadings on the pre-filters and high-efficiency particulate air (HEPA) filters are well within the system design limits. Therefore, the licensee concluded that the SGTS retains its capability to meet its design-basis function of limiting the offsite dose within the guidelines of 10 CFR 50.67 following a DBA.

Based on its review, the NRC staff concludes that the proposed EPU will not adversely affect operation of the SGTS because any increase in fission product release due to the proposed EPU would be within the capability of the current system design. Therefore, operation of the SGTS at the proposed EPU conditions is acceptable.

4.5 Other Engineered Safety Feature Systems

4.5.1 Main Steam Isolation Valve Leakage Control

The removal of the DAEC MSIV leakage control system was evaluated in the SE issued with DAEC License Amendment No. 207, dated February 22, 1995. Thus, an additional evaluation in this SE is not necessary. MSIVs are under scrutiny for leakage and closure time from surveillance requirements (SRs) in the plant TS. The proposed EPU does not affect the function of the MSIVs to perform containment isolation functions. The TS SRs require testing of MSIVs for leakage and closure times. Details of the NRC staff's review of MSIVs are addressed in Section 3.7 of this SE.

4.5.2 Post-LOCA Combustible Gas Control System

The licensee indicated that post-LOCA combustible gas control is provided by the containment atmosphere control system (CACS). The CACS consists of three subsystems: (1) the primary containment purge system, (2) the primary containment nitrogen inerting system, and (3) the containment atmosphere dilution (CAD) system. The CACS is designed to maintain the post-LOCA containment atmosphere below hydrogen flammability limits by controlling the concentration of oxygen to not exceed 5 percent by volume. The design of the system is based on the production of hydrogen from (1) the metal-water reaction of active fuel cladding, (2) corrosion of zinc and aluminum exposed to water during a postulated LOCA, and (3) radiolysis of water. Only post-LOCA production of hydrogen and oxygen from radiolysis will increase in proportion to the power level. The hydrogen contribution from the metal-water reaction of fuel cladding will not be affected by the proposed EPU, but is affected by fuel design. The licensee's analysis considered the impact of GE-14 fuel introduction on metal-water hydrogen production.

The licensee indicated that the time required to reach the 5-percent oxygen limit following a LOCA, assuming zero containment leakage, decreases from 3.5 days for current reactor power to 2.3 days for EPU reactor power. This reduction in time required for CAD system initiation does not affect the ability of the operators to respond. Therefore, the CACS retains its capability of meeting its design-basis function of controlling oxygen concentration following the postulated LOCA.

Evaluation of the nitrogen requirements to maintain the containment atmosphere below the 5-percent flammability limit for 7 days post-LOCA shows that the necessary stored volume increases from 50,000 standard cubic feet (scf) (pre-EPU) to 67,000 scf (EPU). The licensee indicated that the CAD system has a minimum stored nitrogen capacity of 75,000 scf and the TS-required volume for CAD would be increased from its current value of 50,000 scf to the proposed EPU value of 67,000 scf.

The licensee indicated that the containment atmosphere monitoring system is currently required to be operating post-LOCA. The system sample lines are heat-traced to ensure accurate readings by preventing condensation whenever the containment atmosphere is significantly higher than the temperature of the sample lines. The existing heat tracing is effective up to 200 °F. Because of operating temperature limits on the radiation monitors that also use these sample lines, it is not practical to increase the temperature setting on the existing heat tracing to bound the new containment temperatures. The EPU containment analysis shows that the post-LOCA containment temperatures for the DBA would return below 200 °F approximately 22 hours after the event begins. The time required to reach the 5-percent oxygen limit following a DBA-LOCA is 2.3 days at EPU conditions. Therefore, by establishing an administrative requirement following an event, it would be possible to accurately monitor and assess the hydrogen and oxygen trends for at least 24 hours prior to the 2.3-day mark when the CAD system would be required to inject nitrogen to maintain containment below the 5-percent oxygen limit.

In its supplemental letter dated July 25, 2001, in response to an RAI from the NRC staff, the licensee indicated that this condition is a deviation from its previous commitments to both Item II.F.1(6) of NUREG-0737, "Clarification of TMI Action Plan Requirements," dated November 1980, and RG 1.97 "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Access Plant and Environs Conditions During and Following an Accident," dated December 1980, regarding continuous hydrogen and oxygen monitoring. During the initial 22-hour period, the accuracy of these monitors will not conform to the NUREG-0737 specification, but the monitors will be functional. The stated temperature effect causes the monitors to read in the conservative direction (i.e., higher than actual hydrogen and oxygen concentration). (The high temperature would not affect the function or the accuracy of the monitors when the DBA temperature returns below 200 °F.) Thus, to preclude action to actuate the CAD system prematurely, the licensee has chosen administratively not to take direct actions based solely on these hydrogen and oxygen monitors during the first 24 hours. While the monitors will not be used to obtain an absolute reading during this initial accident period, they will provide valuable trending information if hydrogen and/or oxygen concentration changes are occurring inside the containment. As per DBA analysis, a combustible gas mixture will not be generated for approximately 2.3 days. Consequently, this potential inaccuracy in these monitors during the first 22 hours will not hinder the ability to effectively execute the emergency plan. The emergency response facilities have sufficient information available, using the Severe Accident Management Guidelines, to diagnose whether a flammable mixture is developing inside the containment and recommend that the control room take appropriate actions to protect the containment. Based on the above, the NRC staff finds the proposed deviation for the initial 24 hours after a DBA from the previous commitment to NUREG-0737, Item II.F.1(6), and RG 1.97, regarding accuracy of continuous hydrogen and oxygen monitoring is acceptable as stated. Any specific provision on such hydrogen and oxygen monitoring in an order imposing requirements addressing NUREG-0737, Item II.F.1(6), would be controlled by this amendment.

After a review of the licensee's rationale and evaluation as described above, the NRC staff concludes that the operation of the post-LOCA combustible gas control system will remain acceptable at the proposed EPU conditions.

4.5.3 Emergency Cooling Water System

The NRC staff's evaluation of the emergency cooling water system is addressed in Section 6.4 of this SE.

4.5.4 Emergency Core Cooling Auxiliary System

DAEC does not have an emergency core cooling auxiliary system.

4.5.5 Control Room and Technical Support Center Habitability

The control building ventilation system (CBVS) processes the control building intake atmosphere to limit the release to the control room of radioisotopes that may leak from containment under DBA-LOCA conditions. The CBVS provides a positive differential pressure between the control room and the outside environment to minimize the potential for unprocessed in-leakage into the control room. The licensee stated that this capability will not be affected by the proposed EPU.

The technical support center (TSC) air cleanup system processes the TSC intake atmosphere to limit the release to the TSC of radioisotopes that may leak from containment under DBA-LOCA conditions. The licensee stated that this capability will not be affected by the proposed EPU.

The licensee stated that the charcoal filter and bed removal efficiency for iodine will be unaffected by the proposed EPU. As a result of the application of the ASTs derived from RG 1.183, the calculated total iodine loadings on the CBVS and TSC air cleanup system standby filter units (SFUs) are well below the RG 1.52 value of 2.5 mg/gm of charcoal. Therefore, the systems contain sufficient charcoal to ensure iodine removal efficiencies greater than 90 percent.

By letter dated June 21, 2001, in response to an NRC staff request, the licensee explained that the large decrease in charcoal filter loadings was related to the change in the assumed chemical form of the iodine associated with the AST (i.e., 95 percent of the DBA-LOCA iodine source term is assumed to be in the particulate form). The large increase in the particulate iodine species, which is filtered by mechanical filters, results in significantly decreased loadings on the charcoal filters to values "well below" the RG 1.52 value.

The licensee evaluated fission product accumulation on both the CBVS and TSC Air cleanup system SFU pre-filters and HEPA filters by performing a comparison to the SGTS, which is a system with a larger capacity and exposed to a higher loading under post-DBA-LOCA conditions. On the basis of this evaluation, the licensee concluded that the CBVS and TSC air cleanup system retain the capability to meet the design-basis function of limiting control room operator and emergency response personnel dose within the guidelines of 10 CFR Part 50, Appendix A, GDC 19, and 10 CFR 50.67, following a DBA-LOCA.

In its supplemental letter dated June 21, 2001, in response to an NRC staff RAI, the licensee explained that while the above simplified evaluation compared relative filter sizes and system flow capacities of the CBVS and TSC air cleanup system SFUs with those of the SGTS to determine filter loading results, actual filter loading calculations were also performed as part of the AST analyses. Based on the calculated filter loadings, the licensee continues to conclude that the SFUs are capable of maintaining the dose to control room and TSC personnel well within regulatory limits.

Based on the licensee's rationale, the conservative analysis and the NRC staff's assessment of the information provided by the licensee, the NRC staff concludes that the proposed EPU will not adversely affect control room and TSC habitability.

5.0 INSTRUMENTATION AND CONTROL

5.1 Nuclear Steam Supply System and Balance-of-Plant Monitoring and Control Systems

In its EPU application, the licensee stated that each existing instrument of the affected NSSS and BOP systems was evaluated to determine its suitability for the revised operating range of the affected process parameters. Where operation at the proposed EPU conditions affected safety analysis limits, the evaluation verified that an acceptable margin would continue to exist under all conditions of the power uprate, and, where necessary, setpoint and uncertainty calculations for the affected instruments would be revised. Apart from the few devices that needed changes, the licensee's evaluations found most of the existing instrumentation acceptable for the proposed EPU operation. As a result of the evaluations, the licensee proposed the following changes:

- Conversion of the turbine control valves (TCVs) to partial arc admission, which would result in control system logic and valve internal modifications;
- Replacement of the APRM flow-biased trip circuit cards to implement the MELLLA setpoint changes;
- Replacement of MSL flow-high isolation instrumentation to accommodate the new setpoint.
- Expansion of the indicating range on various control room and in-plant instrumentation.
- Installation of new main condenser high back pressure alarm and trip units that have power variable setpoints.

These changes would be performed to accommodate the revised process parameters. The NRC staff agrees with the licensee's conclusion that when the above-noted modifications and changes are implemented during the next refueling outage, the DAEC instrumentation and control systems will accommodate the proposed EPU, and are acceptable.

5.2 Instrument Setpoint Methodology

Reactor Protection System/Engineered Safety Features Actuation System Instrumentation Trip Setpoint and Allowable Values

In the EPU application, the licensee identified that instrument setpoints in the TS are established using GE setpoint methodology. The NRC staff has previously reviewed this instrument setpoint methodology and found it acceptable for establishing new setpoints in EPU applications. During a conference call on March 16, 2001, the NRC staff requested the licensee to add a reference to GE setpoint methodology in the TS Bases. In its response, the licensee stated that the use of GE setpoint methodology is incorporated into the DAEC licensing basis via the UFSAR and the TS Bases provide a detailed discussion of the application of the methodology to explain the relationship between the ALs in the accident analysis and the development of the AVs and trip setpoints. The NRC staff finds the licensee's response acceptable and concludes that 10 CFR 50.59 provides adequate controls for those portions of the setpoint methodologies described in the UFSAR or TS Bases. The NRC staff notes that the licensee, in its supplemental letter dated April 16, 2001 (ADAMS Accession No. ML011140200), in response to an NRC staff request, stated that it has not applied the GE setpoint methodology to non-safety-related instrumentation such as BOP instruments. The NRC staff finds the licensee's response acceptable because this methodology is used for only non-safety-related instrumentation and therefore, does not require the NRC staff's review and approval.

The proposed setpoint changes resulting from the proposed EPU are intended to maintain existing margins between operating conditions and the reactor trip setpoints, and would not significantly increase the likelihood of a false trip or failure to trip upon demand. Therefore, plant operation would not be significantly affected by the setpoint changes necessary to accommodate the proposed EPU, and they are acceptable.

5.3 TS Changes Related to Instrumentation Setpoint for the Proposed Extended Power Uprate

The following TS changes have been proposed by the licensee:

1. TS Limiting Condition for Operation (LCO) 3.3.1.1: SR 3.3.1.1.2

   The licensee proposes to reduce from 25 percent to 21.7 percent the percentage of RTP value, which is used to defer the SR for 12 hours during plant startup. The RTP value being changed is contained in SR 3.3.1.1.2 and the associated note. The licensee's justification for this change is that the existing value is based on a point in the plant startup sequence where an accurate heat balance calculation can be performed by the plant computer, which is tied to sufficient steam flow through the turbine to synchronize the main generator to the grid. This steam flow and corresponding reactor power level would not be changed by the proposed EPU. Therefore, the CRTP would be reduced to 21.7 percent for the proposed RTP EPU to retain the absolute power level below which the SR may be deferred. On this basis, the NRC staff finds this proposed TS change acceptable.

2. TS LCO 3.3.1.1: Required Action E.1, SR 3.3.1.1.16, and Table 3.3.1.1-1 Functions 8 and 9

   The licensee has proposed to revise the percentage-of-RTP value corresponding to the power level where the reactor protection system (RPS) trip on turbine stop valve (TSV) or on TCV fast closure is automatically bypassed from 30 percent to 26 percent. The licensee's justification for this change is that these scram signals are automatically bypassed at a low power level when the turbine bypass steam flow capacity is sufficient to mitigate a TSV or TCV closure transient. Because the turbine bypass capacity would not be changed by the proposed EPU, the corresponding percentage of RTP would be revised to maintain the current thermal power value in MWt, corresponding to the existing bypass steam flow capacity. On this basis, the NRC staff finds the licensee's justification for this TS change acceptable.

3. TS LCO 3.3.4.1: Applicability, Required Action C.2, and SR 3.3.4.1.4

   The licensee has proposed to reduce from 30 percent to 26 percent the percentage-of-RTP value corresponding to the power level where the end-of-cycle recirculation pump trip on TSV or TCV fast closure is automatically bypassed. The licensee's justification is that the revised value is consistent with the RPS trips discussed above since this function is not required when the companion RPS functions are not required to be operable. On this basis, the NRC staff finds the proposed TS change acceptable.

4. TS LCO 3.3.1.1: Table 3.3.1.1-1 Function 2b

   The licensee has proposed to revise the AV for the TLO APRM flow-biased, high RPS trip with an equation for the AV. A footnote (c) would also be added to define the term "W" used in the AV equation. The proposed EPU is based on the adoption of the MELLLA. The licensee's safety analysis in the EPU application is based on the MELLLA power/flow map and corresponding APRM AVs. The NRC staff's review of the MELLLA is documented in Section 2.3.1 of this SE. Based on the acceptance of the MELLLA analysis, the NRC staff finds the proposed TS changes acceptable.

5. TS LCO 3.3.1.1: Table 3.3.1.1-1 Footnote b

   The licensee has proposed to replace the current AV for the SLO APRM flow-biased high RPS trip with an equation for the AV. The new footnote (c) identified above would be used to define the term "W" used in the AV equation. The licensee has proposed this change to adjust the AV for the TLO APRM flow-biased trip to account for the difference in recirculation-drive-flow to core-flow relationship in SLO. The higher core pressure drop associated with the proposed EPU necessitates a different adjustment factor than the one currently used. Based on the acceptance of the MELLLA analysis, the NRC staff finds the proposed TS change acceptable.

In addition to the above changes, the licensee would implement new setpoints for instrumentation listed in the TS for which setpoints are given as a percentage of flow or pressure, without changing the percentage. The licensee has identified this instrumentation as follows:

(a) APRM scram fixed

(b) MSL high flow isolation

(c) Rod block monitor (RBM) upscale function

Based on the above review and justifications, the NRC staff concludes that the licensee's instrument setpoint methodology and the resulting TS setpoint changes for the proposed EPU are consistent with the DAEC licensing basis and are, therefore, acceptable.

6.0 ELECTRICAL POWER AND AUXILIARY SYSTEMS

6.1 AC Power

6.1.1 Offsite Power System

The NRC staff has reviewed information provided by the licensee to determine the impact of the power uprate on offsite power. The areas reviewed were the grid stability analysis and related electrical systems.

6.1.1.1 Grid Stability and Reliability Analysis

A grid stability analysis was performed for 1790 MWt (641 megawatts electric (MWe) - gross) to demonstrate conformance to GDC 17 (10 CFR Part 50, Appendix A). GDC 17 addresses onsite and offsite electrical supply and distribution systems for safety-related components. Operation at 1790 MWt (EPU-Phase I), has essentially no effect on grid stability or reliability. This grid stability analysis was discussed in the Safety Analysis Report. The current output capability is based on the currently installed main transformer rating of 660 mega volts-amp (MVA) (with upgraded cooling units) and the isolated phase bus rating of 18000 amperes. In response to an RAI from the NRC staff, the licensee provided a supplemental letter dated May 11, 2001, describing the assumptions, methods, inputs, results, findings, and conclusions of the current grid stability analysis (1790 MWt - EPU-Phase I). The licensee stated that the reliability study included the effects of trips of DAEC with contingencies for 68 transmission line outages as required by MAPP/MAIN for Iowa grid reliability and stability studies. All voltages at DAEC were within the acceptance limits of 95-percent to 105-percent voltage. Additionally, as long as the reactive power requirement for a trip of the King-Eau Claire-Arpin line is maintained, voltage at DAEC will remain above the minimum required (95 percent voltage at the 161 kV bus) for all contingencies modeled. To compensate for DAEC mega volt-amp-reactive (MVAR) capacity reduction at 1790 MWt and for other grid reliability reasons unrelated to the DAEC power uprate, capacitor banks are being installed in the Cedar Rapids area. The licensee concluded that DAEC's conformance to GDC 17 will not be compromised.

Based on the above reasoning, the NRC staff concluded that the results of the analysis show that DAEC can proceed to 1790 MWt and GDC 17 will be met.

The licensee further indicated in response to the NRC staff's RAI on grid stability analysis for the proposed EPU that this analysis would be performed again when the main transformers are replaced or modified to achieve higher power output as described in the supplemental letter dated September 24, 2001. Many factors directly affect the grid stability analysis. Proposed additions that would affect the current grid stability analysis include (1) a 345 kV transmission line from the Arrowhead substation in Minnesota to the Weston substation in Wisconsin, (2) the potential installation of gas turbine generation capacity within the Alliant Energy territory, and (3) an additional 2000 MWe of new generation in the Alliant territories in Iowa and Wisconsin in the near future. The licensee plans to update the existing grid stability study as additional changes occur, as provided by its licensing basis in UFSAR Section 8.2.2.1. The licensee indicated that an analysis performed today projecting the conditions at the time DAEC achieves the proposed EPU of 1912 MWt would not be meaningful in demonstrating that grid stability will remain acceptable. The licensee committed to perform a new stability analysis for the main transformer replacement/modification (required to increase power above the 1790 MWt level) and for any significant increase in actual plant electrical output from operation above 641 MWe main generator output.

