SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 191 TO FACILITY OPERATING LICENSE NO. DPR-19

AND AMENDMENT NO. 185 TO FACILITY OPERATING LICENSE NO. DPR-25

EXELON GENERATION COMPANY, LLC

DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3

DOCKET NOS. 50-237 AND 50-249

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1.0 OVERVIEW

1.1 Introduction

By letter dated December 27, 2000 (Reference 1), Commonwealth Edison Company (ComEd), requested amendments to Facility Operating Licenses DPR-19 and DPR-25 for the Dresden Nuclear Power Station, Units 2 and 3 (DNPS). The proposed amendments would allow an increase in the maximum authorized operating power level from 2527 megawatts thermal (MWt) to 2957 MWt. These proposed changes would increase the current rated thermal power (RTP) by approximately 17 percent and are considered an extended power uprate (EPU). The original rated thermal power (ORTP) for DNPS was 2527 MWt. These amendments would change the Technical Specifications (TS) appended to the operating licenses to allow plant operation at 2957 MWt. These amendments would also modify license conditions and request additional license conditions to support the power uprate.

The original application was submitted by ComEd, the former licensee. ComEd subsequently transferred the licenses to Exelon Generation Company, LLC (EGC, the licensee). By letter dated February 7, 2001, EGC informed the Nuclear Regulatory Commission (NRC) that it assumed responsibility for all pending NRC actions that were requested by ComEd. EGC later supplemented the original license amendment application by letters dated February 12; April 6 and 13; May 3, 18, and 29; June 5, 7, and 15; July 6 and 23; August 7, 8, 9, 13 (two letters), 14 (two letters), 29, and 31 (two letters); September 5 (two letters), 14, 19, 25, 26, and 27 (two letters); October 17; November 2, 16, and 30, and December 10, 17, and 18, 2001.

1.2 Background

The DNPS safety analysis of the proposed EPU was provided in Attachments A and E of the licensee's December 27, 2000, submittal. Attachment E of the licensee’s submittal is the licensee’s Safety Analysis Report (SAR), General Electric (GE) Nuclear Energy licensing topical report (LTR) NEDC-32962P (Reference 2). Revision 2 of the SAR (Reference 28) changed some proprietary designations and updated the text to reflect information provided to NRC in preceding correspondence or to revise information that does not significantly affect the conclusions of the original submittal. The licensee's submittal contained plant-specific information consistent with the scope and content of the NRC-approved GE LTR NEDC-32424P-A (Proprietary), “Generic Guidelines for General Electric Boiling Water Reactor (BWR) Extended EPU," February 1999 (Reference 3), known as ELTR1, which included the staff’s position paper on ELTR1 (Reference 4). For some items, the licensee referenced the analyses and evaluations in the NRC-approved GE LTR NEDC-32523P-A (Proprietary), "Generic Evaluation of General Electric Boiling Water Reactor Extended EPU (ELTR2)," February 2000 (Reference 5), known as ELTR2. The ELTR2 generic evaluations are based on (a) an increase in the thermal power up to 20 percent above the unit’s ORTP, (b) reactor pressure vessel dome operating pressure up to 1095 psia, (c) reactor system temperature up to 556 °F, and (d) a steam and feedwater (FW) flow increase of about 24 percent. 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 DNPS EPU.

As part of the EPU review process, the staff visited the GE facility in Wilmington, North Carolina, from June 18 to 22, 2001, to audit the Global Nuclear Fuel (GNF) adherence to the NRC-approved analytical methods for performing the EPU safety analyses, the representative ‘equilibrium’ core, and the DNPS cycle-specific analyses in support of the EPU. The audit findings and their resolutions are discussed in Section 2.6 of this safety evaluation (SE).

The proposed amendment included changes to the reactor vessel water level - low scram and isolation setpoints to support the EPU. However, EGC stated that changing these setpoints would provide additional margin and allow operators to prevent a scram in the event of perturbations in feedwater flow. By letter dated February 22, 2001, EGC requested that the change to the reactor vessel water level - low setpoint be approved independent of the EPU. The NRC approved the setpoint change for DNPS by letter dated December 18, 2001; therefore, the changes to the reactor vessel water level - low scram and isolation setpoints are not discussed in this SE.

The December 27, 2001, submittal also requested a change that would permit the licensee to take credit for the safety function of the Target Rock safety/relief valve. Currently, this valve is not credited in the safety analyses, is not required by TS to be operable, and can not be used to satisfy the TS-required number of operable safety valves. The licensee proposed TS changes that would permit the licensee to take credit for this valve in the event that one of the other safety valves becomes inoperable. The licensee provided additional information to support this request by letter dated December 18, 2001. While the staff has not completed its review of this change, it is not needed to support EPU operations and, thus, does not fall within the scope of the Federal Register Notice. The staff is addressing this issue separately from the EPU and will issue its findings under a separate cover. This does not effect the EPU in any way.

1.3 Approach

To accomplish the EPU, the licensee proposed to increase the plant’s operating domain by implementing the maximum extended load line limit analysis (MELLLA) power/flow map. The licensee also proposed to implement the average power range monitor (APRM)/rod block monitor (RBM) TS (ARTS) power- and flow-dependent limits. The proposed EPU will not increase the operating pressure or the current licensed core flow. EPU operation will not increase reactor vessel dome pressure because the plant will have (after modifications to power generation equipment) sufficient pressure control and turbine flow capabilities to control the pressure at the turbine inlet. Higher steam flow will be generated through a more uniform (flattened) core power distribution, which will yield a higher core RTP, and through an increase in the corresponding FW flow to match the higher steam flow. The ‘flattened’ power distribution refers to an increase in the average bundle power, while the peak bundle power limit remains the same. The licensee also plans to revise the loading pattern of the core, use larger reload batch sizes, and introduce GE-14 fuel. The NRC approved the use of GE-14 fuel by DNPS via letter dated November 2, 2001.

1.4 Staff Evaluation

The NRC staff's review of the DNPS EPU amendment request used applicable rules, regulatory guides (RGs), the Standard Review Plan (SRP, Reference 7), and NRC staff positions on the topics being evaluated. Additionally, the staff evaluated the DNPS submittal for conformance to the generic boiling-water reactor (BWR) EPU program as defined in ELTR1 and ELTR2. ELTRs 1 and 2 have previously been accepted by NRC as a guideline for EPU applications (References 4 and 6). The staff also used the 1998 SE for the Monticello Nuclear Generating Plant EPU as a guide for scope and depth of review. The licensee’s application requested EPU for both DNPS and Quad Cities Nuclear Power Station, Units 1 and 2 (QCNPS), the sister site of DNPS, using a “bounding unit” approach, where applicable. The staff reviewed the DNPS and QCNPS EPUs in parallel and will issue the QCNPS EPU SE under separate cover.

Table 1-3 of the DNPS SAR (Reference 2) lists the nuclear steam supply system (NSSS) computer codes used in the EPU evaluations. The table indicates that all the applicable codes have been reviewed and approved by the NRC, except for the BILBO code, which is not a safety analysis code, and the Technical Activity Steering Committee (TASC) code for application to emergency core cooling system (ECCS) loss-of-coolant-accident (LOCA) analyses. The licensee stated that TASC is an improved version of the NRC-approved SCAT code, with the added capability to model advanced fuel features (partial length rods and new critical power correlation). The code has been accepted for transient analyses and TASC is currently under staff review for LOCA analysis. (The staff is currently completing its review of TASC.) Based on the status of the review, the staff concludes that the use of the TASC code for the DNPS EPU would have an insignificant effect on the consequence of the relevant accident analyses. Therefore, the staff concludes that the analysis results which are based on the TASC code are valid.

The DNPS EPU transition reload cores contain the existing co-resident Siemens Power Corporation ATRIUM-9B (9x9) fuel and 9x9-2 fuel, with fresh GNF GE-14 (10x10) fuel, while the equilibrium EPU core will consist exclusively of GE-14 fuel. The EPU safety analyses and the cycle-specific reload analyses were performed in accordance with NRC-approved GE analytical methodologies described in the latest version of NEDE-24011-P-A-10-US, “General Electric Standard Application for Reactor Fuel (GESTAR II)” (Reference 35). The LTRs specifying the codes and methodologies used for performing the safety analyses are listed in Section 5 of the DNPS TS. The limiting anticipated operational occurrences (AOO) and accident analyses are reanalyzed or confirmed to be valid for every reload and the nonlimiting safety analyses of record are documented in Chapter 15 of the DNPS updated final safety analysis report (UFSAR). Limiting transient or accident analyses are generally defined as analyses of events that could potentially affect the core operating and safety limits that ensure the safe operation of the plant.

Detailed discussions of individual review topics follow. Since the licensee's submittal and SAR follow the format of the previously reviewed generic ELTRs, the evaluations below generally follow the same format and section numbering scheme.

2.0 REACTOR CORE AND FUEL PERFORMANCE

The core thermal-hydraulic design and fuel performance characteristics are evaluated for each fuel cycle. The following sections address the effect of the EPU on fuel design performance, thermal limits, the 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 AOOs, (b) any damage to the fuel bundles would not be so severe as to prevent control rod insertion when required, (c) the number of fuel rod failures during accidents is not underestimated; and (d) the coolability of the core is always maintained. For each fuel vendor, use 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 (Reference 7) and the applicable general design criteria (GDC) of 10 CFR Part 50, Appendix A. The fuel vendors perform thermal-mechanical, thermal-hydraulic, neutronic, and material analyses to ensure that the fuel system design can meet the fuel design limits during steady-state, AOO, or accident conditions.

The licensee's SAR (Reference 2) states that the requested EPU would increase the average total core power density proportionally to the power increase, but the increased power density would remain within the power density limits of existing GE-supplied BWRs. The increased operating power would affect the operating flexibility and the reactivity characteristics. The EPU capability is achieved by redesigning the loading pattern of the reload core, by using larger reload batch sizes and by introducing new fuel designs (GE-14).

The licensee's SAR states that, for operation at the currently licensed power or at the proposed EPU, the fuel and core design limits will continue to be met by varying the fuel enrichment and burnable poisons, supplemented by control rod pattern management. The reload core design will flatten the radial power distribution while limiting the absolute power in individual fuel bundles to currently allowable values (AVs). NRC-approved core design methods are used to analyze the core performance at the proposed EPU operation.

The EPU fuel cycle calculations were performed using a representative "bounding unit" equilibrium GE-14 core design to demonstrate the feasibility of operation at the higher thermal power and with the modified MELLLA rod line, while maintaining the fuel design limits. Limits on the fuel rod linear heat generation rates (LHGRs) ensure compliance with the fuel mechanical design bases. The thermal-hydraulic design and the operating limits (OL) ensure an acceptably low probability of boiling transition-induced fuel cladding failure in the core in the event of an AOO. The EPU fuel cycle design calculations demonstrated that these fuel design limits would be maintained and the subsequent reload core designs at the EPU power level will take into account these limits to ensure acceptable differences between the licensing limits and their corresponding operating values. The currently approved fuel design burnup limits will not be exceeded. This is acceptable to the staff.

2.2 Thermal Limits Assessment

GDC 10 of 10 CFR Part 50, Appendix A, requires that the reactor core and the associated control and instrumentation systems be designed with appropriate margin to ensure that the specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operation, including AOOs. OLs are established to assure that regulatory and/or 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 in the following sections. Thermal limits management with ARTS power- and flow-dependent limits is discussed in Section 9.2 of the licensee's SAR.

2.2.1 Minimum Critical Power Ratio (MCPR) Operating Limit

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

Table 9-1 of the licensee's SAR provides plant parameters used for the original rated thermal power (ORTP), and the representative equilibrium GE-14 core at the DNPS EPU power level of 2957 MWt. Table 9-2 presents the EPU transient analyses results based on the calculated SLMCPR, which is slightly lower than the value for the SLMCPR for the pre-EPU cycle. The SLMCPR is established or confirmed every reload, based on the actual core configuration and operating conditions.

The licensee analyzed the limiting transients for operation at the EPU operating domain, based on the GE-14 equilibrium core. Table 9-2 of the licensee's SAR provides the OLMCPR for the limiting transients. The licensee stated that the required OLMCPR is not expected to change significantly from the results shown in Table 3-1 of ELTR1 and Figure 5-3 of ELTR2.

During a previous EPU audit conducted in March 2001, the 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. The DNPS EPU reload cores introduce GE-14 fuel. The NRC staff considered that the audit and the resolution of the audit findings ensure the CPR correlations used to determine the MCPR are properly developed and experimentally benchmarked.

The staff's audit findings and the GNF corrective actions to resolve the findings are summarized in Section 2.6 and Attachment 1 of this document. Based on the staff's review and evaluation of the licensee's information, the staff finds the licensee's evaluation and response to be acceptable. The staff finds that the GNF corrective action to re-correlate GEXL14 using available experimental data will ensure that the MCPR limits are properly determined. The ARTS power-and flow-dependent MCPR limits are discussed in Section 9.2.

2.2.2 Maximum Average Planar Linear Heat-Generation Rate (MAPLHGR) and Maximum LHGR Operating Limits

The MAPLHGR OL is based on the most limiting LOCA and ensures compliance with the ECCS acceptance criteria in 10 CFR 50.46. For every new fuel type, the fuel vendors perform LOCA analyses to confirm compliance with the LOCA acceptance criteria, and for every reload licensees confirm that the MAPLHGR OL for each reload fuel bundle design remains applicable.

As discussed in Section 4.3 of the SE, the licensee performed the LOCA evaluation based on the representative GE-14 equilibrium core and operation at the EPU power level. The licensee stated that the LOCA analysis shows no change in the MAPLHGR or the LHGR limits for normal two recirculation loop operation (TLO) and for single recirculation loop operation (SLO). The LOCA analyses are required to account for the increased thermal power. The licensee revised the MAPLHGR multipliers to account for SLO in the higher MELLLA region. The licensee stated that the LHGR limits are fuel dependent and apply regardless of the power level, but added that changes to the GNF advanced core methods will allow the MAPLHGR and the LHGR limits to be monitored independently. The licensee stated that separate MAPLHGR and maximum LHGR limits will be maintained for each GNF fuel type as described in Sections 5.7.2.2 and 5.7.2.3 of ELTR1. ELTR1 states that EPU fuel thermal-mechanical limits will be confirmed to be within the fuel design criteria as part of each cycle-specific reload analysis. This is acceptable to the staff. ARTS power- and flow-dependent LHGR limits are discussed in Section 9.2.

The licensee evaluated the plant's response to operation at the higher MELLLA rod line and power level based on the representative bounding unit equilibrium GE-14 core. Although the initial transition reload cycle-specific analysis will not be based on the final EPU conditions, the final transition cycle reload analysis will be based on the MELLLA/ EPU operating conditions and cycle-specific core design. The flatter radial power distribution will result in more fuel bundles operating 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 submit an amendment request for NRC for review. As stated above, the audit team reviewed the GE-14 CPR correlation database, which was used to develop the GEXL14 CPR correlation for GE-14 fuel and whose accuracy affects the TS SLMCPR calculations. The licensee will specify the other thermal limits in the cycle-specific core OL report (COLR), as required in Section 5 of the TS. Also, the licensee cannot exceed the NRC-approved burnup limits. The staff concludes that the licensee has appropriately considered the effects of the MELLLA/EPU operation on the fuel design performance and that the thermal limits are acceptable based on the staff review of the licensee's submittal and the staff's audit of the fuel performance and thermal limit evaluations.

2.3 Reactivity Characteristics

The licensee stated that for a given core design, operation at higher power could reduce the hot excess reactivity, typically by about 0.2 to 0.3 percent delta K for each 5-percent power increase. The loss of reactivity is not expected to affect the ability to manage the power distribution needed to meet the target power through the cycle. The lower hot excess reactivity can result in an earlier all-rod-out condition during the operating cycle, however, through reload fuel cycle-specific core analyses, the core can be designed with sufficient excess reactivity to maintain the fuel cycle length. Changes to the hot excess reactivity can also affect the cold to hot reactivity difference. The licensee added that the reload core analysis will ensure that the minimum shutdown margin requirements are met for each core design and that the current design and TS cold shutdown margin will be met. Since the licensee will continue to confirm that the TS cold shutdown requirements will be met for each reload core operation, using measured plant data and analysis methods that were reviewed and found acceptable by the staff, the staff finds this acceptable.

2.3.1 Power/Flow Operating Map

To achieve the 17-percent increase above the ORTP, the licensee proposes to operate at the MELLLA rod line. The EPU operating domain will be defined by (a) the MELLLA upper boundary line extended up to the EPU RTP, (b) the maximum EPU power level corresponding to 117 percent of the ORTP, and (c) the existing 100- percent core flow line continued up to the EPU power. The previously analyzed core flow range will be extended so that the RTP will correspond to the EPU power level and the maximum core flow will not be increased. The proposed EPU operating domain power/flow map is shown in Figure 2-1 of the submittal.

The MELLLA upper boundary line replaces the current extended load limit line analysis (ELLLA) upper boundary for single recirculation loop operation. The licensee stated that the maximum power statepoint for the SLO corresponding to the MELLLA upper boundary and recirculation pump speed of 102.5 percent would be 70.2 percent of the EPU RTP (2076 MWt). The associated SLO core flow would then be 55.1 percent core flow (54 million pound mass per hour (Mlbm/hr)). The licensee would perform the EPU SLO safety analysis based on the MELLLA statepoint for SLO. The licensee stated that EPU operation at the higher rod line would also require rescaling of the associated protection system setpoints.

The licensee will rescale the fixed averaged power range monitor (APRM) power signal to the EPU RTP, such that the indications will read 100 percent at uprated power level. The licensee stated that the EPU would have little effect on the intermediate range monitor (IRM) overlap with the source range monitor (SRM) and the APRMs. The licensee will use the normal plant surveillance procedures to adjust the IRM overlap with the SRMs and APRMs. The licensee’s SAR (Reference 2) further stated that the APRM downscale setting does not need to change. The EPU would affect the neutronic life of the local power range monitor (LPRM) detectors and the radiation levels of the TIPs, but the effects would be expected to be very small. Operation at the higher MELLLA rod line will affect the IRM overlap and the staff accepts the licensee’s plan to adjust the overlap for the EPU condition to ensure adequate reactor monitoring.

The licensee states that the analytical limit (AL) (as a percentage of RTP) for the fixed APRM high power scram will not change. The AV for the fixed APRM trip is being changed as described in Section 5.3.4. This is consistent with Section F.4.2.2 of ELTR1. The licensee also evaluated all of the limiting transients that rely on the fixed APRM trip at the EPU conditions.

Since EPU operation will include implementing the MELLLA operational region, the licensee has developed new equations for the flow-biased APRM scrams, both for normal two recirculation loop and SLO operation. The licensee stated that the design bases for the MELLLA operating regime uses a linear relationship for all analytical limits versus the recirculation drive flow, which is consistent with the APRM hardware design and licensing analyses. According to the licensee, the ALs for the flow-biased APRM scrams are straight line equations, in which the slope was changed consistent with other BWR MELLLA applications. The licensee also maintains equivalent margins between the rod blocks and scram trip setpoints to avoid spurious protective actions. The flow-biased APRM scram analytical limits are also specified in Table 5-1 of the EPU submittal. The staff evaluated the licensee's submittal and the analytical methods used by the licensee and reached the same conclusions.

The RBM limits erroneous control rod withdrawal by supplying a trip signal to the Reactor Manual Control System to block further withdrawal. The trip signal is initiated when the RBM output exceeds the rod block setpoint. The licensee stated that the setpoints are determined on a fuel cycle-specific basis and will be modified as needed. The TS SR threshold is unchanged at 30 percent RTP.

2.4 Stability

DNPS is currently operating under the requirements of reactor stability interim corrective actions (ICAs) and is in the process of implementing long-term stability (LTS) solution Option III hardware changes, but has not yet armed the system. The LTS solutions for BWRs are discussed in LTR NEDO-32465-A, "BWR Owners Group Stability Solutions Licensing Basis Methodology and Reload Application" (Reference 37).

If the Option III system is not operable, the ICA procedures (Reference 38) are initiated to restrict plant operation in the high power, low core flow region of the BWR power/flow operating map. The procedures contain specific operator actions in response to reactor operation in the defined restricted regions. This generic interim solution is approved to cover all operations and accident scenarios. ICA stability boundaries remain the same in terms of absolute power and core flow for extended power uprate. The power levels, reported as a percentage of rated power, are rescaled to the uprated power. The ICA region boundaries can be validated using the ODYSY code. The staff's review and acceptance of the ODYSY stability application LTR (NEDC-32992P) are documented in an April 20, 2001, safety evaluation report (SER) (Reference 45). This approach was confirmed during a recent staff audit at GNF San Jose from December 3 through December 7, 2001, and was found to be satisfactory for ICA implementation.

Maintaining adequate SLMCPR protection is assured by using the OPRM scram available in Option III. The application of the so-called *DIVOM* curve was audited in the June 2001 visit. The DIVOM stands for Delta CPR over initial minimum critical power ratio (IMCPR) versus oscillation magnitude. The DIVOM curves are normalized curves of CPR performance versus hot bundle oscillation. GNF has generated generic curves for core-wide and regional mode oscillations. The two curves are intended to be used in the stability licensing methodology during the reload analysis. During a prior EPU audit, the staff reviewed internal General Electric Nuclear Energy (GENE) documentation questioning the applicability of the generic DIVOM curves for EPU operation using GE-14 fuel.

The June audit of DNPS covered the pre-EPU and EPU operation. The staff reviewed the design record files (DRFs) for the EPU equilibrium core and for the first transition reload cycle stability calculations. The staff review further questioned whether the generic DIVOM curves for the regional mode oscillation in NEDO-32465-A (Reference 37) can be met for the EPU/MELLLA operation. The licensee stated that Option III will not be used until resolution of use of the generic DIVOM curve for the EPU operating condition is resolved, as discussed in Section 2.6 of this SE.

On June 29, 2001, GENE submitted a 10 CFR Part 21 notification regarding the use of the DIVOM curve. GENE reported that stability reload licensing calculations using the generic DIVOM curve may be nonconservative for plants using the stability detect and suppress trip systems. For the Option III stability solution, the trip system setpoints, which ensure adequate MCPR safety limit protection from regional mode instability, may be nonconservative. This Part 21 report stated that there is a deficiency for high peak bundle power-to-flow ratios for the regional mode DIVOM curve and for high core-averaged power-to-flow ratios for the core wide mode DIVOM curve. GENE provided a figure of merit for the generic regional DIVOM curve, which licensees could use to determine the applicability of the existing generic DIVOM curve for their units. The licensee states that Option III will not be armed (operational) until the Part 21 issue is resolved. Based on the staff's audit of the stability calculation (Attachment 1) and review of the licensee's submittal and RAI responses, the staff concludes that this is acceptable.

2.5 Reactivity Control

2.5.1 Control Rod Drive 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 scram the reactor by rapidly inserting withdrawn rods into the core. The scram, rod insertion, and withdrawal functions of the CRD system depend on the operating reactor pressure and the difference between the CRD system hydraulic control unit (HCU) pressure and the reactor vessel bottom head pressure to provide the driving force to more the control rods.

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 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 licensee stated that since the generic evaluation concluded that the CRD systems for BWR/2-6 are acceptable for EPU as high as 20 percent above the original rated power, no additional plant-specific calculations are required beyond confirmatory evaluation. The licensee performed confirmatory evaluations of the performance of the CRD system at the EPU conditions based on a reactor dome pressure of 1005 psig with an additional 35 psid added to account for the static head of water in the vessel.

The licensee stated that for CRD insertion and withdrawal, the required minimum pressure between the HCU and the vessel bottom head is 250 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 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 the DNPS 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) function.

During scrams at low reactor pressure, the 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 the system losses. The CRD system is designed to use the reactor pressure to assist the scram for high reactor pressure scrams. Therefore, the higher pressures that might occur as a result of EPU operations during isolation events will not have a significant effect on the scram function of the CRD system. In addition, scram time testing verifies the scram time for individual control rods. The licensee has also evaluated the performance of the CRD insert, withdraw, cooling, and drive functions.

Based on the review of the licensee's evaluation, the staff concludes that the CRD system will continue to meet its design basis and performance requirements at EPU conditions.

2.6 EPU Onsite Audit Reviews

During the weeks of March 26 and June 16, 2001, members of the NRC Reactor Systems Branch (SRXB) staff visited the GNF engineering and manufacturing facility at Wilmington, North Carolina. The purpose of these visits was to perform onsite audit reviews of selected safety analyses and system and component performance evaluations used to support EPU licensing submittals. The March audit focused on the Duane Arnold Energy Center (DAEC) EPU, and the June audit was related to the DNPS EPU submittal. The areas covered by these audits are related to the following sections of the licensee's SAR:

2 Reactor Core and Fuel Performance

2.1 Fuel Design and Operation
2.2 Thermal Limits Assessment
2.3 Reactivity Characteristics
2.4 Stability

9 Reactor Safety Performance Evaluations

9.1 Reactor Transients
9.3 Design Basis Accidents
9.4 Special Events

The staff's audit report is attached (Attachment 1).

The SRXB staff audit, conducted during the week of June 16, 2001, covered the areas of the licensee's SAR being reviewed by SRXB. As stated in Attachment 1, most questions were resolved during the audit, and the rest were resolved by requests for additional information (RAIs) and the licensee responses. With the exception of the GEXL14 correlation reevaluation and the ATWS questions in the Attachment, all open items were resolved.

In response to the staff concerns, the GEXL14 correlation was re-evaluated and submitted to the staff for review (Reference 58). The GE re-correlation topical report submittal is currently under staff review using the approved GESTAR-II (Amendment 22) process. Any changes resulting from the staff review that might affect the TS SLMCPR would be separately submitted by the licensee for staff review and approval.

As a result of the audit, the staff requested and received additional information from the licensee on the ATWS events that were analyzed at the EPU conditions.

The limiting events for each of the five ATWS acceptance criteria in Section 9.4.1 of the licensee's SAR are identified as Pressure Regulator Failure - Open (PRFO) for Criteria 1, 2, and 3, and the Main Steam Isolation Valve Closure (MSIVC) for Criteria 4 and 5. The licensee confirmed that the operator response to an ATWS event is not being modified from that described in Section L.3.2, "Operator Actions," of ELTR1. The licensee confirmed that for all limiting ATWS events, the SLC system for DNPS, Unit 2 will be able to inject at the appropriate time without lifting the SLC bypass relief valve (RV). The cycle-specific reload analysis for DNPS Unit 3 will confirm the SLC capability or will identify required system modifications. The licensee also confirmed that the SLC system meets the ATWS acceptance criteria for DNPS even if the operator requests SLC actuation before the time assumed in the analysis, and the RV lifts and remains open until the valve inlet pressure decreases to the valve reseat pressure. The licensee will verify the valve reseat pressure and the lack of valve chatter upon reseat at the next refueling outage for each unit. The licensee's response to the staff's questions was summarized in a letter dated November 2, 2001 (Reference 55).

Based on the review of the licensee submittal, the on-site audit of the application of approved methodologies, and the licensee response to the request for additional information including the commitments made, the staff finds the ATWS and SLC evaluations acceptable.

3.0 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

The staff's review of this section of the SAR provided by the licensee focused on the effects of power uprate on the structural and pressure boundary integrity of the piping systems and components, their supports, and reactor vessel and internal components, and the control rod drive mechanisms (CRDMs), certain pumps and valves, and the balance-of-plant (BOP) piping systems.

The GE generic guidelines for BWR power uprate were based on a 24 percent higher steam flow; an operating temperature increase to 556 °F, and an operating pressure increase to 1080 psig. For DNPS, the maximum reactor vessel dome pressure (1005 psig) is the same as at the ORTP level, and the dome temperature is also unchanged (remaining at 547 °F). The steam flow rate will increase from 9.81 $\times 10^6$ lb_m/hr to 11.71 $\times 10^6$ lb_m/hr (an increase of approximately 19.4 percent) for DNPS. The maximum core flow rate remains unchanged for the proposed power uprate conditions at DNPS.

3.1 Nuclear System Pressure Relief

The safety and relief valves (S&RVs) provide overpressure protection for the NSSS, preventing potential failure of the nuclear system pressure boundary and uncontrolled release of fission products during an overpressure event. Each unit has eight spring-actuated safety valves (SSVs) (unpiped) which discharge directly into the drywell, rather than the suppression pool. Each unit also has four RVs, and a single dual function safety/relief valve (SRV), which are piped to the suppression pool. These S&RVs, together with the reactor scram function, provide the overpressure protection. The S&RV 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 S&RV actuation setpoints. The S&RV

setpoints are also selected to be high enough to prevent unnecessary S&RV actuations during normal plant maneuvers.

The licensee evaluated the capabilities of the S&RVs to provide overpressure protection based on the current setpoints and tolerances for operation at the EPU power level and determined that the nuclear boiler pressure relief system has the capability to provide sufficient overpressure protection. The analytical limits (ALs), using the upper tolerance limits of the valve setpoints, are shown in Table 5-1. The licensee also stated that the EPU evaluation is consistent with the generic evaluations and discussions 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 SSV, RV, and SRV setpoints.

Table 5-1 of the licensee's SAR lists the ALs of the SRV, SSVs and RVs, using the ± 1 percent tolerance. DNPS has 13 safety and RVs, with 1 SRV set to 1135 psig, 2 SSVs set to actuate at 1240 psig, 2 SSVs set at 1250 psig, and 4 SSVs set at 1260 psig. Two RVs are set to actuate at 1101 psig, and two are set at 1124 psig.

Since the licensee performed limiting American Society of Mechanical Engineers (ASME) overpressure analyses (discussed in Section 3.2 of this SE) based on 102 percent of the EPU power level, and the current S&RV setpoints and upper tolerance limits will not change, the staff accepts the licensee's assessment that the S&RVs will have sufficient capacity to handle the increased steam flow associated with operation at the EPU power level. The ASME overpressure situation is evaluated during each cycle-specific reload analysis. Therefore, the capability of the S&RVs to ensure ASME overpressure protection will be confirmed in all the subsequent reload analyses.

3.2 Reactor Overpressure Protection Analysis

The design pressure of the reactor vessel and the reactor coolant pressure boundary (RCPB) remains at 1250 psig. 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), which is the acceptance limit for pressurization events. The most limiting pressurization transient is analyzed on a cycle-specific basis and this approach would be applicable for each EPU reload cycle. 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 the main steam isolation valve (MSIV) closure with failure of the valve position scram and turbine trip with bypass failure (TTNBP). The licensee analyzed both events based on an initial dome pressure of 1005 psig with one SRV out of service (OOS), 102 percent of the EPU RTP, 108 percent core flow, and a representative GE-14 equilibrium core. The licensee determined that MSIV closure with valve position scram failure was the most limiting pressurization transient, relative to the TTNBP calculation. The MSIV closure event resulted in a maximum reactor dome pressure of 1336 psig, which corresponds to a vessel bottom head pressure of 1358 psig. Therefore, the peak calculated dome pressure (1336 psig) remains below the TS 1345 psig safety limit and the peak reactor vessel pressure (1358 psig) remains within the ASME limit of 1375 psig. The licensee concluded that there is no decrease in safety margin and the EPU overpressure protection analysis (given in Figures 3-1 and 3-2 of Reference 2) is consistent with the generic analysis in Section 3.8 of ELTR2.

The maximum calculated pressure in the current ASME overpressure transient analysis meets both the ASME and the TS pressure limits. Therefore, the staff concludes that the licensee has demonstrated an acceptable plant response to overpressure conditions for EPU operation.

3.3 Reactor Pressure Vessel (RPV) and Internals

The staff had previously reviewed and accepted the DNPS pressure-temperature (P-T) limits. However, the NRC staff had some technical issues with the methodology used to derive the fluence values used in the P-T limits evaluation. The original fluence estimate was based on early dosimetry and associated analysis that does not satisfy the guidance of RG 1.190. New fluence estimates calculated for the EPU amendment use the fluence methodology of GE topical report NEDC-32983P, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluations," which is currently under review by the staff. The staff concluded that these issues must be resolved 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 Reference 33, the licensee requested interim approval for the P-T curves until December 31, 2003, for Unit 2 and until November 30, 2004, for Unit 3. This is approximately one cycle of EPU operation.

The peak inside surface vessel fluence value for DNPS for 32 EFPYs of operation (including the power uprate) is 4.4×10^{17} n/cm^2. The original estimate for the same quantity was 5.1×10^{17} n/cm^2. The new value appeared to be low in absolute value and lower than the original estimate even with the power uprate. The licensee justified the low absolute value based on: (1) the fact that the DNPS vessel has a larger diameter than BWRs with comparable power level (2) the fact that the power density is lower than that in comparable power pressurized water reactor plants and (3) the fact that the licensee practiced low leakage loadings (and will continue the practice in the future).

The staff finds the proposed justification acceptable because (1) the larger diameter increases the neutron flux attenuation, (2) the lower power density will decrease the neutron leakage, and (3) the core loading scheme will further decrease neutron leakage. The recalculation of the peak 32 EFPY fluence indicates that the existing value that was used for the calculation of the pressure temperature curves is conservative. The staff finds the justification for low absolute peak inside vessel value reasonable, based on known physical parameters, and providing adequate assurance of safety for the proposed time limit. However, new P-T curves or a justification for continued use of the current curves must be submitted before the end of the first cycle of EPU operation. Further discussion of the P-T limits evaluation is contained in Section 3.3.1 of this SE.

3.3.1 Reactor Vessel Fracture Toughness

In Sections 3.3.1 and 3.5 of Reference 2 the licensee assessed the effects of the Dresden EPU on the RPV and RCPB piping of each unit. With regard to the RPV, the licensee provided an assessment of the impact of the EPU on the RPV wall fluence, the need to revise the P-T limit curves, and the validity of previously approved upper-shelf energy (USE) equivalent margin analyses. For EPU, the 32 EFPY shift in RT_{NDT} resulting from neutron irradiation decreases and consequently requires no change in the adjusted reference temperature (ART). EPU does not affect the existing surveillance program schedule.

To analyze the RPV, the licensee examined the effect on the RPV beltline fluence of increasing thermal power for DNPS Units 2 and 3 from 2527 MWt to 2957 MWt. The analyses 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 EPU decreases from the UFSAR end-of-license value because the pre-EPU fluence is based on conservative dosimetry values and the pre-EPU fluence bounds the fluence calculated for the EPU evaluations. This lower 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:

- The USE remains bounded by the equivalent margin analysis for the design life of the vessel and maintains the margin requirements of 10 CFR Part 50, Appendix G.

- The P-T curves contained in the current TSs remain bounding for EPU operation up to 32 EFPYs. Therefore, the TSs do not need to change.

- For EPU, the 32 EFPY shift in RT_{NDT} resulting from neutron irradiation decreases and consequently requires no change in the ART which is the initial reference temperature of nil-ductility transition (RT_{NDT}) plus the shift, plus a margin term.

- The maximum operating dome pressure for EPU operation is the same as for current operation. Therefore, the current hydrostatic and leakage test pressures are acceptable for the EPU.

The licensee concluded that the vessel remains in compliance with the regulatory requirements during EPU conditions.

The staff concludes that many of the existing RPV-related evaluations and analyses remain valid and applicable for the EPU. The basis for this conclusion is that (1) the current design assessments show significant design margins in reactor integrity analyses which are not affected by the proposed power uprate, (2) the loading conditions are either unchanged or are bounded by the analyzed loading conditions, and (3) the licensee predicts no increase in end-of-life fluence. The staff concludes that the USE remains bounded by the equivalent margin analysis for the design life of the vessel and maintains the margin requirements of 10 CFR Part 50, Appendix G. The maximum operating dome pressure for EPU operation is the same as for current operation. Therefore, the current hydrostatic and leakage test pressures are acceptable for the EPU.

However, as mentioned in Section 3.3 of this SE, the NRC staff has technical issues with the methodology used to derive the fluence values. These values form the basis for evaluating reactor vessel integrity and fracture toughness, including P-T limits. The licensee commits to revise the fluence predictions using an acceptable methodology before the end of the first cycle of EPU operation on each unit or to provide justification for continued use of the existing fluence estimate. The staff evaluated the RV integrity and fracture toughness for EPU conditions based on the fluence provided by the licensee, 4.4×10^{17} n/cm^2. If the fluence is projected to increase, the licensee must reevaluate the P-T limits and the RV integrity issues before the vessel fluence is predicted to exceed 4.4×10^{17} n/cm^2.

3.3.2 Reactor Vessel Integrity

The licensee evaluated the effects of the DNPS power uprate on the reactor vessel and internal components in accordance with their current design basis. The loads considered in the evaluation include reactor internal pressure difference (RIPD), LOCA, flow loads, acoustic loads, thermal loads, seismic, and dead weight. The licensee indicated that the load combinations for normal, upset and faulted conditions were considered consistent with the current design basis analysis. In the evaluation, the licensee compared the proposed power uprate conditions (pressure, temperature and flow) against those used in the design basis. For cases where the power uprate conditions were bounded by the design basis analyses, no further evaluation was performed. If the power uprate conditions were not bounded by the design basis, new stresses were determined by scaling up the existing design basis stresses proportionate to the proposed power uprate conditions. The resulting stresses are compared against the applicable AVs, consistent with the design basis. The staff review of the licensee's evaluation finds that the methodology used by the licensee is consistent with the NRC-approved methodology in Appendix I of Reference 3 and, is therefore, acceptable.

The stresses and cumulative fatigue usage factors (CUFs) for the reactor vessel components were evaluated by the licensee in accordance with the ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition which is the code of record at DNPS. The licensee indicated that for DNPS, the reactor internal components are not ASME code components, since ASME Section III, Subsection NG, was not in place at the time the plant was licensed. However, ASME code requirements in Section III, Subsection NG, were used for this application. The staff concludes that the licensee's assessment is acceptable and in compliance with the code of record at DNPS.

3.3.3 Reactor Vessel Internals and Pressure Differentials

The licensee provided the calculated maximum stresses and CUFs for the reactor vessel components in Table 3-3 of Reference 2. The reactor vessel components not listed in Table 3-3 have maximum stresses and CUFs that are either not affected by the power uprate or are already bounded by those listed in the table. The maximum calculated stresses shown in the table are within the allowable limits, and the CUFs are less than the code limit of unity. The licensee evaluated the reactor internal components for DNPS by comparing the changes in loads that were affected by the power uprate against the margins available in the design basis analysis. Reference 22 shows that the existing margins are sufficient to accommodate the increase in loads for the power uprate. For some cases the licensee compared the affected loads (i.e., reactor internal pressure differential (RIPD)) on certain components against their design basis loads. Reference 22 shows that the design basis loads are bounding for the power uprate. The maximum stresses for certain critical components of the reactor internals are also provided in Reference 22 for the power uprate conditions. The calculated stresses are shown to be less than the allowable Code limits.

In its assessment of the potential for flow-induced vibration (FIV) on the components, the licensee indicated that the steam separators and dryers in the upper zone of the reactor are most affected by the increased steam flow due to the proposed power uprate. The effect of the power uprate on the FIV of other components in the reactor annulus and core regions is less significant, because the proposed power uprate conditions do not require any increase in core flow, and very little increase (less than 2.2 percent) in the drive flow. For components other than the steam separators and dryers, the evaluation of FIV for the reactor internal components was performed based on the vibration data recorded during startup testing at DNPS, the GE prototype BWR/4 plant vibration data, and operating experience from similar GE BWR plants. The vibration levels were calculated by extrapolating the recorded vibration data to power uprate conditions and comparing the extrapolations with the plant allowable limits. The stresses at critical locations were calculated based on the extrapolated vibration peak response displacements and found to be within the GE allowable design criterion of 10 ksi. Stress values less than 10 ksi are within the endurance limit without the need to compute the cumulative fatigue usage for the component due to flow-induced vibration. The licensee concluded that vibration levels of all safety-related reactor internal components are within the acceptance criteria. The staff concludes that the licensee's evaluation is acceptable and consistent with the ASME limit of 13.6 ksi for the peak vibration stress.

The licensee indicated, in Reference 22, that the steam dryers and separators are not safety related components: however, their failure may lead to an operational concern. The licensee also indicated that, although the design basis criteria do not require evaluation of the flow-induced vibration 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 indicated that the dynamic pressure loads, which may induce dryer vibrations, are small in comparison to loads for the design basis faulted condition. Accordingly, stresses in the dryers due to vibration associated with the proposed uprated condition is estimated less than the allowable limit. In addition, the dryers are normally visually inspected during removal in each refueling outage, and any significant cracking can be detected and repaired. The licensee indicated that it will examine the dryer and connected supporting brackets after the first cycle of operation following the power uprate. The need for future examinations will be based on this assessment. The design basis for the steam dryers specifies that the dryers maintain their structural integrity when subjected to a steam line break occurring beyond the main steam isolation valves (MSIVs). Since the dome pressure is not changed, the current steam dryer analysis remains bounding for the proposed power uprate conditions. On the basis of information provided by the licensee in Reference 22, the staff concludes that the licensee has reasonably demonstrated that the steam dryers and separators will meet their design basis requirements and maintain their structural integrity following the proposed extended power uprate.

Based on its review of the licensee's evaluation of the reactor vessel and internals, the staff finds that the maximum stresses and fatigue usage factors are within the code-allowable limits. The staff also concurs with the licensee's conclusion that the reactor vessel and internal components will continue to maintain their structural integrity at the power uprate condition.

The licensee indicated that the CRDMs have been designed in accordance with the code of record, the ASME Boiler and Pressure Vessel Code Section III, 1965 Edition, with Addenda up to and including Summer 1965. The components of the CRDM, which form part of the primary pressure boundary, have been designed for a bottom head pressure of 1250 psig, which is higher than the AL of 1095 psig for the reactor bottom head pressure. The licensee's evaluation indicated that the maximum calculated stress for the CRDM is less than the allowable stress limit. The maximum CUF of 0.15 for the CRDM was calculated based on the staff approved analysis of record. This is less than the code-allowable CUF limit of 1.0.

On the basis of its review, the staff concurs with the licensee's conclusion that the CRDMs will continue to meet their design basis and performance requirements at uprated power conditions.

3.3.4 Steam Separator and Dryer Performance

The steam separators and dryers do not have a safety-related function other than structural integrity; however, their operational performance is important to equipment design and steam moisture content is a factor in design inputs such as transport of particulate radioactive material from the reactor. The steam separator and dryer performance evaluations are generically described in Section 5.5.1.6 of ELTR1 (Reference 12). A plant-specific performance evaluation determined that hardware modifications are required to reduce the moisture content. As noted in the licensee's letter dated May 18, 2001 (Reference 12), a startup test will evaluate the performance of the steam separator-dryers and demonstrate that the moisture levels are within appropriate limits. In its letter dated August 7, 2001 (Reference 19), the licensee noted the design criterion for the planned modification was established to maintain moisture content $\leq$0.2 wt. percent under most operating conditions. Acceptable moisture content will be demonstrated based on actual moisture carryover data collected at both Dresden and Quad Cities Stations.

Based on the review of the licensee's evaluation, the staff concludes that the moisture content of the steam will be acceptable and subject to verification by collection of data, after the EPU.

3.4 Reactor Recirculation System

DNPS is currently licensed to operate at a maximum core flow of 98 Mlb/hr (100 percent of the rated flow) and the EPU does not require an increase in the maximum allowable core flow. Because future applications of the increased core flow option may increase the maximum core flow to 108 percent of the current rated value, some analyses are performed at this value. The primary function of the recirculation system is to vary the core flow and power during normal operation. However, the recirculation system also forms part of the RCS pressure boundary.

The licensee evaluated the system operating pressure and temperature at the EPU conditions and determined that changes are small and result in conditions less than the current rated conditions. The DNPS EPU will not involve any increase in the steady-state dome pressure. However, operation at the EPU power level would increase the two-phase flow resistance, requiring a slight increase in the recirculation system drive flow. The licensee estimated the required pump head and pump flow at the EPU conditions and determined that the power demand of the recirculation motors will increase slightly. The increased drive flow will require increasing the pump speed. The licensee stated that the DNPS recirculation system and its components are capable of providing the core flow required for operation at the EPU conditions. The recirculation system evaluations are consistent with the generic evaluation in Section 4.5 of ELTR2, Supplement 1. Section 4.5 of supplement 1, to ELTR2 evaluated the recirculation system performance for a 20-percent power uprate with a 75-psig increase in the normal dome operating pressure and concluded that the recirculation system design can accommodate the operating conditions associated with the power uprate.

The staff reviewed the impact that a recirculation pump trip (RPT) would have on plant safety. The plant is analyzed for decreases in the reactor core coolant flow rate that depend on the operation of the recirculation pumps and motors. The transient events in this category are

(a) single and multiple RPTs, (b) recirculation flow controller failure malfunction, (c) recirculation pump shaft seizure (normal and SLO), and (d) recirculation pump shaft break. In these events, core flow is reduced, resulting in a corresponding decrease in the reactor power. For DNPS, these transients are nonlimiting in terms of thermal limits and are not reanalyzed in the cycle-specific reload analysis. EPU operation is not expected to make these transients limiting.

DNPS is currently licensed to operate with SLO, and the licensee stated that SLO operation would be limited to 70.2 percent of the EPU power level (2076 MWt) at 55.1 percent core flow (54 Mlb/hr). This power level corresponds to the MELLLA upper boundary at the maximum recirculation pump speed of 102.5 percent. The staff concurs with this evaluation, based on the staff's review of the licensee submittal and on the audit evaluation of the EPU safety analyses.

The licensee also stated that EPU conditions would not significantly increase the net positive suction head (NPSH) required or reduce the NPSH margin for the recirculation pump and jet pump. The licensee will maintain the flow cavitation protection interlock at the current setpoints of actual FW 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 is consistent with the evaluation in Section F.4.2.6 of ELTR1.

The licensee will not change the percent flow values of the recirculation pump flow mismatch specification in the TS.

The staff evaluated the licensee's assessment and has concluded that the changes to the cavitation interlock, the recirculation pump mismatch power basis, and the jet pump TS surveillance requirement, are acceptable.

Section 4.5.3 of Supplement 1 to ELTR2 discussed the impact of a 20-percent power uprate on the recirculation system safety functions for (a) the closure of the discharge valve during low-pressure coolant injection (LPCI), (b) the pump trip in transients and anticipated transients without scram (ATWS), and (c) measurement of the drive flow used in the APRM flow-biased setpoint and rod blocks. For LOCA response, one or both recirculation system discharge valves must close to ensure LPCI injection into the core. Since the DNPS power uprate 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 ELTR2, the recirculation system fast transient analysis is necessary to support EPU operation for the plants that have adopted the APRM/RBM TS (ARTS) feature to ensure adequate protection during the transient. The ARTS program replaces the flow-biased APRM trip setdown during operation at off-rated conditions. Under these conditions, ARTS plants use power-and flow-dependent MCPR and LHGR limits for operation at the off-rated conditions. Table 9-2 of the DNPS SAR provides the delta-CPR value for the fast recirculation flow transient and confirms that the ARTS multipliers used to develop the power-dependent MCPR(P) and shown in Table 9-3 remain bounding. The staff has evaluated this methodology and has concluded that it is acceptable.

3.5 Reactor Coolant Piping and Components

The licensee evaluated the effects of the power uprate steady state and transient conditions, including higher flow rate, temperature, pressure, fluid transients and vibration effects on the RCPB and the BOP piping systems and components. The components evaluated included 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 design basis analyses, and the original analytical techniques were used in the evaluation. No new assumptions were introduced that were not in the original analyses.

3.5.1 Pipe Stresses

The RCPB piping systems evaluated include the reactor recirculation, main steam (MS), main steam drains, isolation condenser, high-pressure coolant injection (HPCI), FW, reactor water cleanup (RWCU), core spray (CS), standby liquid control (SLC), shutdown cooling (SDC), LPCI/containment cooling (CC), RPV head vent line, and RV/SRV discharge line systems using the present code of record. The licensee indicated that the evaluation follows the process and methodology defined in Appendix K of ELTR1 (Reference 3) and in Section 4.8 of Supplement 1 of ELTR2 (Reference 5). In general, the licensee compared the increase in pressure, temperature, and flow rate due to the power uprate against the same parameters used as input to the original design-basis analyses. The comparison resulted in the 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 Code-allowable limits. As a result of the comparison, the licensee concluded that there are sufficient design margins to justify operation at the power uprate condition. The bounding percentage increases were also applied to the original calculated stresses for the piping to determine the stresses at the proposed power uprate condition. The staff has concluded that the licensee's approach, described above, is conservative and acceptable.

In its response to the staff's request for additional information (RAI) (Reference 20), the licensee indicated that most of the RCPB piping systems at DNPS are designed to American National Standards Institute (ANSI) B31.1- 1967, which does not require a fatigue analysis. Other codes were used during the plant operation: American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section I, 1965 Edition, through Summer 1966 Addenda, including Code Cases N-1 thru N-3 and N-7 thru N-11, and ASME Code Section III, Subsection NC (Class 2), 1977 through 1978 Winter Addenda and ASME Code Section III, Subsection ND (Class 3), 1974 through 1976 Summer Addenda. These codes do not include fatigue requirements. The licensee further indicated that the ASME Code, Section III Subsection NB, 1980 edition, including the Summer 1982 Addenda, was used for the reactor recirculation piping at DNPS Unit 3, since it was replaced in the mid 1980s. This code includes fatigue requirements. However, the licensee found that the calculated maximum stresses and fatigue usage factors for the reactor recirculation piping remain unchanged as a result of the proposed uprate. As a result of its evaluation, the licensee concluded that for all RCPB piping systems the original piping design has sufficient design margin to accommodate the slight changes due to the proposed power uprate. The staff reviewed relevant portions of the evaluation provided by the licensee in Reference 22 and finds the licensee's conclusion acceptable.

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 and pressure from the design basis analysis input for steady state and transient conditions. The evaluated BOP systems include lines that are affected by the power uprate, but not evaluated in Section 3.5 of Reference 2, such as isolation condenser, LPCI/CC water line, FW condensate and heater drain lines, main steam drain lines, and portions of the MS, FW, HPCI, and SDC cooling systems outside the primary containment. The existing design analyses of the affected BOP piping systems were reviewed against the uprated power conditions. As a result, the licensee indicated that some main steam and torus-attached piping did not have a sufficient margin in the original design analyses to accommodate the changes due to the proposed power uprate. For these piping systems, the licensee performed detailed analysis that, in most cases, would demonstrate the adequacy of the existing piping design for the power uprate conditions. However, in some cases, piping modifications are required to bring the piping within the Code-allowable stress limits. The licensee committed to completing the piping modifications prior to implementation of the power uprate at DNPS. With the required modifications, the calculated stresses are provided by the licensee in Reference 20. The staff finds that the stresses and stress ratios provided in the tables are within the Code-allowable limits and are, therefore, acceptable. The required modifications are Confirmatory Item No. 1 which must be verified to the NRC prior to power uprate at DNPS.

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 increase in pipe support loads due to the power uprate conditions is similar to the increase in piping stresses. However, when these increases are combined with the loads such as seismic and deadweight that are not affected by the power uprate, the overall support load increases are generally insignificant except for the main steam and torus-attached piping. The licensee found, as a result of the evaluation, that some supports, structural attachments, and supporting steel require modifications to meet Code requirements and Code-allowable stress limits. The licensee reviewed the original postulated pipe break analysis and concluded that the existing pipe break locations were not affected by the power uprate, and that no new pipe break locations were identified. The staff has reviewed the licensee's evaluation and concludes that it is acceptable. The staff further finds that the required torus-attached piping modifications represent a confirmatory item that must be verified prior to power uprate at DNPS.

The licensee indicated that the flow-induced vibration (FIV) levels for the safety-related MS and FW piping systems will increase in proportion to the increase in the fluid density and the square of the fluid velocity following the proposed power uprate. To ensure that the vibration level will be below the acceptable limit, the licensee is committed to perform a piping vibration startup test program, as outlined in Section 10.4.3 of the amendment submittal. The startup testing would include monitoring and evaluating the FIV during the plant startup for the proposed uprated power operation. Vibration data will be collected at interim test conditions, which correspond to 50-percent, 75-percent, and 100-percent of the ORTP, and at each 5-percent step increase in power level above 100 percent of ORTP, up to the final proposed uprated power level. The vibration at the power uprate level may be determined based on extrapolation of the vibration data taken at the lower power levels. The measured vibration levels are compared against the allowable vibration stress levels, which depend on the design fatigue endurance stress intensity limits established by the ASME code for stainless and carbon steel.

The staff finds the licensee's methodology in assessing FIV to be consistent with the ASME code limits and acceptable.

Based on the above review, the staff concurs with the licensee's conclusion that the design of piping, components and their supports including the required modifications discussed above, is adequate to maintain their structural and pressure boundary integrity at the proposed power uprate condition.

3.5.2 Flow-Accelerated Corrosion

For the RCPB piping, the licensee provided an assessment of changes in the potential for flow-accelerated corrosion (FAC) damage due to the EPU. The licensee evaluated the effect of the EPU on FAC in the following systems: recirculation, main steam and associated piping systems, FW system, and other RCPB piping. The licensee's evaluation of the reactor coolant piping confirmed that changes in the flow parameters associated with the EPU would have few or no significant effects on the potential for FAC in those systems which might be susceptible to the phenomenon (e.g., FW or main steam systems).

The components in the recirculation system are made from stainless steel, which is not susceptible to FAC. FAC damage will not, therefore, occur in this system after power uprate.

The main steam and associated piping system contains components made from carbon steel, which are prone to FAC. However, these components are exposed to steam having a 99.5-percent quality level and in this environment no FAC damage will occur. Since the power uprate is expected to result in some change in moisture content, there is a possibility of the formation of an active FAC environment. In order to prevent this, the licensee committed, as a part of the power uprate implementation, to modify the reactor vessel moisture separation equipment. This modification will maintain carryover levels consistent with values before power uprate and will prevent damage from FAC.

The FW system has carbon steel components, which are affected by FAC. After the power uprate, there will be some changes in operating conditions caused by the operation of an additional pump. Also, system pressure and temperature are expected to change. These changes will affect loss of material caused by FAC. However, the licensee will account for these changes by modifying its CHECWORKS predictive code. The predictions obtained from this modified code will be used by the licensee to assess wear rates and schedule frequency of inspections for the components currently included in the program. The predictions will also identify other components that may become susceptible to FAC after power uprate.

The power uprate will only slightly affect the inlet temperature in the other RCPB pipes and will not change their operating environment. Therefore, no potential will exist for FAC damage to these pipes.

The staff reviewed and evaluated the licensee's analyses of the systems where power uprate may have some effect on FAC. The staff has concluded that the licensee has demonstrated that EPU will have a very small effect on FAC. This effect will be accounted for by the licensee, by making some modification to the reactor vessel moisture separation equipment, enhancing the predictive FAC model, and modifying the FAC inspection program so that timely corrective procedures can be implemented.

3.6 Main Steam Flow Restrictors

The licensee stated that there is no impact on the structural integrity of the restrictor for the power uprate. In Section 3.2 of the power uprate license amendment request, the licensee indicated that a higher peak RPV transient pressure of 1336 psig results from the proposed DNPS plant power uprate conditions, but this value remains below the ASME Code limit of 1375 psig. The main steam line flow restrictor will maintain its structural integrity following the power uprate since the restrictor was designed for a differential pressure of 1375 psig which exceeds that for the uprated power condition.

3.7 Main Steam Isolation Valves (MSIVs)

The MSIVs are part of the reactor coolant pressure boundary. Their safety function is to isolate the main steam lines. 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 TSs.

The licensee stated that the MSIVs were generically evaluated in Section 4.7 of ELTR2. 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 function of the MSIVs. The generic evaluation 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) a steam and FW increase of about 24-percent. The licensee stated that the conditions for DNPS are bounded by those in the generic analysis. The dome pressure and temperature do not increase with the EPU. The increase in flow rate assists MSIV closure, which results in a slightly faster MSIV closure time. TS closure timing requirements will continue to be met.

The licensee did request an increase in the setpoint for initiation of MSIV closure on high flow. The increase is equivalent to 125-percent of uprated steam flow for DNPS Unit 2 and 140-percent of uprated steam flow for DNPS Unit 3 in each steamline, consistent with ELTR1 section F.4.2.5. This setpoint change is evaluated in Section 5.3, item 8 of this SE. The licensee noted that the new break flow setpoint will remain bounded by the analyzed choked flow through the steam line flow restrictors. For lower magnitude breaks the licensee noted (Reference 19) that breaks between 120-percent and 125 or 140-percent flow will result in a low- pressure isolation signal and additionally a break in the steam tunnel would actuate the high- temperature switches. Both these actuations will also isolate the MSIVs. Therefore, EPU operation as indicated above remains bounded by the conclusion of the generic evaluation in Section 4.7 of ELTR2, and the MSIVs are acceptable for EPU operation.

MSIV closure time will be maintained as analyzed and specified in the TS. In addition, various TS surveillances require routine monitoring of MSIV closure time and leakage to ensure that the licensing basis for the MSIVs are preserved. Based on the review of the licensee's rationale and evaluation and the staff's generic evaluation of ELTR2, the staff concurs with the licensee's conclusion that the plant operations at the proposed EPU level will not affect the ability of the MSIVs to perform their isolation function.

3.8 Isolation Condenser

The DNPS units are equipped with isolation condensers (ICs). The IC system provides core cooling in the event of a transient when the RPV is isolated from the main condenser concurrent with the loss of all feedwater flow (LOFWF).

The IC system has been evaluated for the LOFWF event and is consistent with the bases and conclusions of the generic evaluation in Section 3.1 of ELTR2. The EPU evaluation for this event was performed at a power level of 1.02 times the RTP (3016 MWt) with a reactor vessel high-pressure initiation time delay of 15 seconds, compared with the current maximum delay of 17 seconds.

The licensee has analyzed the LOFWF transient for the EPU operation, and conservatively evaluated the performance of the IC system. The staff have reviewed the licensee's submittal and performed an audit of the transient evaluations, and finds the licensee's assessment acceptable.

3.9 LPCI/Containment Cooling and Shutdown Cooling Systems

The generic residual heat removal (RHR) capability evaluation process is described in Section 5.6.4 of ELTR1. The LPCI/CC system is designed to restore and maintain the coolant inventory in the reactor vessel while the Shutdown Cooling (SDC) system provides primary system decay heat removal (DHR) after reactor shutdown for post-accident conditions. The LPCI/CC system is designed to operate in the low-pressure coolant injection (LPCI) mode, suppression pool cooling (SPC) mode, and containment spray cooling (CSC) mode. The SDC system is designed to provide SDC, or fuel pool cooling (FPC) to assist in heat removal. The LPCI mode is discussed in Section 4.2.2 of this SE, while the effects of the EPU on the other modes are described below. The results of the following evaluations are consistent with the generic evaluation in Section 4.1 of ELTR2.

3.9.1 Shutdown Cooling Mode

The operational objective of normal shutdown is to reduce the bulk reactor temperature after scram to achieve the TS required cold shutdown of 212 °F.

Since the SDC evaluation at the EPU condition demonstrated that the plant can meet this TS cooldown, the staff finds it acceptable.