The licensee determined that no modifications were required for the generator breakers. Additionally, a 40 MVAR capacitor bank would be installed in the switchyard in the fall of 2001 to partially compensate for the loss of reactive power capability of the main generator as a result of implementation of the proposed EPU.

On the basis of this information, the NRC staff concludes that the proposed power uprate for the proposed EPU-Phase I at DAEC will not adversely affect grid stability and reliability. The NRC staff also concludes that the licensee is committed, as set forth in DAEC's licensing basis in UFSAR Section 8.2.2.1, to perform a new stability analysis for the main transformer replacement/modification prior to increasing power above 641 MWe. Such a study would identify any matters associated with the proposed uprate to 1912 MWt that would need to be addressed to maintain appropriate grid stability. Any change to this commitment would have to be evaluated under the provisions of 10 CFR 50.59. Based on the above, the NRC staff has reasonable assurance that GDC 17 will be met for all of the proposed EPU conditions. Further licensee analyses for the proposed EPU power level of 1912 MWt will be subject to future NRC audit or inspection.

6.1.1.2 Related Electrical Systems

The licensee performed a power uprate review to determine the adequacy of electrical systems associated with the main turbine generator auxiliary systems. The NRC staff reviewed the main generator, isolated phase bus duct, and main transformer systems, which are part of the electrical system.

6.1.1.2.1 Main Generator

The existing main generator is rated at 715.225 MVA, 0.95 power factor, and 22 kV. The expected generator output is 679.46 MWe at 0.95 power factor. The net plant EPU-related output would be 677 MWe, which is within the capability of the generator. The licensee plans to replace the hydrogen cooling units to improve heat removal capability to accommodate full uprated power production during EPU-Phase I. The NRC staff has determined that the electrical system's configuration and operating voltage ranges would be unchanged and would remain adequate for operation at the higher output.

6.1.1.2.2 Isolated Phase Bus Duct

The existing isolated phase bus duct rating is 18000 amps and 22 kV for the main section. The maximum current output is 18232 amperes [660000/(1.7321x22x0.95)] with a main transformer output of 660 MVA and 95 percent of 22 kV. The NRC staff has determined that the isolated phase bus duct would be adequate for both rated voltage and low-voltage current output for EPU-Phase I. The maximum current output is 19757 amps (715.225 MVA/(1.7321x22x0.95)) with a generator output of 715.225 MVA and 95 percent of 22 kV. The licensee proposes to modify the isolated phase bus to increase its rating from 18000 to 20000 amperes and improve the bus cooling unit's heat removal capacity during EPU-Phase II. The NRC staff has determined that the proposed modifications would assure that the isolated phase bus duct would be adequate for the proposed EPU of 1912 MWt.

6.1.1.2.3 Main Transformer

The existing main transformer rating is 600 MVA and 22/161 kV. The licensee plans to add new oil-cooling units to increase the transformer's rating from 600 MVA to 660 MVA; this would be done during EPU-Phase I. The existing main transformer must be replaced/modified to accommodate the full EPU power output from the main generator; this would be done during EPU-Phase II. The licensee is committed, as provided by its licensing basis in UFSAR Section 8.2.2.1, to perform a new stability analysis when the main transformer is replaced/modified, providing reasonable assurance that DAEC will continue to meet GDC 17. Thus, the turbine generator and major electrical components from the isolated phase bus to the switchyard would remain adequate for operation at the higher output after implementation of the proposed modifications and GDC 17 will continue to be met.

6.1.2 Onsite Power Distribution System

The onsite power distribution system consists of transformers, buses, switchgear, and distribution panels. The alternating current (ac) power to the distribution system is provided from the transmission system or the onsite emergency diesel generators. Station batteries provide direct current (dc) power to the dc distribution system. Station loads under normal operation/ distribution conditions are computed from equipment nameplate data. Conservative demand factors are applied. The only identified change in electrical load demand is associated with the recirculation pumps, condensate pumps, and reactor feed pumps. These pumps would experience increased flow under the proposed EPU conditions. The existing design-basis calculations would be performed again to reflect the increased motor demand and to confirm that the increased electrical distribution loading due to the proposed EPU would not affect the system's capacity to provide electrical power within equipment ratings. Protective relay settings would be modified to accommodate the increased motor demands on the condensate pumps and reactor feed pumps. Operation at the proposed EPU RTP level would be achieved by new or existing equipment operating within its design capability; therefore, under normal conditions, the electrical supply and distribution components are adequate.

Station loads under emergency operation/distribution conditions (i.e., emergency diesel generator loads) are based on equipment nameplate data. Operation at the proposed EPU RTP level would be achieved by existing equipment operating at or below the nameplate rating and within the calculated brake horse power for the stated pumps. Therefore, under emergency conditions, the electrical supply and distribution components would be adequate.

The licensee stated that no increase in flow or pressure would be required of any ac-powered ECCS equipment for the proposed EPU. Therefore, the proposed EPU would not increase the amount of power required to perform safety-related functions (pumps and valves loads). The existing diesel generator load calculations would not be changed by the proposed EPU conditions, and the current emergency power system design remains adequate. The system has sufficient capacity to (1) support the required loads for safety shutdown, (2) maintain a safe-shutdown condition, and (3) operate the required engineered safety feature equipment following a postulated accident. In response to the NRC staff's concern regarding the increase in the heat load in the drywell and reactor building, the licensee stated that the slight increase in drywell heat load would occur during normal operation and not under accident conditions. The TS requirement to maintain normal drywell temperature $\leq$ 135 °F is not proposed to be changed by the proposed EPU. Thus, under DBA conditions, the drywell cooling system load on the emergency diesel generators will not be changed by the increase in heat load during normal operation. The proposed EPU would increase various heat loads of the reactor building closed cooling water system (RBCCWS), but they are within the system's heat removal capacity. The RBCCWS pumps are automatically shed from essential busses under accident conditions; thus, the proposed EPU would not affect the loading on the emergency diesel generator. Therefore, the proposed EPU would have no impact on the emergency onsite power system.

On the basis set forth above, the NRC staff has reasonable assurance that DAEC will continue to meet GDC 17 for the proposed EPU of 1912 MWt after completing all the modifications, completing a new stability analysis, and taking whatever actions are found necessary in light of the stability analysis.

6.2 <u>DC Power</u>

The NRC staff has reviewed information provided by the licensee to determine the impact of the proposed EPU on the dc power system. The dc power distribution system provides control and motive power for various systems and components in the plant. The licensee noted that system loads are computed from equipment nameplate data, except for the motor-operated valves (MOVs), which use values based on MOV testing with conservative demand factors applied. Operation at the proposed EPU RTP level would not increase any loads beyond the nameplate rating or design-basis loading or require the revision of any control logic. The licensee stated that the dc power distribution system would be adequate.

On the basis of this information, the NRC staff concludes that the proposed EPU at DAEC would have no impact on the dc power system and DAEC will continue to meet GDC 17 for the proposed EPU of 1912 MWt.

6.3 <u>Fuel Pool Cooling</u>

The licensee plans to pursue advanced core designs, including the use of GE-14 fuels for DAEC. Accordingly, in a separate licensing amendment request (dated November 17, 2000), the licensee presented an SFP T/H analysis to reflect the effects of GE-14 fuels used in the advanced core designs that increase fuel burnup, cycle length, and reload batch size on SFP cooling. Also, the SFP T/H analysis was performed for a power level of 1950 MWt (102 percent of 1912 MWt) with the anticipation of the DAEC operations at the proposed EPU level.

In the SE issued with DAEC License Amendment No. 242, dated September 21, 2001, the NRC staff found that the SFP T/H analysis conforms to the guidance described in SRP Section 9.1.3, “Spent Fuel Pool Cooling and Cleanup System,” for SFP, and is acceptable. Therefore, the NRC staff concludes that the design and operation of the SFP cooling systems (including the SFP cooling system and the RHR system in the SFP cooling assist mode) at DAEC are acceptable for plant operations at the proposed EPU level.

6.4 Water Systems

6.4.1 Service Water Systems

The service water systems are designed to provide cooling water to various systems (both safety-related and non-safety-related systems).

6.4.1.1 Safety-Related Service Water Systems (Safety-Related Loads)

These systems include the emergency service water (ESW) system and the RHR service water (RHRSW) system. All heat removed by these systems is rejected to the ultimate heat sink (UHS).

6.4.1.1.1 Emergency Service Water System

The ESW system provides cooling water to the following essential components/systems following a LOCA: emergency diesel generator coolers, RHR pump seal coolers, RHR and core spray pump room cooling units, HPCI and RCIC room cooling units, control building chillers, core spray and RHRSW pump bearing coolers, heating ventilating and air conditioning (HVAC), instrument air compressors, and SFP emergency makeup (if needed).

The licensee performed evaluations and stated that the performance of the ESW system during and following a LOCA is not significantly dependent on the RTP. The heat loads from diesel generators remain unchanged for LOCA conditions following uprated operations. The building cooling loads also remain the same because equipment performance in these areas remains essentially unchanged for post-LOCA conditions. In addition, the ability to supply emergency makeup[6] to the SFP is not changed following the EPU condition. Therefore, plant operations at the proposed EPU level do not require modification of the ESW system for the safety-related loads.

Based on the NRC staff’s review of the licensee's evaluation and rationale, and the experience gained from the review of power uprate applications for other BWR plants, the NRC staff finds that DAEC operations at the proposed EPU conditions do not change the design aspects and operation of the ESW system, and have an insignificant or no impact on the ESW system. Therefore, the NRC staff concludes that the ESW system at DAEC remains adequate for plant operations at the proposed EPU level to perform its safety function during and following a LOCA.

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[6] As reported in Section 6.3 of this SE regarding SFP rerack for DAEC, the calculated maximum boil-off rate is 53.05 gpm, which is less than the design makeup capacity of 59.5 gpm available from the ESW system.

6.4.1.1.2 Residual Heat Removal Service Water System

The RHRSW system provides cooling water to the RHR heat exchangers[7] under normal or post-accident conditions, and is capable of supplying water to flood containment for post-accident recovery. The licensee performed containment pressure and temperature response analyses which demonstrate that the capability of the containment system is adequate to operate at the proposed EPU level. In the containment pressure and temperature response analyses, the post-LOCA RHRSW flow rate and temperature were assumed to be unchanged for the proposed EPU conditions. Therefore, the RHRSW system remains adequate for plant operations at the proposed EPU level to perform its safety function during and following a LOCA. The NRC staff's evaluation of the containment system performance for plant operations at the proposed EPU level is addressed in Section 4.1 of this SE.

During SDC with the RHR system, heat loads on the RHR heat exchangers will increase in proportion to the increase in reactor operating power level, thus increasing the time required to reach the shutdown temperature. The licensee stated that this has no effect on plant safety. The NRC staff's evaluation of the effect of plant operations at the proposed EPU level on SDC with the RHR system is addressed in Section 3.9.1 of this SE.

In addition, since DAEC operations at the proposed EPU level do not change the design aspects and operations of the RHRSW system, the capability of the RHRSW system to flood the containment following a LOCA is not affected by plant operations at the proposed EPU level.

Based on the NRC staff's review of the licensee's rationale, the evaluation described above, and the experience gained from the review of power uprate applications for other BWR plants, the NRC staff finds that the RHRSW system is acceptable for DAEC operations at the proposed EPU level.

6.4.1.2 General Service Water System (Non-Safety-Related Loads)

The general service water (GSW) heat loads will increase approximately proportional to the increase in the reactor operating power level. The licensee stated that the major GSW heat load increases from the proposed EPU reflect an increase in main generator heat losses rejected to the stator water coolers, hydrogen coolers, and exciter coolers in addition to increases in bus cooler heat loads. The licensee performed evaluations which demonstrate that the GSW system is adequate for plant operations at the proposed EPU level.

Since the GSW system does not perform any safety-related function, the impact of the proposed EPU on the designs and performances of this system was not reviewed.

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[7] The long-term containment pressure and temperature responses following a LOCA are governed by the ability of the RHR system to remove the decay heat from the suppression pool.

6.4.2 Main Condenser, Circulating Water, and Normal Heat Sink System Performance

The main condenser, circulating, and normal heat sink systems are designed to provide the main condenser with a continuous supply of cooling water for removing heat rejected to the condenser, thereby maintaining condenser pressure as recommended by the turbine vendor. The licensee stated that the performance of the main condenser, circulating water, and normal heat sink systems was evaluated and found adequate for plant operations at the proposed EPU level.

Since the main condenser, circulating water, and normal heat sink systems do not perform any safety-related function, the impact of the proposed EPU on the designs and performances of these systems was not reviewed.

6.4.3 Reactor Building Closed Cooling Water System

The reactor building closed cooling water (RBCCW) system is designed to remove heat from various auxiliary plant equipment housed in the reactor building during normal plant operations. The licensee performed evaluations and stated that the increase in heat loads on this system due to plant operations at the proposed EPU level is insignificant.

Since the RBCW system does not perform any safety-related function, the impact of the proposed EPU on the designs and performances of this system was not reviewed.

6.4.4 Well Water System

The well water system supplies cooling water to many of the non-safety HVAC units. The licensee performed evaluations and stated that the well water system heat loads would not increase significantly due to the EPU. The well water system has adequate heat removal capability for plant operations at the proposed EPU level.

Since the well water system does not perform any safety-related function, the impact of the proposed EPU on the designs and performances of this system was not reviewed.

6.4.5 Ultimate Heat Sink

The UHS for DAEC is the Cedar River. During plant operation, heat loads from both safety-related and non-safety-related systems are rejected to plant cooling towers (normal heat sinks). Following a LOCA, the ESW and RHRSW heat loads are preferably to be rejected back to the plant cooling towers. However, if the cooling towers are not in operation or not operable, the total ESW and RHRSW heat loads are rejected to the UHS. The licensee performed an evaluation and concluded that the UHS would provide a sufficient quantity of water at a temperature of 95 °F (design temperature) following a DBA. The total heat rejected by the ESW system and the RHRSW system has a negligible thermal effect at the discharge structure.

Based on the licensee's evaluation and rationale, the NRC staff agrees that the total heat rejected to the UHS would have a negligible thermal effect. For this reason and based on the experience gained from the review of EPU applications for other BWR plants, the NRC staff finds that DAEC operations at the proposed EPU level will have an insignificant impact on the UHS.

6.5 Standby Liquid Control System

The licensee evaluated the effect of the proposed EPU on the SLC system injection and shutdown capability. The DAEC SLC system is a manually operated system that pumps sodium pentaborate solution into the vessel in order to provide neutron absorption and bring the reactor to a subcritical shutdown condition from RTP.

The licensee stated that an increase in the core thermal power does not by itself directly affect the ability of the SLC boron solution to bring the reactor to and maintain it in a safe-shutdown condition. However, implementation of a higher fuel batch fraction, a change in enrichment, or a new fuel design could affect the required shutdown concentration. The SLC system shutdown capability is, therefore, reevaluated each reload. According to the licensee, for the proposed EPU conditions, a new fuel design combined with an extension in the fuel cycle operating time would require an increase in the minimum reactor boron concentration from 600 ppm to 660 ppm. By increasing the volume of the stored boron solution, the licensee can provide the required amount of boron for the EPU cycle. The licensee submitted a license amendment application dated September 19, 2000, proposing to increase the SLC solution volume separately. The NRC staff approved the amendment request by DAEC License Amendment No. 236, dated January 23, 2001.

According to the licensee, the SLC system is designed to inject at a maximum reactor pressure equal to the upper analytical setpoints for the second lowest SRVs operating in the safety mode. The licensee stated that since the reactor dome pressure and the SRV setpoints will not change, the current SLC system process parameters will not change. According to the licensee, during this scenario, there is sufficient margin to lifting the SLC system relief valve. Therefore, the NRC staff agrees with the licensee’s conclusion that small changes in the SRV setpoint would have no effect on the SLC system’s capability to inject the required flow rate.

The SLC ATWS performance is addressed in Section 9.3.1 of this SE and the licensee has stated that the evaluation is based on a representative core design at the proposed EPU conditions. The licensee determined that the ATWS analysis showed that there is no adverse effect on the ability of the SLC system to mitigate an ATWS. The licensee concluded that the capability of the SLC system to perform its function would not be affected by the proposed EPU.

The NRC staff asked the licensee to confirm that for all limiting ATWS analyses, the SLC system would be able to inject the required flow rate at the required time in the analyses without lifting of the SLC system relief valve. In its August 16, 2001, supplemental letter, the licensee responded with an explanation of the sequence of events for the bounding loss of offsite power (LOOP) ATWS event. During this scenario, the peak vessel pressure reached 1185 psig during three short spikes after the initiation of the SLC system at about 120 seconds from the start of the event. All of the SRVs opened to relieve the pressure during the spikes, which result from reactor vessel level undershoots. The undershoot is caused by a code (ODYN) limitation in modeling the HPCI and RCIC systems. The undershoot of the water level results in overcorrection of the level, and the resulting overshoot of the level generates a high core flow and core power, and eventually generates excessive steam. This method of calculation results in the peak vessel pressure (1185 psig) that is greater than the maximum allowable vessel pressure for the SLC system injection (1172 psig), given a design basis 125 psi design margin to avoid lifting the SLC system relief valve. The available margin would instead be 112 psi during these short spikes.

Considering that the ODYN calculation is very conservative (plant response to the water level transient is expected to be considerably faster than ODYN models it to be), that there will still be 112 psi of margin to lifting the SLC system relief valve, and that the pressure spikes that are calculated occur only three times, for a very short duration, the NRC staff agrees with the licensee's conclusion that the SLC system will be able to inject boron into the reactor coolant system as required by 10 CFR 50.62.

6.6 Power-Dependent HVAC Systems

The HVAC systems consist mainly of heating, cooling supply, exhaust, and recirculation units in the turbine building, reactor building, and drywell. Plant operation at EPU conditions is expected to result in slightly higher process temperatures and higher electrical currents in some motors and cables. The licensee stated that HVAC systems affected by the proposed EPU are those systems in the turbine building, reactor building, MS tunnel, and drywell.

In the turbine building, the areas affected by the proposed EPU include the feedwater heater bay and condenser areas. Other areas are unaffected by the proposed EPU because the process temperatures remain relatively constant. Due to the proposed EPU, the temperature at the feedwater heaters in the turbine building would increase approximately 5 percent relative to the current operating temperature.