3.9.2 Suppression Pool Cooling (SPC) Mode

During normal plant operation, the SPC function is to maintain the suppression pool temperature below the TS limit. Following abnormal events, the SPC function controls the long-term suppression pool temperature such that the design temperature limit of 281 °F is not exceeded. Following a LOCA, the increase in decay heat due to EPU increases the heat input to the suppression pool, resulting in a slightly higher peak containment temperature and pressure, as discussed in Section 4.1.1 of this SE. The analysis at 102-percent of EPU power discussed in Section 4.1.1 of this SE results in only an 8 °F increase in the peak temperature and confirmed that the suppression pool temperature remains below its design limit. The higher temperature reduces the NPSH available to the LPCI/CC pumps during operation; the increased pressure partially offsets this effect. Section 4.2.5 shows that adequate NPSH margin remains under post-LOCA operating conditions. Based on the review of the licensee's rationale and evaluation, the staff concludes that SPC operations at the proposed EPU level is acceptable.

3.9.3 Containment Spray Cooling (CSC) Mode

The CSC mode of the LPCI/CC system is designed to provide water from the suppression pool via the spray headers to the drywell and suppression chamber air spaces to reduce the long-term containment pressure and temperature during post-accident conditions. The power uprate slightly increases the containment spray water temperature. This increase has a negligible effect on the ability of the CSC mode to maintain containment pressure and temperature within design limits, as the peak pressure and temperatures are reached well before the use of containment spray is assumed to occur.

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

3.9.4 Fuel Pool Cooling Assist Mode

As a result of plant operations at the proposed EPU, the decay heat load for specific fuel discharge scenarios will increase. In the event that the spent fuel pool (SFP) heat load exceeds the heat removal capability of the fuel pool cooling and cleanup system (FPCCS) (e.g., during full-core offload events), the SDC system will be operated in the FPC assist mode to provide supplemental cooling to the SFP and to maintain the SFP temperature within acceptable limits. Section 6.3 addresses the adequacy of the combined heat removal capability of the FPCCS and the SDC system operating in the FPC assist mode to meet the increases in SFP heat loads resulting from the proposed EPU.

3.10 Reactor Water Cleanup (RWCU) System

The RWCU system, as a component of the reactor coolant pressure boundary piping systems, is evaluated in Section 3.5 of this SE.

3.11 Main Steam, Feedwater, and Balance-of-Plant Piping

The main steam, FW, and balance-of-plant piping evaluation is addressed along with reactor coolant piping in Section 3.5 of this SE.

4.0 ENGINEERED SAFETY FEATURES

4.1 Containment System Performance

The DNPS UFSAR provides the results of analyses of the containment response to various postulated accidents that constitute the design basis for the containment. Operation at the EPU level of 2957 MWt would change some of the conditions and assumptions of the containment analyses. Section 5.10.2 of ELTR1 (Reference 3) requires the power uprate applicant to show the acceptability of the effect of the uprate power on containment capability. The applicant's evaluations must include containment pressures and temperatures, LOCA containment dynamic loads, safety-relief valve 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 power uprate. These analyses must cover the response through the time of peak drywell pressure throughout the range of power/flow operating conditions with power uprate. Appendix G states that the applicant must analyze short-term containment pressure and temperature response using the previously applied GE code M3CPT. The DNPS EPU analyses uses the LAMB code with Moody's Slip Critical flow model to generate the blowdown flow rates used as inputs to M3CPT. This approach, using a code with a more detailed RPV model, results in more realistic break flows for input to M3CPT, and differs from the current UFSAR analyses. Plant-specific use of the LAMB code, which has been previously reviewed by the NRC for Appendix K LOCA analyses, was addressed in ELTR1, Appendix G.

Appendix G of ELTR1 also requires the applicant 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. SHEX is partially based on M3CPT and is used to analyze the period from when the break begins until after peak suppression pool heatup (i.e., the long-term response). The SHEX code was already used for DNPS UFSAR analyses, and its use was preceded by performing confirmatory calculations for validating the results using the HXSIZ code. Therefore, the use of the SHEX code is within the current licensing basis and is acceptable for EPU containment analyses.

In a letter dated August 13, 2001, providing additional information (Reference 23), the licensee addressed the EPU effect on TS section 3.6.2.1 on the suppression pool temperature limit. This TS is applicable in Modes 1, 2 and 3 with limits varying above and below 1-percent RTP. The licensee noted that the 1-percent RTP value is approximately equal to heat losses, such that the reactor is effectively shut down; that the number is based on engineering judgment and would remain applicable with the new EPU RTP which is 17 percent higher.

Based on the licensee's rationale the staff concurs with the licensee's conclusion that the references to 1-percent RTP should be retained for TS 3.6.2.1.

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 DNPS 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 (design basis accident (DBA LOCA)), while the long-term analysis was performed to determine the peak suppression pool temperature response considering decay heat addition. In Reference 19, the licensee provided both short-term and long-term curves for parameters of interest for containment response for a DBA-LOCA including temperature and pressure for the drywell and wetwell atmosphere suppression pool temperature. Reference 19 also included appropriate curves for parameters used in the NPSH calculations. These curves use different conservative assumptions for determining available suction pressure for the ECCS pumps. These curves, including the statements of assumptions used and explanatory notes, clarify the containment response and analysis results for the effect of the EPU.

The licensee indicated that the containment analyses were performed in accordance with NRC guidelines using GE codes and models. As noted above, 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 EPU.

4.1.1.1 Suppression Pool Temperature Response

(a) Bulk Pool Temperature

The licensee indicated that the long-term bulk suppression pool temperature response with the EPU was evaluated for the DBA-LOCA. The bounding analysis was performed at 102-percent of EPU RTP. The analysis was performed using the SHEX code and a more realistic decay heat model. The staff determined that the model used, the ANS/ANSI 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 196 °F, based on revised EPU methodology, which is an increase of 20° F in peak pool temperature over the current licensing basis temperature 176 °F. However, a portion of that increase is caused by the change in methodology. The licensee performed calculations using the new methodology for ORTP and EPU conditions. These calculations show that the EPU results in a 8 °F increase in peak pool temperature relative to ORTP, using EPU methodology and input assumptions. The peak suppression pool temperature remains below the wetwell structure design temperature of 281 °F.

Based on the staff's review of the licensee's analyses, and experience gained from the staff's review of power uprate applications for other BWR plants, the staff concludes that the peak bulk suppression pool temperature response remains acceptable for the power uprate.

(b) Local Pool Temperature With Relief Valve Discharge

DNPS is equipped with four RVs and one SRV per unit. Because of concerns resulting from unstable condensation observed at high pool temperatures, the local pool temperature limit for RV/SRV discharge is specified in NUREG-0783. Elimination of this limit for plants with quenchers on the RV/SRV discharge lines is justified in GE report NEDO-30832, "Elimination of Limit on Local Suppression Pool Temperature for SRV Discharge with Quenchers." In a SER dated August 29, 1994, the staff eliminated the maximum local pool temperature limit for plants with quenchers, provided that steam entrainment in the ECCS suction is not a concern. The licensee indicated an evaluation of the worst-case geometry, where the quencher and the ECCS suction strainers are located in the same sections (i.e., bays) in the torus, has been performed for DNPS. The licensee provided details of the EPU evaluation of the likelihood of steam ingestion in Reference 19. The evaluation conservatively assumed that the water is locally saturated in the vicinity of the quenchers and ECCS suction strainers, that all ECCS pumps were operating, and that there was full RV/SRV discharge flow. The licensee quantified the size of the steam plume and envelope of flow drawn into the strainer. Since the evaluation shows that the steam plume will not intersect the flow envelope, steam ingestion into the ECCS suction is not a concern.

Based on the review of the licensee's rationale and evaluation, the staff concludes that the plant operations at the EPU will have no impact on the local pool temperature with RV/SRV discharge.

4.1.1.2 Containment Airspace Temperature Response

The containment airspace temperature limit of 340 °F was based on a bounding analysis of the superheated gas temperature that can be reached with blowdown of steam to the drywell during a DBA-LOCA. The licensee calculated the peak DBA-LOCA drywell gas temperature of 291 °F at the EPU level, which remains below the drywell airspace design temperature of 340 °F. The current licensing basis analysis had calculated a temperature of 290 °F. Using the same methods as the EPU analyses, the peak drywell air temperature for ORTP is 289 °F which is 2 °F lower than the calculated temperature at EPU power. The EPU peak DBA-LOCA drywell air temperature is 10 °F above the shell design temperature of 281°F; however, the brief duration above design temperature (less than 10-seconds) is not long enough to bring the shell temperature above its design value.

The licensee indicated that the limiting design basis accident with respect to peak drywell temperature is a steam line break. A steam line break produces a higher drywell temperature response than the DBA-LOCA (liquid line break) because the steam has a higher energy content than liquid at the same pressure. The licensee provided additional detail describing the limiting steam line break in its letter dated August 14, 2001 (Reference 24). The licensee analyzed four break sizes ranging from .01 to 0.75 ft^2. The peak drywell airspace temperature of 337.9 °F remains below the 340 °F temperature limit, and the peak drywell shell temperature of 277.9 °F remains below the 281°F design temperature following EPU. The peak drywell airspace temperature occurs early in a steam line break event and before drywell spray initiation at 600 seconds; therefore, the licensee stated it is relatively insensitive to power level. The drywell shell temperature is calculated to rise to the saturation temperature for the steam partial pressure in the drywell rapidly (around 277 °F), and continue rising more slowly due to natural convection from the hotter drywell airspace temperature. The rise is terminated at the peak with the initiation of drywell sprays.

The licensee stated that review of results for DBA-LOCA and steam line breaks analyzed at EPU conditions shows that the DBA-LOCA is the limiting event for the wetwell airspace and suppression pool temperatures. The analyses for DBA-LOCA calculated a peak wetwell air space temperature of 257 °F which occurs during the blowdown period. In the early phase of the DBA-LOCA, noncondensable gas in the drywell is transported to the wetwell. Compression effects cause the airspace temperature to increase above the suppression pool temperature. Previous UFSAR analyses had assumed thermal equilibrium. The peak calculated wetwell airspace temperature remains below the wetwell structural limit of 281° F for the EPU; and is unchanged from that temperature calculated with current power levels and current methods.

Therefore, the drywell and wetwell air temperature response has no adverse impact on the containment.

Based on the review of the licensee's evaluation, the staff concludes that the drywell and wetwell air temperature response will remain acceptable after the EPU.

4.1.1.3 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 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 EPU RTP per RG 1.49, with the break flow calculated by using a more detailed model than used for previous licensing basis analyses. Use of the NEDE-20566-P-A, GE model for LOCA analyses in accordance with 10 CFR Part 50 Appendix K, was addressed in NRC approved topical report ELTR1, "Generic Guidelines for General Electric Extended Power Uprate." These analyses calculated a peak drywell pressure of 43.9 psig at EPU, which remains below the containment design value of 62 psig. The licensee noted that this represents a reduction from the current UFSAR analysis results of 47 psig; however, a portion of that reduction is due to the change in methodology. The licensee evaluated the containment pressure response using the new methodology for ORTP and EPU conditions. Comparing the results indicates that the EPU caused an increase of only 1.1 psig peak drywell pressure.

The DBA-LOCA analysis wetwell pressure peaks at 36.7 psig during the early phase of the transient due to compression effects of non-condensable gases. This is well below the maximum allowable internal pressure of 62 psig. The peak is 9.7 psig higher than that calculated with current UFSAR methods, because those methods assumed thermal equilibrium between the wetwell pool and associate airspace. The change in methodology accounts for most of the change. The licensee performed calculations using the new methodology for ORTP and EPU conditions. Comparing the results shows that EPU caused an insignificant increase (only 0.1 psig) in the peak wetwell pressure.

The current value of peak calculated primary containment internal pressure for the design basis accident (P_a) used for containment testing is 48.0 psig. The licensee has proposed TS changes to decrease this value to 43.9 psig based on the above pressure response for EPU per 10 CFR Part 50, Appendix J. In response (Reference 19) to the staff's RAI, the licensee provided a draft of proposed UFSAR Section 6.2.1.3. The draft is consistent with the EPU application for this change and is referenced as the basis for TS B 3.6.1.4. The staff finds the proposed change to TS 5.5.12 to be acceptable

Based on the review of the licensee's evaluation, the staff concludes that the containment pressure response following a postulated LOCA will remain acceptable after the 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 EPU is based primarily on the short-term recirculation suction line break DBA-LOCA analyses. These analyses were performed similarly to the analysis described above in Section 4.1.1.3 using the Mark I Containment Long Term Program method, except the break flow is calculated using the more detailed RPV model of the NEDE-20566-P-A GE model for LOCA analyses in accordance with 10 CFR Part 50, Appendix K. 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 with the EPU include pool swell, condensation oscillation, and chugging. For a Mark I plant like DNPS, the vent thrust loads are also evaluated.

The licensee stated that the short-term containment response conditions with the EPU are within the range of test conditions used to define the pool swell and condensation oscillation loads for the plant. The long-term response conditions with EPU for times beyond the initial blowdown period, in which chugging would occur, are within the conditions used to define the chugging loads. The licensee also indicated that the vent thrust loads with the EPU are calculated to be less than the plant-specific values calculated during the Mark I Containment Long Term Program. Therefore, the pool swell, condensation oscillation, chugging loads, and vent thrust loads for the EPU remain bounded by the existing load definitions.

Based on the review of the licensee’s rationale and evaluation, the staff concludes that the LOCA containment dynamic loads will remain acceptable after the EPU.

4.1.2.2 Relief Valve and Safety Relief Valve Loads

The RV and SRV loads include discharge line loads, suppression pool boundary pressure loads, and drag loads on submerged structures. These loads are influenced by the opening pressure setpoint, the initial water leg height in the discharge line, the discharge line geometry, and suppression pool geometry. For the first valve actuations, the only EPU-related parameter change which can affect the loads is an increase in the opening pressure setpoint. This EPU does not include an increase in the opening setpoint pressures; therefore, it has no effect on the loads from the first actuations.

After valve closure, water refloods the discharge line, condenses steam, creates a low pressure which causes the vacuum breaker to open, allowing water level in the discharge line to decrease. The licensee indicated that to mitigate the effects of subsequent valve actuations for the existing design, a timer setting (longer than the minimum time) has been built into the DNPS RV and SRV control logic. This timer extends the time between the valve closure and subsequent reopening, ensuring that the water column height during subsequent actuations has been reduced such that reactuation loads are acceptable. The EPU has no impact on the calculated minimum time intervals between valve openings, which is based on time, vacuum breaker capacity, and reflood height. Therefore, the loads remain bounded by the existing load definition.

Based on the review of the licensee’s rationale and evaluation, the staff concludes that the EPU will have insignificant or no impact on the RV and SRV containment loads.

4.1.2.3 Subcompartment Pressurization

The licensee indicated that because the EPU does not increase the reactor operating pressure, there is only a minor increase in the asymmetrical loads on the vessel, attached piping and biological shield wall due to a postulated pipe break in the annulus between the reactor vessel and biological shield wall. The results of the updated calculations including the effects of the EPU indicate that the biological shield wall and component designs remain adequate, because there is sufficient pressure margin available.

Based on the review of the licensee's rationale and evaluation, the staff concludes that plant operation at the EPU will have an insignificant impact on the subcompartment pressurization.

4.1.3 Containment Isolation

The licensee indicated that the system designs for containment isolation have been evaluated for the EPU conditions. 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.

Based on the review of the licensee's evaluations, the staff concludes that plant operations at EPU will have an insignificant or no impact on the containment isolation system.

4.1.4 Generic Letter (GL) 96-06

The licensee indicated that a review of the licensee's past response to GL 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions," was conducted to assess the impact of the EPU. The containment analysis demonstrates that the original post-accident containment temperatures increase slightly.

Based on review of the containment pressure and temperature conditions during design basis accidents, the staff concludes that the licensee's past response remains valid for the EPU.

4.2 Emergency Core Cooling System (ECCS)

The ECCS components are designed to provide protection in the event of a LOCA due to a rupture of 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 10 CFR Part 100 limits. For a LOCA, 10 CFR 50.46 specifies design acceptance criteria based on (a) the peak cladding temperature (PCT), (b) local cladding oxidation, (c) total hydrogen generation, (d) coolable core geometry, and (e) long-term cooling. The LOCA analysis considers a spectrum of break sizes and locations, including a rapid circumferential rupture of the largest recirculation system pipe. 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 maximum average planar linear heat generation rate (MAPLHGR) OL is based on the most limiting LOCA analysis, and licensees perform LOCA analyses for each new fuel type to demonstrate that the 10 CFR 50.46 acceptance criteria can be met.

The ECCS for DNPS includes the high-pressure coolant injection system (HPCI), the low-pressure coolant injection system (LPCI) mode of the LPCI/CC, the CS system and the automatic depressurization system (ADS). ECCS performance is discussed in Section 4.3 of this SE.

4.2.1 High-Pressure Coolant Injection System

The HPCI system (in conjunction with other ECCS systems) is designed to maintain reactor water level inventory during small- and intermediate-break LOCAs, isolation transients, and LOFWF. For a large-break LOCA, the reactor will depressurize rapidly, thereby rendering the HPCI system inoperable.

The HPCI system is required to start and operate reliably over its design operating range. During LOFWF and isolation transients, the HPCI will maintain water level above the top of active fuel (TAF) in the event the IC is not available. For the MSIV closure, the RVs open and close as required to control pressure and HPCI will eventually restore water level.

The licensee evaluated the capability of the HPCI system, for operation at the EPU power level, to provide core cooling to the reactor to prevent excessive fuel PCT following small- and intermediate-break LOCAs, and to ensure core coverage up to the TAF in isolation and LOFWF transients. The licensee stated that the HPCI evaluation is applicable to and is consistent with the evaluation in Section 4.2 of ELTR2. The licensee determined that the HPCI system is acceptable for the EPU.

The generic evaluation in Section 4.2 of the supplement to ELTR2 is based on typical HPCI pump design pressures. The licensee evaluated the capability of the HPCI system to perform as designed and analyzed its performance at the EPU conditions, and 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 LOCA and isolation transients. The staff evaluated the licensee's submittal and the analytical methods used by the licensee and reached the same conclusions.

4.2.2 Low-Pressure Coolant Injection (LPCI)

The LPCI mode of the LPCI/CC system is automatically initiated in the event of a LOCA and, in conjunction with other ECCS systems, the LPCI mode is required to provide adequate core cooling for all LOCA events. The licensee further stated that the existing system has the capability to perform the design injection function of the LPCI mode for operation at the EPU conditions and that the generic evaluation in Section 4.1 of ELTR2 bounds the DNPS LPCI system performance. Based on the staff's review of the licensee's submittal and the staff's audit which confirmed that approved methodologies were used, the staff concludes that the licensee's evaluation is acceptable.

4.2.3 Core Spray (CS) System

The CS system initiates automatically in the event of a LOCA. In conjunction with other ECCS systems, the CS system provides adequate core cooling for all LOCA events.

The licensee stated that, as indicated in the ECCS performance discussion in Section 4.3 of this SE, the calculated LOCA PCT could increase slightly at the EPU. However, the existing CS system, combined with other ECCS systems, will provide adequate long-term post-LOCA core cooling. The licensee added that the existing CS system hardware has the capability to perform its design injection function at the EPU conditions and that the generic evaluation in Section 4.1 of ELTR2 bounds the DNPS CS system performance. Based on the staff's review of the licensee's submittal and the staff's audit which confirmed that approved methodologies were used, the staff concludes that the licensee's evaluation is acceptable.

4.2.4 Automatic Depressurization System (ADS)

The ADS uses the RVs and SRV to reduce reactor pressure after a small-break LOCA, allowing the LPCI and CS systems to provide cooling flow to the vessel. The plant design requires the RVs and the SRV to have a minimum flow capacity. After a specified delay, the ADS actuates either on low water level plus high drywell pressure or on sustained low water level alone. The licensee stated that the ability of the ADS to initiate on appropriate signals is not affected by the power uprate. The EPU decay heat is higher, increasing the required flow capacity. The licensee stated that the increase in the required flow capacity requires five ADS valves to be operable, instead of the current requirement of four ADS valves. Based on the staff's review of the licensee's submittal and the staff's audit which confirmed that approved methodologies were used, the staff concludes that the licensee's evaluation is acceptable.

4.2.5 Net Positive Suction Head (NPSH)

The licensee indicated that the containment analysis for the NPSH was performed for DBA-LOCA at 102 percent of EPU RTP, using the ANS 5.1+ two sigma decay heat with fuel exposure applicable for GE-14 fuel with a 24-month fuel cycle. The results of the analysis determined that additional credit for containment overpressure, as compared with the current license condition B.2, is required because the suppression pool temperature increases at a faster rate and peaks at a higher value during a LOCA than under the pre-EPU conditions. The increase in suppression pool temperature from EPU decay heat load results in increased vapor pressure, reducing the available suction head available for the ECCS pumps. Section 4.1.8.5 of ELTR2, Supplement 1, addressed the need for BWR 3's, such as Dresden Units 2 and 3, to take credit for positive containment pressure to augment the NPSH available to the pumps following EPU, noting that the adequacy of the RHR and LPCS pumps would be evaluated at the increased suppression pool temperature associated with power uprate. The NRC staff conducted an audit at Dresden, Units 2 and 3, on October 22-23, 2001. The audit examined the EPU application relating to the NPSH, licensee responses to requests for additional information, and licensee calculations supporting the EPU application.

In the Supplement to their request for a license amendment for Power Uprate Operation, dated August 29, 2001, (Reference 26), the licensee requested the below overpressure credit for Dresden Unit 2. In a response to the staff, dated August 13, 2001, (Reference 23) the licensee stated that overpressure credit for Dresden, Unit 3 would be handled in a future submittal. In the Supplement to their request for a license amendment for Power Uprate Operation, dated September 25, 2001, (Reference 50) the licensee requested the same overpressure credit for Dresden Unit 3 as follows:

From (sec)	To (sec)	Requested Credit (psi)
Accident start	290	9.5
290	5,000	4.8
5,000	30,000	6.6
30,000	40,000	6.0
40,000	45,500	5.4
45,500	52,500	4.9
52,500	60,500	4.4
60,500	70,000	3.8
70,000	84,000	3.2
84,000	104,000	2.5
104,000	136,000	1.8
136,000	Accident end	1.1

Although the licensee has requested overpressure credit higher than previously approved, they have calculated that more pressure than requested is available during a DBA-LOCA. Two time periods were analyzed: short-term (before 600 seconds) and long-term (after 600 seconds). In calculating the amount of overpressure required, assumptions were made that maximize the pool temperature and minimize the overpressure, including operation of LPCI/CC loops in the containment spray mode, initial suppression pool water level at the low water level and at 95° F, and both CS pumps and all four LPCI pumps running with a single failure of the loop selection logic resulting in ECCS flow directly into the drywell from the faulted recirculation loop.

The licensee provided curves (Figures 6 and 7 of Reference 19) depicting the Dresden DBA-LOCA containment pressure and temperature response, and also provided curves (Figures 1 and 2 of Enclosure 1 to Reference 50) for both short-term and long-term NPSH; depicting pool pressure, credited pressure, and available pressure. The licensee's analysis indicates that prior to 290 seconds sufficient NPSH is available. The licensee noted that operators have been trained and procedures include cautions concerning ECCS pump NPSH limits and control of containment pressure. After 600 seconds, the licensee assumes that operators will effectively throttle ECCS flows to restore adequate NPSH. Pump cavitation for the brief time from 290 seconds until 600 seconds is not of concern due to the short duration of cavitation. The duration of ECCS pump cavitation following EPU is shorter than the period from 260 seconds until 600 seconds which the staff previously approved for DNPS Units 2 and 3 (Amendments Nos. 157 and 152, respectively issued April 30, 1997). Approval of the pump cavitation period was based on successful ECCS pump cavitation testing, using a Quad Cities RHR pump, under test conditions which were more severe than pump operational conditions analyzed for EPU. The tested pump is similar to the DNPS ECCS pumps and the test data is applicable to DNPS operational conditions.

Dresden calculated the amount of containment pressure credit needed to satisfy their ECCS NPSH requirements for the EPU using the methodology and assumptions described above for the limiting short-term case and for the long-term flow rate required for adequate core and CC. The long-term ECCS flow rate required to maintain adequate core and CC after EPU is 9,750 gpm. This flow rate is provided by one CS pump operating at 4,750 gpm and one LPCI pump operating at 5,000 gpm.

The NRC staff conducted an audit of the ECCS strainers at Dresden, Units 2 and 3, on March 29-31, 1999. In the audit report, "Report on Results of Staff Audit Conducted on March 29-31, 1999, of Dresden Nuclear Power Station's Resolution of Issues Identified in NRC Bulletin 96-03," (Reference 34), the staff concluded, in part, that "Dresden has adequately designed their ECCS strainers to withstand the high debris loads anticipated during a LOCA." However, the staff did identify some concerns that Dresden needed to address. Specifically, the staff concluded that "some of the analysis methods used by Dresden's contractor to size their strainers are inadequate. These methods are not consistent with the NRC approved methodologies, and lack sufficient supporting data or analysis to support their use. The staff's assessment of Dresden's analysis methods is that these analysis methods could lead to erroneous conclusions in any future operability assessments, design modifications or procedure changes (e.g., suppression pool cleaning). This is particularly important at Dresden because they have a low NPSH margin, and configuration control is, as a result, important to ensuring that they do not exceed the design basis of the strainers. In addition, the audit team concluded that Dresden has inadequately defined their licensing basis. They have performed a number of parametric analyses demonstrating the performance capability of their strainer under different conditions, but have not defined which parametric case constitutes their licensing basis. This concern affects their bases for such things as configuration control and foreign material issues. We have concluded that these concerns need to be resolved by Dresden." (Reference 34)

The staff's audit (described above) verified, through independent confirmatory calculations, that the new strainers installed in response to NRC Bulletin 96-03 are adequately sized to handle expected debris loadings during a LOCA. The EPU for Dresden 2 does not increase the operating pressures in the plant's high energy piping; therefore, it is not expected that a LOCA under the new uprate operating conditions would generate significantly more debris than at existing licensed power levels. In their response to the staff (Reference 23), the licensee committed to perform calculations of the suction strainer head loss and submit a description of the methods and the results to the NRC for DNPS Units 2 and 3. These items were provided in Attachment C to the licensee's Supplement to the request for license amendment for Power Uprate Operation, dated September 25, 2001 (Reference 50).

The licensee's analysis for suction strainer head loss determined the quantity of the debris generated during a LOCA, the quantity of the debris transported to the suppression pool, the transport of the debris within the suppression pool to the strainers, the filtration of the strainers for the transported debris, and the associated head loss. The licensee assessed both short-term and long-term debris generation and transport for fibrous materials, sludge and reflective metal insulation; consistent with the particular strainer geometry and plant-specific features. The licensee's revised methodology is consistent with the guidance in the Utility Resolution Guidance for ECCS Suction Strainer Blockage and the associated NRC SER contained therein (Reference 60). The resulting plant-specific strainer head loss values were used as input to the NPSH required for ECCS pumps as discussed above.

Based on review of the licensee's evaluation including the staff's review of the associated calculations, the staff concludes that operation for DNPS Units 2 and 3, with the requested levels of containment pressure credit in the ECCS NPSH analysis, is acceptable.

4.3 Emergency Core Cooling System (ECCS) Performance Evaluation

The ECCS is designed to provide protection against postulated LOCAs caused by ruptures in the primary system piping. The 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, using GE-14 fuel. The ECCS-LOCA analysis was based on the NRC-approved methodology (SAFER/GESTR). The licensee determined the licensing basis PCT at the current rated core operating conditions using the standard adder required by the SAFER/GESTR methodology to account for uncertainties. For the EPU conditions, the licensing basis PCT, based on the limiting GE-14 fuel design, is less than 10 °F higher at rated core flow than the pre-EPU PCT.

For SLO conditions, the licensee applied a multiplier to the normal two loop operation MAPLHGR limits. The licensee stated that the multiplier to the MAPLHGR for the SLO ensures that the SLO nominal PCT is less than the PCT for the nominal two loop operation. Attachment 1 discusses the findings from the staff audit of these calculations and the licensee response.

The licensee determined that the ECCS performance under LOCA conditions and the analysis models satisfies the requirements of 10 CFR 50.46 and Appendix K.

As part of the EPU review process, the NRC staff audited the DNPS LOCA analysis. The staff focused on the GNF use of the LOCA codes and their applicability to the DNPS EPU. The staff examined DRFs describing both the pre- and post-EPU LOCA analyses, and made the following observations:

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

2. DNPS was closely involved in the development of the plant-specific information required by GNF in developing the model.

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

4. The GNF method for single-loop operation (SLO) uses statistical adders derived from RTP operation. The staff had questioned this approach in a prior audit and GNF had responded that any uncertainty introduced by using these values would be compensated for by the conservative nature of the SLO application procedure. This procedure leads analysts to derive conservative SLO multipliers. After further review, the staff accepts this explanation and concurs with the GNF conclusion.

The staff concluded that the DNPS ECCS-LOCA performance complies with 10 CFR 50.46 and Appendix K requirements and the analyses were performed with NRC-approved methods and codes.

4.4 Standby Gas Treatment System (SGTS)

The SGTS is designed to process the secondary containment atmosphere and exhaust it through the plant chimney to limit the release to the environment of radioisotopes that may leak from primary containment under accident conditions. The capacity of the SGTS was selected to provide a negative differential pressure between secondary containment and the outside environment of at least 0.25 inch of water. The licensee stated that this capability is not affected by the EPU.

The licensee stated that the SGTS charcoal filter removal efficiency of 95 percent for radioiodine is not affected by the EPU. Post-LOCA total iodine loading increases from 6.0 mg/gm to 11.8 mg/gm of activated carbon at EPU conditions, using conservative RG 1.3 assumptions for the iodine chemical form and transport within containment. Despite the increase in iodine loading as a result of the EPU and 24-month fuel cycle, test work at high iodine loading supports filter removal efficiencies in excess of 99 percent at 60 mg/gm. Based on RG 1.3, the iodine release is assumed to be primarily composed of elemental and organic iodine that require treatment using activated carbon filtration.