Heat loads in the drywell increase slightly due to increase in the recirculation pump motor horsepower and the feedwater process temperature. The maximum temperature increase is 1.3 °F. The increases in the condensate pump motor, feedwater pump motor, and reactor recirculation motor generation set motor horsepower result in a temperature increase that is less than 2 °F.

The heat loads discussed above represent an increase of 2 percent to 5 percent in the drywell, reactor building, and MS tunnel, and approximately 21 percent in the heater bay area. The licensee stated that based on the review of design-basis calculations and environmental qualification design temperatures, these heat load increases are within the excess design margin. By supplemental letter dated July 25, 2001, in response to the NRC staff's RAI, the licensee stated that the numerical values for increases in normal containment temperature are derived from DAEC plant-specific calculations. These plant-specific calculations are documented in GE's design record files.

By supplemental letter dated June 21, 2001, in response to the NRC staff's RAI, the licensee explained that for the evaluation of the turbine building HVAC performance, assumptions were made to maximize the duty on the cooling units. For example, the largest increase in the "sub-area" heat load (i.e., an increase of 21 percent near the main condenser and feedwater heater #1) was conservatively assumed to apply to the entire condenser/heater bay area. Most "sub-areas" were predicted to experience an increase in heat load of only 4 percent to 10 percent.

The licensee further explained that the turbine building HVAC system is sized with enough margin to accommodate the expected increase in actual heat load for the feedwater heater bay area. This can be seen by the predicted small increase in outlet cooling water temperature of the coolers for the above increase (21 percent) in heat load. Because of the excess in cooling capacity and the use of very conservative inputs to the analysis, the licensee does not expect to see any noticeable increase in actual operating temperatures in this area.

As determined in the licensee's rationale as described above, and based on the experience gained from the review of EPU applications for other BWR plants, the NRC staff concludes that the proposed EPU does not adversely affect the operation of HVAC.

6.7 Fire Protection Program

The NRC staff finds that the operation of DAEC at the proposed EPU RTP will have no impact on the existing fire detection or suppression systems, the existing fire barriers provided to protect safe-shutdown capability, or the administrative controls that are specified in the plant's fire protection plan required by 10 CFR 50.48(a). The NRC requirements for achieving and maintaining safe shutdown following a fire require (1) that one train of systems necessary to achieve and maintain hot shutdown be maintained free of fire damage, and (2) that the systems necessary to achieve and maintain cold shutdown can either be repaired within 72 hours if using redundant systems, or the systems can be repaired and cold shutdown can be achieved within 72 hours if using alternative or dedicated shutdown capability. Table 6-3 of the Safety Analysis Report indicates that the limits for important reactor process variables (PCT, primary systems pressure, primary containment pressure, and suppression pool bulk temperature) are not exceeded following a fire event.

Section 3.8, "Reactor Core Isolation Cooling," of the Safety Analysis Report states that for certain beyond-design-basis events (Appendix R or ATWS), operation of the RCIC system at suppression pool temperatures greater than the operation limit may be accomplished by using the dedicated condensate storage tank (CST) volume source of water. Section 4.2.1, "High Pressure Coolant Injection," of the Safety Analysis Report states that for certain beyond-design-basis events (Appendix R or ATWS), operation of the HPCI system at suppression pool temperatures greater than the operation limit may be accomplished by using the dedicated CST volume source of water. The NRC staff has accepted the use of either HPCI or RCIC with suction from either the suppression pool or the CST for providing reactor coolant makeup to achieve hot shutdown when those systems are protected in accordance with the requirements specified in Section III.G of Appendix R to 10 CFR Part 50.

While the higher decay heat associated with the proposed EPU may reduce the time available for the operators to achieve cold shutdown, it should not impact the time required to repair those systems necessary to achieve and maintain cold shutdown, and would therefore only affect those fire areas in the plant where alternative or dedicated shutdown systems are relied upon to satisfy NRC requirements (i.e., those plant areas that must achieve cold shutdown within 72 hours following a fire). The licensee has stated that the safe-shutdown systems and equipment used to achieve and maintain cold-shutdown conditions do not change and are adequate for the proposed EPU conditions. Based on the above discussion, the NRC staff find this acceptable.

The proposed EPU may also reduce the time available for the operators to stabilize the plant in hot shutdown, and may affect the systems necessary to achieve and maintain hot shutdown for those plant areas that rely upon the use of SRVs in conjunction with the use of low-pressure systems, such as core spray and LPCI, to provide reactor coolant makeup. The licensee has analyzed these systems for the proposed EPU and stated that the operator actions required to mitigate the consequences of a fire would not be affected by the proposed EPU and that sufficient time is available for the operator to perform the necessary actions. Based on the above discussion, the NRC staff finds this acceptable.

Therefore, based on the information provided by the licensee in the Safety Analysis Report, the NRC staff concludes that the proposed EPU would not adversely affect the post-fire safe-shutdown capability and is therefore acceptable.

6.8 Systems Not Affected or Insignificantly Affected by Extended Power Uprate

The licensee identified systems that are not affected or insignificantly affected by plant operations at the proposed EPU level. The NRC staff has reviewed those systems (i.e., auxiliary steam, instrument air, service air, miscellaneous HVAC, diesel generator, and their associated supporting systems, etc.). Based on the NRC staff's review of the systems identified by the licensee and the experience gained from the review of EPU applications for other BWR plants, the NRC staff agrees that plant operations at the proposed EPU level has no or insignificant impact on those systems.

7.0 POWER CONVERSION SYSTEMS

7.1 Turbine Generator

The turbine generator was originally designed to have the capability to operate continuously at 105 percent of rated steam flow conditions with a degree of margin to allow control of important variables such as steam inlet pressure. As a result of the proposed plant operations at the proposed EPU power level, the high-pressure turbine will be modified to increase its steam flow capability to approximately 122 percent of the original rated steam flow.

The licensee performed evaluations to verify the mechanical integrity of the turbine under plant operations at the proposed EPU level. The licensee stated that results of the evaluations showed that, other than for the modification to the high-pressure turbine, only minor (nonsafety) modifications to the turbine generator are needed.

The licensee further stated that there would be an insignificant increase in the probability of turbine overspeed and the associated turbine missile production due to plant operations at the proposed EPU level. There is sufficient design margin in the current turbine overspeed protection trip settings. The licensee's setpoint methodology has been reviewed and accepted by the NRC staff. Therefore, based on the licensee's rationale and evaluation, the NRC staff concludes that the upgraded turbine generator system could be continuously operated safely at the proposed EPU conditions.

7.2 Miscellaneous Power Conversion Systems

The licensee evaluated miscellaneous steam and power conversion systems and their associated components (including the condenser air removal and steam jet air ejectors, turbine steam bypass, feedwater and condensate systems, and condensate demineralizers) for plant operations at the proposed EPU level. The licensee stated that the existing equipment for these systems with the exception of feedwater and condensate systems is acceptable for plant operations at the proposed EPU level. Modification to some non-safety-related equipment in the feedwater and condensate systems is necessary to attain the proposed EPU core thermal power.

Since these systems do not perform any safety-related function, the NRC staff has not reviewed the impact of plant operations at the proposed EPU level on the design and performance of these systems.

8.0 RADWASTE SYSTEMS AND RADIATION SOURCES

8.1 Liquid and Solid Waste Management

The single largest source of liquid and wet solid waste is from the backwash of the condensate demineralizers and from the spent resin tank. The licensee stated that plant operations at the proposed EPU level would result in an increase of flow rate through the condensate demineralizers; therefore, the average time between backwashes would be reduced slightly. This reduction would not affect plant safety. Similarly, the RWCU filter demineralizer may require more frequent backwashes due to slightly higher levels of activation and fission products. The licensee further stated that the activated corrosion products in liquid wastes are expected to increase in proportion to the proposed EPU. The increase in dry solid waste is insignificant. However, the total volume of processed waste is not expected to increase appreciably, since the only significant increase in processed waste is due to more frequent backwashes of the condensate demineralizers and RWCU filter demineralizers. The licensee reviewed plant operation and effluent reports, and concluded that the requirements of 10 CFR Part 20 and 10 CFR Part 50, Appendix I, will continue to be satisfied.

Based on the licensee's rationale and evaluation, and based on NRC experience gained from the review of EPU applications for other BWR plants, the NRC staff finds the liquid and wet solid radwaste systems acceptable.

8.2 Gaseous Waste Management

Gaseous wastes generated during normal and abnormal operation are collected, controlled, processed, stored, and disposed of utilizing the gaseous waste processing treatment systems. These systems, which are designed to meet the requirements of 10 CFR Part 20 and 10 CFR Part 50, Appendix I, include the offgas system and SGTS, as well as other building ventilation systems. Various devices and processes, such as radiation monitors, filters, isolation dampers, and fans, are used to control airborne radioactive gases. The results of the licensee’s analyses demonstrate that airborne effluent activity released through building vents is not expected to increase significantly due to plant operations at the proposed EPU level. The release limit is an administratively controlled variable, and is not a function of core power.

Based on the licensee's rationale and evaluation, and based on NRC experience gained from the review of EPU applications for BWR plants, the NRC staff concludes that plant operations at the proposed uprate power level will have an insignificant impact on the above systems.

8.2.1 Offgas System

Core radiolysis (i.e., formation of H_2 and O_2) increases linearly with core power, thus increasing the heat load on the offgas recombiner and related components. The licensee evaluated the impact of the increases of these offgases resulting from plant operation at the proposed EPU level on the offgas system. The licensee stated these operational increases in offgas due to EPU remain well within the design capacity of the system. The system radiological release rate is administratively controlled and does not change with operating power. Therefore, the proposed EPU would not affect operation of the offgas system since it remains within its design limits.

The NRC staff reviewed the licensee's rationale and evaluation, and based on that rational and evaluation, and the NRC experience gained from the review of EPU applications for other BWR plants, the NRC staff concludes that plant operations at the proposed EPU level will remain within the design limits of the offgas systems.

8.3 <u>Radiation Sources in the Reactor Core</u>

The NRC staff has reviewed the licensee's plan for the proposed EPU with respect to its effect on the facility radiation levels and on the radiation sources in the core. During power operation, the radiation sources in the core include the fission process itself, accumulated fission products, and neutron reactions as a secondary result of reactor power. The radiation sources in the core are expected to increase in proportion to the increase in power. However, this increase is bounded by the existing safety margins of the design-basis sources. Since the reactor vessel is inaccessible during operation, a 15.3-percent increase in the radiation sources in the reactor core will have no affect on occupational worker personnel doses during power operations. Due to design shielding and containment surrounding the reactor vessel, worker occupational doses would be largely unaffected, and doses to the public from radiation shine from the reactor vessel would essentially remain zero as a result of implementation of the proposed EPU.

The post-operational radiation sources in the core are the result of accumulated fission products. Two forms of post-operational source data are used for shielding analysis purposes. The first of these is the core gamma-ray source. The total gamma energy source increases in proportion to reactor power. The shielding at DAEC was conservatively designed so that the proposed increase in radiation sources in the core will not affect radiation zoning in the plant.

The second set of post-operation source data consists of tabulated isotopic activity inventories for fission products in the fuel. These are used for post-accident evaluations. Most fission product inventories reach equilibrium within a 3-year period. These inventories can be expected to increase in proportion to the thermal power increase. The results of the post-accident evaluations using these revised fission product activities are contained in Section 9 of the Safety Analysis Report.

Based on the experience gained from the review of EPU applications for other BWR plants and for the reasons described above, the NRC staff finds the level of the radiation sources in the reactor core following implementation of the proposed EPU to be acceptable.

8.4 Radiation Sources in the Reactor Coolant

During operations, the reactor coolant passing through the reactor core region becomes radioactive as a result of nuclear reactions. The activation products in the reactor water will increase in approximate proportion to the increase in thermal power. The installed shielding at DAEC was conservatively designed so that the increase in activation products in the reactor water resulting from the proposed EPU would not affect radiation zoning in the plant. However, the licensee will monitor radiation levels throughout the plant and restrict access to areas when necessary to maintain occupational doses as low as reasonably achievable (ALARA).

The dose rates in some areas of the plant from the activation product N-16 in the steam may increase in approximate proportion to the increase in thermal power. DAEC has been implementing hydrogen water chemistry (HWC) (injecting hydrogen into the feedwater) to mitigate the effects of intergranular stress corrosion cracking (IGSCC) since 1989. The use of HWC results in a large increase in the concentration of N-16 in the steam relative to the concentration with normal water chemistry. Between 1994 and 1996, the licensee increased the hydrogen injection rate into the feedwater from 6 scfm to 15 scfm to extend corrosion protection to portions of the core internals. This resulted in dose rates in (primarily due to N-16) certain areas of the plant that were 3.3 times higher than the dose rate levels without hydrogen injection. Although occupancy in some plant areas was restricted due to these higher dose rates, no shielding modifications were required to maintain plant radiation levels within acceptable levels. In 1996, the licensee implemented a noble metals injection program at DAEC to protect the core internals from corrosion. One of the benefits of this program was that the hydrogen injection rates were lowered to the level where there were no discernable dose rate increases due to N-16 from hydrogen injection. Under the current noble metal injection program, the projected overall 20-percent increase in the N-16 dose rates resulting from the proposed EPU would be well bounded by DAEC’s experience with HWC and will not have an impact upon the acceptability of the shielding design.

Activated corrosion products (ACP) are the result of the activation of metallic wear materials in the reactor coolant. Under the proposed EPU conditions, the feedwater flow rate would increase with power, the activation rate would increase with power, and the filter efficiency of the condensate demineralizers may decrease as a result of the feedwater flow increase. The net result may be an increase in the ACP production and an increase in the ACP concentration in the reactor coolant. However, the expected ACP increase should not exceed the design-basis concentrations. Most of the areas (e.g., recirculation pumps and the RWCU) that would be affected by this increase in activated corrosion products are located in locked areas or areas that are inaccessible during plant operation, such as the drywell (primary containment). Since these areas are usually high dose rate areas, personnel access to these areas will be restricted during plant operations as required by 10 CFR Part 20 high radiation area (HRA) requirements, and in accordance with the DAEC TS and required licensee implementing procedures.

Fission products in the reactor coolant result from the escape of minute fractions of the fission products that are contained in the fuel rods. Fission products in the primary coolant are separable into the products in the steam and the products in the reactor water. The activity in the steam consists of noble gases released from the core, plus carryover activity from the reactor water. Since the current fuel thermal limits (which affect the rate of release of fission products from the fuel rods) would be maintained for the proposed EPU, there would be no change in the amounts of fission products released to the reactor coolant from the fuel. Therefore, the fission product activity levels in the steam and reactor water are expected to be approximately equal to current measured data. The current measured fission product activity levels in the reactor coolant are a small fraction of the design-basis levels. Even if the fission product activity in the reactor coolant were to increase by 20 percent as a result of the proposed EPU, the resulting fission product activity levels in the reactor coolant would still be a small fraction of the design-basis levels.

The licensee has stated that the various radiation sources in the reactor coolant would either remain relatively unchanged or would increase in approximate proportion to the increase in thermal power as a consequence of the proposed EPU. In all cases, however, the increased level of radiation sources following implementation of the proposed EPU would be well below the design-basis data levels. On this basis and for the reasons described above, the NRC staff finds the increased level of radiation sources in the reactor coolant to be acceptable.

8.5 Radiation Levels

Radiation sources in the reactor coolant contribute to the plant radiation levels. As discussed previously, the overall proposed 20-percent EPU would result in a proportional increase in certain radiation sources in the reactor coolant. This increase in reactor coolant activity would result in some increases (up to 20 percent) in plant radiation levels in most areas of the plant. The increase in plant radiation levels may be higher in certain areas of the plant (e.g., near the reactor water piping and liquid radwaste equipment) due to the presence of multiple radiation sources (i.e., ACPs, fission products, N-16).

Post-operational radiation levels in most areas of the plant are expected to increase by no more than the percentage increase in thermal power level. This increase in post-operational radiation levels could be slightly higher in a few areas near the reactor water piping and liquid radwaste equipment. Many of these areas are normally locked, controlled in accordance with 10 CFR Part 20 HRA requirements, and require infrequent access.

During the initial power ascension steps of the proposed EPU, the licensee will conduct a startup test program. This startup program will include radiation monitoring to ensure that personnel exposures are maintained ALARA, radiation survey maps are accurate, and radiation zones are properly posted. The licensee also stated that many portions of the plant were originally designed for higher-than-expected radiation sources. Therefore, the small potential increase in radiation levels resulting from the proposed EPU would not affect radiation zoning or shielding in the various areas of the plant that may experience higher radiation levels. The doses to individual workers would be maintained within acceptable limits by controlling access to radiation areas. The licensee will use procedural controls to compensate for any increased radiation levels and to maintain occupational doses ALARA.

The licensee has established a number of programs over the past several years to reduce post-operation radiation levels and/or reduce the number of repairs required in radiation areas. These programs include a successful cobalt reduction program, zinc injection, hydrogen water chemistry, and noble metal chemical addition. In addition, the licensee performed chemical decontaminations of the recirculating system to reduce dose rates in 1990, 1992, 1993, and 1995. As a result of these actions, DAEC's rolling 3-year dose average has decreased in each of the past 8 years.

The proposed EPU would result in a small increase in post-accident radiation levels. Item II.B.2 of NUREG-0737 states that the occupational worker dose guidelines of GDC 19 (10 CFR Part 50, Appendix A) shall not be exceeded during the course of an accident. Conformance with Item II.B.2 ensures that operators can access and perform required duties and actions in designated vital areas. GDC 19 requires that adequate radiation protection be provided such that the dose to personnel shall not exceed 5 rem whole body, or its equivalent, to any part of the body (the equivalent extremity limit is 75 rem), for the duration of the accident. The licensee has determined that the post-accident vital mission dose associated with accessing the post-accident sampling system (PASS) is the highest dose to personnel of all the post-accident missions and, as such, is the limiting case. The licensee calculates that the post-accident mission dose to the whole body will increase from 4.46 rem TEDE to 4.66 rem total effective dose equivalent (TEDE) while the extremity dose will increase from 22.83 rem to 24.57 rem. These mission doses are below the dose limits of 5 rem TEDE and 75 rem, respectively. Therefore, personnel access to, and work in, designated vital areas for accident mitigation following a LOCA can still be accomplished without exceeding the dose requirements of GDC 19. Additionally, the calculated dose estimates for personnel performing required post-LOCA duties in the plant's TSC remain within GDC limits.

Several physical plant modifications will need to be completed prior to full implementation of the power rate increase. These modifications will be planned and conducted in accordance with the station ALARA program. Some of these modifications were implemented during refueling outage RF017. The collective dose accrued to implement these modifications was approximately 5 rem. The balance of the proposed EPU modifications will be made in RF018. The licensee expects that it will take another 5 rem to implement these additional modifications for a total of approximately 10 rem to make the modifications for the proposed EPU. This expected, one-time occupational dose to make these modifications is a small fraction of the average yearly worker collective dose at DAEC.

8.6 <u>Normal Operation Off-Site Doses</u>

For the proposed EPU, normal operation gaseous activity levels are expected to increase in proportion to the percentage increase in core thermal power. The limits within the DAEC TS implement the guidelines of 10 CFR Part 50, Appendix I. At the ORTP, the radiation effluent doses were a small fraction of the doses allowed by the TS limits. The proposed EPU would not involve significant increases in the offsite doses from noble gases, airborne particulates, iodine, or tritium. Radioactive liquid effluents are not routinely discharged from DAEC. There are no offsite dose contributions due to skyshine from N-16. Present offsite radiation levels are a negligible portion of background radiation. Therefore, the normal offsite doses would not be significantly affected by operation at the proposed EPU RTP level and would remain well within the TS dose limits and below the limits of 10 CFR Part 20 and 10 CFR Part 50, Appendix I.

On the basis its review of the EPU application, as described above, the NRC staff concludes that the proposed 15.3-percent (20-percent overall) EPU would have little effect on personnel occupational doses and that these doses would be maintained ALARA in accordance with the requirements of 10 CFR Part 20. Additionally, the operator-calculated doses from external exposures from a DBA will be less than the allowable GDC 19 criteria, and will allow operators access into vital areas for needed emergency activities. Therefore, the NRC staff finds the proposed EPU to be acceptable from normal operations occupational and GDC-19 accident dose perspectives.

9.0 REACTOR SAFETY PERFORMANCE FEATURES

9.1 Reactor Transients

AOOs are abnormal operational occurrences or transients which are expected to occur one or more times in the life of a plant and are initiated by a malfunction, a single failure of equipment, or a personnel error. The applicable acceptance criteria for the AOOs are based on 10 CFR Part 50, Appendix A, GDC 10, GDC 15, and GDC 20. GDC 10 requires that the reactor core and associated control and protection systems be designed with margin sufficient to ensure that the specified acceptable fuel design limits are not exceeded during normal operation and during AOOs. GDC 15 stipulates that sufficient margin be included to ensure that the design conditions of the RCPB are not exceeded during normal operating conditions and AOOs. GDC 20 specifies that the protection system shall automatically initiate the operation of appropriate systems to ensure that the specified fuel design limits are not exceeded during any normal operating condition and AOOs.

The SRP further states that (1) pressure in the reactor coolant and MS system should be maintained below 110 percent of the design values according to the ASME Code, Section III, Article NB-7000, “Overpressure Protection;” (2) fuel cladding integrity should be maintained by ensuring that the reactor core is designed to operate with appropriate margin to specified limits during normal operating conditions and AOOs; (3) an incident of moderate frequency should not generate a more serious plant condition unless other faults occur independently; and (4) an incident of moderate frequency, in combination with any single-active component failure or single operator error, should not result in the loss of function of any fission product barrier other than the fuel cladding. A limited number of fuel cladding perforations are acceptable.

The DAEC UFSAR evaluates a wide range of potential transients. Chapter 15 of the UFSAR contains the design-basis analyses that evaluate the effects of an AOO in the following categories: (1) a decrease in core coolant temperature, (2) an increase in reactor pressure, (3) a decrease in reactor core coolant flow rate, (4) reactivity and power distribution anomalies, (5) an increase in reactor coolant inventory, and (6) a decrease in reactor coolant inventory. The plant’s responses to the most limiting transients are analyzed each reload cycle and are used to establish the thermal limits. A potentially limiting event is an event or an accident that has the potential to affect the core operating and safety limits.

The generic guidelines for EPU evaluation (Appendix E of ELTR1) identified (a) the limiting transient to be considered in each event category, (b) the analytical methods to be used, (c) the operating conditions assumed in the generic evaluation presented in the report, and (d) the criteria that were applied. The licensee stated that in support of the proposed EPU, the limiting transient for each category of the transients listed in Table E-1 of ELTR1 was analyzed. Table 9-1 of the Safety Analysis Report describes the reactor operating conditions used in analyzing the limiting transients for the recent pre-EPU fuel cycle (Reload 16) and for the EPU representative core. The table also lists the nominal dome operating pressure and the SLMCPR used in the transient analyses and in calculating the OLMCPR. The EPU transients analyses were based on a representative GE-14 core and the licensee calculated a corresponding SLMCPR value of 1.08 for the representative core.

The licensee stated that input parameters related to the performance improvement features or equipment out of service (OOS) have been included in the safety analyses for the proposed EPU. DAEC is licensed or seeks to implement MELLLA, SLO, one ADS OOS, ARTS, turbine bypass valve (TBV) OOS, recirculation pump trip (RPT) OOS, and MSIV OOS for EPU operation. Therefore, the EPU transient analyses that were performed considered these operating features. According to the licensee, most of the transient events are analyzed at full power and at the maximum allowed core flow operating point on the power/flow map (Figure 2-1). The licensee also included the 2-percent power uncertainty in the analyses, except where it is already accounted for in the analysis methodology or is not required. The licensee analyzed the following limiting transients (Table 9-2 of the Safety Analysis Report provides the results):

- load rejection with bypass failure (LRWOB)
- TTNBP
- feedwater controller failure maximum demand
- loss of feedwater heating (LFWH)
- inadvertent HPCI actuation
- rod withdrawal error (RWE)
- fast recirculation increase
- slow recirculation increase
- load reject with bypass
- MSIVC all valves
- MSIVC one valve

The licensee determined that, as shown in Table 9-2 and Figures 9-1 thru 9-4 of the Safety Analysis Report, there are no changes to the basic characteristics of any of the limiting events due to EPU operating conditions.

Table 9-2 does not include the pressure regulator downscale failure transient, which is included in Table E-1 of ELTR1. However, DAEC is equipped with a backup regulator and this event is considered to be a mild transient. In addition, other transients in the category of decrease in heat removal by the reactor coolant system bound this event. Also, Table 9-2 does not include LOFW, which forms the basis for evaluating the RCIC capability to perform its design-basis function. However, as discussed in Section 3.8 of this SE, the licensee analyzed this transient. Appendix E of ELTR1 does include a loss of single feedwater pump transient, but the licensee considers this event to be nonlimiting with respect to MCPR. The NRC staff agrees with this assessment since loss of all feedwater bounds loss of single feedwater pump in terms of MCPR.

In its February 8, 1996, staff position on ELTR1, the NRC staff accepted that the minimum set of limiting transients described in Appendix E of ELTR1 needed to be included in the power uprate amendment request. The NRC staff also stated that a list of all of the transients analyzed in support of the proposed EPU should be included, with an explanation of how the limiting transients were selected. The EPU application did not provide the bases for selecting the EPU limiting transients. However, in plant-specific submittals, GE selects the limiting EPU transients by evaluating the seven categories of transient events based on the EPU parameters to ensure that (a) the UFSAR events remain bounded by the reload transient events, (b) no nonlimiting events become limiting in terms of thermal limits due to the EPU, and (c) no additional limiting event in terms of thermal limits are caused by the EPU operating conditions. Appendix E.2.2 of ELTR1 also discusses the bases for selecting the limiting transients to analyze in support of the proposed EPU. The stated justifications are applicable to DAEC.

In support of operation at the higher MELLLA rod line and the proposed EPU power level, the licensee analyzed the limiting transients using a representative GE-14 core. The current EPU analyses are based on NRC-approved analytical methods and codes. The transient evaluations also take into account the impact of performance improvement programs or special features in establishing the thermal limits for the proposed EPU operation. The NRC staff agrees with the licensee's conclusions that the EPU transient analyses do not identify any major changes to the basic characteristics of any of the limiting events due to the proposed EPU operating conditions. The licensee will be uprating in phases, and will analyze or confirm the limiting transients based on the actual core design (as described in Section 1.3 of the Safety Analysis Report) and the uprated power level at each phase of the uprate process. Therefore, the NRC staff finds this approach acceptable.

9.2 Design-Basis Accidents

In December 1999, the NRC issued a new regulation, 10 CFR 50.67, “Accident Source Term,” which provided a mechanism for licensed power reactors to replace the traditional accident source term used in their DBA analyses with ASTs. Regulatory guidance for the implementation of these ASTs is provided in RG 1.183. The regulation at 10 CFR 50.67 requires a licensee seeking to use an AST to apply for a license amendment and requires that the application contain an evaluation of the consequences of affected DBAs. NMC submitted an application dated October 19, 2000, as supplemented March 23, April 9, and June 27, 2001, addressing these requirements in proposing to use the AST described in RG 1.183 as the DAEC DBA source term used to evaluate the radiological consequences of DBAs. As part of the implementation of the AST, the TEDE acceptance criterion of 10 CFR 50.67(b)(2) replaces the previous whole body and thyroid dose guidelines of 10 CFR 100.11 and 10 CFR Part 50,

Appendix A, GDC 19, for the LOCA, the main steamline break (MSLB) accident, and the control rod drop accident.

The accident source term is intended to be representative of a major accident involving significant core damage and is typically postulated to occur in conjunction with a large LOCA. As a result of significant core damage, fission products are available for release into the containment environment. An AST is an accident source term that is different from the accident source term used in the original design and licensing of the facility and has been approved for use under 10 CFR 50.67. Although an acceptable AST is not set forth in the regulations, RG 1.183 identifies an AST that is acceptable to the NRC staff for use at operating reactors.

By DAEC License Amendment No. 240, dated July 31, 2001, the NRC approved the licensee's October 19, 2000, application concerning AST implementation. The amendment allows the replacement of the accident source term used in design-basis radiological analyses with an AST pursuant to 10 CFR 50.67. The NRC had previously approved the TS changes associated with secondary containment operability during refueling operations and the selective implementation of the AST to the FHA in DAEC License Amendment No. 237, dated April 16, 2001. The SE issued with Amendment No. 240 addresses the NRC staff's review of the DBA analyses. The NRC staff reviewed the assumptions, inputs, and methods used by the licensee to assess the radiological impacts of the proposed changes. In doing this review, the NRC staff relied upon information placed on the docket by the licensee, NRC staff experience in doing similar reviews and, where deemed necessary, the NRC staff's confirmatory calculations. The NRC staff concluded that the licensee used analysis methods and assumptions consistent with the conservative guidance of RG 1.183, the proposed TS changes, and the proposed EPU.

The NRC staff found reasonable assurance that DAEC AST implementation will continue to provide sufficient safety margins with adequate defense-in-depth to address unanticipated events and to compensate for uncertainties in accident progression and in analysis assumptions and parameters.

Since these analyses were performed at a power level of 1950 MWt (102 percent of 1912 MWt), the NRC staff finds that the radiological consequences of these DBAs would remain bounding up to an RTP of 1912 MWt.

9.3 Special Events

9.3.1 Anticipated Transient Without Scram

ATWS is defined as an AOO with failure of the RPS to initiate a reactor scram to terminate the event. The requirements for ATWS are specified in 10 CFR Part 50.62. The regulation requires BWR facilities to have the following mitigating features for an ATWS event:

(1) SLC system with the capability of injecting into the RPV a borated water solution with reactivity control equivalent to the control obtained by injecting 86 gpm of a 13-weight percent sodium pentaborate decahydrate solution at the natural boron-10 isotope abundance into a 251-inch inside diameter reactor vessel

(2) an alternate rod injection (ARI) system that is designed to perform its function in a reliable manner and that is independent (from the RTS) from sensor output to the final actuation devise

(3) equipment to trip the reactor coolant recirculation pumps automatically under conditions indicative of an ATWS

BWR performance during an ATWS is also compared to other criteria that were used in the development of the ATWS safety analyses described in GE LTR "Assessment of BWR Mitigation of ATWS," Volume II, dated December 1979 (Reference 10). The criteria include (a) limiting peak vessel bottom pressure to less than the ASME Service Level C limit of 1500 psig, (b) ensuring that the PCT remains below the 10 CFR 50.46 limit of 2200 °F, (c) ensuring that the cladding oxidation remains below the limit in 10 CFR 50.46, (d) limiting peak suppression pool temperature to less than 281 °F (containment design temperature), and (e) limiting the peak containment pressure to a maximum of 62 psig (110 percent of containment design pressure).

The ATWS analyses assume that the SLC will inject within a certain time to bring the reactor to and maintain it in a subcritical condition even after the reactor has cooled to cold-shutdown condition. For every reload, the licensee evaluates how plant modifications, reload core designs, changes in fuel design, and other reactor operating changes affect the applicability of the ATWS analysis of record.

The licensee stated that DAEC meets the ATWS mitigation requirements defined in 10 CFR 50.62 because (a) an ARI system is installed, (b) the boron injection capability is equivalent to 86 gpm of a solution of the required concentration into the specified reactor size, and (c) an automatic ATWS-RPT has been installed. Section L.3 of ELTR1 discusses the ATWS analyses and provides a generic evaluation of the following limiting ATWS events in terms of overpressure and SPC: (a) MSIVC, (b) pressure regulator failure-open, (c) LOOP, and (4) inadvertent opening of a relief valve. The licensee performed the ATWS analyses, as discussed in ELTR1, at the MELLLA/EPU operating condition to demonstrate that DAEC meets the ATWS acceptance criteria. To provide a benchmark for the plant's response to limiting ATWS events, the licensee also performed the ATWS analyses based on the ORTP.

Tables 9-7 and 9-8 of the Safety Analysis Report provided the key input parameters used in the ATWS analyses and the corresponding results (peak vessel bottom pressure, PCT, peak suppression pool temperature, and peak containment pressure). The licensee stated that the results of the ATWS analyses meet the ATWS acceptance criteria. Therefore, the plant's response to an ATWS event for EPU operation is acceptable.

Table 9-8 shows that the ATWS PCT for the ORTP is 1418 °F and the EPU PCT is 1380 °F. The NRC staff asked the licensee to verify the PCT values. The licensee confirmed that the PCT values are correct and explained the basis for the reduced ATWS PCT for the proposed EPU operation. The average bundle power increases for the EPU operation (flatter power distribution), which increases the two-phase flow resistance of the average channels. The relative flow distributions between the hot and the average bundles change and the fraction of the flow passing through the hot bundles increase. The increased flow through the hot bundles moderates the PCT increase for the EPU operation. Since the ATWS analyses are based on

NRC-approved methods and the licensee performed the ATWS analyses at the MELLLA/EPU conditions, the NRC staff accepts the licensee's evaluation.

The NRC staff agrees with the licensee that DAEC meets ATWS mitigating features stipulated in 10 CFR 50.62 and the results of the ATWS analyses at the EPU/MELLLA operation meet the ATWS acceptance criteria. Future reload analyses would confirm that the plant's response to an ATWS event based on the cycle-specific condition will continue to meet the ATWS acceptance criteria.

<u>ATWS Instability</u>

The potential for instability following a transient ATWS-RPT event has been the subject of extensive research and discussions between the NRC and the BWROG. In GE LTR "ATWS Rule Issues Relative to BWR Core Thermal-Hydraulic Stability," dated June 1995 (Reference 8), the BWROG and GE generically addressed the potential for T/H instability during an ATWS event and its impact on high power density BWR/5 and BWR/6 reactors operating at reactor power levels of 3323 MWt. The NRC staff reviewed and accepted the LTR and issued a safety evaluation report on February 5, 1994, that found the report acceptable. In the safety evaluation report, the NRC staff stated:

(a) Although large power oscillations may worsen the overheating and severity of fuel damage resulting from an ATWS event, the analyses indicate that core coolability and containment integrity can be maintained. The NRC staff concluded that the prescriptive requirements of the ATWS rule remained appropriate.

(b) The BWROG had proposed to revise the EPGs [Emergency Procedure Guidelines] and direct immediate action to be taken by the operators to reduce core inlet subcooling after confirmation of an ATWS event and direct earlier injection of boron in the presence of power oscillations. The NRC staff noted that the risk prospective reviews of the proposed actions were continuing, but these actions are sufficient for mitigating the consequences of a bounding ATWS event with oscillation.

(c) By reducing the core inlet subcooling, the EPGs will instruct the operators to continue decreasing the water level and maintain it at a level of about 1 meter or more below the feedwater spargers to ensure effective termination of power oscillation. Reducing the water level below the feedwater spargers would ensure that when the feedwater flow is resumed, the incoming cold water is heated by mixing with the steam. The NRC staff stated that injection of additional water would not provide significant benefit to the response to instability and other criteria must be used to determine whether water level reduction below the TAF is warranted.

The NRC staff also stated that the recommended operator actions to lower water level to below the feedwater nozzles and earlier SLC system activation were appropriate for mitigating the ATWS event with oscillations.

Section L.3.1, "Power Conditions for ATWS Evaluation," and Section L.3.2, "Operator Action," of ELTR1 discuss some aspects of ATWS instability. The Safety Analysis Report stated that the effect of operation along the maximum extended operating domain (MEOD) will be considered, explaining that MEOD operation will maximize the natural circulation power level after an ATWS-RPT. In addition, ELTR1 stated that operator actions would be assumed to be consistent with the BWR EPGs and with typical operator actions for ATWS including:

(1) tripping the feedwater pumps on high suppression pool temperature or other confirmed ATWS symptoms,
(2) starting the SLC system on confirmed ATWS symptoms,
(3) maintaining the RPV water level near the TAF during an ATWS event, and
(4) starting the RHR in the pool cooling mode on high suppression pool temperature.

The Safety Analysis Report further stated that in "some areas, manual actions are involved in ATWS evaluation. It is most consistent for the plants to assume that these actions are performed in response to symptoms as they may occur during the postulated event." ELTR1 also recommended tripping the feedwater pumps to reduce subcooling, which is an important destabilizing factor. Maintaining the reactor water level at the TAF (below the feedwater spargers) would also reduce subcooling and excess reactivity.

The NRC staff asked the licensee to confirm that DAEC's EPGs are consistent with ELTR1 and the recommendations in Reference 8. In its August 16, 2001, supplemental letter, the licensee confirmed that the basic strategies and operator responses in the Emergency Operating Procedures (EOPs) have not been changed as a result of the proposed EPU. The current EOPs are consistent with the recommended ELTR-1 Section L.3.2 actions, and they will continue to remain so after implementation of the proposed EPU.