In response to the staff, the licensee stated (Reference 24) that an industry study demonstrated charcoal filter removal efficiencies of over 99 percent for elemental iodine (which makes up 91 percent of the evaluated inventory) can be achieved with iodine loading as high as 60 mg/gm, even under adverse waterlogged conditions. The licensee further stated that for organic iodine (which makes up 4 percent of the evaluated inventory), an industry study demonstrated filter removal efficiencies of 99 percent with iodine loading as high as 4.4 mg/gm. This is approximately a factor of ten higher than the organic iodine loading of 0.47 mg/gm for the EPU. Therefore, the charcoal loadings from both elemental and organic iodine at EPU conditions are well below values that yield a filter removal efficiency of at least 99 percent. In addition, the design basis high-efficiency particulate air (HEPA) filter efficiency of 99 percent for removal of particulate iodine is not affected by the small increase in iodine loading at EPU conditions.

In order to obtain reasonable assurance of the licensee’s assertions, the staff reviewed Oak Ridge National Laboratory (ORNL) reports ORNL-4180, “Removal of Radioactive Methyl Iodide from Steam-Air Systems (Test Series II),” dated October 1967, and ORNL-TM-2040, “Removal of Elemental Radioiodine from Flowing Humid Air by Iodized Charcoals,” dated November 2, 1967. The staff found that the licensee’s assertions are consistent with industry studies.

The licensee stated (Reference 24) that the testing and maintenance criteria for SGTS filters based on RG 1.52 (Revision 2) continue to be met in accordance with plant regulatory requirements.

The licensee stated that the amount of cooling airflow needed to limit the temperature increase of the charcoal adsorber due to fission product decay heating is affected by the EPU. However, although the minimum cooling airflow increased from 48 scfm to 74 scfm, it is well below the available design flow of 300 scfm. The licensee stated that no other SGTS parameter is affected by the EPU.

Based on the staff's review of the licensee's rationale, and the experience gained from the staff's review of power uprate applications for other BWR plants, the staff concludes that the EPU does not adversely affect operation of the SGTS.

4.5 Other Engineered Safety Features Systems

4.5.1 Post-LOCA Combustible Gas Control System

The licensee indicated that the post-LOCA control of hydrogen and oxygen concentrations inside of the primary containment is provided by the combustible gas control system (CGCS). The CGCS consists of several subsystems: the primary containment inerting system, the nitrogen containment atmosphere dilution (CAD) system, the containment atmosphere monitoring system, and the augmented primary containment venting system. The CGCS 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. Design of the system is based on the production of hydrogen from (1) 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. The EPU only affects post-LOCA production of hydrogen and oxygen from radiolysis, which will increase in proportion to the EPU power level. The hydrogen contribution from metal-water reaction of fuel cladding is additionally affected by the fuel design change. Therefore, the analysis considers the impact of GE-14 fuel on metal-water hydrogen production.

In Reference 19, the licensee supplemented its initial application with five graphs of parameters related to CGCS operation varying with time after a LOCA. The parameters graphed included hydrogen generation rates, hydrogen and oxygen concentrations both without and with nitrogen dilution, cumulative nitrogen usage, and containment pressure both with and without nitrogen injection.

The licensee indicated that the time required to reach the 5-percent oxygen limit following the LOCA, based on 1-percent per day containment leakage, decreases from 25 hours for current reactor power to 19 hours for EPU reactor power with GE-14 fuel. This reduction in time required for nitrogen CAD system initiation does not affect the ability of the operators to respond. Therefore, the CGCS 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 minimum stored volume increases to 141,000 scf for EPU reactor power. The licensee indicated that the CAD system has a minimum stored nitrogen capacity of 200,000 scf, which is sufficient to accommodate 7 days of post-LOCA operation. The licensee additionally calculated that the containment pressure buildup as a result of CAD system operation shows that the operating pressure limit of 31 psig (50 percent of the design pressure) is not reached until 32 days after the LOCA. This satisfies the minimum 30-day acceptance limit for containment pressure buildup.

In Dresden Units 2 and 3 license amendments 150 and 145, issued June 26, 1996, the NRC previously approved deletion of TSs relating to the CAD system. This was based on relocation of requirements to licensee controlled procedures, administrative controls, and being consistent with the custom TSs for Quad Cities. Subsequent conversion to BWR Improved Standard

Technical Specifications (ISTS) did not require addition of the STS 3.6.3.4 on CAD System because it was not part of the current licensing basis. The staff concludes, notwithstanding the slightly increased oxygen generation rate following EPU and the increased hydrogen generation associated with GE-14 fuel, that it remains acceptable to control operability requirements for the CAD system in licensee controlled procedures and administrative controls.

In response to the staff, the licensee addressed the capacity of the containment hardened vent considering EPU conditions (Reference 19). One of the design inputs for the hardened wetwell vent was the ability to exhaust energy equivalent to 1-percent RTP. The design of the hardened wetwell vent was based on the current power level. Based on the as-built design, the hardened wetwell vent will exhaust approximately 1-percent at 2957 MWt. Therefore, the design of the existing hardened wetwell continues to be acceptable for preventing containment overpressure at the EPU conditions.

In its August 13, 2001, letter providing additional information (Reference 23), the licensee explained the EPU effect on TS Section 3.6.2.5 (drywell-suppression pool differential pressure) and on TS Limiting Condition for Operation 3.6.3.1 (primary containment oxygen concentration). The TSs are applicable in Mode 1 from 24 hours after exceeding 15-percent RTP on a startup and 24 hours before reducing RTP below 15-percent for a shutdown. The licensee noted that the 15-percent RTP value relates to the window for relaxed deinerting requirements for the primary containment. The basis for the relaxation remains the low probability of an event that generates hydrogen during these time periods and would remain applicable with the new EPU RTP, which is 17-percent higher.

Based on a review of the licensee's rationale, the staff concludes that the references to 15-percent RTP should be retained for TSs 3.6.2.5 and 3.6.3.1.

Based on the review of the licensee's rationale and evaluation, the staff concludes that plant operations at the proposed uprate power level, combined with use of GE-14 fuel, will have a minor impact on the post-LOCA CGS and the nitrogen CAD system will remain acceptable.

4.5.2 Main Control Room Atmosphere Control System (MCRACS)

The MCRACS processes the control room intake atmosphere to limit the release of radioisotopes to the control room that may leak from containment under DBA-LOCA conditions. The capacity of the MCRACS (also called the control room emergency ventilation (CREV) system in plant TSs) 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 the increase in heat gain to the control room resulting from the EPU for both normal and emergency modes is insignificant. By letter dated August 14, 2001 (Reference 24), in response to the staff, the licensee explained that the heat load increases resulting from the EPU do not adversely impact the MCRACS, since these increases occur outside the control room areas. Major control devices in the control room remain unchanged. The small electrical currents transmitted to some indicating devices in the control room increase because of higher process temperature and electrical loads. The associated minor heat load increases from these electrical signals have an insignificant effect on the pre-EPU design margin of the MCRACS in both the normal and the emergency modes.

The licensee stated that the only EPU effect on the MCRACS results from an increase in the radioiodine released during a DBA-LOCA. The licensee evaluated the effect of the EPU, in combination with a 24-month fuel cycle, on the post-LOCA iodine loading of the control room charcoal filters. The post-LOCA iodine releases collected on the control room intake filters at EPU conditions was estimated using the 0-2 hour X/Q values for the entire duration of the event, assuming no deposition or holdup of iodines in the main steam lines or in the secondary containment. Despite the increase in iodine loading as a result of the EPU and 24-month fuel cycle, the iodine loading on the control room filters remains a small fraction of the identified RG 1.52 allowable limit of 2.5 mg of total iodine (radioactive plus stable) per gram of activated carbon. Therefore, the control room filter efficiency is not affected by the EPU. The licensee stated that the technical support center (TSC) is not affected by the EPU.

In response to the staff (Reference 24), the licensee described the evaluation and the assumptions utilized in determining the effect of the EPU and 24-month fuel cycle on the post-LOCA iodine loading of the control room charcoal filters. Based on docketed information provided by the licensee, the staff concluded that the evaluation and its assumptions were acceptable. The licensee also pointed out that the iodine loading on the control room filters for DNPS is calculated to be 2.15E-3 mg of total iodine per gram of activated carbon, and that this iodine loading is a small fraction of the above design limit identified in RG 1.52. The licensee further stated that the control room filter efficiency of 99 percent associated with the MCRACS HEPA and charcoal filters continues to be effective under EPU conditions.

The licensee also stated in Reference 24 that the existing commitments to regulatory requirements and guidelines included in the design basis for the MCRACS are unchanged for the EPU. The requirements and guidelines include 10 CFR Part 50, Appendix A, General Design Criterion 19, RG 1.52 (Revision 2), and SRP 6.4. The regulatory requirements of GL 99-02 are also met.

Based on the staff's review of the licensee's rationale, and the experience gained from the staff's review of power uprate applications for other BWR plants, the staff concludes that the EPU does not adversely affect the operation of the MCRACS.

4.5.3 Standby Coolant Supply System

The licensee stated (Reference 49) that the standby coolant supply system is unaffected by EPU. The staff evaluated the licensee's submittal and reached the same conclusions.

5.0 INSTRUMENTATION AND CONTROL

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

For the proposed power uprate, each existing instrument of the affected NSSSs and BOP systems was evaluated by the licensee to determine its suitability for the revised operating range of the affected process parameters. Where operation at the power-uprated conditions impacted safety analysis limits, the evaluation verified that the acceptable safety margin continued to exist under all conditions of the power uprate. Where necessary, setpoint and uncertainty calculations for the affected instruments were revised. Apart from a few devices that needed to be changed, the licensee's evaluations found most of the existing instrumentation acceptable for the proposed power uprate operation. The evaluations resulted in the following changes:

- Modify the tripping logic of the fourth condensate pump on LOCA to allow the continued use of the FW pumps.

- Implement reactor recirculation pump runback on loss of FW flow or loss of a condensate pump to reduce the potential for a scram on reactor low water level and allow continued operation.

- Replace the APRM flow control trip reference card to add the clamp function for the APRM flow-biased rod block.

- Install an additional steam line steam resonance compensator card designed to attenuate third-order harmonics in the electrohydraulic control system and thereby reduce electrical noise in the system.

- Replace the main steam line flow/high differential pressure indicating switches to accommodate the new setpoint.

- Expand the indicating range on various control room and in-plant instrumentation.

- Replace the offgas condenser outlet gas temperature switches to accommodate the new span.

In addition to these changes, the licensee will implement a setpoint change for the isolation condenser time delay relay to be consistent with the power uprate analysis.

These changes will be made to accommodate the revised process parameters. The staff concludes that based on the licensee's evaluation of each instrument's operating range revised for EPU conditions, the Dresden instrumentation and control systems will accommodate the proposed power uprate when the above-noted modifications and changes are implemented during the next refueling outage.

5.2 Instrument Setpoint Methodology

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

The instrumentation setpoints are determined based on plant operating experience, conservative licensing analysis, and/or limiting design and operating values. The licensee stated that the instrumentation setpoints in the DNPS TS are established using the GENE setpoint methodology for the APRM setpoint and the licensee's setpoint methodology for the others (References 39 and 40). Each setpoint is selected with sufficient margin between the actual trip setting and the value used in the safety analysis (the AL) to allow for instrument accuracy, calibration and drift. To avoid inadvertent initiation of the protective actions (spurious trip avoidance), sufficient margin is established, whenever possible, between the actual trip setting and the normal OL (Table 5-1 of Reference 2). If the AL does not change based on the results of the EPU safety analyses, then the associated plant setpoints and the nominal trip setpoints do not change.

The staff has previously reviewed both of these instrument setpoint methodologies as part of the review for ISTS approval. The staff finds them acceptable for establishing new setpoints in power uprate applications. However, the staff was concerned about the reduction of margin between the instrument setpoints and the AVs and ALs, and, in a conference call on May 16, 2001, the staff requested the licensee to provide changes in instrument setpoints and AVs along with the ALs in Table 5-1 of the licensee's SAR (Reference 2). In its response dated June 15, 2001 (Reference 16), the licensee provided the table containing instrument setpoints, AVs and ALs. Based on the review of this table, the staff has determined that the proposed power uprate will not result in any significant reduction of margin. Therefore, the staff finds the licensee's response acceptable.

The proposed setpoint changes resulting from the power uprate are intended to maintain existing margins between operating conditions and the reactor trip setpoints and do not significantly increase the likelihood of a false trip or failure to trip upon demand. Therefore, the existing licensing basis is not affected by the setpoint changes to accommodate the power uprate.

5.3 TS Changes Related to Instrumentation Setpoint for the Power Uprate

The following TS changes have been proposed by the licensee:

1. TS Section 3.3.1.1, Surveillance Requirement (SR) 3.3.1.1.2

   The licensee has proposed to remove the reference to TS Section 3.2.4, which requires gain adjustment. The APRM gain and setpoint adjustment requirements are superseded by the APRM/RBM TS ARTS power-and flow- dependent limits. The staff's evaluation of the removal of TS Section 3.2.4 is discussed in Section 9.2.1 of this SE. On this basis, the staff finds the proposed change acceptable.

2. TS Section 3.3.1.1, SR 3.3.1.1.14, Required Action E.1, and TS Table 3.3.1.1-1, Functions 8 and 9

   The licensee has proposed to reduce from 45 percent to 38.5 percent the percentage-of-RTP value corresponding to the power level where the reactor protection system (RPS) trips on turbine stop valve (TSV) fast closure or where turbine control valve (TCV) fast closure is automatically bypassed. The licensee's justification of 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 is not being changed by this EPU, the corresponding percentage of RTP is being revised to maintain the current thermal power value in MWt, corresponding to the existing bypass steam flow capacity. On this basis, the staff finds the licensee's justification for this TS change acceptable.

3. TS Table 3.3.1.1-1, Function 2.b

The licensee has proposed to revise the APRM flow-biased scram equations for reactor recirculation two-loop and single-loop operation. The licensee has also raised the AV for the clamped portion of the APRM flow-biased neutron flux high from ≤120 percent to ≤122 percent. The staff's evaluation of the clamped portion of the AV is discussed in the next item of this SE. The APRM flow-biased trip function provides protection against transients where thermal power increases slowly. This function also protects fuel cladding integrity by ensuring that the MCPR safety limit is not exceeded. Because of the lower scram trip setpoint, the APRM flow-biased trip will initiate a scram before the clamped AV is reached during any transient event that occurs at a reduced recirculation flow. These changes are necessary to ensure consistent operation with the MELLLA power/flow map. 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 staff finds the licensee proposed TS changes acceptable.

4. TS Table 3.3.1.1-1 Functions 2.b and 2.c

The licensee has proposed to revise the clamped portion of the AV for the APRM flow biased neutron flux high from ≤120 percent to ≤122 percent. The transient analysis for the power uprate is based on the AL of 125 percent RTP. The APRM setpoint calculations determined that, based on this AL, an AV of 122 percent is appropriate and ensures that the AL is maintained. On this basis, the staff finds the licensee's justification for this TS change acceptable.

5. TS Table 3.3.1.1-1, Function 10

The licensee has proposed to revise the AV for the turbine condenser vacuum–low scram setpoint. The licensee has not revised the AL for this function. Since the staff-accepted setpoint methodology has been used to calculate the AV, the transient analyses are not affected by this change. On this basis, the staff finds the proposed change to the TS acceptable.

6. TS Section 3.3.5.2, SR 3.3.5.2.3

The licensee has proposed to reduce the reactor vessel high-pressure initiation time delay for the isolation condenser from ≤17 seconds to ≤15 seconds. The purpose of the isolation condenser instrumentation is to ensure adequate core cooling when the reactor vessel is isolated from the main condenser. The loss of FW evaluation was performed for uprated power conditions with a reduced time delay of 15 seconds. The proposed change RPV will ensure that the isolation condenser initiates before RV operation reduces pressure below the isolation condenser pressure setpoint. On this basis, the staff finds the licensee-proposed TS changes acceptable.

7. TS Table 3.3.6.1-1, Function 1.a

The licensee has proposed (Reference 26) to revise the AV for main steam line isolation on reactor vessel water level - low low from ≥ minus 56.77 inches to ≥ minus 56.34 inches. The licensee has justified this change based on the fact that the revised AV is based on wider and thus more conservative temperature range for this instrumentation. The current AVs for other functions in the TS related to this instrumentation have been determined using the appropriate temperature ranges and therefore require no changes. Also, the AV has been calculated with the staff approved setpoint methodology and therefore the staff finds the proposed change acceptable.

8. TS Table 3.3.6.1-1, Function 1.d

The licensee has proposed to increase the AVs for the main steam line flow–high isolation function. The AVs are being increased to maintain adequate margin between the setpoint and the increase full power steam flow. The differences in the AVs between units is due to physical differences in the flow restrictors between units. Since the flow restrictors do not change the maximum steam flow, the proposed change decreases the difference between the AV and the maximum flow. The purpose of this instrumentation is to provide protection against pipe breaks in the main steam line outside the drywell. For a complete severance of one main steam line, steam flow increases almost instantaneously to the maximum rated steam flow as limited by the flow restrictors. Thus the present and proposed setpoint would be attained virtually at the same time and the consequences of the main steam line break remain unchanged. On this basis, the staff finds the proposed change by the licensee acceptable.

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

6.0 ELECTRICAL POWER AND AUXILIARY SYSTEMS

6.1 AC Power

6.1.1 Offsite Power System

The 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

The licensee performed a grid stability uprate review to determine the adequacy of grid stability for the DNPS power uprate. The grid stability studies, considering the increase in electrical output, demonstrated conformance to 10 CFR 50, Appendix A, General Design Criterion (GDC) 17. GDC 17 addresses onsite and offsite electrical supply and distribution systems for safety-related components. There is no significant effect on grid stability or reliability. There is no modification associated with EPU that would increase electrical loads beyond those levels previously included or revise the control logic of the distribution systems.

The staff requested that the licensee provide details about the grid stability analysis, including major assumptions and results and conclusions of the analysis. In response to the staff request, the licensee stated (Reference 9) that GE Power Systems Energy Consulting performed a study using a relative approach to determine the impact of the proposed plant uprates on the performance of the power system. System performance at the current plant outputs was determined first in order to establish the benchmark. Then the system performance with both units uprated was determined and compared to the benchmark. Both power flow and stability analyses were performed. The power flow analyzed the branch loading and bus voltage levels under normal and contingency operating conditions. The stability analysis evaluated both first-swing stability and system damping. A variety of disturbance scenarios were analyzed, including single transmission line outages, single generating unit outages, double transmission line outages, double generating unit outages, and combined transmission line and generating unit outages. The amount of reactive power (i.e., MVAR) in the system for available support was also studied. It is expected that compensating measures will be required for MVAR support at certain times. Implementation of these compensating measures will be in accordance with the interconnection agreements and will be accomplished following completion of the current study by the Transmission and Distribution entity of the Exelon Energy Delivery Company (EDC).

The GE study for transient stability concluded that, for all fault scenarios, system performance was stable with damped oscillation. The GE study for power flow analysis concluded that the EDC power grid will accommodate the uprate power flows for the planned 100 percent summer and winter peaks. As the power uprate implementation approaches, the Transmission and Distribution entity of EDC is reviewing the impact of the uprate on the power grid as currently configured. Resolution of any issues discovered during these reviews will be accomplished prior to operation at power uprate. The EDC System Planning and Operating Guide ensures that adequate voltage is maintained at the DNPS switchyard with either or both units shutdown. This assures that offsite power will be available to the units to meet the requirements of Appendix A to 10 CFR Part 50, “General Design Criteria for Nuclear Power Plants.”

The licensee stated (Reference 18) that the transmission and distribution entity of EDC has approved the connection of the uprated DNPS Unit 2 and Quad Cities Nuclear Power Station (QCNPS) Unit 2 to the power grid. These are the units that will connect to the grid under EPU conditions in the years 2001 and early 2002. The approval shows that sufficient MVAR support will be available. The approval of the remaining units will be obtained before the additional load is supplied to the grid. Additional MVAR support can be accomplished by having any of the generating units on the system (i.e., either EGC, LLC, units or other units) reduce their MW output and increase their MVAR output.

On the basis of this information, the staff concludes that the proposed power uprate at DNPS will not adversely affect the grid stability and reliability. Therefore, the staff has reasonable assurance that GDC-17 will be met for the EPU condition.

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 staff reviewed the following electrical systems:

6.1.1.2.1 Main Generator

The existing main generator is rated at 920 MVA (828 MW), 0.90 power factor, 18 kV. After uprate the expected generator output will be 960 MVA (912 MW) at 0.95 power factor. The licensee stated (Reference 57) that the General Electric Company evaluated the main generator for EPU conditions and determined that the generator was acceptable for operation at 960 MVA provided that stator heat removal capability was increased. The increased stator heat removal capability will be obtained by resizing orifices in the service water system supply to the stator cooling system to provide additional flow. The staff's review determined that the electrical system's configuration and operating voltage ranges are unchanged and 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 33000 amps for the main section and 2000 amps for the branch section. The maximum current output is 32,413 amps (960MVA/[1.7321x18x0.95]) using generator output of 960 MVA and 95 percent of 18 kV. The review determined that the isolated phase bus duct is adequate for both rated voltage and low-voltage current output. The bus duct cooling upgrade is required even though the isolated phase bus duct electrical rating is 33000 amps. This is because the isolated phase bus duct cooling system at DNPS is not performing at design capability. The licensee stated (Reference 18) that a modification has been developed to replace the existing air handling units at DNPS. The replacement units will include new fans and new cooling coils with a higher heat removal rating. The modification will also reconfigure the air-flow path through the three phases. Currently, air from the cooling units is routed from the main generator to the main power transformer along the B phase and returns via the A and C phases. The new configuration will send air from the cooling unit along all three phases and back to the cooling unit via a common return duct. This change will reduce the system pressure drop allowing a higher air-flow rate through the bus duct.

Detailed evaluations indicate that the cooling system enhancements are required year round under EPU conditions. Therefore, the modification will be completed prior to unit startup from the EPU refueling outage. The staff concludes that the proposed modifications will assure that the isolated phase bus duct would be adequate for the EPU condition.

6.1.1.2.3 Main Transformer

The existing main transformer rating is 985 MVA for Unit 2 and 952 MVA for Unit 3. The main power transformers and the associated switchyard components are adequate for the uprated output.

Thus, the turbine-generator and major electrical components extending from the isolated phase bus to the switchyard will remain adequate for operation at the higher output after 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 and distribution conditions are computed based on equipment nameplate data and the calculated brake horsepower with the actual diversity factor applied. The only identifiable change in electrical load demand is associated with the condensate and booster pumps, reactor recirculation pumps, reactor FW pumps, and condensate demineralizers. The increased flow due to uprate conditions requires energizing the installed spare (third) reactor FW pump, energizing the installed spare (fourth) condensate and booster pump, and increasing the operating point for the two reactor recirculation pumps. Design basis calculations show that these additional loads result in acceptable operation of the electrical auxiliary system during normal startup and operation with two auxiliary transformers in service. However, operation at EPU conditions on a single transformer (due to unavailability of another transformer for some reason) exceeds the non-safety 4 kV switchgear shortcircuit rating, transformer winding rating, and bus duct rating. A fast transfer to single transformer operation at EPU conditions would create the same situation. To address this potential operational problem, the licensee will institute a procedurally controlled load-shedding scheme to be implemented within 1 hour after a fast transfer. This approach will be confirmed by thermal analysis or an engineering evaluation to address the overload conditions for the auxiliary transformers, the bus duct, and related connections. In response to the staff's concern about the operation of all loads on a single transformer and as a result of overloading the transformer and exceeding the non-safety 4160 V switchgear short circuit rating and bus duct rating, the licensee stated (Reference 56) that the loads fed from the unit auxiliary transformer (UAT) and reserve auxiliary transformer (RAT) include both safety-related and non-safety-related equipment. For EPU, with the transfer of loads to one transformer, a potential overload occurs only when all the equipment for full power EPU operation continues to run. The licensee evaluated the transformers, the switchgear, load breaker, and the protective relay settings as follows:

The UATs and RATs were designed to ANSI/Institute of Electrical and Electronics Engineers (IEEE) C57.12, "Standard for General Requirements for Liquid-Immersed Distribution and Power Regulating Transformers." For EPU conditions, the transformers were evaluated in accordance with ANSI/IEEE C57.92-1981, "Guide for Loading Mineral-Oil-Immersed Power Transformers Up to and Including 100 MVA," and ANSI/IEEE C57.91-1995, "Guide for Loading Mineral-Oil-Immersed Transformers Revision of IEEE Std. C57.92-1981 and IEEE Std. C57.115-1991," for loading beyond the nameplate rating. These standards allow for a temporary overduty of 125-percent of nameplate rating for two hours without any damage or loss of transformer life. The EPU condition in which all running loads are fed from one transformer requires the affected transformer to supply only 120-percent of its nameplate rating. Thus, operation of the transformer with the overduty caused in this scenario is acceptable for at least two hours. The connections (i.e., bus duct) between the transformers and the switchgear were supplied by General Electric Company. A GE evaluation performed for this condition demonstrates that the connections will be able to carry the increased load for at least two hours.

The licensee further stated that, based on load calculations for DNPS Unit 2, when all loads were fed from the RAT, the voltages maintained at the buses are at acceptable levels. Preliminary calculations for the remaining unit indicate similar conditions. However, when all loads are fed from the UAT, a bus undervoltage may occur depending on the voltage maintained at the transformer prior to the transfer of loads. Operator actions for this scenario are initiated by control room alarms. Main control room alarms will indicate a transfer of loads

to one transformer. For EPU operation, the alarm response procedures will be modified to require operator action to reduce transformer load within one hour. This action, to reduce electrical loads, involves simple operator actions such as reducing reactor recirculation flow and securing excess FW and/or condensate pumps. The one-hour time was selected as a reasonable time for operators to take action and yet remain within two hours of acceptable operation indicated
above.

In addition, a bus undervoltage alarm will occur if bus voltage reaches a nominal setpoint of 94-percent of the rated bus voltage due to the temporary overload condition. The undervoltage alarm starts a five-minute timer. If voltage is not restored within five minutes, the undervoltage relay will actuate and strip loads from the bus. The operator actions to restore voltage are described in the alarm response procedures and are unaffected by EPU. These actions involve raising the main generator output voltage or requesting the system power dispatcher to raise the grid voltage. These actions are procedurally directed and are integrated into the operator training program.

To address the potential operational problem due to the switchgear overduty condition, a test to upgrade the switchgear and breakers to a higher momentary current rating will be performed and a time delay of about six cycles on the short-circuit interrupting will be implemented. In response to the staff's concern regarding a test to upgrade the switchgear and breaker to a higher momentary current rating, the licensee contracted Pacific Breaker Systems, Inc., to specify the testing, procure the equipment, and perform the tests. The licensee provided adequate details regarding the tests. The licensee is currently working with GE Industrial Systems Division to provide the modifications and perform the final momentary test. After successful tests, the bracing will be modified in the field. The licensee stated (Reference 18) that GE Industrial Systems Division performed the momentary rating test. The test applied current that had a first peak of 154.8 kA for 17 cycles before being interrupted by the station breaker. The test was successful in demonstrating that, with the modified bracing, the switchgear and the breaker can meet the EPU momentary current requirements of 151.5 kA for the first peak. The bracing of the switchgear for the load cubicles will be modified to reflect the tested configuration. The six-cycle time delay on the short circuit interrupting capability of the load breaker will be accomplished by disconnecting the instantaneous trip from the overcurrent protection for the load breakers.

The licensee stated (Reference 56) that the overcurrent protection for the load breakers is provided by GE type IAC 66M relays that include an instantaneous overcurrent setting and a high dropout setting with a time delay. The instantaneous overcurrent relay for the load breakers for buses 21, 22, 31, and 32 for DNPS will be disconnected, leaving the high dropout feature, which will actuate after a six cycle (i.e., 0.1 second) time delay. Based on ANSI/IEEE C57.12, the UAT and RAT can provide the short circuit current for two seconds without damage. Based on the protection scheme coordination curves, the capability of the 4 kV bus duct to withstand the short circuit current is not affected by the six cycle time delay. Thus, the overcurrent relays still provide adequate protection. The remaining portions of the protective relaying were not changed for EPU. The coordination between the main breaker to the switchgear, motor feeds, the bus duct capability, and the transformer capability is maintained.

A review of the 4160 V bus and auxiliary transformer overcurrent relay setpoints was to be performed to ensure proper settings for operation at EPU conditions. In response to the staff's

RAI regarding relay setpoints and coordination, the licensee provided details of the completed review (Reference 9). The licensee stated that the existing settings will remain the same and no changes are required.

The staff finds that the licensee has provided adequate evaluations of the transformers (UAT and RAT), the switchgear and load breakers, and protective relay settings for EPU conditions when the loads are transferred to one transformer. For the above condition, the alarm response procedures will be modified to require operator action to reduce transformer load within one hour. On this basis, the staff concludes that there is reasonable assurance that UAT and RAT, non-safety 4160V switchgear, load breakers, and protective relays will perform satisfactorily during a single transformer operation at EPU conditions.

The licensee stated that no increase in flow or pressure is required of any ac-powered ECCS equipment for the EPU. Therefore, the amount of power required to perform safety-related functions (pumps and valves loads) is not increased with the EPU. The existing diesel generator load calculations are unchanged by the uprated conditions, and the current emergency power system design remains adequate. The system has sufficient capacity to support the required loads for safe shutdown, to maintain a safe-shutdown condition, and to operate the required engineered safety feature equipment following a postulated accident.