The NRC staff realizes that the proposed EPU safety analyses did not include a review of the applicability of the generic instability analyses specified in Reference 8 to DAEC EPU operation involving a high-density core, MELLLA, and GE-14 fuel design. However, DAEC does meet the 10 CFR 50.62 and GDC 12 requirements. Therefore, the NRC staff's acceptance of DAEC's ATWS-RPT instability protection relies on the fact that (1) the ATWS mitigating features will ultimately terminate the event, (2) DAEC is less likely to be susceptible to regional mode instability, and (3) the DAEC EOPs are consistent with the recommendations and staff position specified in ELTR1 and Reference 8.

9.3.2 Station Blackout

As required by 10 CFR 50.63, the reactor core and the associated coolant, control, and protection systems must have sufficient capacity and capability to cool the core and maintain containment integrity in the event of a station blackout (SBO) of a specified duration. Under 10 CFR 50.63, the licensee must analyze the plant's capability to cope with an SBO of a specified duration. RG 1.155, "Station Blackout," dated August 1988, describes one method that is acceptable to the NRC staff to meet the requirements of 10 CFR 50.63. Nuclear Management and Resources Council, Inc. (NUMARC) 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," also provides guidance for performing the coping analyses. Table 1 of RG 1.155 provides a cross-reference to NUMARC 87-00, with notes on where the RG takes precedence.

The licensee has evaluated the impact of the proposed EPU on the capability of DAEC to cope with an SBO based on NUMARC 87-00, except where RG 1.155 takes precedence. The licensee stated that the proposed higher EPU power level would increase decay heat, which would affect the plant's responses and coping capabilities during an SBO. DAEC is classified as a 4-hour SBO duration plant. The licensee stated that the proposed EPU would not change the 4-hour coping time or the systems and equipment used to respond to an SBO.

The licensee has made the following changes to the SBO initial conditions and assumptions for the proposed EPU:

(1) The pre-EPU analysis assumed an operating history of 100-percent power for approximately 200 days for the decay heat analysis. The EPU decay heat calculations assumed an operating history of 100 days at 100-percent power, which is consistent with Section 3.2.1 of RG 1.155.

(2) The pre-EPU analysis assumed that the MSIVs closed at time zero, but the EPU analysis assumed the MSIVs closed at 3.5 seconds. The licensee stated that this was consistent with the design-basis assumptions.

(3) The licensee changed the initial condensate storage tank temperature. The licensee also changed the initial reactor pressure vessel (RPV) temperature to the saturation temperature corresponding to the initial RPV pressure.

The licensee stated that these changes are consistent with NUMARC 87-00 and RG 1.155.

The following areas are identified as dominant areas of concern for the SBO analysis because they contain equipment necessary to mitigate the SBO event:

(a) control room
(b) HPCI and RCIC equipment rooms
(c) drywell and suppression pool
(d) essential switchgear and battery rooms

The licensee's evaluation shows:

(1) The temperatures in the control room, battery room, and HPCI/RCIC rooms are not affected by the proposed EPU.

(2) The electrical power requirements during an SBO are not affected by the proposed EPU.

(3) The equipment operability remains bounded due to conservatism in the existing design and qualification bases.

(4) The drywell and suppression pool temperatures remain below the design temperatures, and

(5) The condensate storage tank (CST) capacity requirements have increased, but the current CST still ensures that adequate water volume is available.

The licensee determined that the EPU analysis demonstrates that sufficient coolant inventory is available and the coolant continues to meet the requirements of 10 CFR 50.63 after operation at the proposed EPU conditions.

Operation at the proposed EPU level and the introduction of GE-14 fuel would result in an increase in the decay heat load in the SFP. The current analyses for SFP cooling, radiation shielding, and reactivity control were evaluated for an SBO at the proposed EPU conditions. Prevention of criticality in the spent fuel under EPU conditions remains bounded by the current analysis. The EPU analysis of the SFP coolant inventory removed an excessively conservative assumption from the existing analysis and thus, changed the methodology of the current analysis. The current SBO analysis assumed that the SFP would begin to boil immediately at the beginning of the SBO event. The EPU analysis calculated an estimated time-to-boil after loss of pool cooling for determining SFP coolant inventory loss. The NRC staff's review of the SFP is provided in the SE issued with DAEC License Amendment No. 242, dated September 21, 2001. The SBO analysis for the proposed EPU is acceptable as it is more realistic and consistent with the loss-of-pool-cooling analysis. The results of the EPU analysis demonstrate that sufficient coolant inventory is available to assure adequate cooling of the spent fuel and radiation shielding during the SBO coping period.

Section 3.2.3 of RG 1.155 states that the ability to maintain adequate reactor coolant system inventory to ensure that the core is cooled should be evaluated, taking into account shrinkage, leakage from the pump seals, and inventory loss from letdowns or other normal open lines dependent on ac power for isolation.

In SAIC-91/6670, "Technical Evaluation Report, Duane Arnold Energy Center, Station Blackout Evaluation," Science Application International Corporation (SAIC - an NRC contractor) reviewed DAEC's SBO response and coping capability at the pre-EPU power level. The technical evaluation report (TER) stated that the licensee maintains 75,000 gallons of condensate inventory and that 62,800 gallons of condensate would be needed for decay heat removal and cooldown during a 4-hour event. Therefore, the site has sufficient condensate to cope with an SBO event. The pre-EPU TER also reviewed DAEC's ability to maintain adequate reactor core coolant inventory during an SBO event. The pre-EPU SBO analysis assumes that the SRVs lift early in the event, and HPCI and RCIC systems, which rely on steam-driven turbines, initiate and inject into the reactor. The HPCI and RCIC systems stop on high reactor vessel water level and the operators subsequently prevent injection of the HPCI system, operating the HPCI system in the recirculation mode to and from the CST. Water level is maintained using the RCIC system. Thirty minutes into the event, the operators start controlled reactor vessel depressurization at less than the 100 °F/hr limit. At 100 minutes, the RPV is maintained at about 200 psig, using the HPCI and RCIC systems as necessary.

The higher decay heat for the proposed EPU operation would increase the boil-off rate, therefore, the ability of the plant to maintain core coverage using the available inventory in the CST would be affected. In its August 16, 2001, supplemental letter responding to an NRC staff RAI, the licensee stated that its new 4-hour coping analysis determined that approximately 66,750 gallons of CST inventory would be used, and this continues to be less than the 75,000 gallons available in the CST.

The NRC staff has reviewed DAEC's ability to cope in a 4-hour duration SBO and ensure core cooling and coverage during the event. Based on the discussion above, the NRC staff accepts the licensee's conclusion that the plant's SBO coping capabilities will not be adversely affected by EPU operation.

Based on the NRC staff's review and the experience gained from the review of EPU applications for other BWR plants, the NRC staff agrees with the licensee's conclusion that the impact of plant operations at the proposed EPU level on the systems and equipment used to cope with an SBO event is insignificant. Further, the NRC staff has reviewed the information provided by the licensee to determine the impact of the proposed EPU on the existing analysis for SBO at DAEC and agrees with the licensee's rationale and evaluation that the plant continues to meet 10 CFR 50.63 requirements.

10.0 ADDITIONAL ASPECTS OF EXTENDED POWER UPRATE

10.1 High-Energy Line Breaks

To achieve the proposed higher power at DAEC, the licensee plans to expand the operating envelope on the power/flow map through implementation of maximum load line limit analysis (MELLLA). Operation at the proposed EPU level would not require an increase in the reactor vessel dome pressure over the pre-EPU value to supply more steam to the turbine. Because plant operations at the proposed EPU level would not have a significant impact due to changes in fluid conditions (i.e., pressure or enthalpy within the system piping) on the mass and energy release rates following a high-energy line break (HELB) outside the primary containment, the NRC staff finds operation at the proposed EPU level acceptable.

10.1.1 Temperature, Pressure and Humidity Profiles Resulting From HELB

The licensee performed an HELB analysis for all systems (e.g., MS system, feedwater system, RCIC system, etc.) evaluated in the UFSAR. The licensee stated that the resulting environmental conditions (i.e., pressure, temperature, and humidity profiles) due to plant operations at the proposed EPU level are bounded by the existing profiles used to qualify equipment and systems that support a safety-related function.

Based on the NRC staff's review of the licensee's analysis, the NRC staff agrees with the licensee that the existing environmental conditions used to qualify equipment and systems that support a safety-related function remain bounding for the pressure, temperature, and humidity profiles resulting from an HELB outside the containment and are acceptable for plant operations at the proposed EPU level.

10.1.1.1 Main Steamline Break

The licensee stated that the critical parameter normally affecting the MSLB analysis relative to the proposed EPU would be an increase in reactor vessel dome pressure. Since there is no increase in the reactor vessel dome pressure, there is no increase in the blowdown rate following an MSLB in the steam tunnel. Therefore, the pressure and temperature profiles following an MSLB in the steam tunnel are not affected for plant operations at the proposed EPU level.

The NRC staff reviewed the licensee's evaluation and rationale, and the NRC staff agrees with the licensee's conclusion that the existing pressure and temperature profiles following an MSLB in the steam tunnel are not affected and are acceptable for plant operations at the proposed EPU level.

10.1.1.2 Feedwater Line Break

At the proposed EPU level, the feedwater temperature, pressure, and flow rate would increase slightly. The licensee performed an analysis for a feedwater line break in the steam tunnel. The licensee stated that design margins within the HELB analysis for a feedwater line break in the steam tunnel are conservative and are bounded by the MSLB.

Based on the NRC staff's review of the licensee's rationale and evaluation, the NRC staff agrees with the licensee that the pressure and temperature profiles following a feedwater line break in the steam tunnel are bounded by the MSLB.

10.1.1.3 High-Pressure Coolant Injection Line

Because there is no increase in the reactor dome pressure relative to the current analyses, the mass release rate following a HPCI or RCIC line break does not increase. The licensee stated that the previous analyses for these line breaks are bounding for the proposed EPU conditions.

Based on the NRC staff's review of the licensee's rationale, the NRC staff agrees with the licensee that the previous analyses for these line breaks remain bounding for the proposed EPU conditions.

10.1.1.4 Reactor Core Isolation Cooling Line Breaks

Addressed in Section 10.1.1.3 above.

10.1.1.5 Reactor Water Cleanup Line Breaks

The licensee performed evaluations and stated that as a result of the small increase in subcooling with no reactor vessel dome pressure increase, the blowdown rate increases slightly. The resulting of decrease in enthalpy due to subcooling offsets the slight increase in the blowdown rate. The net result is insignificant or no increase in peak temperature and pressure in the area outside containment. Therefore, the previous HELB analysis regarding RWCU line breaks remains bounding for the proposed EPU conditions.

Based on the NRC staff's review of the licensee's rationale, the NRC staff agrees with the licensee that the previous analysis for RWCU line breaks remains bounding for the proposed EPU conditions.

10.1.1.6 High-Energy Sampling and Instrument Sensing Line Breaks

The licensee evaluated the high-energy sampling and instrument sensing line break analysis and determined that the blowdown rate remains the same and there is no pressure increase for the proposed EPU. Therefore, the previous HELB analysis regarding the high-energy sampling and instrument sensing line breaks remains bounding for the proposed EPU conditions.

Based on the NRC staff's review of the licensee's rationale and evaluation, the NRC staff agrees with the licensee that the previous analyses for the high-energy sampling and instrument sensing line breaks remain bounding for the proposed EPU conditions.

10.1.1.7 Internal Flooding

In response to an RAI from the NRC staff, the licensee performed an evaluation of the effects of plant operations at the proposed EPU level on the internal flooding outside the containment. The licensee stated that the worst-case internal flooding is from a postulated pipe break in the circulating water system inside the turbine building. The licensee determined that the previous evaluations of internal flooding are not affected by the proposed EPU, as there is no change in the circulating water system flow.

Based on the NRC staff's review of the licensee's rationale and evaluation, the NRC staff agrees with the licensee that the previous analyses regarding internal flooding remain bounding for the proposed EPU conditions.

10.1.2 Moderate-Energy Line Break

The licensee stated that a moderate-energy line break (MELB) analysis is not within the DAEC licensing basis, and is not specifically required for EPUs by ELTR1.

With regard to MELB for the proposed EPU conditions, the NRC staff's primary concern is internal flooding resulting from a postulated MELB outside the containment. As indicated in Section 10.1.1.7 above, the worst-case internal flooding is from a postulating pipe break in the circulating water system inside the turbine building. Since the previous evaluations of internal flooding are not affected by the proposed EPU, the NRC staff concludes that MELB is not a concern for DAEC operations at the proposed EPU conditions

10.2 <u>Equipment Qualifications</u>

10.2.1 Environmental Qualification of Electrical Equipment

The licensee evaluated the safety-related electrical equipment to ensure qualification for the normal and accident conditions expected in the area in which the equipment is located. The licensee applied margins to the environmental parameters in accordance with Division of Operating Reactors (DOR) or Institute of Electrical and Electronics Engineers, Inc. (IEEE) 323-1974 guidelines, as applicable; these margins will continue to be met for the proposed EPU.

The EPU uses an AST based on NUREG-1465, "Accident Source Terms for Light-Water Nuclear Power Plants," dated February 1995, as the DAEC design and licensing bases for evaluating offsite and control room doses. However, the evaluation of the effect of the proposed EPU on EQ is based on the interim guidance given in SECY-99-240, where the continued use of the total integrated dose (TID)-14844 post-accident source term release is considered acceptable for evaluating the effect upon proposed plant modifications on previously analyzed integrated component doses, regardless of the accident source term used to evaluate offsite and control room doses.

10.2.1.1 Inside Containment

EQ for safety-related electrical equipment located inside the containment is based on MSLB and/or DBA-LOCA conditions and their effects on temperature, pressure, humidity, and radiation and includes the environments expected to exist during normal plant operation. The licensee provided temperature and pressure parameters during EPU-related accident conditions. The increases in the normal operating temperature do not affect the capability of environmentally qualified equipment to function in a harsh environment for which it is qualified during its qualified life. However, the qualified life of the equipment may be reduced and should therefore be evaluated.

For the first hour after a postulated SLB, the temperature profiles using EPU RTP conditions are bounded by the current drywell temperature profile. After the first hour, the temperature profiles using EPU RTP conditions exceed the current temperature profile. The licensee stated that the equipment inside the containment would be requalified or upgraded to the new temperature profiles as part of the implementation of the proposed EPU. In response to the NRC staff's concern regarding the requalification of equipment to the new temperature, the licensee stated that the proposed EPU drywell temperature for the limiting SLB exceeded the existing EQ profile by about 1 hour, but the current profile remained bounding for the maximum peak value. For example, for the drywell electrical penetration assemblies, the as-tested accident profile included 10 days at 281 °F (the drywell design temperature), which was used to demonstrate an equivalent post-accident period of 56 days at a temperature of 200 °F for current DAEC conditions. However, for the proposed EPU, a new post-accident profile of 12 days at 205 °F and 140 °F for 18 days thereafter, has been established. To demonstrate that the as-tested accident profile still envelops the proposed DAEC EPU profile, the Arrhenius methodology is conservatively applied to demonstrate an equivalent of 50 days at 205 °F.

In addition to the changes resulting from the new accident temperature profile, there is a minor change in the normal operating temperature in the drywell. With the EPU, the ambient temperature increases 1.3 °F. The increase does not impact the qualified life of the equipment in the drywell because this minor increase is within the temperature tolerance used in the determination of qualified life for this location. Qualified life determinations for equipment in the drywell use actual in-plant operating data obtained from either locally mounted devices or area-monitoring temperature elements used for routine temperature monitoring; so, if any temperature changes occur, the licensee will monitor and incorporate the changes into the equipment evaluation as part of the normal EQ program.

The existing qualification of all components in the EQ program was reviewed for impact as a result of changes in environments, both normal and post-accident, due to the proposed EPU. All existing EQ equipment is qualified for EPU conditions because the as-tested profiles for pressure, temperature, humidity, and radiation bound the EPU conditions.

Similarly, the calculated peak drywell pressure at EPU RTP conditions is not bounded by the current peak pressure. However, a comparison of the demonstrated qualification pressure of each component in the drywell to the higher peak pressure confirmed that the higher peak pressure had no effect on EQ.

The licensee reevaluated the current 40-year normal radiation dose inside the containment and determined that it would increase approximately 20 percent (proportional to the increase in EPU RTP). However, the accident dose decreased approximately 18 percent as a result of a change in calculation methods. Although both the current and EPU calculations are based on the TID-14844 source term, the EPU evaluation used a more detailed integration method for the post-accident dose than the method used in the current evaluation. The evaluation demonstrates that the increase in the normal drywell dose is offset by the decrease in the accident dose for the proposed EPU.

The current EQ for equipment inside the containment is based on a 100-percent humidity environment. This would not changed for the proposed EPU.

In summary, the safety-related electrical equipment inside the primary containment will continue to be qualified for the proposed EPU.

10.2.1.2 Outside Containment

Accident temperature, pressure, and humidity environments used for qualification of equipment outside containment are calculated for an MSLB in the steam tunnel or some other HELB, whichever is limiting for the plant area. The accident temperature, pressure, and humidity conditions resulting from an MSLB or HELB would not change for the proposed EPU.

The EPU normal and accident doses are bounded by the doses at the current power level, or the increases are insignificant and do not exceed the minimum value for a harsh environment, with two exceptions. The normal dose in the RWCU heat exchanger room and RWCU pump room would increase for the proposed EPU. The post-accident dose in the RWCU heat exchanger and pump rooms would not change due to the proposed EPU. The equipment in these rooms remains qualified because its as-tested qualification for TID exceeds the EPU values. For example, for the RCWU heat exchanger room, which has a 40-percent increase in normal dose, the calculated TID is 8.34E+06 rads. The minimum as-tested TID for equipment in that room is 2.0E+07 rads. Thus, the EPU total dose (i.e., normal and accident) in these rooms is bounded by the current dose level used to qualify all components potentially affected by this increase. Therefore, these components would continue to be qualified for the proposed EPU.

In summary, the proposed EPU would have a negligible effect on the environmental conditions currently used by the EQ program for safety-related electrical equipment outside the primary containment.

10.2.2 Environmental Qualification of Mechanical Equipment with Nonmetallic Components

In response to an RAI from the NRC staff, the licensee stated that the DAEC plant design control program ensures that nonmetallic components (i.e., seals, gaskets, lubricants, and diaphragms) are properly specified and procured for the environment in which they are intended to function.

Based on the NRC staff's review of the licensee's rationale, and since the changes for the normal and accident environmental conditions inside and outside the containment and for the system process temperatures are negligible, the NRC staff concludes that the EQ of the nonmetallic components exposed to the EPU conditions would not be adversely impacted.

10.2.3 Mechanical Components Design Qualification

10.2.3.1 Equipment Seismic and Dynamic Qualification

The licensee evaluated EQ for the proposed EPU conditions. The dynamic loads such as SRV discharge and LOCA loads (including pool swell, CO, and chugging loads) that were used in the equipment design will remain unchanged as discussed in Section 4.1.2 of the Safety Analysis Report. This is because the plant-specific hydrodynamic loads, which are based on the range of test conditions for the DBA at DAEC, are bounding for the proposed EPU conditions.

Based on its review of the proposed EPU amendment, the NRC staff finds that the original seismic and dynamic qualification of safety-related mechanical and electrical equipment would not be affected by the EPU conditions for the following reasons:

(1) The seismic loads are unaffected by the proposed EPU;
(2) No new pipe break locations or pipe whip and jet impingement targets are postulated as a result of the uprated condition;
(3) Pipe whip and jet impingement loads do not increase for the proposed EPU; and
(4) SRV and LOCA dynamic loads used in the original design-basis analyses are bounding for the proposed EPU.

10.2.3.1.1 Safety-Related SRV

The licensee performed the over-pressure protection analysis at the uprated power condition using a 3-percent SRV setpoint tolerance. The analysis calculated a peak RPV steam pressure of 1313 psig at the bottom of the vessel. This peak pressure remains below the ASME Code allowable of 1375 psig (110 percent of design pressure) and safety-related SRV operability would not be affected by the proposed EPU. Furthermore, the maximum operating reactor dome pressure would remain unchanged for the proposed EPU. Consequently, the licensee concluded that the SRV setpoints and ALs would not be affected by the proposed EPU, and that the SRV loads for the SRVDL piping will remain unchanged. The NRC staff agrees with the licensee's conclusion that the SRVs and the SRV discharge piping will continue to maintain their structural integrity and provide sufficient over-pressure protection to accommodate the proposed EPU.

10.2.3.1.2 Safety-Related Power-Operated Valves

As discussed in its original request and response to the NRC staff's questions, the licensee evaluated the effect of the proposed EPU on the capability of power-operated valves to perform their safety functions at DAEC. The licensee reviewed calculations and settings for the safety-related MOVs within the scope of the programs established in response to GL 89-10, "Safety-related Motor-Operated Valve Testing and Surveillance - 10 CFR 50.54(f), dated June 28, 1989, and GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," dated September 18, 1996. The review included potential effects of the proposed EPU on the operating requirements for the valves and output of safety-related MOV motor actuators. In addition, the licensee is evaluating its air-operated valves (AOVs) as part of an industry-wide effort, and has confirmed that the proposed EPU will not adversely affect the capability of AOVs at DAEC to perform their safety functions. The licensee has also evaluated the potential pressure locking and thermal binding of its safety-related power-operated gate valves as a result of the proposed EPU. The licensee reported that the proposed EPU conditions did not impact its screening criteria established in response to GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," dated August 17, 1995. The licensee evaluated the valves previously determined to be susceptible to pressure locking or thermal binding, and determined that the proposed EPU would not adversely affect those valves. Based on the licensee's evaluation and NRC experience with previous BWR EPU reviews, the NRC staff finds the licensee's evaluation of the effect of the proposed EPU on the capability of safety-related power-operated valves at DAEC to be acceptable. The licensee also indicated that the proposed EPU conditions are bounded by the current containment analysis and thus have no impact on the evaluation in response to GL 96-06, "Assurance of Equipment Operability And Containment Integrity During Design-Basis Accident Conditions," dated September 30, 1996, on potential overpressurization of isolated piping segments for DAEC.

Based on the information provided by the licensee described above, the NRC staff concludes that the proposed EPU will not have an adverse effect on the performance of mechanical components of safety-related valves at DAEC.

10.3 Required Testing

10.3.1 Generic Test Guidelines for GE BWR Extended Power Uprate

ELTR1, Section 5.11.9, provides the general guidelines for EPU testing, which are:

(1) A testing plan will be included in the uprate licensing application. It will include pre-operational tests for systems or components which have revised performance requirements. It will also contain a power increase test plan.

(2) Guidelines to be applied during the approach to and demonstration of uprated operating conditions are provided in Section L.2, "Guidelines for Uprate Testing," of ELTR1. (The Safety Analysis Report provides additional information relative to EPU testing.)

10.3.2 Startup Test Plan

The licensee will conduct limited startup testing at the time of implementation of the proposed EPU. The tests will be conducted in accordance with the guidelines of ELTR1 to demonstrate the capability of plant systems to perform their designed functions under uprated conditions. The licensee has proposed a license condition addressing the testing requirements.

The tests will be similar to some of the original startup tests, described in Table 14.2-3 and Section 14.2.1.3 of the DAEC UFSAR. Testing will be conducted with established controls and procedures which have been revised to reflect the uprated conditions.

The tests will consist essentially of steady-state, baseline tests between 90 and 100 percent of the currently licensed power level. Several sets of data will be obtained between 100- and 115.3-percent current power with no greater than a 5-percent power increment between data sets. A final set of data at the proposed EPU power level will also be obtained. The tests will be conducted in accordance with a site-specific test procedure currently being developed by the licensee. The test procedure will be developed in accordance with written procedures as required by 10 CFR Part 50, Appendix B, Criterion XI, "Test Control."

Criterion XI of Appendix B to 10 CFR Part 50 also requires, in part, that a test program be established to ensure that testing is performed to demonstrate that structures, systems, and components will perform satisfactorily in service, and that written procedures for performing such testing incorporate the requirements and acceptance limits contained in applicable design documents.

The licensee indicated that the power increase test plan will have features as described in the Safety Analysis Report, Section 10.4, “Required Testing,” and will include the following items:

(1) Testing will be performed in accordance with the DAEC TS SR on the instrumentation that requires recalibration for the EPU conditions.

(2) Steady-state data will be taken at points from 90 percent up to the previous RTP so that system performance parameters can be projected for EPU before the previous power rating is exceeded.

(3) Power increases beyond the previous RTP will be made in increments of ≤ 5 percent power. Steady-state operating data, including fuel thermal margin, will be taken and evaluated at each step. Routine measurements of reactor and system pressures, flows, and vibration will be evaluated from each measurement point prior to the next power increment.

(4) Control system tests will be performed for the feedwater/reactor water level controls and pressure controls. These operational tests will be made at the appropriate plant conditions for each test and at each power increment above the previous rated power condition to show acceptable adjustments and operational capability. The same performance criteria will be used as in the original power ascension tests.

(5) A test specification identifies the EPU tests, the associated acceptance criteria, and the appropriate test conditions. All testing will be done in accordance with 10 CFR Part 50, Appendix B, Criterion XI.

The licensee's test plan follows the guidelines of ELTR1 and satisfies the applicable requirements in Appendix B to 10 CFR Part 50. In view of the above, the NRC staff finds the test plan is acceptable.

10.3.3 Systems/Components with Revised Performance Requirements

The guidelines in ELTR1, Section 5.11.9, specify that preoperational tests will be performed for systems or components which have revised performance requirements. These tests will occur during the ascension to EPU conditions. The performance tests and associated acceptance criteria are based on DAEC's original startup test specifications and previous GE BWR EPU test programs. The licensee has identified performance tests for the following systems:

- Intermediate range neutron monitors assure SRMs and APRM overlap
- APRM calibration
- Pressure regulatory system setpoint steps, failures, incremental regulation
- Feedwater control system setpoint changes, incremental regulation
- Radiation measurements survey
- Feedwater system vibration
- MS system vibration

With regard to the steam pressure or recirculation flow testing, neither parameter has changed for the uprate program. Therefore, testing of system performance is not necessary.

The results from the uprate test program will be used to revise the operator training program to more accurately reflect the effects of the proposed EPU.

On this basis, the NRC staff finds that the power ascension test program outlined by the licensee will demonstrate that DAEC meets performance requirements that satisfy design and licensing bases criteria for the uprated operational envelope and is, therefore, acceptable.

10.3.4 Large Transient Tests

Section 5.11.9 of ELTR1, "Power Uprate Testing," states that a MSIVC test, equivalent to that conducted in the initial startup testing, will be performed if the EPU is more than 10 percent above any previously recorded MSIVC transient data. ELTR1 also states that a generator load rejection test equivalent to that conducted in the initial startup testing will be performed if the EPU is more than 15 percent above any previously recorded generator load rejection transient data. DAEC experienced unplanned events at approximately 1658 MWt that provided the data to fulfill the specifications of Section L.2.4 of ELTR1 up to and including power levels of 1823.8 MWt for the MSIVC test and 1906.7 MWt for the generator load rejection test. Therefore, the large transient tests are not required for EPU-Phase I. However, consistent with ELTR1, these tests should be performed prior to EPU-Phase II.

The licensee has proposed a license condition to address large transient tests which states:

> The licensee will perform the generator load reject and full main steamline isolation valve closure transient tests required by the General Electric Licensing Topical Report for Extended Power Uprate (NEDC-32424P-A) - ELTR-1, including the allowances described in Section L.2.4 (2) of ELTR-1 regarding credit for unplanned plant transient events, using the thermal power level (1658 MWt) to establish ELTR-1 power level limits. The testing shall be performed at an initiating power level greater than the steady-state operation power level exceeding the respective ELTR-1 power level limit for each transient.

The NRC staff finds that the licensee's proposed EPU testing program and proposed license condition are consistent with ELTR1, Section 5.11.9, and pursuant to the requirements of 10 CFR Part 50, Appendix B, will demonstrate that DAEC meets performance requirements that satisfy design and licensing bases criteria for the proposed EPU to 1912 MWt. Therefore, the NRC staff finds the testing program acceptable. In addition, this testing provides reasonable assurance that DAEC will perform as designed in the event of one of these large transients. Accordingly, the proposed license condition appropriately requires the licensee to perform such testing.

10.4 <u>Individual Plant Examination</u>

The EPU application was submitted in accordance with ELTR-1 and ELTR-2. Consistent with ELTR-1, the licensee provided a plant-specific evaluation of the risks associated with their proposed EPU. The NRC staff reviewed this risk information, using the guidelines delineated in RG 1.174, "An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis," dated July 1998. The NRC staff's evaluation of the licensee's submittal focused on the capability of the licensee's PRA to analyze the risks stemming from both the current, pre-uprate plant operations and the EPU conditions. The NRC staff's evaluation did not involve an in-depth review of the licensee's PRA. However, it did involve a review of the licensee's discussions of EPU impacts on core damage frequency (CDF) and large early release frequency (LERF) due to internal events, external events (i.e., fire and seismic), and shutdown operations. The evaluation also addressed the quality of the DAEC probabilistic risk assessment (PRA), commensurate with its use in the licensee's and NRC staff's decision-making processes.

10.4.1 Internal Events

Consistent with ELTR1, the licensee evaluated the changes due to EPU implementation for impact on the PRA models for internal events in the following key areas: initiating event frequency, component reliability, system success criteria, and operator response. Each of these areas is specifically addressed in the following subsections, followed by a description of the overall risk impacts from internal events for the proposed EPU.

10.4.1.1 Initiating Event Frequency

For the original DAEC PRA, initiating event frequencies were developed for:

- Transients, such as manual reactor scram, turbine trip, LOFW, loss of condenser vacuum, MSIVC, inadvertent opening of relief valves, and LOOP, including SBO;
- ATWSs, including MSIVC, LOFW, loss of condenser vacuum, and turbine trip;
- Small-, medium-, and large-break LOCAs, LOCAs between interfacing systems, and LOCAs outside containment; and
- Other special events, such as loss of 125V dc power, loss of instrument air, loss of river water supply, and internal flooding.

These internal initiating events were qualitatively assessed by the licensee by reviewing the underlying bases in relation to the frequency of occurrence of the elements and considering the potential impacts of the proposed EPU.

The licensee determined that the transient contributors that could most likely be affected by the proposed EPU are those associated with trip setpoints, such as reactor scram, system isolations, and operating equipment trips. However, upon review, the licensee concluded that the operational margin to trip setpoints would not be substantially reduced by the proposed EPU and thus, the frequency of occurrence of plant transient events would not be affected.

For the LOOP initiating event frequency, the licensee concluded that grid-related events and weather-related events would not be affected by the proposed EPU and that plant-centered events would not be increased since design changes to support EPU operation (e.g., changes to the main transformers, key electrical breakers (coordination), and main generator and bus cooling systems) would maintain or increase existing operating margins.

The frequency of ATWS events is determined by multiplying the frequency of the associated transient events by the probability of failing to scram. Since there are no modifications being made to the CRD or the RPS, the probability of failing to scram is not expected to change. Thus, since the transient initiating event frequency and the failure to scram probability are not expected to change, the overall ATWS frequency is also not expected to change.

Since the primary cooling system pressure would not change for the proposed EPU, the licensee concluded that the frequency of LOCA events is also not expected to change. Likewise, monitoring programs for detecting piping degradation would not be changed by the proposed EPU and, therefore, the frequency of internal flooding events is not expected to change.

For the river water supply, instrument air, and 125V dc systems, the duty on these systems for the proposed EPU would essentially be unchanged from current conditions. Therefore, the frequency of losing any of these systems is not expected to change.

The NRC staff finds that it is reasonable to conclude that the initiating event frequencies will not change as long as the operating ranges or limits of equipment are not exceeded. However, it is also noted that if there are any changes observed in the future in initiating event frequencies, these changes will be tracked under the plant's existing monitoring programs, such as the maintenance rule, erosion/corrosion, EQ, and instrument trending program.

10.4.1.2 Component Reliability

To assess the potential impact of the proposed EPU on equipment reliability, the licensee used the DAEC PRA to screen out sequences for which component failures could not increase the CDF by at least 1E-6/year (or the LERF by at least 1E-7/year). The sequences that were above these criteria were reviewed to determine if the proposed EPU could affect the reliability of the involved components. The licensee found no specific mechanism that would affect the reliability of these components. Therefore, the licensee concluded that the proposed EPU would not impact the plant's equipment reliability. Nevertheless, the licensee stated that if any component degradation were to occur as a result of the proposed EPU, existing plant component monitoring programs (e.g., maintenance rule, erosion/corrosion, EQ, and instrument trending programs) would compensate for this effect and the functionality and reliability of these components would be maintained. Therefore, the licensee concluded that it expected no changes in the component failure rates used in the DAEC PRA models.

The NRC staff finds that changes in component reliability are not expected as long as the specified operating ranges or limits of equipment are not exceeded and, therefore, no changes in component failure rates are expected. In addition, the NRC staff finds that the licensee's intention to continue to monitor equipment performance to detect any degradation and to maintain the current reliability of the equipment is prudent.

10.4.1.3 Success Criteria

The licensee's system success criteria were developed using the overall success criterion of preventing core and containment damage. The overall success criterion is expressed in terms of discrete system performance (e.g., integral number of trains, pumps, and heat exchangers). The licensee reported that the discrete nature of the criterion typically produces equivalent "system success criteria" that have substantial margin over the minimum to fulfill the overall success criterion. As an example, for a given event, success in preventing core damage is achieved by having System A available for injection, but the rated flow from System A may be 25 percent greater than actually needed for adequate core cooling per the supporting T/H analysis. Thus, the proposed EPU could increase the required injection flowrate of System A up to its rated flow capacity without affecting the existing success criterion for that event.

The licensee identified the critical safety functions as reactivity control, reactor pressure control, containment pressure control, and reactor inventory makeup. The evaluation of the overall success criterion for these critical safety functions for the proposed EPU is based on a series of evaluations using the industry-recognized T/H code Modular Accident Analysis Package, Version 3.0B (MAAP 3.0B), which analyzed the plant's T/H performance and timing of events at the proposed EPU power level. This information was translated into system success criteria and then compared to the specific system success criteria used for the previous (pre-uprate) PRA.

While some plant parameters would be affected by the proposed EPU, such as increased decay heat level, these changes were determined by the licensee to be within the existing margin of the current system success criteria in the DAEC PRA and changes were not required to satisfy the critical safety function success criteria. Therefore, the licensee determined that the success criteria for the EPU PRA did not change from the success criteria for the previous (pre-uprate) PRA.

The licensee has indicated that there have not been any significant changes in system success criteria since it submitted the DAEC individual plant examination (IPE). Therefore, as part of the NRC staff's evaluation, the DAEC IPE system success criteria were reviewed. The NRC staff found that the DAEC system success criteria were reasonable and comparable to the system success criteria of other BWRs. The NRC staff reviewed the licensee's analysis, as described above, and, based on that analysis, the NRC staff finds it reasonable to conclude that the system success criteria are not expected to be impacted by the proposed EPU.

10.4.1.4 Operator Response

The licensee conducted an evaluation to determine how the proposed EPU would impact operator response capabilities during accidents. When less time is available for an operator to diagnose and execute an action in response to an accident situation, a higher human error probability (HEP) was assumed for that action. Similar to the assessment of component reliability, the licensee used the DAEC PRA and screened out operator actions that could not increase the CDF by at least 1E-6/year (or the LERF by at least 1E-7/year) if the operator action failed. The operator actions were further screened to exclude those errors that would occur before the initiating event (e.g., instrument calibration errors), those whose timing were not related to reactor power (e.g., operator actions based on battery capacity), and those in which the operators had several hours to diagnose the problem and complete the tasks such that the reductions in the times available to respond were negligibly small.

The screening identified the following five operator actions that were evaluated further by the licensee for their impact on plant risk:

(1) Initiation of SLC for turbine trip and MSIVC ATWS events;

(2) Inhibiting the ADS for MSIVC ATWS events with high-pressure injection initially available;

(3) Initiation of reactor water level control in order to reduce power for MSIVC ATWS events;

(4) Initiation of SLC and power/level control for turbine trip ATWS events with bypass available; and

(5) Depressurization of the vessel to allow low-pressure injection into the vessel following failure of the high-pressure injection systems for non-ATWS events with the reactor at high pressure.

These operator actions and the associated impacts due to the proposed EPU are discussed below, followed by a discussion of the cumulative effects of the proposed EPU on operator actions.