The staff concludes that the power uprate has no impact on the emergency onsite power system.

6.2 DC Power

The staff has reviewed information provided by the licensee to determine the impact of the 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 based on equipment nameplate data. Operation at the EPU conditions does not increase any loads beyond nameplate rating or revise any control logic. The licensee stated that the dc power distribution system is adequate.

However, a modification is required to the main feed cables to the reactor building dc panels to improve the voltage at the panels. The licensee stated that the present design has two 1/C 250 MCM cables routed from the turbine building 125 Vdc buses to the reactor building buses. This cable length is quite long and during high current loading conditions (i.e., when load shedding occurs at the 4 kV buses), the voltage drop within the main feed cables is higher than desirable at pre-EPU conditions. Currently, the voltage at the reactor building buses, with worst case loading, is 87.84 V for Unit 2 and 82.2 V for Unit 3. Specific calculations and modifications using an interposing relay design for some of the 4 kV breakers control circuits have been performed to address and resolve this issue.

At EPU conditions, additional loading will be present, resulting from tripping of the additional running FW and condensate pump breakers during a load shed. A modification to install another 250 MCM conductor per polarity will be implemented as part of the EPU project. This will reduce the total cable resistance by half and therefore decrease the cable voltage drop of about 13 V for Unit 2 and 20 V for Unit 3 in half during high loading periods. This will raise the minimum voltage at the reactor building buses, with worst case loading, to approximately 94 V for Unit 2 and 92 V for Unit 3.

On the basis of this information, the staff concludes that the proposed modification will improve the voltage at the reactor building dc panels. The staff concurs with the licensee that the dc power system is adequate for EPU at DNPS.

6.3 Fuel Pool Cooling (FPC)

The FPCCS is important to safety in that it removes the decay heat released from stored irradiated fuel assemblies to maintain the pool water temperature at or below design temperature under normal operating conditions. For the higher expected heat loads, any one of three SDC loops at DNPS can be aligned to the SFP to provide supplemental cooling. Makeup water systems maintain sufficient coolant inventory for operation of the cooling systems and to protect the fuel from damage following a sustained loss of forced cooling.

By increasing the amount of power produced in each fuel assembly and, therefore, the decay heat generated in each assembly, the EPU directly affects the decay heat generation rate in the SFP, the rate of temperature increase following a loss of cooling, and the rate of coolant loss if the pool reaches bulk boiling conditions. In Reference 23, the licensee described changes in operating assumptions (i.e., rate of fuel transfer) and evaluation methods (i.e., credit for evaporative cooling) relative to those described in the DNPS UFSAR. The increase in the rate of fuel transfer increases the peak decay heat rate in the SFP, while the credit for evaporative cooling reduces the conservatism in the evaluation of SFP conditions.

The licensee’s bounding evaluation of SFP conditions for planned partial-core discharges was based on the decay heat calculated for a series of refueling batches of 306 fuel assemblies that operated at the EPU level of 2957 MWt through 24-month operating cycles. The decay heat rate was calculated using ANSI/ANS Standard 5.1-1979 with an additional margin for uncertainty. The decay time of the most recent batch transfer assumed 100 hours decay prior to fuel transfer and a transfer rate of 10 assemblies per hour. The resultant peak decay heat rate was 17.4 E+06 BTU/hr. A subsequent unplanned full-core offload 24 months after the last partial-core discharge increased the peak decay heat rate to 39.1 E+06 BTU/hr. The staff found this method of decay heat rate determination acceptable, and the staff concluded that the applied assumptions were likely to bound future planned partial-core discharges. Because a full-core offload closer to the previous refueling discharge would produce a higher peak decay heat rate, the evaluated full-core offload would not bound all potential discharge scenarios. However, the calculated decay heat rate for the full-core offload and its associated boiloff rate of 70 gpm would likely be bounding for planned full-core offloads for refueling.

The licensee’s evaluation also considered the following heat removal paths: one of two FPCCS pumps supplying two heat exchangers, one SDC loop and evaporative cooling of the SFP. Because shutdown safety management procedures at DNPS require the ability to align a spare loop of SDC to the SFP within eight hours of the loss of the operating SDC loop, the licensee considered failure of an FPCCS pump the limiting single failure for planned offloads. Both FPCCS pumps were considered available for unplanned offloads. In its letter dated September 5, 2001 (Reference 31), the licensee committed to implement procedural controls to ensure reactor building conditions are consistent with conditions assumed in the evaluation of credited evaporative cooling capacity. The staff concluded that the credited heat removal capability was sufficiently reliable for both planned refueling and unplanned maintenance offloads.

The licensee maintained the SFP temperature acceptance criteria of 141 °F for planned offloads and 150 °F for unplanned offloads. The credited heat removal capacity was adequate to satisfy these acceptance criteria for the evaluated planned and unplanned offloads. In Reference 31 the licensee also committed to apply the same methods and acceptance criteria in evaluating planned offloads that are not bounded by the existing analysis. The staff found the analytical methods and SFP temperature limits acceptable for evaluation of refueling-outage-specific evaluations of SFP cooling capability.

Available makeup water capacity from each evaluated source continues to exceed the maximum calculated boiloff rate. The licensee stated (Reference 31) that testing demonstrated the capability of one operating condensate transfer pump to deliver over 400 gpm to the skimmer surge tank, which would overflow into the SFP if the FPCCS was not operating. The licensee also described the capability to deliver over 90 gpm through hoses on the refueling floor to the SFP from either the condensate transfer system, the clean demineralized water system, or the fire water system. The capability of these sources exceeds the peak calculated boiloff rate of 70 gpm, and the calculated minimum time of 8 hours for the SFP temperature to increase from 150 °F to 212 °F allows adequate time to align any of the above makeup sources. Therefore, the staff found the existing makeup water systems adequate for the EPU conditions.

Based on the staff's review of the licensee's rationale and evaluation, and the experience gained from the staff's review of power uprate applications for other BWR plants, the staff concludes that operation of the SFP cooling system at EPU conditions is acceptable.

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 Loads

The safety-related service water systems provide cooling water to the following essential components and systems: CC heat exchangers, diesel generator cooling water (DGCW) pump motors, LPCI room coolers, CC service water (CCSW) pump vault coolers, CCSW keepfill, alternate water supply, DGCW heat exchangers, HPCI room cooler, and the CREV system refrigeration condensing unit. All heat removed by these systems is rejected to the ultimate heat sink (UHS) (Section 6.4.5).

The licensee performed evaluations and stated that the performance of the safety related service water systems during and following a LOCA with loss of offsite power (LOOP) has been found acceptable. The licensee noted that the EPU results in an increase of 8 MBTU/hr, rejected to the CCSW, resulting in a peak heat load of 102 MBTU/hr for the CCSW. Additional details are provided in the licensee's letter dated August 13, 2001, (Reference 23).

The CCSW provides cooling water to the CC heat exchangers under post-accident conditions. The long-term containment pressure and temperature response following a LOCA is governed by the ability of the LPCI and CC systems to remove the decay heat from the suppression pool.

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. In the containment pressure and temperature response analyses, the post LOCA CCSW cooling was assumed to be unchanged for power uprated conditions. Therefore, the CCSW cooling remains adequate for plant operations at the proposed EPU to perform its safety function during and following a LOCA. The staff’s evaluation of the containment system performance for plant operations at the proposed EPU is addressed in Section 4.1.

Based on the review of the licensee's rationale, the staff finds that DNPS operations at the proposed EPU maintain the containment temperature and pressure response at acceptable levels and do not change the operations of the safety-related service water systems, and otherwise have an insignificant or minor impact. Therefore, the staff concludes that the safety-related service water systems at DNPS remain adequate for plant operations at the proposed EPU to perform their safety function during and following a LOCA.

6.4.1.2 Non-Safety-Related Loads

Several non-safety related service water heat loads will increase as a result of the EPU. The licensee stated that the major heat load increases from the EPU reflect an increase in main generator heat losses rejected to the stator water coolers and hydrogen coolers in addition to increases in turbine building closed cooling water (TBCCW) and reactor building closed cooling water heat loads. The licensee performed evaluations which demonstrate that the temperature of the service water temperature discharged to the circulating water system is slightly increased at the proposed EPU.

Since the service 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.

6.4.2 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 EPU operation increases the heat rejected to the condenser, and therefore increases the condenser backpressure. If the condenser pressure approaches the backpressure limit, then the licensee must reduce reactor power to maintain an adequate vacuum.

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

6.4.3 Reactor Building Closed Cooling Water (RBCCW) System

The 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 increases in heat loads on this system due to plant operations at the proposed EPU are not significant. These increases are due to running the reactor recirculation pumps at a higher speed and the additional decay heat load for the fuel pool coolers. The operation of the remaining equipment cooled by the RBCCW system is not power dependent and is not affected by EPU. The licensee provided additional detail of the EPU effect on the RBCCW heat loads (Reference 23) in response to the staff. The RBCCW heat loads remain within the system heat removal capacity, with the exception of the system's capability to achieve refueling temperature (<140 °F) within 24 hours. For this condition, the revised heat loads of 436 MBTU/hr exceed the system design heat removal capability of 234 MBTU/hr. With lower service water temperatures the DNPS can achieve the required heat transfer rates. The licensee reevaluated this capability for commercial reasons as part of the EPU evaluation. There are no safety concerns associated with achieving refueling temperatures within 24 hours. The heat removal rate required to achieve the TS cold shutdown temperature of 212 °F remains within the system capability.

Based on the review of the license's rationale, the staff finds that the heat loads in equipment cooled by the RBCCW system have been evaluated for power uprate operations and the loads remain within system capability for modes of concern. Therefore, the staff concludes that the impact of plant operations at the proposed EPU on the RBCCW system is acceptable.

6.4.4 Turbine Building Closed Cooling Water (TBCCW) System

The TBCCW system supplies cooling water to many of the non-safety heating, ventilation, and air conditioning (HVAC) units and other turbine building equipment. The bus duct cooler increased heat loads and the operation of a fourth condensate/booster pump and a third reactor feed pump added heat. Other loads do not increase significantly due to the EPU. The licensee evaluations of the increased TBCCW system heat loads demonstrated a coolant increase of less than 0.5 °F. The TBCCW system has adequate heat removal capability for plant operations at the proposed EPU.

Since the TBCCW 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 (UHS)

The Kankakee River is the normal heat sink via the intake canal and discharge canal (which flows to the Illinois River), providing essential cooling water for DNPS at the EPU conditions. However, in the event of loss of the downstream dam, water trapped in the intake canal becomes the UHS. In this event, makeup water is required to the UHS for DHR heat removal. This makeup activity is currently required for plant operation. The licensee stated that sufficient time is available to replenish water in the UHS following a loss of the dam. As noted below, the licensee has evaluated that the UHS replenishment may be required within 4 days following a failure of the downstream dam during EPU conditions, as opposed to 5½ days at the current licensed power level.

In its August 13, 2001, response to the staff's RAI (Reference 23), the licensee provided additional information regarding the impact of EPU on the ability of the DNPS UHS to maintain both units in safe shutdown considering the increased decay heat load resulting from EPU operations. The Dresden design basis credits the isolation condenser (IC) to bring the reactor temperature to 212 °F. The licensee response noted that UFSAR Section 9.2.5 provides the design basis and that the EPU will require manual actions to place portable pumps for makeup from the river to the UHS sooner, but that this was a negligible impact given the small increase in volume required.

In its September 5, 2001, response to the staff's RAI (Reference 32), the licensee provided additional information relating to the UHS, including methods to make up water to the UHS. In its September 26, 2001, response to the staff's RAI (Reference 56), the licensee provided additional information regarding the ability to shut down the Dresden Unit 2 and 3 reactors following a dam failure, including details of the assumed makeup sources and the volumes required and available. These responses also provided additional details regarding the adequacy of the UHS and the isolation condenser under seismic conditions, including the licensee's planned future modifications to address the Dresden IPEEE outliers. The NRC staff conducted an audit at Dresden Units 2 and 3 on October 22-23, 2001. The audit examined the EPU application relating to the UHS licensee responses to requests for additional information noted above, and licensee calculations and evaluations supporting the EPU application. The water sources available, the licensing basis assumptions, and EPU impacts are discussed below.

Isolation Condenser (IC) Shell Inventory

Prior to EPU, the IC shell has sufficient water inventory for 20 minutes of IC operation. The design heat removal capacity was based on removing the decay heat at 5 minutes after shutdown at ORTP. Calculations indicate that, for EPU conditions, decay heat will match the IC heat removal capacity 8.8 minutes after shutdown. The licensee's calculations also considered the effect of water carryover in the vapor exhausted from the IC shell. The IC heat removal rate is determined by surveillance and adjustment of the condensate return valve. As noted above, this rate is not affected by EPU. Therefore, as a result of EPU, the RVs will cycle for an additional period of time until the decay heat rate is within the design capability of the IC, and with no operator action the units will experience less cooldown during the initial 20 minute period.

Initial Makeup Sources

DNPS relies on diverse, non-seismic, sources for initial makeup to the IC and states that these can be lined up within 20 minutes, both pre- and post-EPU. The preferred water source is the clean demineralized water tank with a typical operating volume of 130,000 gallons and a low-level alarm at 84,000 gallons. Redundant, diesel-driven makeup pumps are used to provide this water to the IC shell through seismically qualified piping. The clean demineralized water transfer pumps can alternately be used to provide IC makeup from the clean demineralized water tank through non-seismic piping. The Unit 1 diesel-driven fire pump can also be used as an initial makeup source, taking water from the Unit 1 intake canal. This pump pressurizes the station fire headers which can be used to makeup IC shell inventory with a separate makeup line to the IC. Although the water level in the Unit 1 intake canal could drop as low as 495 feet immediately following a dam failure, the Unit 1 fire pump's suction is located at elevation 492 feet. Therefore, the pump will still be available for initial makeup. An additional source of initial IC makeup is contaminated condensate from the 2/3A, 2/3/B, and 1A condensate storage tanks. These tanks have a combined capacity of 700,000 gallons and are administratively controlled to contain an inventory of 130,000 gallons per operating unit. All of the initial makeup sources are available using pumps and valves operated from the control room.

The licensee estimated that 40,000 gallons of water is needed per unit for two hours of IC operation following EPU. This evaluation, examined during the staff audit, included the effects of moisture carryover and considered that the IC water level would be maintained at a level that would minimize carryover following dam failure. Thus, there are diverse initial makeup sources with sufficient inventory for at least 2 hours of IC operation following a dam failure post-EPU.

Makeup from UHS

Within 2 hours of dam failure, the licensee notes that makeup to the IC can be supplied from the UHS. Upon loss of level in the intake bays, procedures direct the operators to install stop logs and reflood the intake compartment that provides a suction source for the Unit 2 and 3 diesel fire pump. The intake compartment is reflooded by aligning the discharge of the installed refuse pumps, which take suction from the bottom of the intake bay and are fed from motor control centers capable of being powered from emergency diesel generators. This compartment also provides a suction for the CC service water pumps. The licensee stated that the action to install stop logs and reflood the intake compartment within 2 hours is written in procedures and has been validated. Thus, makeup to the IC from the UHS will be available prior to depletion of the initial makeup sources following EPU.

Additional IC makeup capability is provided from the UHS by the service water pumps which provide makeup to the IC through the fire protection system. However, the licensee does not credit these pumps under dam failure scenarios because their suctions are at an elevation of 494 feet. If operable, this makeup path is available in the same time frame as the initial makeup sources.

UHS Inventory

The UHS inventory at DNPS consists of water contained by the retaining structures and the canals connecting the water sources with the intake and discharge structures. UFSAR Section 9.5.2 notes that, due to the topography of the circulating water canals, approximately 9 million gallons of water is trapped within the UHS, not including water in the cooling lake. As the licensee noted in its August 13, 2001, response to the staff (Reference 23), the EPU increases the amount of water required for a 30-day period from 2.5 million gallons to 2.9 million gallons for each unit, with 6 million gallons available. In its letter dated September 26, 2001, the licensee clarified that this volume consists of an excess of 3 million gallons in the intake canal and an estimated additional volume of 3 million gallons in the discharge canal. The licensee also noted that the amount of water required for the 30-day period does not consider the effects of carryover.

In its letter dated September 26, 2001 (Reference 53), the licensee noted that the volume of water available in the Unit 2and 3 intake canal is not sufficient to provide makeup for 30 days to maintain either or both reactors in hot shutdown following a dam failure, both pre- and post-EPU. The licensee notes that this was previously evaluated in the systematic evaluation program (SEP) for DNPS. The basis for the SEP conclusion regarding the limited volume of water available in the UHS is stated in the NRC contractor's technical evaluation report (TER) forwarded to the licensee by the Safety Evaluation of Hydrology SEP Topics II-3.A, II-3.B, II-3.B.1, and II-3.C dated June 21, 1982 (Reference 59). The TER noted, considering that water used to cool the plant auxiliary equipment would be removed from the intake canal and returned to the discharge canal, that if the deicing line were to fail or if the deicing line slide valve were unable to be opened, water in the discharge canal would not be available. The TER stated that "Because the amount of water available in the intake canal is large, it can be expected that a significant period or time would pass before makeup would be required. It can be conservatively estimated to be several days to a week or more."

UFSAR Section 9.5.2 also notes that following dam failure, flow to the river through the discharge flume will stop at an elevation of 498 feet because of high points in the canals, and backflow from the intake canal will similarly stop at an elevation of 495 feet. However, the licensee now assumes that the level in the discharge canal will equalize with that in the intake canal through any of three paths: (1) leakage through the flow diverter gates in the discharge canal, (2) backflow through circulating water system piping, and (3) opening of the deicing line between the discharge canal and the intake canal. In its evaluation of the water available from the UHS following dam failure post-EPU, the licensee credited only the water entrapped in Unit 2 and 3 intake canal. The licensee evaluation considered that only the part of the intake canal trapped inventory above the suction of the diesel generators (2 million gallons) would be available from the UHS, as the makeup path potentially relies on on-site power. The licensee, in its evaluation, did credit return of the DGCW to the intake canal from the discharge canal (through any of the three paths noted above); however, the licensee did not take credit for the volume of water trapped in the discharge canal. This inventory lasts approximately four days following EPU, and for pre-EPU conditions the same inventory would last for approximately 5½ days. If the offsite power is restored within the 4-day period, the time would increase because the entire volume of the intake canal would be available with no diesel generator cooling required.

Additional water is likely to be available in the discharge canal, the hot and cold canals, and the cooling lake. During the site audit the NRC staff noted that licensee procedures direct the operators to preserve makeup to the intake canal from these other sources by arranging flow control station gates, cooling lake spillway gates, and lift pumps in a manner that avoids losing inventory to the river over the intake canal invert at elevation 495 feet. Although the licensee now credits water returning from the discharge canal to the intake canal following a seismic event, there are three diverse paths available for return of this water. Additionally the only water credited is diesel cooling water. Although the licensee now assumes most water in the discharge canal is lost to the river via backflow through the three diverse paths noted above, there remains a volume of water entrapped in the discharge canal below the intake canal invert at elevation 495 feet. Therefore, credit for return of the diesel cooling water is acceptable considering the topography of the discharge canal.

Replenishment of the UHS

Before depletion of water in the intake canal, the licensee noted that makeup can be provided from the Kankakee River using portable, low head, high volume, engine-driven pumps, which can be readily obtained from other stations or purchase or rental. The licensee noted that at least four days are available before this replenishment is required under EPU conditions. Therefore, the basis for the conclusion reached during the SEP, that several days to a week would be available to obtain portable pumps for UHS replenishment, is unaffected by EPU. This basis was founded, in part, on a NRC review of emergency plans and procedures for dam failures.

Both DNPS units can be simultaneously brought to hot shutdown and maintained in that condition for 30 days using the IC following EPU. The sources of makeup water are not seismically qualified but, considering the redundancy and diversity of the sources, there is a high confidence that at least one source will be available following a design basis event, including seismic events that could cause dam failure. Based on the review of the licensee's rationale and evaluation, the staff agrees with the licensee's conclusion that the ability of the DNPS UHS to support operations at the proposed EPU conditions is acceptable.

6.5 Standby Liquid Control (SLC) System

The licensee evaluated the effect of the EPU on the SLC system injection and shutdown capability. The DNPS SLC is a manually operated system that pumps a sodium pentaborate solution into the vessel in order to provide neutron absorption and is capable of bringing 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 subcritical and to maintain the reactor in a safe-shutdown condition. Operating at the EPU condition does not effect the required boron solution. Implementation of a higher fuel batch fraction, a change in fuel enrichment, and a new fuel design are the conditions that might affect the shutdown concentration. The SLC system shutdown capability is reevaluated for each reload core. The new fuel design combined with a planned extension in the fuel cycle operating time does not currently require an increase in the minimum reactor boron concentration of 600 ppm, and therefore no increase in the volume of the stored boron solution for the EPU cycle.

According to the licensee, the SLC system is designed to inject at a maximum reactor pressure equal to the upper analytical setpoints for the lowest group of S&RVs operating in the relief mode. The licensee stated that since the reactor dome pressure and the S&RV setpoints will not change, the current SLC system process parameters will not change. The licensee added that the SLC pumps are positive displacement pumps, where small changes in the S&RV setpoints would have no effect on the SLC system capability to inject the required flow rate.

The SLC ATWS performance is addressed in Section 9.4.1 and the licensee has stated that the evaluation is based on a representative core design at the EPU condition. 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. Therefore, the capability of the SLC system to provide its backup function is not affected by the EPU.

As a result of the audit, the staff requested and received additional information from the licensee on the ATWS/SLC events that were analyzed at the EPU conditions.

The limiting events for each of the five ATWS acceptance criteria in Section 9.4.1 of the licensee's SAR are identified as the PRFO for Criteria 1,2, and 3, and the MSIVC for Criteria 4 and 5. The licensee confirmed that the operator response to an ATWS event is not being modified from that described in Section L.3.2, "Operator Actions," of ELTR1. The licensee confirmed that for all limiting ATWS events, the SLC system for DNPS, Unit 2 will be able to inject at the appropriate time without lifting the SLC bypass RV. The cycle-specific reload analysis for DNPS Unit 3 will confirm the SLC capability or will identify required system modifications. The licensee also confirmed that the SLC system meets the ATWS acceptance criteria for DNPS even if the operator requests SLC actuation before the time assumed in the analysis, and the RV lifts and remains open until the valve inlet pressure decreases to the valve reseat pressure. The licensee will verify the valve reseat pressure and the lack of valve chatter upon reseat at the next refueling outage for each unit. The licensee's response to the staff's questions was summarized in a letter dated November 02, 2001 (Reference 55).

During the staff audit, Project Task Report T0902, "Anticipated Transient Without Scram," was reviewed and GNF and licensee staff discussed the DNPS bounding LOOP ATWS event. For this event, the calculated peak vessel pressure would reach a maximum of 1316 psig at about 9.2 seconds from the start of the event, before the initiation of the SLC system at 123 seconds. The S&RVs would open to relieve the pressure during any further pressure spikes, resulting from calculated reactor vessel level undershoots. The calculated undershoot is caused by a computer code (ODYN) limitation in modeling the HPCI systems. The undershoot of the water level results in an overcorrection of the level, and the resulting overshoot of the level generates a high core flow and core power, and eventually generation of excessive steam. This artifice of the calculation can result in increased vessel pressure.

Considering that the ODYN calculation is conservative, i.e, plant response to the water level transient is expected to be considerably faster than the ODYN model, and that there would still be sufficient margin to lift the SLC RV, and that the pressure spikes that are calculated occur for a short duration, the staff concludes that the SLC system will be able to inject boron into the RCS as required by 10 CFR 50.62.

Based on the review of the licensee submittal, the on-site audit of the application of approved methodologies, and the licensee response to the request for additional information including the commitments made, the staff finds the ATWS/SLC evaluations acceptable.

6.6 Power-Dependent Heating, Ventilating, and Air Conditioning (HVAC) Systems

The HVAC systems consist mainly of heating or cooling supply, exhaust, and recirculation units in the turbine building, reactor building, and drywell. The EPU is expected to result in a small increase in the heat loads caused by slightly higher process temperatures and higher electrical currents in some motors and cables.

The affected areas are the steam tunnel, ECCS pump rooms, and drywell in the reactor building; the FW heater bay and condenser area, the FW pumps, the condensate/condensate booster pumps, and the motor-generator set areas in the turbine building. Other areas are unaffected by the EPU because the process temperatures remain relatively constant.

In the steam tunnel, the heat load increases due to the increase in the FW process temperature. The maximum area temperature increase is 0.5 °F.

In the drywell, the increase in FW process temperature and the increase in the recirculation pump motor horsepower are within the margins in the system capacity. In response to the staff, the licensee stated (Reference 24) that the HVAC system is designed for heat loads from the recirculation pump motors at the DNPS of 2,190,000 BTU/hr. At EPU conditions, the expected heat load from pump motors is 1,573,840 BTU/hr, providing a margin of approximately 616,000 BTU/hr. At EPU conditions, the FW temperature increase is 13.8 °F. The associated increase in FW piping heat load is 10,439 BTU/hr. The FW piping and the recirculation pump motors are in the same space and are cooled by the same cooling system. The margin in the HVAC design for the recirculation pump motor heat load is sufficient to compensate for the increase in FW piping heat load.

In the ECCS pump rooms, the heat loads increased as a result of a higher suppression pool temperature. The ECCS pump room coolers have adequate cooling capacity to maintain the design ECCS room temperature. The HPCI room at DNPS is not affected by the EPU since there are no process temperature, electrical, or other heat load changes that effect the pre-EPU design heat loads.

In the turbine building, the maximum temperature increase in the FW heater bay and condenser areas is approximately 4 °F due to the increase in the FW process temperatures. The FW pump motors and motor-generator sets are internally cooled by separate, dedicated once-through ventilation systems. The heated ventilating air is directly exhausted to the atmosphere without mixing with the room air; thus, the effect on area temperature is negligible. The effects of the higher internal temperature in the pump motors and motor-generator sets have been evaluated and shown to be acceptable for operation during the remaining plant life. The operation of the fourth condensate pump increases the temperature in the condensate pump area by approximately 9 °F.

In response to the staff, the licensee stated (Reference 24) that the operation of the fourth condensate/booster pump, required for EPU operation, increases the heat load. Since the cooling capacity of the ventilation system is not being changed, the pre-EPU design room temperature may be exceeded when the outdoor air is at the design temperature (i.e., periods of expected seasonal high temperatures), but the high temperatures do not continue for extended periods. The normal operation of the non-safety related pumps in this area is not affected, based on a review of the motor insulation ratings, which exceed the EPU temperatures. The licensee stated that all equipment in the EQ program affected by such temperature increases has been evaluated and is acceptable.

Based on the licensee's review of design basis calculations and EQ design temperatures, the design of the HVAC is adequate for the EPU. In response to the staff, the licensee stated (Reference 24) that, in several reactor building areas, the post-LOCA temperature increases a few degrees due to higher EPU heat loads. The secondary containment is isolated and the HVAC systems for the general areas do not operate post-LOCA. The licensee stated that the equipment in all such areas in the EQ program has been evaluated and found acceptable, as described in the site EQ program documentation.

The licensee stated (Reference 24) that a separate EPU evaluation for the ECCS-related HVAC systems was performed for DNPS. In the ECCS room coolers, DNPS does not take credit for the operation of the LPCI and CS room coolers. The licensee further explained that the other HVAC systems are similar enough between sites for normal operations that they could be evaluated together. The evaluations determined that no changes in the operation or configuration of these systems were required for the EPU, and that all of the systems continued to meet design requirements.

Based on the staff's review of the licensee's rationale, and the experience gained from the staff's review of power uprate applications for other BWR plants, the staff concludes that the EPU does not adversely affect the operation of HVAC.

6.7 Fire Protection Program

The staff finds that the operation of the DNPS at the EPU 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 that (1) one train of systems necessary to achieve and maintain hot shutdown be maintained free of fire damage, and (2) that the (a) systems necessary to achieve and maintain cold shutdown can be repaired within 72 hours if redundant systems are being used, or (b) the systems can be repaired, and cold shutdown can be achieved, within 72 hours if alternative or dedicated shutdown capability is being used.

While Section 6.7, "Fire Protection," of the licensee's SAR (Reference 2) only addresses cold-shutdown capability and is silent concerning hot-shutdown capability, Table 6-3 of the report indicates that the limits for the important reactor process variables (i.e., PCT, primary systems pressure, primary containment pressure, and suppression pool bulk temperature) are not exceeded following a fire event using the HPCI or IC and CRD systems. The staff has accepted the use of HPCI 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 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 EPU conditions. The staff finds this acceptable.

The EPU may affect 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 CS and LPCI, to provide reactor coolant makeup, or those plant areas that rely on alternative or dedicated shutdown capability as defined in Section III.G.3 of Appendix R. For example, Section 4.2.4, "Automatic Depressurization System," notes that to achieve the required flow capacity for the EPU conditions, five ADS valves must be operable and that prior to the EPU only four ADS valves were required to be operable. However, the licensee has not credited ADS operation in conjunction with low pressure systems for Appendix R hot shutdown scenarios. The HPCI, Isolation Condenser and CRD are used for a fire at Dresden. The EPU has reduced the time available for the operators to stabilize the plant in hot shutdown using HPCI or Isolation Condenser and CRD. The licensee has stated that the operator actions required to mitigate the consequences of a fire are not affected by the EPU, sufficient time is available for the operators to perform the necessary actions, and any necessary changes to procedures will be accomplished prior to the EPU implementation. The staff finds this acceptable.

An evaluation of the effect of the EPU on the top 10 fire scenarios in terms of core damage frequency (CDF) contribution was performed by the licensee. The licensee concluded that the EPU would have only a minor effect of the fire risk estimated in the licensee's individual plant examination of external events (IPEEE). The staff finds this acceptable.

Therefore, based on a review of the information provided by the licensee in Reference 2, the staff concludes that the EPU will not adversely affect the safe shutdown capability in the event of a fire and is therefore acceptable.

6.8 Systems Not Impacted or Insignificantly Impacted by EPU

The licensee identified those systems which are not affected or insignificantly affected by plant operations at the proposed EPU. The staff has reviewed those systems (e.g., auxiliary steam, instrument air, service air, miscellaneous HVAC, diesel generator, and the associated supporting systems). Based on the staff's review of the systems identified by the licensee and the experience gained from the staff's review of EPU applications for other BWR plants, the staff concludes that plant operations at the proposed uprate power level have no or insignificant impact on these 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 EPU, the high pressure turbine will be modified to maintain the GE standard flow margin of 3 percent of the EPU rated steam flow.

The licensee performed evaluations to verify the mechanical integrity of the turbine-generator and components, under plant operations at the proposed EPU. These evaluations covered stationary and rotating components and valves, control systems, and other support systems. The licensee stated that results of the evaluations showed that modification of the high pressure turbine to increase flow and some other non-safety modifications to the turbine-generator are needed for the EPU.

In response to the staff, the licensee described some of these changes (Reference 19). These include new boreless high pressure turbine rotors and nozzle diaphragms for increased volumetric flows, new setpoints for the cross-around RVs and the stator water cooling alarm, runback setpoint changes, and various changes to the electrohydraulic control/turbine supervisory instrumentation.

The licensee further stated that it evaluated the probability of turbine overspeed and associated turbine missile production due to plant operations at the proposed EPU. In response to the staff the licensee noted that since the geometry of the LP rotors and blading will not change as a result of the EPU, the existing analysis remains valid. The current overspeed trip settings will be reduced, as applicable to preclude rotor train speeds in excess of 120 percent of rated speed in the unlikely event of a simultaneous full load rejection and failure of both control and intermediate valves. For DNPS, the backup overspeed trip setpoint is within the original equipment manufacturer's recommendation and does not require revision. Therefore, the turbine could be continuously operated safely at the proposed EPU.

The staff requested additional information regarding the implications of the increase in reactor power which may be limited by the main generator capability of 912 MWe following EPU. The licensee's response (Reference 19) stated that, due to the change in plant efficiency over the operating cycle, reactor power could vary from approximately 96 percent of thermal power under optimal conditions in the winter to 100 percent of power on warm summer days. The licensee stated that these variations in reactor power do not approach the magnitude of changes required for surveillance testing and rod pattern alignments. Additionally, the licensee stated that the effect of having thermal power limited by main generator capacity (load follow) on radioactive waste generation will be minimal in that the major change for such generation at EPU conditions is increases in FW flow and conductivity.

7.2 Miscellaneous Power Conversion Systems

The licensee evaluated miscellaneous steam and power conversion systems and their associated components, including the condenser, air removal system, and steam jet air ejectors for plant operations at the proposed EPU. The licensee stated that the existing equipment for these systems is acceptable for plant operations at the proposed EPU. Modification to some non-safety related equipment, such as steam dilution modifications to the condenser air removal systems, is necessary to provide adequate capacity for the proposed uprate core thermal power.

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

7.3 Turbine Steam Bypass

The turbine bypass valves were initially rated for a steam flow of 40 percent of the original rated steam flow. For EPU conditions, the resulting bypass capability will be 33.3 percent of EPU steam flow. The licensee has proposed revisions to TSs reflecting the revised percentage of rated steam flow. Transient analyses remain based on actual mass flow rates, which are not changed for EPU.

Since the turbine bypass system does not perform any safety-related function, the staff has not reviewed the impact of plant operations at the proposed EPU on the design and performance of this system.

7.4 Feedwater and Condensate Systems

The licensee noted that EPU operation requires modifications related to these systems, such as recirculation system runbacks, as well as alteration of operating system lineups, such as running all three FW pumps (versus two previously) and all four condensate/condensate booster pumps (versus three previously). As stated by the licensee, the FW and condensate systems do not perform system-level safety-related functions. Therefore, the staff performed a limited review of the impact of plant operations at the proposed EPU on the design and performance of these systems.

In response to a staff question, the licensee addressed various changes that are planned to improve plant trip avoidance capability under EPU conditions (Reference 19). A reactor recirculation pump runback is being added to reduce potential for reactor scrams on low water level following a loss of either a FW or condensate pump. The runback is enabled whenever main steam flow exceeds the capability of two FW pumps. When enabled, a runback will rapidly reduce the core flow to the equivalent of 82 percent power if less than three FW pumps are running coincident with a reactor low level alarm setpoint or if all condensate pumps are not running. The licensee's analyses indicates that these changes should reduce core flow and reactor power to within the capability of the running FW/condensate pumps to avoid reduction in the reactor water level to the revised (lower) scram and isolation setpoints.

The licensee will also scale FW control and indication loops, and adjust FW pump runout logic to accommodate EPU flow rates.

The licensee stated that proper operation of the runback and FW pump suction trip logics will be verified in post-modification testing. The FW control system response and FW pump performance will be verified at various power levels during post-EPU startup testing.

The staff requested additional information regarding the effect of the EPU on the FW system, specifically the system's capability to handle additional flow in the FW heater drains to avoid challenges to operators and safety systems potentially caused by loss of FW heaters. In its response dated August 7, 2001 (Reference 19), the licensee stated that an evaluation of the FW heater level control and drain valves was performed to assess flow passing capabilities. The licensee determined that the EPU operating conditions do not significantly challenge the capability of the level control valves, with the exception of the DNPS Unit 2 and 3 FW heater B-level control valves, which require valve trim replacement. The licensee also reviewed thermal-hydraulic conditions and determined that shell modifications were required to support a rerate of the C and D FW heaters for increased EPU design pressure conditions; the C FW heaters are rerated to 100 psig from 75 psig and the D FW heaters are rerated to 178 psig from 150 psig.

Based on the review of the licensee's rationale, the staff finds the FW and condensate systems acceptable for EPU operations.

8.0 RADWASTE SYSTEMS AND RADIATION SOURCES

DNPS uses waste treatment systems designed to collect and process gaseous, liquid, and solid waste that might contain radioactive material. These radioactive waste treatment systems were evaluated in the final environmental statement (FES) dated November 1973. The proposed 17 percent EPU will not involve any significant physical changes in the waste treatment systems, nor will it affect the environmental monitoring of any waste stream described in the FES. For normal operations, no new or different radiological waste streams are created as a result of the proposed power increase.

8.1 Liquid and Solid Waste Management

The major impact of the power uprate on the station's solid radioactive waste production is the increased generation of spent condensate cleanup resins, the major component of low-level radioactive waste (LLRW). LLRW also includes filter sludge, dry active waste, metals, etc. Because of the estimated increased levels of activated corrosion products in the FW system, SFCR quantities should increase as a result of the increased changeout frequency for resin bed media. Due to the increases in condensate/FW flow and temperature, the licensee expects that the increase in solid waste production (chiefly resins) will be proportional to the power uprate.

This estimate is supported by experience gained at other BWR facilities now operating with smaller power uprates (2–5 percent). Based on this estimate, the overall increase in solid radioactive wastes is expected to be a small percentage (approximately 8 percent) of the stations yearly projected low-level waste burial volume for the year 2000 (144 cubic meters). This amount is bounded by the FES.

It is not expected that the volume of liquid radioactive waste released will be impacted by the power uprate. The site recycles a substantial fraction of the water used to process liquid radioactive material waste streams. However, due to the expected increased presence of fission products and activated corrosion and wear products in the reactor condensate, FW, and coolant, and increased flow through the condensate and RWCU demineralizers, more liquid backwashes of these demineralizers will be necessary. However, since the water quality of these backwashes is high, these waters will be recycled and thereby will not add to the volume of water released off site.

Since the amount of activity (number of curies) of radioactive material contained in the liquid effluents is expected to increase in proportion to the 17 percent power uprate, the concentration of radioactive materials released as liquid wastes is expected to increase by the same amount. From 1995 to 1999, the average offsite doses to the public from the liquid release pathway were very small fractions of the Part 50, Appendix I, numerical standards and the limits of 40 CFR Part 190. From 1995 to 1999, the highest calculated whole body dose component was less than 1 percent of Appendix I criteria, while the highest critical organ dose component was less than 0.07 percent of the 40 CFR Part 190 limit. For that same period, the average calculated dose from liquid effluents was about 0.02 percent of the Appendix I guidelines. A projected 17 percent increase of these very small values results in a negligible increase in calculated public dose, and the overall contribution to the public dose from the liquid effluent pathway would remain a very small fraction of the regulatory limits.

8.2 Gaseous Waste Management System (GWMS)

The GWMS consists of the main offgas system and various building (turbine, reactor, and radwaste) ventilation systems. Airborne radioactive material releases are controlled, processed, filtered, and monitored, and include gaseous and particulate forms. Gaseous fission products such as krypton-85 and iodine-131 are produced by the fuel in the core during normal reactor operation. A small percentage of these fission gases are released to the reactor coolant from the small number of fuel assemblies that are expected to develop leaks during reactor operation. The main offgas system removes these fission gases directly from the plant main condenser and processes them before release. These main offgas effluent release quantities are greater than the sum of all other gaseous release streams. Thus, the effluent release rate (and the resultant public dose) depend primarily on the fuel defect rate. Current and expected fuel performance at DNPS has been significantly better than the original design. The licensee conservatively assumed a 17 percent increase in gaseous effluents (as a linear function of the power increase). Using the highest calculated dose over the period 1995 to 1999, this assumed increase would result in the worst case offsite pathway dose (in terms of percentage of the 15 mrem limit) of less that 0.25 percent of the 10 CFR Part 50, Appendix I, numerical design objectives. For that same period, the average calculated dose from gaseous effluents was 0.09 percent of the Appendix I guidelines. Therefore, as a result of the 17 percent power rate increase, the calculated dose to the public from the overall release of gaseous effluents will remain a very small fraction of the dose limits of 10 CFR 20.1301.

8.2.1 Offgas System

Radiolysis of water (i.e., formation of H_2 and O_2) in the core increases linearly with 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 on the offgas system, and provided additional information in a letter dated August 7, 2001(Reference 19). The licensee calculated that the heat load for the offgas recombiner will increase from approximately 83 percent to 97.5 percent of the system design, with a radiolytic hydrogen flow rate of 30.9 lbs/hr post-EPU. The licensee stated that this is a bounding case using hydrogen water chemistry, which requires hydrogen injection into the FW system at close to the upper limit of the normal injection range. The licensee stated that it intends to operate with low levels of hydrogen injection in combination with noble metal application. Since the hydrogen injection rate decreases considerably when using noble metal injection, the hydrogen mass flow rate will be considerably less than the bounding value.

The offgas system processes air in-leakage evacuated from the main condenser. The system also processes non-condensable radioactive gases in the main condenser. These gases consist of activation gases and fission product noble gases transported through the steam lines and turbine. The rate of main condenser in-leakage is unaffected by EPU. This in-leakage determines the holdup time for radioactive decay since the increased radiolytic hydrogen flow from the EPU power increase will be removed in the offgas recombiner before the holdup volume. The design basis noble gas release rate (0.2 Ci/s) for DNPS is independent of power level and referenced to a 30-minute holdup time, which is not affected by EPU conditions. Expected offgas releases will be a fraction of the design basis release rate, which bounds the effect of increased power.

The licensee assumed that the radioactive gases will increase proportionally to the EPU increase. In Reference 19 the licensee corrected a statement in Section 8.4.3 of its SE (Reference 2) to note that an increase of 12 percent in fission product activity is expected for the EPU. The concentration of coolant activation products and fission products in the steam lines will remain unchanged as the linear increase in production is diluted by the increase in steaming rate post-EPU. The licensee stated that the gaseous effluents are well within limits at original power and remain well within limits following EPU implementation. The system radiological release rate is administratively controlled, and does not change with operating power. Therefore, EPU does not significantly affect the offgas system design or operation.

Based on the review of the licensee's rationale and the experience gained from the staff's review of power uprate applications for similar BWR plants, the staff concludes that plant operations at the proposed EPU will have an insignificant impact on the offgas system.

8.3 Radiation Sources

The staff has reviewed the licensee's plan for power uprate with respect to its effect on the facility radiation levels and on the radiation sources in the core and coolant. The radiation sources in the core include radiation from the fission process, 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. This increase, however, is bounded by the existing safety margins of the design basis sources. Since the reactor vessel (inside the fully-inerted primary containment) is inaccessible during operation, a 17-percent increase in the radiation sources in the reactor core will have no effect on occupational worker personnel doses during power operations. Due to design shielding and containment surrounding the reactor vessel, worker occupational doses are largely unaffected, and doses to the public from radiation shine from the reactor vessel remain essentially zero as a result of the EPU.

During operations, the reactor coolant passing through the reactor core region becomes radioactive as a result of nuclear reactions. The activation product concentrations in the steam will remain nearly constant following the power uprate since the increase in activation production in the steam passing through the core will be balanced by the increase in steam flow through the core. The activation products in the reactor water, however, will increase in approximate proportion to the increase in thermal power. The installed shielding at DNPS was conservatively designed so that the increase in activation products in the reactor coolant resulting from the proposed power uprate will not affect radiation zoning in the plant.

Activated corrosion products (ACPs), which are the result of the activation of metallic wear materials in the reactor coolant, could increase as a result of the proposed power uprate. The equilibrium level of ACPs in the reactor coolant is expected to increase in proportion to both the increase in FW flow rate and the increase in neutron flux in the reactor, while the increased FW flow will likely reduce the efficiency of the RWCU system. However, it is not expected that the expected ACP increase will 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, such as the drywell (primary containment), that are inaccessible during plant operation. Since these areas are usually high dose rate areas, personnel access to these areas will continue to be restricted during plant operations as required by 10 CFR Part 20 high radiation area (HRA) requirements, and in accordance with plant TSs and required licensee implementing procedures.

In an effort to reduce the occupational worker dose (and the sky shine public dose component), the licensee initiated the noble metal injection process (NIP), consistent with the principle of keeping radiation as low as is reasonably achievable (ALARA). By injecting small quantities of noble metal into the reactor FW system, the level of highly activated radioactive material deposited as crud on primary coolant piping sources and fuel is reduced. Additionally, NIP provides another dose reduction benefit by effectively reducing the radiation sky shine from the steam-side turbine building components. Main steam line dose rates at Dresden have decreased by as much as a factor of four as a result of the NIP process.

Fission products in the reactor coolant result from the escape of minute fractions of the fission products in the fuel rods. Fission product release into the primary coolant is dependent on the nature and number of fuel defects and is approximately linear relative to core thermal power. Using the ANSI/ANS 18.1-1999 normal operations source term methodology, the licensee calculated about a 12 percent increase in fission product concentration in the reactor coolant from the fuel (assuming no increase in fuel cladding defects). However, the fission product concentration in the steam should remain nearly constant following the power uprate, given the proportional increase in steam flow (dilution) through the core. Given that current levels of fission product activity in the reactor coolant and steam are small fractions of the design basis data, a 12 percent increase should have a minimal impact.

8.4 Radiation Levels

Radiation sources in the reactor coolant contribute to the plant radiation levels. As discussed previously, the proposed seventeen percent power uprate will result in a proportional increase in certain radiation sources in the reactor coolant. This increase in reactor coolant activity will result in some increases (up to 17 percent) in plant radiation levels in most areas of the plant. This increase in plant radiation levels may be higher in certain areas of the plant (e.g., inside the drywell and near the RWCU) due to the presence of ACPs. Some post-operational radiation levels may also be higher in those areas of the plant where accumulation of corrosion product crud (activated corrosion and wear products) is expected (i.e., near the spent fuel pool cooling system piping and the reactor coolant piping as well as near some liquid radwaste equipment). Many of these areas are normally locked and controlled in accordance with Part 20 human reliability analysis (HRA) requirements, and require infrequent access.

The licensee has stated that many aspects of the plant were originally designed for higher-than-expected radiation sources. Therefore, the small potential increase in radiation levels resulting from the proposed power uprate will not affect radiation zoning or shielding in the various areas of the plant that may experience higher radiation levels. The purpose of the licensee's ALARA program is to ensure that doses to individual workers will be maintained within acceptable limits by controlling access to radiation areas. The licensee will use procedural access, work planning and controls, and pre-job worker training/briefings to compensate for any increased radiation levels and to maintain occupational doses ALARA. As part of the overall EPU test program, during the incremental 3 percent power step increases, the licensee will perform special surveys for monitoring area external radiation levels to assure that the radiation areas are properly designated, posted and controlled as required by Part 20 and plant TSs.

The proposed power uprate will also cause 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. Compliance 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 should not exceed 5 rem whole body or the equivalent to any part of the body for the duration of the accident (the extremity limit is 75 rem). The licensee has determined that, based on conservative calculations, the post-accident radiation levels will increase by 11–45 percent (as a function of plant location) as a result of the proposed power uprate. Based upon this analysis, the calculated post-accident vital area worker doses (for coolant and air sampling activities) to the whole body and extremities are less than 1 and 1.8 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. The site's emergency operations facility (EOF) is approximately 50 miles from the site, and therefore the EOF habitability is unaffected by the power uprate.

The licensee has calculated the impact on operator doses in the control room from the following DBAs: LOCA, main steam line break accident, fuel handling accident, and control rod drop accident (CRDA). In the worst case, a LOCA provides a 19 percent increase to an operator's whole body dose, which includes the dose from direct radiation shine from sources external to the control room. The resultant LOCA whole body dose is 0.505 rem, a small fraction of the 5 rem GDC limit. See Section 9.3.2 for additional discussion of control room doses from DBAs.

Several physical plant modifications will need to be completed prior to full implementation of the power rate increase. The reactor vessel steam dryer/separator will be modified to compensate for the increase in moisture carryover from the reactor to the steam lines. These modifications will be planned and conducted in accordance with the station ALARA program. It is expected that the one-time occupational dose to modify these and other systems will be a small fraction of the average yearly worker collective dose for the units.

Direct radiation (skyshine) from the main steam system components in the turbine building provides another offsite public dose pathway from an operating BWR. The licensee has calculated the public dose from coolant activation products (chiefly nitrogen-16) in reactor steam. Nitrogen-16 production is increased by routine hydrogen gas injection into the reactor FW in an effort to prevent intergranular stress corrosion cracking of reactor internals. The licensee uses the NIP primarily to maintain worker doses ALARA. NIP provides a public dose reduction benefit allowing a significant reduction in hydrogen injection rates and thus effectively reducing the direct radiation shine from the steam-side turbine building components. Main steam line dose rates have decreased by as much as a factor of four at Dresden as a result of the NIP. While this skyshine dose is not expected actually to increase as a result of the power uprate, the station's required calculation methodology conservatively assumes the skyshine dose is directly proportional to reactor power. Given a 17 percent increase in reactor power, the licensee estimates that the highest dose would be about 29 percent of the 25 mrem dose limit of 40 CFR Part 190.

On the basis of the staff's review of the Dresden Unit 2 and Unit 3 license amendment, the staff concludes that the 17-percent power uprate will have little effect on personnel occupational doses and that these doses will be maintained ALARA in accordance with the requirements of 10 CFR 20.1101. 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 to vital areas for needed emergency activities. The staff, therefore, finds the proposed power uprate at DNPS to be acceptable from a normal operations occupational and GDC-19 accident dose perspective.

9.0 REACTOR SAFETY PERFORMANCE EVALUATION

9.1 Reactor Transients

AOOs are abnormal 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, General Design Criteria (GDC) 10, 15, and 20. GDC 10 requires that the reactor core and associated control and instrumentation systems be designed with sufficient margin to ensure that the SAFDLs 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 reactor coolant pressure boundary are not exceeded during normal operating conditions and AOOs. GDC 20 specifies that a protection system be provided that automatically initiates appropriate systems to ensure that the specified fuel design limits are not exceeded during normal operating conditions and AOOs.

The SRP (Reference 7) provides further guidelines: (1) pressure in the reactor coolant and main steam 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 DNPS 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 resulting from changes in system parameters such as (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 criterion that was applied. The licensee stated that in support of the EPU, each limiting transient analysis for each category of the transients listed in Table E-1 of ELTR1 was analyzed. Table 9-1 of the licensee’s SAR (Reference 2) describes the reactor operating conditions used in analyzing the limiting transients for the current pre-EPU fuel cycle 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 MCPR OLs. The EPU transients analyses were based on a representative GE-14 core and the calculated SLMCPR value of 1.09 for the core.

The licensee stated that input parameters related to performance improvement program (PIP) features or equipment out of service (OOS) have been included in the safety analyses for the EPU. DNPS is currently licensed for, or seeks to implement for EPU operation, MELLLA, end-of cycle-coastdown, SLO, final FW temperature reduction (FFWTR), ICF, and ARTS power- and flow-dependent limits. Therefore, the EPU transient analyses that were performed considered these operating constraints. 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 either directly or statistically. The licensee analyzed the following limiting transients and Table 9-2 of the licensee’s SAR provides the results. For all events in Table 9-2, the SRV is assumed OOS.

- load rejection with bypass failure (LRWOB)
- turbine trip with bypass failure (TTNBP)
- feedwater controller failure (FWCF) – maximum demand

- loss of feedwater heating (LFWH)
- inadvertent HPCI actuation (bounded by LFWH)
- rod withdrawal error (RWE)
- fast recirculation increase
- slow recirculation increase
- load reject with bypass
- MSIV closure–all valves
- MSIV closure–one valve

The licensee determined that, as shown in Table 9-2 and in Figures 9-1 through 9-4, there are no changes to the basic characteristics of any limiting events due to the EPU operating conditions. The severity of transients at less than rated power is not significantly affected by EPU, due to the protection provided by the adoption of ARTS power and flow dependent limits, as discussed in Section 9.2.

In its evaluation of ELTR1 (Reference 4), the staff concluded that the minimum set of limiting transients described in Appendix E of the topical should be included in the uprate amendment request. The staff also stated that a list of all of the transients analyzed in support of the power uprate should be included, with an explanation of how the limiting transients were selected. The DNPS submittal did not provide the bases for selecting the EPU limiting transients. However, it was confirmed that GNF 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 non-limiting events become limiting in terms of thermal limits due the power uprate, and (c) no additional limiting events impacting 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 EPU, and the stated justifications are applicable to DNPS.

In support of operation at the higher MELLLA rod line and at the EPU power level, the licensee analyzed the limiting transients using a representative equilibrium 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 the performance improvement programs or special features in establishing the thermal limits for the EPU operation. The staff concludes that the EPU transient analyses do not identify any major changes to the basic characteristics of any of the limiting events due to the EPU operating conditions.

In the current TS, some LCOs and SRs use 25 percent of the RTP to determine when to apply the corresponding requirement. The value of 25 percent of RTP is based on generic analyses conducted for a fuel bundle power of 4.8 MWt. Since the EPU evaluations show less than 4.8MWt/bundle, the 25 percent threshold remains valid. The staff finds this acceptable.

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 the plants that have adopted the ARTS feature to ensure adequate protection during the transient. The ARTS program replaces the flow-biased APRM trip setdown during operation at off-rated conditions. Under these conditions, ARTS plants like DNPS use power and flow dependent MCPR and LHGR values for operation at the off-rated conditions. Table 9-2 of the EPU submittal provided the changes in the CPR for the fast recirculation flow increase transient and confirmed that the ARTS multipliers used to develop the power dependent MCPR(P) are bounding. This is acceptable to the staff.

9.2 Transient Analysis for ARTS Power and Flow Dependent Limit

One of the restrictions on the operating flexibility of a BWR during power ascension from the low-power/low-core flow condition to the high-power/high-core flow condition is the APRM scram and flow-referenced rod block setdown requirements. The APRM/ rod block monitor TS (ARTS) power and flow dependent limits improvement program objectives are to provide adequate fuel thermal limits while increasing plant operating efficiency and flexibility. The licensee states that use of the ARTS power and flow dependent limits ensures that the plant does not exceed any fuel thermal limit, and, thus the margin of safety is not affected. The ARTS program utilizes the results of the AOO analyses to define initial condition operating thermal limits which conservatively ensure that all licensing criteria are satisfied without setdown of the flow-referenced APRM scram and rod block trips. The specific objective of the associated APRM changes is to justify replacement of the APRM trip setdown (gain and setpoint) requirement with the more meaningful ARTS power-dependent and flow-dependent thermal limits. The licensee states that this change reduces the need for manual setpoint adjustments and allows a more direct thermal limits administration, increases reliability, and provides more accurate protection of plant safety. The DNPS ARTS power and flow dependent program is essentially the same as the partial ARTS program previously implemented at the LaSalle County Station units (References 46 and 47).

The elimination of the APRM gain and setpoint requirement can affect fuel thermal-mechanical integrity. The acceptability requirements for this change are that:

- The SLMCPR shall not be violated as a result of any AOOs.
- All fuel thermal-mechanical design bases shall remain within the GE generic fuel licensing limits described in GESTAR-II (Reference 35).

The safety analyses used to evaluate and establish the OLMCPR, so that the SLMCPR is not violated and the fuel thermal-mechanical design bases are satisfied, are discussed in Section 9.2 of the SAR.

The ARTS-specific changes are as follows:

1. The requirement for setdown of the APRM scram and rod blocks is deleted.
2. New power-dependent MCPR adjustment factors, MCPR(P), are added.

3. New flow-dependent MCPR adjustment factors, MCPR(F), replace the K_F multiplier.

4. New power-dependent LHGR adjustment factors, LHGRFAC(P), are added.

5. New flow-dependent LHGR adjustment factors, LHGRFAC(F), are added.

6. The affected TSs and associated Bases are modified or deleted, as required.

As discussed in the subsections below, the ARTS limits are generally determined or confirmed using bounding DNPS-specific analyses, although it is stated that cycle-specific limits may be developed and used. This is acceptable to the staff.

9.2.1 Elimination of APRM Gain and Setpoint Requirement

The original ARTS development program included generic evaluations over a wide range of plant configurations, operating parameters, and power and flow conditions to generate a large database of limiting transients, which can also be applied to DNPS operation in the MELLLA power/flow map region. This generic database was used to develop a methodology for specifying the MCPR and LHGR plant OLs, which assures that margins to fuel safety limits are equal to or larger than those achieved with the APRM gain and setpoint requirements. These generic evaluations also determined the adequacy of power dependent limits developed for two power ranges:

- between rated power and the power level (bypass) where the reactor scrams on TSV closure or TCV fast closure is bypassed, and

- between bypass and 25 percent of the rated power.

The licensee stated that the generic power-dependent (and flow-dependent) MCPR and LHGR limits developed for use in the first power range were verified by DNPS-specific analyses of the limiting transients. Between bypass and 25 percent power, DNPS-specific analyses were performed to establish unique limits for the low power range. The licensee states that these DNPS-specific limits were developed with sufficient conservatism to cover future reloads of GE-14 fuel, using the GEXL-PLUS correlation form and the GEMINI analysis methods, although cycle-specific limits may be used in the future for any portion of the range. Based on the staff's review of the licensee's submittal and the staff's audit which confirmed that approved methodologies were used, the staff concludes that the licensee's evaluation is acceptable.

9.2.1.1 ARTS AOO Analysis Assumptions

To develop and verify the plant-specific, but cycle-independent, ARTS thermal limits, the AOO transient analyses were performed using the EPU thermal power of 2957 MWt and 108 percent rated core flow (ICF option), as shown on the licensee's SAR power flow map in Figure 2-1. The plant EPU conditions and system setpoints are summarized in Tables 1-2 and 5-1. The FWCF event is analyzed with a FW temperature of 256 °F at rated power (equivalent to a reduction of 100 °F). Based on the staff's review of the licensee's submittal and the staff's audit which confirmed that approved methodologies were used, the staff concludes that the licensee's evaluation is acceptable.

9.2.1.2 Power-Dependent MCPR Limit, MCPR(P)

From bypass to rated power, bounding power-dependent trend functions (K_P) are used as multipliers to the rated OL MCPR values to determine the MCPR(P) limits. The licensee states that the FWCF event is more limiting than the generator load reject without bypass as the initiating power is reduced. The DNPS-specific calculated values are compared with the generic limits in Table 9-3 of the licensee's SAR to verify the applicability of the generic limits. Based on the staff's review of the licensee's submittal and the staff's audit which confirmed that approved methodologies were used, the staff concludes that the licensee's evaluation is acceptable.

The licensee notes that the DNPS ARTS program is a partial application (like LaSalle's) in that DNPS is not implementing hardware changes to the RBM system, which would provide protection for an off-rated RWE. Instead, analyses of the off-rated RWE event with no rod block were performed to verify that the combination of the generic K(P) and the DNPS-specific MCPR(P) limits bound the SLMCPR limit requirement.

The licensee states that the idle recirculation loop startup (IRLS) was considered generically for ARTS and that the assumption of an initial 50 °F delta-T between loops is appropriate and consistent with the DNPS TS requirements.

Below bypass and above 25 percent power, bypass of the direct scram on closure of the TSV and TCV changes the characteristics of the FWCF and load reject without bypass (LRNBP) transient events. Both events were analyzed and the MCPR(P) limits are calculated as OLMCPR bounding values for both initial high-flow and low-flow conditions. The calculated and limiting values are shown in Table 9-4 and Figure 9-5 of the licensee's SAR.