The first operator action addresses the reduction in time available for the operators to initiate SLC for turbine trip and MSIVC ATWS events. This scenario pertains to ATWS events with the main condenser not available as a heat sink. If injection by both SLC pumps is successful early on, then the need for reactor vessel emergency depressurization will be avoided, as the heat capacity temperature limit for the suppression pool will not be reached. If this operator action is not performed early in the scenario, the suppression pool's heat capacity temperature limit will be reached and emergency depressurization will be required. Still, if SLC injection from at least one SLC pump is initiated within a reasonable time, in conjunction with the initiation of SPC, containment failure from high suppression pool temperature will be prevented. The two different time windows for this operator action determine the success criterion (i.e., number of trains) required later in the event analysis for SPC to avoid containment failure due to overheating. Early SLC injection leads to the need for only one train of SPC, while late SLC injection leads to the need for two trains of SPC. Due to the proposed EPU, the early SLC initiation timing would be reduced from 6 minutes to 4 minutes, while the late SLC initiation timing would be reduced from 20 minutes to 14 minutes. Based on the reduction in available time, the HEP for early SLC initiation would be increased from 1.1E-1 to 1.8E-1 and the HEP for late SLC initiation would be increased from 7.5E-2 to 9.5E-2. Due to the short time available for early SLC initiation, the NRC staff investigated this action in further detail. This evaluation, in which the NRC staff concludes the operators have sufficient time to perform this action, is provided in Section 10.5 of this SE.

The second operator action addresses the reduction in time available for the operators to inhibit ADS in MSIVC ATWS events. This scenario pertains to ATWS events for which the main condenser is not available as a heat sink and the feedwater and condensate systems are not available for reactor inventory makeup. High-pressure injection, however, is initially available. The failure to inhibit ADS results in the automatic injection of a large quantity of water by the low-pressure ECCS. This failure would dilute the boron in the core, resulting in a recriticality. Successfully inhibiting ADS within a specified time limit will preclude the low-pressure ECCS from injecting. Due to the proposed EPU, the time for inhibiting ADS would be reduced from 16 minutes to 10 minutes and thus, the HEP for this action would be increased from 1.4E-2 to 3.4E-2.

The third operator action addresses the reduction in time available for the operators to initiate reactor water level control in order to reduce power for MSIVC ATWS events. This scenario pertains to ATWS events in which other mitigative strategies are not able to completely shut down the reactor. Successfully lowering the reactor vessel water level to lower reactor power within a specified time will avoid the need for emergency depressurization due to the suppression pool temperature reaching the heat capacity temperature limit. Due to the proposed EPU, the time for initiating reactor water level control would be reduced from 15 minutes to 12 minutes, and thus, the HEP for this action would be increased from 1.5E-2 to 3.4E-2.

The fourth operator action addresses the reduction in time available for the operators to initiate SLC in the longer term (i.e., early SLC injection not performed, but late SLC injection may still occur) combined with a reduction in the time available to initiate power/level control for turbine trip with bypass available ATWS events. This scenario pertains to ATWS scenarios for which the main condenser is available via the main turbine bypass valves. For this scenario, early injection of SLC is not successful and the reactor power being generated is in excess of the bypass valve capacity. This excess power is added to the suppression pool by the SRVs. Consequently, power/level control must be implemented, per the EOPs, before the suppression pool reaches the heat capacity temperature limit. The timing for this scenario was not explicitly estimated since it is bounded by the scenario pertaining to the third operator action described above, where all the reactor power being generated is added to the suppression pool. Thus, the licensee used the times and HEPs associated with the third operator action described above to address this scenario. Due to the proposed EPU, the timing for this scenario would be reduced from 15 minutes to 12 minutes, and thus, the HEP for this action would be increased from 1.5E-2 to 3.4E-2.

The fifth operator action addresses the reduction in time available for the operators to depressurize the vessel to allow low-pressure injection into the vessel following failure of the high-pressure injection systems for non-ATWS events with the reactor at high pressure. This scenario pertains to transients, small LOCAs, and medium LOCAs in which the high-pressure injection systems are not available. Thus, vessel depressurization is required to allow injection by the low-pressure systems. The time available for this operator action corresponds to the time at which vessel water level drops below the 1/3 core submergence required for adequate core cooling and prevention of significant core damage. Due to the proposed EPU, the timing for this scenario would be reduced for transients and small LOCAs from 64 minutes to 55 minutes, and thus, the HEP for this action would be increased from 2.1E-4 to 2.6E-4. In the previous (pre-uprate) PRA, the medium LOCAs were treated the same as the transients and small LOCAs. However, since medium LOCAs have a greater inventory loss rate, the PRA was enhanced for the proposed EPU to address this specific condition. For medium LOCAs, the timing for this scenario would be reduced from the 64 minutes previously assumed available to 25 minutes, and thus, the HEP would be increased from 2.1E-4 to 1.2E-2.

For internal events, the changes in the HEPs discussed above result in a 9.3-percent increase in CDF to about 1.3E-5/year (ΔCDF of about 1.10E-6/year) and about a 16-percent increase in LERF to about 9.9E-7/year (ΔLERF of about 1.37E-7/year). About 78 percent of the increase in CDF is from ATWS events that involve the failure to reduce reactivity, leading to the early failure of the containment and subsequent core damage due to loss of reactor makeup capability. The ATWS events with loss of both high- and low-pressure reactor makeup capability, which leads directly to core damage, constitutes about 14 percent of the increase in CDF. The non-ATWS events with the reactor at high pressure in which there is a loss of high-pressure makeup contributed another 4 percent to the CDF increase, and the remaining 4-percent contribution is from various events. These results are discussed further below.

In addition to the evaluation of the above operator actions, in response to NRC staff RAIs, the licensee performed some sensitivity analyses to determine if there were a number of operator actions that individually were below the screening criteria, but collectively could have a significant impact on the results. The licensee identified only one operator action that was near the screening criteria. This operator action, which was the recovery of the river water supply, was determined to have a small impact on the CDF (increase of 5.0E-7/year) and no impact on LERF, if it were assumed failed (i.e., probability of failure set equal to one). As a second check, the licensee doubled the HEP values for the operator actions that did not exceed the initial screening criteria. The resulting increases in CDF and LERF were 1.4E-6/year and

9.3E-8/year, respectively. Thus, the licensee concluded that the sensitivity analyses show that there are no significant impacts from the operator actions that are not explicitly addressed.

The NRC staff finds that the assumed increases in the HEP values for the identified operator actions reasonably reflect the reductions in the times available for the operators to perform the necessary actions under the proposed EPU conditions. Further, the NRC staff finds that the sensitivity studies performed by the licensee support the determination that there are no operator actions that were initially screened out that could have a significant impact on the change in risk in implementing the proposed EPU.

10.4.1.5 Summary of Internal Events Evaluation

The licensee indicated that there were no impacts expected due to the proposed EPU on initiating event frequencies, component reliabilities, and success criteria. Impacts of the proposed EPU were identified for selected operator actions due to the decrease in available operator response times. The changes in the HEPs discussed above result in a 9.3-percent increase in internal events CDF to about 1.3E-5/year. This represents an increase of about 1.1E-6/year from the current CDF due to internal events.

The current DAEC PRA results indicate that the dominant risk contributors are LOOP (54 percent), inadvertent opening of a relief valve (10 percent), turbine trip with bypass (9 percent), and MSIVC (8 percent). Based on the licensee's evaluation at EPU conditions, there is no change in the initiating events that dominate risks, but their percentage contributions are slightly changed; with LOOP (49 percent), turbine trip with bypass (12 percent), MSIVC (11 percent), and inadvertent opening of a relief valve (9 percent). These changes are mainly driven by the ATWS scenarios that are affected by the reduced operator response times.

The licensee reported that the proposed EPU would not have a direct impact on the DAEC Level 2 analysis. The licensee states that the systems credited for debris cooling and containment pressure control have sufficient margin to accommodate the 15-percent increase in reactor power. The events that challenge containment integrity were analyzed using MAAP 3.0B and were found to not be appreciably affected by the proposed EPU in magnitude or severity. The only impact was in the sequence timing, which impacts the available operator response times. Since the operator actions credited in the Level 2 analysis are mostly long-term in nature, the licensee determined that the associated HEPs would remain unchanged. However, the LERF estimate does change when the post-initiator operator actions are propagated through the Level 2 analysis. As a result, the LERF value would increase by about 16 percent to about 9.9E-7/year due to the proposed EPU. This represents an increase of approximately 1.4E-7/year from the current LERF value for internal events.

Based on the reported analyses and results, the NRC staff finds that the changes in CDF and LERF from internal events due to the proposed EPU are small and are within the guidelines provided in RG 1.174.

10.4.2 External Events

The licensee reviewed the DAEC individual plant examination of external events (IPEEE) to determine if any potential plant vulnerabilities existed from internal fires, seismic events, and other external events. For DAEC, only the areas of internal fires and seismic events were found to have a measurable impact on CDF in the original IPEEE. However, the licensee reported that the fire hazards and seismic events are not directly affected by the proposed EPU. Consequently, any increases in the CDF due to fire-related or seismic events are due to the increases in post-initiator HEPs from the Level 1 (i.e., internal events) analysis discussed above. Carrying these HEP impacts through the external events analysis results in an EPU external events CDF of about 3.7E-6/year, which is a change of about 2E-8/year (less than a 1 percent increase from the current (pre-uprate) external events CDF).

The NRC staff finds that the increase in CDF from external events due to the proposed EPU are small and are within the guidelines provided in RG 1.174.

10.4.3 Shutdown Risk

The licensee indicated that it does not have a PRA model specifically tailored for evaluating shutdown risk. However, the licensee did state that it uses simplified risk evaluation tools to evaluate the risks associated with shutdown activities. The licensee uses a defense-in-depth approach to managing risk during plant shutdowns that is based on the guidelines provided in NUMARC 91-06. This process specifically monitors decay heat removal (DHR) capability, vessel inventory control, electrical power availability, reactivity control, and containment control. The licensee stated that these controls are implemented through plant procedures.

The operational objective for a normal shutdown at DAEC is to reduce the bulk reactor temperature to allow refueling operations using two RHR loops. The effect of the proposed EPU would be to increase the amount of decay heat following shutdown. The decay heat for the proposed EPU would be increased in proportion to the power level increase, which for DAEC increases the time required to reach the shutdown temperature by approximately 10.5 hours. Thus, the greatest impact is on the DHR capability, which the licensee evaluates regularly during a shutdown. The licensee indicated that it calculates a “time to boil” at least once per shift, assuming the loss of all DHR. Due to the proposed EPU, the “time to boil” would be reduced proportionally from the current plant condition, as would the time for the operators to respond to a loss of DHR. The NRC staff finds that due to the typically long “time to boil” (e.g., hours) for BWRs, the HEPs for these actions are not expected to be significantly affected.

The licensee further stated that it determines the decay heat load using a plant-specific decay heat curve, which is then compared to the heat removal capacity of the available systems. This evaluation is used to determine whether these systems can be removed from service for maintenance or testing. Therefore, the proposed EPU would extend the time that the existing DHR systems would need to remain in service during plant shutdown and remain available right after shutdown.

Based upon the above risk management process, the licensee asserts that the proposed EPU would have little or no effect on the process controls for shutdown risk management and a negligible effect on the overall ability of the licensee to adequately manage shutdown risk.

The NRC staff finds that the impact on shutdown risk due to the proposed EPU is negligible based on the licensee's current shutdown risk management process.

10.4.4 Quality of PRA

The quality of the PRA used to support a license application should be commensurate with the role that the PRA results play in the utility's and staff's decision-making process and should be commensurate with the degree of rigor needed to provide a valid technical basis for the NRC staff's decision. In this case, the licensee is not requesting relaxation of any deterministic requirement for the proposed EPU and the NRC staff's approval is based on the licensee meeting the current deterministic requirements, with the risk assessment providing confirmatory insights.

Therefore, to determine whether the PRA used in support of the license application is of sufficient quality, scope, and detail, the NRC staff evaluated the information provided by the licensee in its EPU application and considered the review findings on the original DAEC IPE and IPEEE, as well as the fact that the DAEC PRA has been through a peer review as part of the BWROG PRA certification program. The NRC staff's evaluation of the licensee's submittal focused on the capability of the licensee's PRA model to analyze the risks stemming from the proposed EPU and did not involve an in-depth review of the licensee's PRA.

The NRC SEs on the DAEC IPE and IPEEE state that the licensee met the intent of GL 88-20, "Individual Plant Examination For Severe Accident Vulnerabilities," dated November 23, 1988. Neither SE identified any significant weaknesses with in licensee's analyses that would invalidate their results and conclusions.

The licensee stated that it maintains the DAEC PRA models to conform to the plant operating configurations and procedures and uses the PRA to assess hardware changes to the facility and operating and maintenance practices for their impact on overall plant risk. The PRA has also been used for screening components and in the development of reliability goals in accordance with the maintenance rule. Because of its ongoing use, the licensee submitted the DAEC PRA for a peer review as part of the BWROG PRA certification process. This peer review, which was completed in March 1997 indicates that all review elements were consistently graded as sufficient to support applications requiring a risk significance determination supported by deterministic insights. In particular, this peer review specifically recognized the accident sequences evaluation, human reliability analysis, and T/H analysis as strengths of the DAEC PRA and did not identify any major weaknesses.

The NRC staff finds that the licensee has provided information that indicates that the quality of its PRA is sufficient for this application.

10.4.5 Conclusions

The NRC staff finds, based on the licensee's analyses, that no changes are expected for initiating event frequencies, success criteria, and component reliabilities and failure rates as a result of the proposed EPU. The NRC staff further agrees with the licensee's intention to continue to monitor these parameters under the existing monitoring programs to ensure that the impact on plant risk from these areas as a result of the proposed EPU is detected early so that any degradation in performance and safety are minimized.

The NRC staff finds that the risk increases due to the reduced operator response times available under the proposed EPU conditions are small and within the guidelines of RG 1.174 for both internal and external events. Further, the NRC staff finds that the licensee has a process for managing plant risk during shutdown operations and that the risk impact due to the proposed EPU during these operations would be negligible.

Based on the licensee's reported analyses and results, the NRC staff concludes that the increases in CDF and LERF from internal, external, and shutdown events due to the proposed EPU are small and that the risk impacts are within the guidelines set forth in RG 1.174.

10.5 Human Factors

This evaluation is limited to the operator performance impacts expected from the increased maximum power level. It includes required changes to operator actions, the human-system interface, procedures, and training resulting from the change in maximum power level. The evaluation is based on the licensee's responses to five broad questions regarding human performance.

The NRC staff's guidance for this review includes Information Notice 97-78, "Crediting of Operator Actions In Place of Automatic Actions and Modifications of Operator Actions, Including Response Times," and ANSI/ANS-58.8, "Time Response Design Criteria for Safety-Related Operator Actions," 1984.

10.5.1 Human Factors Review

The NRC staff's evaluation of the licensee's responses to the five questions is provided below.

Question 1 - Describe how the proposed EPU will change the plant emergency and abnormal procedures.

The licensee responded that minor changes to curves and limits were made to the EOPs, but none of the changes have any impact on existing accident response strategies or require new operator actions. Similarly, the AOPs require minor changes, but no significant changes to operator actions have been identified. The NRC staff finds these statements regarding changes to procedures to be satisfactory.

Question 2 (a) - Describe any new risk-important operator actions required as a result of the proposed EPU.

As stated above, no new risk-important operator actions have been identified.

Question 2 (b) - Describe changes to any current risk-important operator actions that would occur as a result of the proposed EPU.

The licensee described five operator actions considered to be risk important in which the time available to perform the action would be decreased as a result of the proposed EPU. Based on the criteria of ANSI/ANS-58.8, only one operator action, to initiate SLC in turbine trip and MSIVC ATWS events, appears to present an issue. If the action can be successfully completed within 6 minutes of the beginning of the event (4 minutes after EPU), the reactor vessel emergency depressurization will be avoided. The ANSI/ANS 58.8 criteria indicate that 9 minutes should be available for this action. However, if the licensee can justify a shorter time, the shorter time is acceptable.

In its letter dated July 11, 2001, the licensee provided a detailed description of the steps an operator would take to diagnose the need for SLC system injection and the execution of that action, including a discussion of the controls used to initiate SLC system injection and the ATWS EOP to be followed. The licensee further indicated that this scenario is a routine training exercise and that boron injection using the SLC system before reaching the boron injection initiation temperature (BIIT) curve limit is a “critical task” in the training program. The licensee stated that training records from 1997 to present show that 58 evaluated scenarios involving ATWS events were conducted and that 100 percent of the crews successfully executed this task. It should be noted that while time to accomplish the injection task was not recorded in these simulations, all were successfully accomplished before reaching the BIIT curve limit. The licensee estimates the actual task to take between 10-15 seconds, well within the 4 minutes available with the proposed EPU. As an independent verification of this operator action, the NRC staff had a qualified license examiner review the EOP and the scenario conditions and provide an informed assessment of the operators' ability to successfully accomplish the required actions in the time available. Based on the above, the NRC staff accepts this justification for the shorter available task time.

Question 2 (c) - Explain any changes in plant risk that result from changes in risk-important operator actions.

See Section 10.4.1.1 of this SE.

Question 3 (a) - Describe any changes to the operator interfaces for control room controls, displays, and alarms as a result of the proposed EPU. For example, what zone markings (e.g., normal, marginal, and out-of-tolerance ranges) on meters will change?

The licensee provided a comprehensive list of control room indications that will need to be rescaled or rebanded. In addition, the following items will be added or replaced: flow transmitters for hydrogen injection, feedwater pump suction indication, and RWCU flow transmitters.

Question 3 (b) - What setpoints will change?

The licensee stated that the following setpoints will change: APRM, MSL high flow and high radiation isolations, and turbine first-stage pressure trip bypass.

Question 3 (c) - How will operators know of the change?

The licensee stated that all setpoint changes are made under the licensee’s design control process, which requires that all design changes be evaluated by the training department for impact on both operator and craft training.

Question 3 (d) - Describe any controls, displays, and alarms that will be upgraded from analog to digital instruments as a result of the proposed EPU.

The licensee stated that the condensor backpressure alarm is being replaced with a digital device, but operator actions in response to this alarm are unaffected.

Question 3 (e) - How will operators be tested to determine they can use the instruments reliably?

The licensee stated that testing is not necessary as the response to the alarm has not changed. However, the modification will be discussed in training.

Question 4 (a) - Describe any changes the proposed EPU will have on the safety parameter display system (SPDS).