9.2.1.3 Power-Dependent LHGR Limit, LHGRFAC(P)

Power-dependent LHGR limits are achieved by a LHGRFAC(P) multiplier derived from the generic database. The licensee states that, for GNF fuel designs, both incipient centerline melting of the fuel and the plastic strain of the cladding are considered. DNPS -specific transient analyses were performed to confirm the applicability of the generic LHGRFAC(P) limits above bypass, as shown in Table 9-5 of the licensee's SAR. Below bypass, both high and low core flow multipliers were calculated by DNPS-specific analyses to establish limits with sufficient margin to apply to future GE-14 reloads, as shown in Table 9-6 of the licensee's SAR. Figure 9-6 shows the bounding DNPS-specific power dependent LHGRFAC(P) multipliers for both power ranges and for both low and high initial core flow. Based on the staff's review of the licensee's submittal and the staff's audit which confirmed that approved methodologies were used, the staff concludes that the licensee's evaluation is acceptable.

9.2.1.4 Flow-Dependent MCPR Limit, MCPR(F)

The licensee states that the flow-dependent MCPR(F) limits ensure that the safety limit MCPR is not violated during recirculation flow increase transient events. The design basis event is a slow-flow increase which is not terminated by a scram, but which stabilizes at a new higher power corresponding to the maximum possible core flow. The generic flow dependent MCPR limits were verified by performing flow runout at a typical mid-cycle exposure plant condition (at constant xenon), along a rod line bounding the MELLLA power up to the maximum core flow runout at 108 percent core flow. The bounding generic and cycle-independent ARTS MCPR(F) limits are shown in Figure 9-7 of the licensee's SAR. Based on the staff's review of the licensee's submittal and the staff's audit which confirmed that approved methodologies were used, the staff concludes that the licensee's evaluation is acceptable.

9.2.1.5 Flow-Dependent LHGR Limit, LHGRFAC(F)

The licensee states that the flow-dependent LHGRFAC(F) limits assure that all fuel thermal-mechanical design bases are met for a slow recirculation flow runout event. The same generic transient analyses were statistically evaluated for the bounding overpower as a function of the initial and maximum core flow, to ensure that the peak transient LHGR would not exceed fuel mechanical limits. These bounding flow dependent limits, as shown in Figure 9-8 of the licensee's SAR, are generic, and cycle-independent. Based on the staff's review of the licensee's submittal and the staff's audit which confirmed that approved methodologies were used, the staff concludes that the licensee's evaluation is acceptable.

9.2.2 Overall Governing MCPR and LHGR Limits

The licensee states that for a given power/flow statepoint (P,F) all four limits (MCPR(P), LHGRFAC(P), MCPR(F), and LHGRFAC(F)) are determined and the most limiting MCPR (maximum value) and most limiting LHGR (minimum value) will be the governing limits. Note that the MCPR curves have to be adjusted if the assumed SLMCPR value of 1.09 (Table 9-1) is to be changed. Changing the TS SLMCPR would require a separate submittal. The staff evaluated the licensee's assessment and has concluded that the licensee's analysis is acceptable.

9.3 Design Basis Accidents

9.3.1 Background to Evaluation of Radiological Consequences of Design Basis Accidents

ELTR1 provides generic guidelines for justifying operation at up to 20 percent increased core thermal power. The guidelines for the performance of radiological evaluations are contained in Section 5.4 and Appendix H of ELTR1. Section 5.4 shows that the magnitude of the potential radiological consequences of a DBA is proportional to the quantity of fission products released to the environment. This release depends on the activity released from the core and the transport mechanisms between the core and the effluent release point. In general, the inventory of fission products in the fuel rods, the creation of radioactive materials outside of the fuel by irradiation, and the concentration of radioactive material in the reactor coolant system are directly proportional to the RTP. Thus, an increase in the RTP can be expected to increase the inventory of radioactive material that is available for release. The previously analyzed transport mechanisms could be affected by plant modifications associated with the power uprate, potentially resulting in a larger release rate. The ELTR1 states that the EPU application will provide justification that current radiological consequences are still bounding and within applicable criteria, or reanalysis of any areas adversely affected by the proposed uprate.

Appendix H of the ELTR1 describes the generic bases to be used in the generic radiological evaluations or in reanalysis of any areas adversely affected by the EPU. ELTR1 is based, in part, on two limitations: (1) the reactor core design undergoes only small modifications by the change in power, and (2) the core design is accomplished with fuel bundles of the same type. If there are significant changes to the fuel loading or design parameters, the EPU application will need to reassess changes to the isotopic concentrations in the fuel. Also, the impact of increased fuel enrichment and burnup would need to be addressed if these parameters exceed any of the requirements of 10 CFR 51.52(a).

Appendix H of the ELTR1 provides that existing calculations as shown in the current UFSAR are valid and that, with few exceptions, the postulated results are changed by the magnitude of the change in radiation source. The increased consequences can be resolved on a ratio-of-the-sources basis. Exceptions are associated with changes in radioactive material transport assumptions and methods caused by modifications to the plant pursuant to the uprate. The appendix provides that new calculations will be carried out only as necessary. There are some design basis events, such as a main steam line break, which release the radioactive materials in reactor coolant to the environment. Since the evaluations for these events utilize the reactor coolant concentrations established by the TS, the consequences of these events will not change unless the mass of coolant lost changes.

Section 2.8 of the NRC staff's position (Reference 4) on ELTR1 provided that the existing calculations found in the SAR should remain valid as a result of the EPU and that the doses will be increased by the magnitude of the change in the source term. The staff noted that the increased doses must meet the dose acceptance criteria in the plant's licensing basis and that the licensee must demonstrate assumptions and conditions stated in the ELTR1 are met. If these assumptions are not met, applicants will be expected to recalculate the affected radiological analyses.

ELTR2 presents specific evaluations of areas of licensing review that are generically applicable to some or all of the BWR product lines. Section 5.3.2.2.3 of ELTR2 addresses the EPU impact on radiological consequences of design basis accidents and provides information comparable in scope and detail to that provided in Section 5.4 and Appendix H of ELTR1.

9.3.2 Plant-Specific Evaluation

Section 9.3 in the licensee's safety analysis (Reference 2) addresses the impact of the EPU on the previously analyzed radiological consequences of DBAs for DNPS. This section is based on the guidelines in Section 5.4 of ELTR1. The plant-specific radiological assessments were evaluated at 102 percent of the proposed RTP, consistent with the guidance of RG 1.49, "Power Levels of Nuclear Power Plants."

<u>Development of Plant-Specific Scaling Factors</u>

The core fission product inventory used in performing the existing, pre-EPU radiological consequence analyses is based on the curies per megawatt-thermal (Ci/MWt) constants provided in TID-14844, "Calculation of Distance Factors for Power and Test Reactor Sites." This document, published in 1962, provides Ci/MWt values for several reactor fission products. These values are representative of the low burnup fuels considered at that time and the fission product generation and depletion analysis methodology then available. These inventories were dominated by fission product yields from uranium-235 (U-235) fission. During power operation, U-239 is produced by the irradiation of U-238, with the U-239 subsequently decaying to plutonium-239 (Pu-239), which is fissionable. At current high fuel burnup levels, the fission of Pu-239 contributes significantly to the fission product inventory in the core. Also, the fission product yields from Pu-239 differ from those for U-235, resulting in changes in the fission product composition. In order to address these impacts of the EPU, EGC had a recalculation performed of the core fission product inventory for GE-14 fuel and a 24-month fuel cycle using the industry-accepted ORIGEN2 code. This code utilizes updated fission product yields and decay chains and includes the fission product contributions of Pu-239 and other transuranic nuclides. In recalculating the fission product inventory, EGC has addressed the ELTR1 guidelines regarding the assessment of the impacts of the EPU and higher burnup fuel impact on radionuclide composition and inventory. The staff finds this approach acceptable.

The scaling factor used to correct the previously analyzed thyroid doses for the impact of the EPU is the ratio of the ORIGEN2 iodine inventories at the EPU power level to the previous TID-14844 iodine inventories at the pre-EPU power level, weighted for the iodine dose factors. Similarly, the scaling factor used to correct the previously analyzed whole body doses for the impact of the EPU is the ratio of the ORIGEN2 noble gas inventories at the EPU power level to the previous TID-14844 noble gas inventories at the pre-EPU power level, weighted for the whole body dose factors. The resulting scaling factors for the thyroid dose and the whole body dose due to the change in core inventory are 1.26 and 1.17, respectively.

Since the previous control room dose DBA LOCA analyses were performed using a fission product inventory based on the pre-EPU RTP without the 2 percent margin, EGC increased the scaling factors for the control room to 1.29 for thyroid and 1.19 for whole body for the DBA LOCA results only.

The staff finds the method used to determine the scaling factors to be appropriate and consistent with the staff-approved ELTR1 and ELTR2 and the conditions identified in the associated staff SER.

<u>Application of Scaling Factors to Pre-EPU Analyses</u>

EGC considered the plant-specific EPU impact on the following DBAs: LOCA, CRDA for offsite only, fuel-handling accident (FHA), main steam line break (MSLB) outside containment, instrument line break outside containment, and an offgas treatment system component failure. The results of these analyses are tabulated in the table below. For the LOCA, CRDA, and FHA, the EPU does impact the fission product inventory. Accordingly, the radiological consequences postulated in prior analyses were multiplied by the plant-specific scaling factors described above. For the LOCA and the FHA, there were no plant modifications that would impact the transport of radioactive material to the environment so no further adjustments or re-analyses were necessary. For the CRDA gland steam release path, the previous analysis did not consider melted fuel. For this reason, the doses for this accident release pathway increase by 30 percent for thyroid and 25 percent for whole body.

For the MSLB and the ILB accidents, the analyses assume that the reactor-coolant-specific activity is at the maximum value allowed by TS, expressed in terms of dose equivalent iodine-131. Therefore, these analyses are not affected by the EPU. The source term used in pre-EPU analyses for evaluating the offgas treatment system component failure was set conservatively and independently of the reactor thermal power. For the MSLB, offgas, and ILB accidents, the EPU does not affect transport assumptions used in the analyses. Specifically, EGC has proposed to operate at the same reactor dome pressure post-EPU as pre-EPU. While the post-EPU normal operational steam flow will be greater, the flow restrictors in the steam lines establish the maximum flow rate at which steam will flow during MSLB conditions.

The pre-EPU analyses were based on the maximum flow rate, which is unaffected by the EPU. As a result of these considerations, the EPU has no impact on previously analyzed consequences of the MSLB, ILB, and offgas treatment system component failure events.

DNPS RADIOLOGICAL ANALYSIS RESULTS,* REM

	0-2 hr EAB		30-day LPZ		30-day CR	
Event	Whole Body	Thyroid	Whole Body	Thyroid	Whole Body	Thyroid
Loss-of-Coolant Accident						
Pre-EPU	2.0	37.0	1.0	230.0	0.42	23.0
Post-EPU	2.3	46.0	1.2	290.0	0.51	29.6
Criterion	25.0	300.0	25.0	300.0	5.0	30.0
Control Rod Drop Accident						
Pre-EPU	0.71	11.4	0.076	0.83	<0.42	<23.0
Post-EPU	0.86	14.8	0.091	1.1	<0.51	<29.6
Criterion	6.25	75.0	6.25	75.0	5.0	30.0
Fuel-Handling Accident						
Pre-EPU	0.16	1.52	0.02	0.18	0.013	4.05
Post-EPU	0.18	1.92	0.024	0.23	0.015	5.1
Criterion	6.25	75.0	6.25	75.0	5.0	30.0

*Results Generated by EGC

Control Room Doses

As noted above, EGC evaluated the consequences of the EPU on control room habitability, using the scaling methodology presented in the staff-approved ELTR1 and ELTR2 topical reports for events other than the CRDA. The staff questioned omitting the CRDA. In its response of August 31, 2001, (Reference 27) EGC stated that the control room dose due to a CRDA would be bounded by that estimated for a DBA LOCA. In this response, EGC provided additional information supporting their conclusion that the LOCA would be limiting. EGC based this conclusion on calculations performed to establish alarm setpoints for the main steam line radiation monitor (MSLRM). The process safety limit for this setpoint was based upon the control room thyroid dose not exceeding 30 rem during a CRDA. In establishing the actual value of the alarm trip setpoint, EGC reduced the MSLRM setpoint to a small fraction of the process safety limit. The estimated thyroid dose to the control room personnel, prior to EPU, would be 16 rem, which is lower that the pre-EPU dose for the LOCA. Based on the information provided by EGC, the staff finds that the post-EPU control room doses following a CRDA would be bounded by those for the LOCA. EGC did state in their response that the control room dose due to a CRDA is not part of the DNPS licensing or design basis. In an August 7, 2001, teleconference, EGC clarified this statement to indicate that to date there are no control room doses for a CRDA reported in the licensing or design basis. EGC agreed, however, that their licensing basis does require them to demonstrate that the control room is habitable for all accidents as required by GDC-19. This position is consistent with Section 15.6.5.5.2 of the DNPS UFSAR and with licensee commitments pursuant to NUREG-0737 which were confirmed in an order issued on March 14, 1983.

The staff is currently evaluating, on a generic basis, deficiencies in the design, operation, and maintenance of control room habitability systems and is pursuing appropriate regulatory action. The staff expects to issue a GL and regulatory guidance on these issues in 2001. One of the primary deficiencies identified by the staff involves unsubstantiated assumptions at many plants regarding the amount of unfiltered in-leakage to the control room envelope during accident conditions. Due to the magnitude of the potential increases in post-EPU accidents, the staff reviewed the EGC submittal to determine whether there was reasonable assurance that the DNPS control room habitability systems could perform their design function to provide plant operators a habitable environment in which to take actions necessary to operate the plant in a safe manner.

The staff reviewed an earlier license amendment application dated May 19, 1997, for DNPS. In this application, the then-licensee, Commonwealth Edison, described the results of tracer gas testing of the unfiltered in-leakage and stated that the measured unfiltered in-leakage was less than leakage previously assumed in control room habitability analyses. The May 19, 1997, licensing action was retracted by Commonwealth Edison. For the EPU application, the staff requested that EGC provide additional information confirming that the in-leakage conclusion was still valid. In its response dated July 6, 2001 (Reference 17), EGC asserted that the in-leakage conclusion was still valid and described ongoing programs and surveillance tests that are intended to assure that any degradation in unfiltered control room in-leakage is identified and corrected. While the staff resolution of the control room habitability issue may generically require periodic boundary integrity retesting, the staff concludes that the earlier testing and the ongoing control program at DNPS provide reasonable assurance that the EPU will not have an adverse impact on control room habitability. The staff's acceptance of EGC's unfiltered in-leakage conclusions does not preclude any future generic regulatory actions that may become applicable to DNPS in this regard.

The staff reviewed the assumptions, inputs, and methods used by EGC to assess the radiological impacts of the proposed EPU at DNPS. In doing this review, the staff relied upon information placed on the docket by EGC, staff experience in doing similar reviews and, the staff-accepted ELTR1 and ELTR2 topical reports. The staff finds that EGC used analysis methods and assumptions consistent with the conservative guidance of ELTR1 and ELTR2. The staff compared the doses estimated by EGC to the applicable criteria. The staff finds, with reasonable assurance, that the licensee's estimates of the EAB, LPZ, and control room doses will continue to comply with 10 CFR Part 100 and 10 CFR 50, Appendix A, GDC-19, as clarified in NUREG-0800 Sections 6.4 and 15. Therefore, DNPS operation at the proposed EPU RTP is acceptable with regard to the radiological consequences of postulated design basis accidents.

9.4 Special Events

9.4.1 Anticipated Transient Without Scram (ATWS)

The ATWS is defined as an AOO with failure of the RPS system to initiate a reactor scram to terminate the event. The requirements for ATWS are specified in

10 CFR 50.62. The regulation requires BWR facilities to have the following mitigating features for an ATWS event:

1. a SLC system with the capability of injecting 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 insertion (ARI) system that is designed to perform its function in a reliable manner and that is independent from sensor output to the final actuation device

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

BWR performance during an ATWS is also compared using the criteria used in the development of the ATWS safety analyses described in NEDO-24222, "Assessment of BWR Mitigation of ATWS," Volume II (Reference 43). 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 202 °F (which is the limiting temperature selected to ensure that the LOCA analysis results remain bounding), 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 system will inject within a specified time to bring the reactor subcritical from the hot full-power condition and to maintain the reactor subcritical after the reactor has cooled to the cold-shutdown condition. In accordance with the GESTAR methodology, the licensee reanalyzes the ATWS event if changes to fuel type or significant plant modifications will affect the ATWS response.

The licensee stated that DNPS 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, 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) MSIV closure, (b) pressure regulator failure - open (PRFO), (c) LOOP, and (d) inadvertent opening of a relief valve (IORV). The licensee performed the ATWS analyses, as discussed in ELTR1, at the MELLLA/EPU operating condition to demonstrate that DNPS meets the ATWS acceptance criteria. To provide a benchmark for the plant response to limiting ATWS events at EPU conditions, the licensee also performed the ATWS analyses based on the current RTP.

Section 9.4.1 of the licensee's SAR lists 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 and that the plant's response to an ATWS event for EPU operation is, therefore, acceptable.

The analysis shows that the ATWS PCT for the current RTP is 1478 °F and that the EPU PCT is 1418 °F. The staff confirmed during the audit that the stated PCT values are correct and examined the bases for these values. The staff also found similar trends (pre-EPU PCTs higher than the EPU PCTs) for other licensee calculations. Since the ATWS analyses are based on NRC-approved methods and the licensee performed the ATWS analyses at the MELLLA/EPU conditions, the staff accepts the licensee evaluation.

As a result of the audit, the staff requested and received additional information from the licensee on the ATWS/SLC events that were analyzed at the EPU conditions.

The limiting events for each of the five ATWS acceptance criteria in Section 9.4.1 of the licensee's SAR are identified as the PRFO for Criteria 1,2, and 3, and the MSIVC for Criteria 4 and 5. The licensee confirmed that the operator response to an ATWS event is not being modified from that described in Section L.3.2, "Operator Actions," of ELTR1. The licensee confirmed that for all limiting ATWS events, the SLC system for DNPS, Unit 2 will be able to inject at the appropriate time without lifting the SLC bypass RV. The cycle-specific reload analysis for DNPS Unit 3 will confirm the SLC capability or will identify required system modifications. The licensee also confirmed that the SLC system meets the ATWS acceptance criteria for DNPS even if the operator requests SLC actuation before the time assumed in the analysis, and the RV lifts and remains open until the valve inlet pressure decreases to the valve reseat pressure. The licensee will verify the valve reseat pressure and the lack of valve chatter upon reseat at the next refueling outage for each unit. The licensee's response to the staff's questions was summarized in a letter dated November 02, 2001 (Reference 55).

Based on the review of the licensee submittal, the on-site audit of the application of approved methodologies, and the licensee response to the request for additional information including the commitments made, the staff finds the ATWS/SLC evaluations acceptable.

The staff concludes that DNPS meets the ATWS mitigating features stipulated in 10 CFR 50.62 and that the results of the ATWS analyses for EPU/MELLLA operation meet the ATWS acceptance criteria. If changes to fuel type or significant plant modifications will affect the ATWS response, reload analyses will confirm that the plant response to an ATWS event, based on the cycle-specific condition, will continue to meet the ATWS acceptance criteria. The effects of the EPU on operator response to ATWS is among the operator actions discussed in Section 10 of this SE.

9.4.2 Station Blackout (SBO)

The staff has reviewed information provided by the licensee to determine the impact of the power uprate on the existing analysis performed for SBO. The licensee stated that SBO evaluation was performed using the guidelines of Nuclear Management and Resources Council (NUMARC)-8700, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," except where RG 1.155 takes precedence. The licensee stated that the plant responses to and coping capabilities for an SBO event are not affected by operation at the EPU level, because the increase in decay heat for EPU is absorbed by the operation of the isolation condenser. There are no changes to the systems and equipment used to respond to an SBO, nor is the required coping time changed.

The initial conditions and assumptions for SBO under EPU conditions have been revised to be consistent with NUMARC 8700 and RG 1.155. The EPU decay heat analysis assumes an operating history of 100 days at the full uprated power conditions of 2957 MWt prior to the SBO event.

On April 6, 2001, the licensee provided the following additional information describing its evaluation of the EPU effect on the dominant areas of concern containing equipment necessary to mitigate the SBO event:

Drywell Temperature

The licensee stated that the RPV temperature and pressure remain the same and there are no significant changes in drywell heat sources. A slight (<17 °F) increase in FW temperature occurs post-EPU; however, the licensee determined that significant margin (calculated to be 74 °F in pre-EPU calculations) to the drywell design temperature would remain.

Suppression Pool Temperature

The licensee determined that the EPU has an insignificant impact, since the isolation condenser is the primary means of DHR. Slightly longer operation of the HPCI system to make up an additional 3500 gallons of reactor water is not significant.

Control Room Ventilation and Auxiliary Electric Equipment Room Ventilation

The licensee's pre-EPU calculations indicated that the peak 1-hour temperatures were acceptable. The heat loads in these areas are primarily related to indicating lights and other non-power-dependent electrical equipment and remain the same as before. Therefore, the pre-EPU evaluation remains valid.

Isolation Condenser Area

The licensee's pre-EPU calculations indicated that, with the boundary doors closed, the temperatures reached 167 °F after four hours. A qualified level transmitter was installed to assure monitoring of the isolation condenser level. The heat loads in this area are dominated by the temperature of the steam piping, which does not change post-EPU. The post-EPU isolation condenser room temperatures remain bounded by the pre-EPU analysis. Therefore, the pre-EPU evaluation remains valid.

HPCI Room Heatup

The licensee noted that the pre-EPU calculation for room temperature assumed continuous operation. Therefore, notwithstanding the slightly longer operating cycle for HPCI makeup described above, the results remain valid for post-EPU.

Condensate Storage Inventory

The higher decay heat for the EPU operation would increase the boiloff rate; therefore, the ability of the plant to maintain core coverage using the available inventory in the CST could be affected.

The staff has reviewed DNPS' ability to cope during a SBO and to ensure core cooling and coverage during the event. The staff accepts the licensee conclusion that the plant's SBO coping capabilities will not be adversely affected by EPU operation.

DC Battery Capacity

The licensee stated that pre-EPU battery cell sizing calculations for 24/48 volt, 125 volt and 250 volt batteries considered a 1-hour load profile with no load shedding, a battery cell electrolyte temperature of 65 °F, and recovery loads. The calculated margins for 24/48 volt and 125 volt batteries was 14 percent and for 250 volt batteries was at least 5-percent.

Under EPU conditions, HPCI will initiate about 45 seconds following the loss of ac power. The current battery calculation conservatively assumes HPCI initiates at the beginning of the event, resulting in a higher battery loading.

After initiation, HPCI operates for 1-cycle of low-low level to high level in the SBO scenario. The pre-EPU battery analysis evaluated a duration for this cycle of 222 seconds. The time for HPCI operation following EPU is slightly longer than pre-EPU value due to the increase in decay heat. A bounding value would be approximately 117 percent of this (i.e. 260 seconds). However, the longer period of HPCI operation under EPU is bounded by the margin in the current calculation for the 250 volt battery. The isolation condenser system is modeled to initiate at 15 seconds in the current battery calculation. This starting time also applies to the SBO scenario under EPU.

The licensee concluded that the pre-EPU battery calculations contain sufficient margin to bound the EPU case for SBO. The licensee stated (Reference 18) that calculated margins for 24/48 volt and 125 volt batteries will be reduced by less than 1 percent and for 250 volt batteries will remain above 5 percent for EPU conditions.

Based on the review of the licensee's rationale, the staff finds that the impact of plant operations at the proposed EPU on the systems and equipment used to cope with an SBO event is insignificant. The staff concludes that the plant will continue to meet the requirements of 10 CFR 50.63 for EPU conditions.

10.0 ADDITIONAL ASPECTS OF EXTENDED EPU

10.1 High-Energy Line Breaks

The licensee's plan to achieve the proposed higher power at the DNPS is to expand the operating envelope on the power/flow map through implementation of MELLLA. Operation at the EPU level does not require an increase in the reactor vessel dome pressure over the pre-EPU value to supply more steam to the turbine. Therefore, plant operations at the EPU level will have an insignificant impact (due to changes in the 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.

10.1.1 Temperature, Pressure, and Humidity Profiles Resulting from HELB

The licensee performed a HELB analysis for all systems (e.g., main steam system and FW system) evaluated in the UFSAR. The licensee stated that affected buildings and cubicles that support the safety-related functions are designed for the environmental conditions (i.e., pressure, temperature, and humidity profiles) due to plant operations at the proposed EPU level. The equipment and systems that support a safety-related function were evaluated and determined qualified for the environmental conditions.

Based on the review of the licensee's rationale, the staff concludes that the environmental conditions used to qualify equipment and systems that support a safety-related function remain bounding or the rooms and equipment have been appropriately evaluated for the EPU effects. The pressure, temperature, and humidity profiles resulting from a HELB outside the containment are acceptable for plant operations at the proposed EPU level.

10.1.1.1 Main Steam Line Break (MSLB)

The licensee stated that the critical parameter normally affecting the MSLB analysis relative to the 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 licensee letter dated August 7, 2001 (Reference 19), provided additional information regarding the effect of increasing the main steam isolation setpoint on high-energy line breaks (HELB). The MSLB was analyzed with a circumferential rupture, resulting in the flow restrictor choking flow and thus bounding other breaks. Credit was taken for isolation on high flow; however, the licensee noted that in the event of smaller breaks not resulting in high steam line flow isolation, low steam line pressure or high steam tunnel temperature isolation signals will function to isolate the HELB. These isolation signals are governed by the DNPS TSs.

Based on the review of the licensee's rationale and the experience gained from the staff's review of power uprate applications for similar BWR plants, the staff concludes 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 EPU level, the FW temperature, pressure, and flow rate increase slightly, resulting in an increase of 6 percent in the mass and energy release for a FW line break. The licensee performed an analysis for a FW line break in the steam tunnel. The licensee provided additional details of the FW line break analyses in its letter dated August 7, 2001 (Reference 19). The FW line break was analyzed with a concurrent main steam line break to establish a design basis for DNPS. For the effect of the EPU, the licensee ran benchmark calculations using both current and EPU conditions to evaluate the effects of the changes. The results were used to estimate that the peak pressure would remain lower than the design basis value of 27.5 psia used for main steam tunnel environmental parameters. The licensee also evaluated the long-term temperature profiles using the COMPARE code to calculate current and EPU temperatures. The results indicated that the temperature difference was insignificant and within the accuracy of the calculation. The licensee stated that design margins within the pre-EPU

HELB analysis for FW line break in the steam tunnel are conservative and remain bounded by the main steam line break with a concurrent FW line break.

Based on the review of the licensee's rationale, the staff concludes that the pressure and temperature profiles following a FW line break in the main steam tunnel have been adequately evaluated.

10.1.1.3 ECCS Line Breaks

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

Based on the review of the licensee's rationale and the experience gained from the staff's review of power uprate applications for similar BWR plants, the staff concludes that the previous analyses for these line breaks remain bounding for the EPU conditions.

10.1.1.4 Isolation Condenser Line Breaks

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

Based on the review of the licensee's rationale and the experience gained from the staff's review of power uprate applications for similar BWR plants, the staff concludes that the previous analyses for these line breaks remain bounding for the EPU conditions.

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. Conservative model assumptions were stated to more than offset the effect of the mass release increase, in all cases except for the RWCU heat exchanger room which resulted in small increases of 1.2 psi and 4 °F. The subcompartment pressure increase was evaluated and determined to be acceptable. Therefore, the previous HELB analysis regarding RWCU line breaks remains bounding or has been adequately evaluated for the EPU condition.

Based on the review of the licensee's rationale and the experience gained from the staff's review of power uprate applications for similar BWR plants, the staff concludes that the previous analysis for RWCU line breaks remains bounding or has been adequately evaluated for the EPU condition.

10.1.1.6 Instrument Line Breaks

The licensee evaluated the instrument line break analysis, which indicates that the blowdown rate remains the same and there is no pressure increase. Therefore, the previous HELB analysis regarding the instrument sensing line breaks remains bounding for the EPU condition.

Based on the review of the licensee's rationale and the experience gained from the staff's review of power uprate applications for similar BWR plants, the staff concludes that the previous analyses for the instrument sensing line breaks remain bounding for the EPU conditions.

10.1.1.7 Internal Flooding from HELB

The licensee stated that the analyses for flooding in the main steam tunnel assumes flooding of the entire below-grade volume. This assumption is conservative and bounding for the EPU conditions. In its August 7, 2001, response to the staff, the licensee addressed the effects of plant operations at the proposed EPU on the internal flooding for other systems outside the containment. The licensee stated that other HELBs in the turbine building; such as breaks in the FW and condensate systems, are bounded by the worst-case internal flooding from a postulated pipe break in the moderate-energy circulating water system inside the turbine building.

Based on the review of the licensee's rationale and the experience gained from the staff's review of power uprate applications for similar BWR plants, the staff concludes that the previous analyses regarding internal flooding remain bounding for the EPU conditions.

10.1.2 Moderate-Energy Line Break (MELB)

The licensee stated that a MELB analysis is based on system parameters not changed with the EPU. The circulating water system can accommodate the EPU heat load at the existing system flow rate; therefore changes are not planned. In response to the staff's RAI, the licensee addressed existing moderate-energy flooding analyses and features to protect safety-related equipment from flooding in the turbine building. At DNPS this includes the CC service water pumps, two of which are protected in watertight vaults. Existing active protective features for circulating water flooding include a trip of the circulating water pumps on high level in the condenser pit area; however, the ultimate consequence remains flooding of the building to the level of the river through gravity feed.

With regard to MELB for the proposed EPU conditions, the 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 postulated pipe break in the circulating water system inside the turbine building. The previous evaluations of internal flooding remain bounding for the proposed EPU as there is no change in the circulating water system. Therefore, the staff concludes that MELB is not a concern for DNPS operations at the proposed EPU conditions.

10.2 Equipment Qualifications

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 devices are located. The licensee applied the margins to the environmental parameters in accordance with the original qualification program and determined that no change is needed for EPU.