As described under Question 1, the licensee stated that various curves and limits will be revised and the SPDS will be updated accordingly.

Question 4 (b) - How will the operators know of the changes?

The licensee stated that these changes will be incorporated into the formal operator training program.

Question 5 (a) - Describe any changes the proposed EPU will have on the operator training program.

The licensee stated that the impact of the proposed EPU on operator training is not expected to be significant. There will be a demonstration of expected plant response to key transient/accident events on the plant reference simulator. As part of the normal design change process, plant modifications are reviewed for impact on training, both for operators and other plant personnel. The licensee uses the INPO-accredited systems approach to training at DAEC, where task analyses are evaluated based on specific hardware modifications and their impacts on critical tasks are identified. Training needs are revised as a result of this evaluation.

Question 5 (b) - Describe any changes the proposed EPU will have on the plant reference control room simulator.

The licensee stated that changes to the plant reference simulator are controlled by the modification process in order to maintain fidelity, per ANSI/ANS-3.5, 1985, “Nuclear Power Plant Simulators for Use in Operator Training and Examination.” The licensee further stated that the new accident analyses performed at the uprated condition will be used to simulate the plant’s response.

Question 5 (c) - Provide the implementation schedule for making the changes.

The licensee stated that the implementation schedule for the simulator is integrated with the implementation of the modifications and will be accomplished over two refueling outages. Thus, the modifications for each outage will be incorporated into the simulator and training for startup from that outage.

The purpose of the above questions is to ensure that the licensee has considered all aspects of the operator’s interaction with the uprated system. Based on the licensee’s responses, the

NRC staff is satisfied that the licensee has considered all of the significant operator issues and has a program in place to accomplish this integration satisfactorily.

The NRC staff concludes that the review topics associated with operators' integration into the proposed uprated system have been satisfactorily addressed by the licensee. The NRC staff further concludes that the proposed EPU should not adversely affect operator performance and only minimally increase HEP based on reduced time available on several risk-important operator actions.

11.0 SUMMARY OF LICENSE AND TS CHANGES

The licensee proposed to make conforming changes to the Operating License and TS to reflect the proposed EPU. Below is a summary of the proposed changes.

(1) Operating License DPR-49, Page 3, Section 2.C.(1)

The maximum power level stated in Section 2.C.(1) would be revised to be 1912 MWt.

Justification for Change:

This change would be made to reflect the maximum licensed power level.

(2) Operating License DPR-49, Page 4, Section 2.C.(2)(a)

Existing license condition 2.C.(2)(a) would be changed to allow existing SRs whose acceptance criteria is affected by the increase in authorized power level to be considered to be performed per TS SR 3.0.1, upon implementation of the license amendment approving the proposed EPU, until DAEC's next scheduled performance, in accordance with TS SR 3.0.2.

Justification for Change:

The purpose for this request is to preclude having to perform these affected SRs prior to their next scheduled performance solely for the purpose of documenting compliance. This does not supercede that aspect of TS SR 3.0.1 that governs cases where it is believed that, if the SR were performed, it would not be met (i.e., the NRC staff has high confidence that the SR would be found to meet its acceptance criteria) even though it has not been performed to actually demonstrate compliance to the new requirements. Performance of the SRs merely to document compliance would unnecessarily divert resources, interfere with plant operations, potentially incur additional personnel dose, and would not improve plant safety.

(3) Operating License DPR-49, Page 4, Section 2.C.(2)

New license condition 2.C.(2)(b) would be added to provide a formal commitment to perform certain transient testing during power ascension to the proposed EPU.

Justification for Change

Startup testing requirements for the original DAEC test program were listed in Specification 22A2569, "General Electric Startup Test Specification." Included in this specification were Level 1 and Level 2 acceptance criteria. Level 1 criteria established a minimum performance where a hold should be placed on operation at a higher power level until the unacceptable performance could be corrected. Level 2 criteria listed performance criteria for desired system performance.

(4) TS Section 1.1, Definitions, Page 1.1-5

The definition of RTP would be revised to be the proposed EPU maximum licensed power level of 1912 MWt.

Justification for Change:

This is the new maximum licensed power level, based on the enclosed safety analysis Safety Analysis Report and BOP evaluations.

(5) Safety Limit 2.1.1.1, Page 2.0-1

The safety limit would be revised for fuel cladding integrity at low core flow and reactor pressure from the current 25-percent RTP to 21.7-percent RTP (25 percent x 1658/1912).

Justification for Change:

The basis for the proposed safety limit is the transition to the SLMCPR, which is based on the GE GEXL correlation. This correlation ensures that above this SLMCPR, 99.9 percent of the fuel rods will avoid boiling transition during plant transients. This correlation is only valid for a range of power densities (kW/l). Thus, the percentage of RTP would be revised to be consistent with the new RTP value of 1912 MWt to maintain the current absolute thermal power value in MWt such that the current power density is maintained.

(6) LCO 3.2.1: Applicability, Required Action B.1, and SR 3.2.1.1, Page 3.2-1

The percentage of RTP value related to thermal limits monitoring would be revised from 25-percent RTP to 21.7-percent RTP.

Justification for Change:

This change would be made to be consistent with the change proposed for Safety Limit 2.1.1.1.

(7) LCO 3.2.2: Applicability, Required Action B.1, and SR 3.2.2.1, Page 3.2-2

The percentage of RTP value related to thermal limits monitoring would be revised from 25-percent RTP to 21.7-percent RTP.

Justification for Change:

This change would be made to be consistent with the change proposed for Safety Limit 2.1.1.1.

(8) LCO 3.3.1.1: SR 3.3.1.1.2, Page 3.3-3

The percentage of RTP value related to deferral of the SR until 12 hours after reaching 25-percent RTP during plant startup would be revised from 25-percent RTP value to 21.7-percent. The RTP value being changed is contained in the SR and the associated note.

Justification for Change:

The existing value is based on the point in the plant startup sequence where an accurate heat balance calculation can be performed by the plant process computer and is generally tied to sufficient steamflow through the turbine to synchronize the main generator to the grid. This steamflow, and in turn, reactor power level in MWt, would not be changed by the proposed EPU. Thus, the percentage of RTP would be revised to be consistent with the proposed RTP value of 1912 MWt to maintain the current absolute thermal power value.

(9) LCO 3.3.1.1: Required Action E.1, SR 3.3.1.1.16, and Table 3.3.1.1-1, Functions 8 and 9, Pages 3.3-2, 3.3-5, and 3.3-9

The percentage of RTP value corresponding to the power level where the direct RPS trips (i.e., scrams) on TSV or TCV fast closure are automatically bypassed would be revised from 30-percent RTP to 26-percent RTP.

Justification for Change:

These direct scram signals are automatically bypassed at a low reactor thermal power level where the turbine bypass steamflow capacity is sufficient to mitigate a TSV or TCV closure transient. Because the turbine bypass capacity would not be changed by the proposed EPU, the corresponding percentage of RTP would be revised to maintain the current absolute thermal power value in MWt, corresponding to the existing bypass steamflow capacity.

(10) LCO 3.3.4.1: Applicability, Required Action C.2, and SR 3.3.4.1.4, Pages 3.3-27, 3.3-28, and 3.3-29

The percentage of RTP value corresponding to the power level where the end-of-cycle recirculation pump trip on TSV or TCV fast closure is automatically bypassed would be revised from 30-percent RTP to 26-percent RTP.

These values would be revised to be consistent with the changes proposed for the RPS trips, as the end-of-cycle recirculation pump trip function is not required when its companion RPS functions are not required to be OPERABLE.

(11) LCO 3.3.1.1: Table 3.3.1.1-1, Function 2b, Page 3.3-7

The current AVs would be replaced for the TLO APRM flow-biased, high RPS trip with the equation for the AV to implement the MELLLA. A new footnote (c) would be added to define the term "W" used in the AV equation.

Justification for Change:

Adoption of the MELLLA is integral to the implementation of the proposed EPU. All safety analyses in the Safety Analysis Report were performed consistent with the MELLLA power/flow map and corresponding APRM RPS AV changes.

(12) LCO 3.3.1.1: Table 3.3.1.1-1, Footnote (b), Page 3.3-7

The current AVs for the SLO APRM flow-biased - high RPS trip with the equation for the AV to implement the MELLLA would be replaced. The new footnote (c) identified above would be used to define the term "W" used in the AV equation.

Justification for Change:

The AVs for the TLO APRM flow-biased trip would be adjusted to account for the difference in recirculation drive flow to core flow relationship in SLO. The higher core pressure drop associated with the proposed EPU necessitates a different adjustment factor than that currently used.

(13) LCO 3.4.1: SR 3.4.1.1 a & b, Page 3.4-3

The percentage of RTP value corresponding to the power level where a recirculation pump speed mismatch surveillance is performed would be revised from 80-percent RTP to 69.4-percent RTP.

Justification for Change:

This SR ensures that the speeds of the two operating recirculation pumps are matched to within a specified tolerance. This ensures that the LPCI loop selection logic will correctly identify the "broken" recirculation loop in the event of a pipe rupture in the reactor recirculation system piping (i.e., a hypothetical LOCA). The original supporting LOCA analysis was not revised for the proposed EPU. Thus, the percentage of RTP would be revised to be consistent with the new RTP value of 1912 MWt to maintain the current absolute thermal power value used in the LOCA analysis.

(14) LCO 3.4.2: SR 3.4.2.1, Page 3.4-5

The percentage of RTP value contained in NOTE 2 corresponding to the power level where the evaluation of jet pump performance can be deferred for up to 24 hours would be revised from 25-percent RTP to 21.7-percent RTP.

Justification for Change:

The basis for the existing deferral is that it is necessary to reach a stable power and flow condition to allow meaningful data to be taken to perform this evaluation of jet pump performance. At low power and flow conditions, there is considerable noise in this measurement such that it is not a reliable indicator of jet pump performance. The absolute conditions of thermal power and flow necessary to obtain adequate data would not be revised by the proposed EPU. Thus, the percentage of RTP would be revised to be consistent with the new RTP value of 1912 MWt to maintain the current absolute thermal power value. (Reference Safety Analysis Report, Section 3.4)

(15) LCO 3.6.3.1: SR 3.6.3.1.1, Page 3.6-33

The volume requirement for nitrogen storage for the CAD system would be revised from 50,000 scf to 67,000 scf.

Justification for Change:

This SR ensures that sufficient nitrogen volume is available for 7 days of CAD operation following a hypothetical LOCA. This volume is increased based on the analysis performed at EPU conditions which concluded that additional nitrogen would be needed for maintaining the oxygen concentration below 5 percent following a LOCA.

(16) LCO 3.6.3.1: SR 3.6.3.1.2, Page 3.6-33

An editorial change would be made to add a “comma” to clearly delineate the requirement for performing the SR for both manual- and power-operated valves in the CAD system.

Justification for Change:

This is an editorial change to correct a typographical error in the SR introduced during the final comment resolution period for the conversion to improved TS (DAEC License Amendment No. 223).

(17) LCO 3.7.7: Applicability and Required Action B.1, Page 3.7-16

The percentage of RTP value where the main turbine bypass valve system is required to be OPERABLE would be revised from 25-percent RTP to 21.7-percent RTP.

Justification for Change:

This change would be made to be consist with the proposed change in the percentage of RTP for the TSV and TCV RPS and end-of-cycle recirculation pump trips discussed above.

(18) Section 5.5.12, Primary Containment Leakage Testing Program, Page 5.0-18

The peak calculated containment pressure (P_a) would be revised from 43 psig to 45.7 psig.

Justification for Change:

This value for P_a would be revised to reflect the increased DBA-LOCA peak drywell pressure from the containment analysis performed at EPU conditions.

While performing the evaluation necessary to complete this SE, the NRC staff reviewed the licensee's proposed TS changes and, for the reasons previously set forth in this SE, finds them acceptable.

12.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Iowa State official was notified of the proposed issuance of the amendment. The State official had no comments.

13.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, 51.32, 51.33, and 51.35, a draft environmental assessment and finding of no significant impact was prepared and published in the *Federal Register* on September 20, 2001 (66 FR 48482). The draft environmental assessment provided a 30-day opportunity for public comment. No comments were received on the environmental assessment. The final environmental assessment was published in the *Federal Register* on November 2, 2001 (66 FR 55703). Accordingly, based upon the environmental assessment, the Commission has determined that issuance of this amendment will not have a significant effect on the quality of the human environment.

14.0 CONCLUSION

The NRC staff has concluded, based on the considerations discussed above, that (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

15.0 REFERENCES

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3) General Electric Nuclear Energy, “General Evaluations of General Electric Boiling Water Reactor Extended Power Uprate,” Licensing Topical Report NEDC-32523P-A (ELTR2), February 2000.

4) General Electric Nuclear Energy, “Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," Supplement 1, Volume 2, Licensing Topical Report NEDC-32523P-A (Supplement 1 to ELTR2), February 1999.

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20) Boiling Water Reactor Owners Group, "10 CFR 50 Appendix G Equivalent Margin Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels," Revision 1, Licensing Topical Report NEDO-32205-A, February 1994.

21) General Electric Nuclear Energy, "GEXL10 Correlation for GE12 Fuel," Revision 2, Licensing Topical Report NEDC-23464P, September 2001.

22) General Electric Nuclear Energy, "GEXL14 Correlation for GE14 Fuel," Revision 2, Licensing Topical Report NEDC-32851P, September 2001.

23) ISL Technical Evaluation Report, "Duane Arnold Energy Center Extended Power Uprate Containment Analysis Audit Calculation," July 2001.

Attachment: List of Acronyms

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LIST OF ACRONYMS

AC - alternating current
ADS - automatic depressurization system
AL - analytical limit
ANSI - American National Standards Institute
AOO - anticipated operational occurrences
AOT - abnormal operating transient
AOV - air-operated valve
AP - annulus pressurization
APRM - average power range monitor
ARI - alternate rod injection
ART - adjusted reference temperature
ARTS - APRM/rod block monitor TS
ASME - American Society of Mechanical Engineers
AST - alternate source term
ATWS - anticipated transient without scram
AV - allowable value
BOP - balance-of-plant
BWR - boiling-water reactor
BWROG - Boiling Water Reactor Owners Group
CACS - containment atmosphere control system
CADS - containment atmosphere dilution system
CBVS - control building ventilation system
CDF - core damage frequency
CF - chemistry factor
CO - condensation oscillation
COLR - core operating limit report
CPR - critical power ratio
CRD - control rod drive
CRDM - control rod drive mechanism
CRTP - current rated thermal power
CSC - containment spray cooling
CST - condensate storage tank
CUF - cumulative usage factor
DAEC - Duane Arnold Energy Center
DBA - design-basis accident
DC - direct current
DHR - decay heat removal
ECCS - emergency core cooling system
EFPY - effective full power years
ELLLA - extended load limit line analysis
EMA - equivalent margins analysis
EOP - Emergency Operating Procedures
EPG - Emergency Procedure Guideline
EPU - extended power uprate
EQ - environmental qualification
ESW - emergency service water

FAC - flow-accelerated corrosion
FIV - flow-induced vibration
FW - feedwater
GDC - general design criteria
GE - General Electric
GL - generic letter
GNF - Global Nuclear Fuel
GSW - general service water
HCU - hydraulic control unit
HELB - high-energy line break
HEP - human error probability
HEPA - high-efficiency particulate air
HPCI - high-pressure coolant injection
HPCS - high-pressure core spray
HVAC- heating ventilating and air conditioning
IEEE - Institute of Electrical and Electronics Engineers
IMCPR - initial minimum critical power ratio
IPE - individual plant examination
IPEEE - individual plant examination of external events
IRM - intermediate range monitor
ISL - Information Systems Laboratories, Inc.
ISP - integrated surveillance program
LCO - limiting condition for operation
LERF - large early release frequency
LFWH - loss of feedwater heating
LOCA - loss-of-coolant accident
LHGR - linear heat generation rate
LOFW - loss-of-feedwater flow
LPCI - low-pressure coolant injection
LPRM - local power range monitor
LRWOB - load rejection with bypass failure
LTP - long term program
LTR - Licensing Topical Report
MAPLHGR - maximum average planar linear heat generation rate
MCPR - minimum critical power ratio
MELB - moderate-energy line break
MELLLA - maximum extended load limit line analysis
MEOD - maximum extended operating domain
MOV - motor-operated valves
MS - main steam
MSIV - main steam isolation valve
MSIVC - main steam isolation valve closure
MSLB - main steamline break
MVA - mega volts-amp
MVAR - mega volts-amp-reactive
NMC - Nuclear Management Company
NPSH - net positive suction head
NRC - U.S. Nuclear Regulatory Commission
NSSS - nuclear steam supply system

OLMCPR - operating limit minimum critical power ratio
OM - oscillation magnitude
OOS - out of service
ORTP - original rated thermal power
PCT - peak cladding temperature
PIE - post-irradiation examination
PRA - probabilistic risk assessment
P/T - pressure-temperature
RAI - request for additional information
RBCCW - reactor building closed cooling water
RBCCWS - reactor building closed cooling water system
RBM - rod block monitor
RG - regulatory guide
RCIC - reactor core isolation cooling
RCPB - reactor coolant pressure boundary
RHR - residual heat removal
RHRSW - residual heat removal service water
RPS - reactor protection system
RPT - recirculation pump trip
RPV - reactor pressure vessel
RTP - rated thermal power
RWCU - reactor water cleanup
RWE - rod withdrawal error
SAFDL - specified acceptable fuel design limit
SBO - station blackout
SE - safety evaluation
SFP - spent fuel pool
SFU - standby filter unit
SGTS - standby gas treatment system
SIL - services information letter
SLC - standby liquid control
SL - safety limit
SLMCPR - safety limit minimum critical power ratio
SLO - single-loop operation
SPC - suppression pool cooling
SPDS - safety parameter display system
SR - surveillance requirement
SRM - source range monitor
SRP - Standard Review Plan
SRVDL - safety/relief valve discharge line
SRV - safety relief valve
SV - safety valve
TAF - top of active fuel
TBV - turbine bypass valve
TCV - turbine control valve
TDP - turbine-driven pump
TEDE - total effective dose equivalent
TER - technical evaluation report
T/H - thermal-hydraulic

TID - total integrated dose
TLO - two-loop operation
TSC - technical support center
TSCR - technical specification change request
TS - technical specification
TSV - turbine stop valve
TTNBP - turbine trip bypass failure
TTWOB - turbine trip with bypass failure
UFSAR - updated final safety analysis report
UHS - ultimate heat sink
USE - upper shelf energy