EPU is expected to increase both the normal and post-accident radiation conditions (integrated dose) in the plant by no more than the percentage increase in power level. However, the licensee performed EPU assessment in conjunction with the change to a 24-month fuel cycle. The increase in accident conditions resulting from combined effect of EPU and a 24-month fuel cycle is dependent, as a function of time, on the controlling radiation source (i.e., suppression pool water, drywell atmosphere, etc.) and the credited shielding. The increase in radiation levels reflects the use of current computer codes, methodology, and nuclear data in developing the uprated core inventory versus the methodology, computer tools, and nuclear data in the development of the original licensing basis core inventory. The increase reflects the inclusion of several hundred additional isotopes in the new core, as well as a 2 percent margin for instrument error recommended by RG 1.49. For purposes of equipment qualification, the maximum increase in the normal and accident radiation environment applicable to existing safety-related equipment is conservatively evaluated to be 20 and 40 percent, respectively.

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 resultant temperature, pressure, humidity, and radiation consequences and includes the environments expected to exist during normal plant operation. The maximum accident radiation levels used for qualification of equipment inside containment are from a DBA/LOCA. The review of the EPU conditions identified some equipment located within the containment that could be affected by the higher accident radiation level. However, the qualification of these equipments was resolved by refined radiation calculations or by the use of new test data. On April 6, 2001, the licensee stated that the drywell pressure and temperature conditions are impacted for EPU as follows.

- The present drywell peak pressure for qualification of 63 psia is bounding for the EPU condition.

- The present and EPU drywell temperature profiles are shown below.

Time (hours)	Present Temperature (°F)	EPU Temperature (°F)
0.01	334	338
0.5	334	338
0.57	287	303
0.8	282	288
61	165	183
588	128	146
8760	112	130

For all equipment inside the containment within the EQ program, evaluations were performed to demonstrate that existing environmental documentation was adequate to meet the revised temperature and pressure values due to EPU. Evaluations were done for each equipment type using the following approach.

1. The qualification test temperature conditions for the required operability period during the first 24 hours following a LOCA were shown to envelop the corresponding EPU temperature profile.

2. The qualification test temperature conditions for the required operability from beyond 24 hours to 1 year following a LOCA were shown to meet the revised EPU temperature profile using the Arrhenius methodology.

3. The maximum test pressure was shown to envelop the revised peak pressure for EPU.

The licensee concluded that EPU did not result in any changes to operating times for equipment required to operate following an accident.

The current EQ for equipment inside the containment is based on a normal relative humidity of 20 percent to 90 percent and an accident relative humidity of 100 percent. This is not changed for the EPU.

Additionally, operation at EPU conditions changes the radiation environments for certain plant areas in which electrical equipment is located. For the EQ equipment, revised radiation values were compared to the existing posted qualified test values. This comparison identified some equipment (electrical penetration assemblies and cables) where the EPU profile exceeded the current posted values. Material analysis and additional test report data for the electrical penetration assemblies were utilized to demonstrate qualification to the EPU values. A unique radiation dose analysis was performed to demonstrate qualification to the EPU values for cables.

In summary, the safety-related electrical equipment inside the primary containment is qualified to the new temperature and radiation profiles due to the EPU.

10.2.1.2 Outside Containment

Accident temperature, pressure, and humidity environments used for qualification of equipment outside containment result from main steam and FW line breaks in the steam tunnel, or other HELBs, whichever is limiting for each plant area. The accident temperature, pressure, and humidity conditions outside containment resulting from a LOCA inside containment may change with the power levels as a result of the increased suppression pool temperature. The licensee stated (Reference 9) that no changes to pressure or humidity environments result in areas outside containment for a LOCA inside containment. Changes for temperature environments outside containment for a LOCA inside containment are being determined and evaluated for effects on qualification of electrical equipment within the EQ program. Evaluations will be done to show that the existing environmental documentation is adequate to meet the revised temperature profile due to EPU. Evaluations will be done for each equipment type using the following approach.

1. Existing documentation will be used to show that the qualification test temperature profile envelops the revised peak temperature for EPU.

2. The qualification test will be shown to meet the revised post-LOCA conditions outside containment for EPU using the Arrhenius methodology.

The licensee stated (Reference 18) that the reviews of EQ equipment were performed and the equipment was shown to meet the revised environmental parameters following EPU. Qualification was shown by one or more of the following industry standard methods for EQ reviews:

1. Existing documentation was used to show that the current qualification test temperature profile and radiation dose bound the EPU conditions.

2. An additional test report was obtained for the equipment.

3. New test data on materials was used to demonstrate qualification.

4. The equipment was replaced with qualified equipment.

5. An equipment-unique radiation calculation was performed.

Most equipment was shown to be qualified for EPU conditions with little or no additional analysis, as identified in item 1 above.

The following is the EQ equipment installed outside primary containment which required more rigorous evaluation, using one or more of the methods defined in items 2 through 5 above, to qualify for the revised EPU environmental conditions.

Equipment	Qualification Parameter	Methodology Used to Qualify
Rosemount Pressure Transmitter	Radiation Exposure	Test data from additional test report
GE/MAC Flow Transmitter	Temperature Radiation Exposure	Not qualified. Items FT2(3)-1549A, FT2(3)-1549B, FT2(3)-1461A, and FT2(3)-1461B will be replaced with qualified equipment (Rosemount Pressure Transmitter 1153D)
Mobil DTE Oil	Temperature	Not qualified. The item will be replaced with a higher viscosity Mobil DTE oil.
Static-O-ring Switches	Radiation exposure	Material analysis
GE Switchgear components	Temperature Radiation Exposure	Additional test reports, qualification data from other EQ binders, and material analysis were used.
Circuit Breaker Systems Motor operated Control Switch	Radiation exposure	Used material analysis and qualification data obtained from other EQ binders.

In summary, the safety-related electrical equipment outside the primary containment is qualified or will be qualified to the new temperature and radiation profiles due to the EPU.

10.2.2 EQ of Mechanical Equipment With Nonmetallic Components

In its August 7, 2001, response to the staff, the licensee stated that the DNPS 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. The licensee stated that the changes in operating conditions, as well as normal and accident environmental conditions, have been determined for EPU. These changes are minor compared with the range of conditions allowed for mechanical components. The most severe change is an increased temperature of the torus water following a LOCA. As a result the licensee is changing the bearing oil for the CS and LPCI pumps which use process water for bearing cooling.

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

10.2.3 Mechanical Components Design Qualification

10.2.3.1 Equipment Seismic and Dynamic Qualification

The licensee evaluated equipment qualification for the power uprate condition. The dynamic loads such as RV discharge and LOCA loads (including pool swell, condensation oscillation, and chugging loads) that were used in the equipment design will remain unchanged as discussed in Section 4.1.2 of Reference 2. This is because the plant-specific hydrodynamic loads, which are based on the range of test conditions for the design-basis analysis at DNPS, are bounding for the power uprate condition.

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

1. The seismic loads are unaffected by the power uprate.

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 power uprate.

4. RV/SRV and LOCA dynamic loads used in the original design basis analyses are bounding for the power uprate.

10.2.3.1.1 Safety-Related Relief Valves

The licensee performed the overpressure protection analysis at the uprated power condition using the upper tolerance limits of the valve set points. The analysis calculated a peak RPV steam pressure of 1336 psig at the bottom of the vessel. This peak pressure remains below the ASME allowable of 1375 psig (110 percent of design pressure), and safety-related RV operability is not affected by the proposed power uprate. Furthermore, the maximum operation reactor dome pressure remains unchanged for the DNPS power uprate. Consequently, the licensee concluded that the RV setpoints and ALs are not affected by the proposed power uprate, and that the loads for the RV/SRV discharge line piping will remain unchanged. The staff concludes that the RVs and discharge piping will continue to maintain their structural integrity and to provide sufficient overpressure protection to accommodate the proposed power uprate.

10.2.3.1.2 Safety-Related Power-Operated Valves and Mechanical Components

As discussed in its original request and response to staff questions, the licensee evaluated the effect of the power uprate on the capability of plant mechanical systems, including safety-related pumps and valves, to perform their safety functions at DNPS. In addition to the review of safety-related pumps, SRVs, and other components for their adequate design for operation at the power uprate conditions, the licensee reviewed in more detail the safety-related air-operated valves (AOVs) in its AOV program, and the safety-related motor-operated valves (MOVs) within the scope of the program established in response to GL 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance.” The licensee evaluated the safety-related

AOVs and MOVs for process and ambient condition changes resulting from the power uprate, including parameters such as fluid flow, temperature, pressure, differential pressure, and ambient temperature. In a supplemental response (Reference 49), the licensee indicated that potential pressure locking and thermal binding of its safety-related power-operated gate valves had been evaluated in light of the proposed power uprate. The licensee determined that the power uprate conditions did not affect the scope of valves evaluated in response to GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves." The licensee also determined that the valves previously evaluated in response to GL 95-07 would not be adversely affected by potential pressure locking or thermal binding as a result of the proposed power uprate. The staff finds the licensee's evaluation of the effect of the proposed power uprate on the capability of safety-related pumps and valves at DNPS to be acceptable.

The licensee confirmed, in Reference 22, that the setpoints of the RVs installed on the penetration piping and the spring check valves contained in the relief bypass line are not affected by the proposed power uprate. The licensee also indicated that for other water-filled piping, the resulting stresses calculated at the proposed power uprate conditions were found to be within the allowable limit. Therefore, the licensee concluded that the proposed power uprate has no impact on the evaluation in response to GL 96-06 on potential overpressurization of isolated piping segments for DNPS. The staff concurs with the licensee's conclusion.

Based on the information provided by the licensee, the staff concludes that the proposed power uprate will not have an adverse effect on the performance of safety-related valves and mechanical components at DNPS.

10.3 Required Testing

10.3.1 Generic Test Guidelines for GE BWR EPU

Section 5.11.9 of ELTR1 (Reference 3), provides the general guidelines for power uprate testing.

- 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.

- 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 licensee's SAR (Reference 2), submitted with the licensee's application, provides additional information relative to power uprate testing.

10.3.2 Startup Test Plan

- The licensee will conduct limited startup testing at the time of implementation of power uprate. 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 tests will be similar to some of the original startup tests, described in Section 14.2.12.2 of the Dresden UFSAR. Testing will be conducted with established controls and procedures, which have been revised to reflect the uprated conditions.

- The tests consist essentially of steady state, baseline testing between 90 and 100 percent of the currently licensed power level. Several sets of data will be obtained between 100 and 117 percent current power with no greater than a 5 percent power increment between data sets. A final set of data at the maximum obtainable uprated 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.

The following power increase test plan is provided in Section 10.4 “Required Testing,” of the licensee’s SAR (Reference 2).

a. Surveillance testing will be performed on the instrumentation that requires re-calibration for the EPU in addition to the testing performed according to the plant TSs schedule.

b. Steady-state data will be taken at points from approximately 90 percent of previous rated thermal power up to the previous rated thermal power, so that system performance parameters can be projected for EPU before the previous power rating is exceeded.

c. Power increases beyond the previous rated thermal power will be made along an established flow control/rod line in increments of $\leq$ 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.

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

A summary report will be submitted after the completion of the EPU test program. A description of the test results, any corrective actions, and a brief discussion of why it was not necessary to repeat specific tests listed in Section 14.2.4.2 of the Dresden UFSAR will be included in the summary report.

With the exception stated below regarding large transient testing, the licensee’s test plan follows the guidelines of ELTR1 and the staff position regarding individual power uprate amendment requests (Reference 4).

10.3.3 Systems/Components With Revised Performance Requirements

The guidelines in Section 5.11.9 of ELTR1 specify that pre-operational 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 the Dresden original startup test specifications and previous GE BWR power uprate test programs. The licensee has identified performance tests for the following systems:

- Intermediate range neutron monitors – assure source range monitors (SRM) and average power range monitors (APRM) overlap
- Average power range monitors – calibration
- Pressure regulatory system – setpoint steps, failures, incremental regulation
- Feedwater control system – setpoint changes, incremental regulation
- Radiation measurements – survey
- Feedwater system – vibration
- Main steam system – vibration
- Steam separator/dryer – moisture carryover

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 extended power uprate.

10.3.4 Large Transient Tests

10.3.4.1 Discussion

To achieve the power uprate, the licensee made several major modifications to the plant. However, most of the major modifications were made to secondary plant systems such as the turbine, main generator, and FW heaters, and not to safety systems. The licensee identified (Reference 12) the major components important to the MSIV closure and generator load rejection tests as: MSIVs, TSVs, TCVs, turbine bypass valves, RVs, main steam line geometry, control rod insertion time, and associated scram signal electronic response. The staff evaluated these and electrical equipment changes.

The licensee’s power ascension test plan (Reference 12) includes hold points for testing and data collection at approximately 50 percent, 75 percent, 90 percent and 100 percent of the pre-EPU licensed power level. After reaching 100 percent of the pre-EPU licensed power level, the licensee will increase power in increments of $\leq$ 5 percent per day and hold for additional testing and data collection. Data collection will include chemical/radiochemical samples, radiation monitoring, APRM calibrations, core performance, FW flow element calibration check, main steam flow element calibration check, primary containment piping vibration, power conversion piping vibration, system/equipment performance data. In addition, the licensee will conduct tests and surveillances for pressure control incremental regulation, FW level control incremental regulation, FW pump runout, and steam dryer performance. The licensee will evaluate the power ascension data and project new values for the next power level. The licensee's power ascension test plan also includes testing of systems and components whose performance requirements have changed as a result of the EPU. Therefore, steady state plant response and system and component performance will be confirmed.

The proposed EPU results in approximately a 20 percent increase in steam and FW flow rates. It also results in a small operating pressure/temperature decrease at the turbine inlet. In addition, the proposed EPU results in increased loading of certain electrical equipment. The effects of these changes on the performance of the major components important to the MSIV closure and generator load reject transients were evaluated. The licensee proposed to not perform the MSIV closure and generator load rejection tests included in the NRC-approved topical report, ELTR1. These tests are similar to those conducted during initial plant startup. ELTR1 includes the MSIV closure test for power uprates greater than 10 percent above any previously recorded MSIV closure transient data; and the generator load rejection test for power uprates greater than 15 percent above any previously recorded generator load rejection transient data. The licensee provided the following reasons for not performing these tests: (1) operating history has shown that previous transients are within expected performance, (2) the power uprate transient analyses show that all safety criteria are met, and (3) these tests will not provide significant new information about plant response, therefore performing these tests will unnecessarily challenge safety systems. The licensee's conclusion is that these tests are not needed to demonstrate safety of its plants. In support of these arguments the licensee provided data (Reference 51) from a generator load transient at Liebstadt (i.e., KKL), a foreign plant that has implemented an EPU of 117 percent of original licensed power level; discussion of operating events at the Hatch plant, which implemented an EPU of 113 percent of original licensed power level; and plant-specific information for DNPS related to these tests.

10.3.4.2 Evaluation

In evaluating the licensee's request to not perform the two large transient tests included in the NRC-approved ELTR1, the staff considered (1) the licensee's justification as presented in its December 27, 2000, initial application for the amendment request (Reference 1) and letters dated May 18, 2001, and September 27, 2001 (References 12 and 51), which were provided in response to staff RAIs related to the two tests, (2) the information presented by the licensee to the Advisory Committee on Reactor Safeguards (ACRS) during the ACRS public meetings on October 25, and November 8, 2001, (3) the modifications made to the plant that are related to the two tests, (4) component and system level testing that will be performed either as part of the licensee's power ascension and test plan or to meet SRs contained in the DNPS TSs, and (5) past experience at other plants. The staff also considered the importance of the additional information that could be obtained from performing the two tests with respect to plant safety.

Large transient testing is normally performed on new plants because experience does not exist to confirm plant's operation and response to events. However, these tests are not normally performed for plant modifications following initial startup because of well established quality assurance programs, maintenance programs including component and system level post modification testing, and extensive experience with general behavior of the equipment not modified. When major modifications are made to the plant, large transient testing can be performed to confirm that the modifications were correctly implemented. However, such testing should only be imposed if it is deemed necessary to demonstrate safe operation of the plant. The determination for the need of such testing considers the extent of modification being made to the equipment, the expected impact of the modifications on performance of the equipment, other testing being performed, and past experience. The components, parameters of interest, and summary evaluations of the effect of the EPU on the parameters of interest are provided in the table below:

COMPONENT	PARAMETER OF INTEREST	SUMMARY EVALUATION
MSIVs	Minimum Closure Time	These valves are required to maintain the minimum closure time under much higher steam line break flows. The higher flow rate in the steam line assists in valve closure, which can lead to a faster closure time. TS SR 3.6.1.3.6 requires the licensee to verify that the isolation time of each MSIV is ≥ 3 seconds and ≤ 5 seconds. This SR is done by test in accordance with the licensee's inservice testing program and ensures that valve closure time is consistent with analyses assumptions.
Main Steam Line Geometry	Length and Volume	Acoustic phenomena will increase as a result of the increased steam flow. The change is included in transient and dynamic loads analyses using approved codes.
Control Rod Insertion for Scram	Maximum Delay and Rod Insertion Time	Steam dome pressure is unchanged. Therefore, control rod insertion times are not affected. In addition, scram times are included in TS 3.1.4 and are required to be verified per the associated SRs.
Relief and Safety/Relief Valves	Opening Delay and Time to Establish Full Flow	Licensing safety analyses show that, for EPU conditions, additional valves will open during pressurization transients. However, the opening delay and time to establish full flow for individual valves are not affected by EPU conditions.

COMPONENT	PARAMETER OF INTEREST	SUMMARY EVALUATION
TSVs/TCVs	Minimum Closure Time	EPU operation results in a slight change in full power operating position of TCVs and slight increase in effective closure time. This effect is included in analyses and is negligible. The TCV and TSV stroking rate will not be affected because these valves are controlled by a servo-controlled hydraulic system designed for valves-wide-open flow.
Scram Signals on MSIV Closure and Turbine-Generator Trip	Maximum Time Signal is Passed to Reactor Protection and Control Rod Drive Systems	Electronic system response is not affected by the EPU. Verification of response time of RPS instrumentation, including those associated with MSIV closure and turbine-generator trip is required by the SRs for TS 3.3.1.1.
Turbine Bypass Valves	Opening Delay and Stroke Time	Turbine bypass opening response is not affected by the EPU because there is no change to the system or the operating conditions. The percent of licensed power capacity of the turbine bypass system is reduced proportional to the increase in power level, however system design is not modified. In addition, turbine bypass system response time testing is required by TS SR 3.7.7.3.
Main Generator, Isophase Bus	Response to Trip	This equipment is fully loaded at power not during plant transient.
Non-Class 1E Switchgear	Breaker Rating	This equipment is individually tested for short circuit current. The tests included in ELTR1 do not include such a testing.
Unit Aux. Transformer (UAT) and Reserve Aux. Transformer (RAT)	RAT at Full Load	No changes were made to existing equipment; however, additional non-safety loads were added. Plant procedures adequately address operator action.

The table shows that changes in the parameters of interest for the identified mechanical equipment important to the MSIV closure and generator load rejection transients are either negligible, covered by other tests, or adequately covered in the models used in the analyses. In addition, with regard to the effect of the EPU on the loading (i.e., stresses) on the piping systems and in-line components, the staff, consistent with the ASME Code, allows such components to be designed using either analysis or testing. The staff has assessed the potential benefits and information to be obtained and has determined that the analyses performed by the licensee are adequate and sufficient and large transient testing would not provide significant additional insights regarding the staff's analysis. The staff notes that the large transient tests would not challenge instrumentation set points modified for the EPU or provide additional information to demonstrate the adequacy of major electrical equipment changed as a result of this EPU. Most of this latter equipment experiences higher load during operation at the EPU power level or during other scenarios not encountered during the two large transient tests in ELTR1.

The licensee provided (Reference 12) additional information related to the ability of the NRC approved ODYN transient code to model the DNPS response to these events following EPU, past power uprate experience at other plants (domestic and foreign), and the risk associated with performing the two tests. Reference 12 also included a summary of the DNPS power ascension and test plan, which includes tests such as pressure control incremental regulation, FW level control incremental regulation, FW pump runout data collection, and steam dryer performance. In addition, the licensee provided a summary of its evaluation of the effects of the proposed EPU on major components important to the MSIV closure and generator load rejection tests. These components included the MSIVs, the main steam piping, scram signals, safety/relief valves, and the turbine valves. The licensee's evaluation concluded that the effects of the EPU do not warrant the performance of these tests.

In Reference 51 and during presentations to the ACRS in public meeting on October 25, 2001, and November 8, 2001, the licensee provided additional information to justify its request. In summary, the licensee indicated that the DNPS safety analyses were performed using the NRC-approved ODYN Code, which has been benchmarked against BWR test data and incorporates industry experience. The licensee further indicated that the DNPS analyses were performed using post-EPU plant-specific inputs to predict integrated plant response. The licensee concluded that ODYN simulations show that no significant changes will occur as a result of the EPU. The licensee added that experience with power uprates has shown that the response of uprated plants to tests and events are within expected code predictions. In addition, the licensee stated that GE has concluded that these tests are no longer necessary for power uprates that do not involve a change in reactor steam dome pressure.

The NRC staff does not consider the information that could be obtained from the large transient tests included in ELTR1 to be necessary for validation of analytical codes for transient analyses. The basis for this conclusion is that these codes have been validated using test data obtained from numerous test facilities and operational experience in operating BWRs at power levels in excess of those proposed for the DNPS EPU. Therefore, additional large transient testing is unnecessary for purposes of validation of analytical codes.

10.3.4.3 Summary

The results of the tests under consideration are not directly comparable to the results of safety analyses used for licensing plants or granting amendments. In performing safety analyses, licensees use bounding assumptions such as assuming the failure of the most limiting component (i.e., single failure). In addition, when performing licensing analyses, licensees do not rely on non-safety related equipment or anticipatory trips for mitigation. In performing the tests under consideration, the licensee would not be expected to disable the limiting component, non-safety equipment, or anticipatory trips to mimic the safety analysis cases. Therefore, the results of the tests would be much less limiting than those of the safety analyses.

Furthermore, because of the availability of the additional equipment (e.g., non-safety related equipment and anticipatory trips), the test cases would be significantly different scenarios (i.e., follow different success paths) from the corresponding safety analyses. Therefore, successful large transient testing in accordance with ELTR1 would not necessarily confirm the adequacy of the safety analyses.

The staff considered the importance of the information that could be gained from the transient tests discussed above in light of experience to date with EPUs at other BWR plants including KKL and Hatch. Equipment modifications made to these plants in order to achieve the higher power levels are similar to those made for DNPS. Although the designs of these plants are not identical to DNPS, the staff considers the experience with EPUs at these plants useful because it provides a measure of how well GE can predict the impact of the power uprate and hardware modifications on equipment response during events. The staff received information from the licensee regarding startup testing performed at KKL including a generator load rejection test. The staff reviewed the information provided and finds that no significant anomalies related to plant safety were identified by the tests.

Tests were not performed at the Hatch plant following that plant's EPU, which increased its licensed power level to 113 percent of the original licensed power level. However, after approval of the Hatch EPU, Hatch Unit 2 experienced an unplanned event that resulted in a generator load rejection in May of 1999. The transient occurred at 98.3 percent of the plant's post-EPU licensed power level or approximately 111 percent of the original licensed power level. This event was reported to the NRC in Licensee Event Report 1999-005. In addition, Hatch Unit 1 experienced a turbine trip event and a generator load reject event from 100 percent of the EPU power level in July 2000 and March 2001. These events were reported to the NRC in Licensee Event Reports 2000-004 and 2001-002. No significant anomalies as a result of the Hatch EPU were identified by these events.

10.3.4.4 Conclusion

Based on the staff's evaluation of the information provided by the licensee in support of its proposal to not perform the MSIV closure and generator load rejection tests, the staff finds that the licensee's plan to perform numerous component, system, and other testing in combination with the evaluation of the systems and components discussed above, are sufficient to satisfactorily demonstrate successful plant modifications and overall equipment operability. The staff finds that information obtained from the MSIV closure and generator load rejection tests could be useful to confirm plant performance, adjust plant control systems, and enhance training material. However, the staff does not consider the benefits to be sufficient to justify the challenges to the plant and its equipment; the potential risk, although small, associated with performing these tests (i.e., the risk due to potential random equipment failures during the test); and the additional burden that would be imposed on the licensee. The staff has concluded that these two large tests do not provide a significant safety benefit in confirming the adequacy of the staff's analysis and evaluation. Therefore, the staff finds the licensee's proposal not to conduct these tests acceptable.

10.3.5 Required Testing Conclusion

The guidelines of NEDC-32424P-A (Reference 3) have been accepted by the NRC as the generic review basis for extended power uprate amendments requests. The staff finds that there is reasonable assurance the applicant's power uprate testing program is consistent with the requirements of 10 CFR 50, Appendix B, and NRC-approved topical report NEDC-32424P-A, Section 5.11.9, for an extended power uprate, except for the recommended large transient testing.

10.4 Risk Implications

To evaluate the impact on risk at DNPS from the proposed EPU, the licensee assessed its plant-specific probabilistic risk assessment (PRA). The results of the assessment were reported in the licensee's EPU SAR (Reference 2), which was provided to the staff for review as Attachment E to the licensee's EPU license amendment request (Reference 1). The assessment was further described and explained in supplemental information and responses to the NRC staff (References 8, 25, 32, 48, 49, 53, and 57). In addition, in July 2001, the NRC staff reviewed the DNPS PRA maintenance and update procedures and processes to support its review of the licensee's proposed EPU.

The NRC SER on the DNPS individual plant examination (IPE) was issued in October 1997 and concluded that the licensee had met the intent of GL 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities." The licensee has significantly upgraded the DNPS PRA models since the staff review relative to GL 88-20 and has used the latest PRA models to support a license application for establishing a risk-informed inservice inspection program. The DNPS PRA has been through two peer reviews as part of the BWR Owners Group PRA certification process. The first peer review, which was performed in January 1998, resulted in a major upgrade of the PRA models. The second peer review, which was performed in November 2000, concluded that the DNPS PRA was adequate to support regulatory applications, when combined with deterministic insights.

The current, pre-uprate plant CDF for internal events is about 2.6E-6/year and the large early release frequency (LERF) is about 1.4E-6/year. Under EPU conditions, the licensee estimated that the CDF increases by 2.1E-7/year to an EPU CDF of about 2.8E-6/year. Likewise, under EPU conditions, the licensee estimated that the LERF increases by 1.4E-7/year to an EPU LERF of about 1.6E-6/year.

The NRC SE on the DNPS IPEEE was issued in September 2001 and concludes, based on the staff's screening review, that the licensee's process is capable of identifying the most likely severe accidents and severe accident vulnerabilities and that DNPS has therefore met the intent of Supplement 4 to GL 88-20.

For the IPEEE seismic analysis, DNPS is categorized as a 0.3g focused-scope plant per NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities." The licensee performed the DNPS seismic evaluation using the Electric Power Research Institute (EPRI) seismic margins assessment (SMA) methodology described in EPRI NP-6041-SL, "A Methodology for Assessment of Nuclear Power Plant Seismic Margin." Therefore, the licensee did not quantify a seismic CDF. However, the licensee states in its supplemental information for the EPU license amendment that the conclusions and results of the SMA were judged to be unaffected by the EPU.

The NRC SE on the DNPS IPEEE indicates that the licensee had implemented a number of improvements during the resolution of unresolved safety issue (USI) A-46, "Verification of Seismic Adequacy of Equipment in Operating Plants," and that a number of additional improvements were still under consideration. In particular, the SE states that the licensee was developing a concept for providing a seismically-qualified/verified make-up path to each unit's isolation condenser and that this design change would be implemented in conjunction with the approved schedule for resolution of the USI A-46 outliers. The DNPS IPEEE SMA took credit for this modification for the scenario in which the dam fails during a seismic event, but the modification has not been implemented at this time.

For the IPEEE fire analysis, the licensee performed a fire PRA, based on the EPRI fire-induced vulnerability evaluation (FIVE) methodology, as described in EPRI technical report TR-100370, and the EPRI fire PRA implementation guide (FPRAIG), as described in EPRI technical report TR-105928. The licensee estimated the contribution to CDF from fires as about 1.7E-5/year for Unit 2 and 3.0E-5/year for Unit 3. Under EPU conditions, the licensee states that the effects of fires on the base CDF are negligible.

For the IPEEE evaluation of high winds, floods, and other external events (HFO), the licensee used the progressive screening approach consistent with the guidance of NUREG-1407. The licensee did not quantitatively estimate the CDF contribution from HFO events since these events were screened out using the licensee's progressive screening approach. Therefore, under EPU conditions, the licensee states that there are no impacts on these other external events.

The license amendment application was submitted in accordance with the guidelines contained in the NRC-approved GE LTRs for EPU safety analyses, ELTR1 and ELTR2 (References 3 and 5). Consistent with ELTR1, the licensee provided in the original submittal and in a subsequent supplemental submittal the results of its plant-specific evaluation of the risks associated with the proposed EPU. The staff reviewed this risk information, as amplified by licensee responses to staff requests for additional 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." The staff notes, however, that this was not a risk-informed application in accordance with RG 1.174. The 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 staff's evaluation did not involve an in-depth review of the licensee's PRA. This evaluation included a review of the licensee's discussions of EPU impacts on CDF and LERF due to internal events, external events, and shutdown operations. The evaluation also addressed the quality of the DNPS PRA, commensurate with its use in the licensee's and staff's decision-making processes. In addition, in July 2001, the staff reviewed the DNPS PRA maintenance and update procedures and processes to support its review of the licensee's proposed EPU.

10.4.1 Internal Events

The licensee evaluated the changes due to EPU implementation for potential 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 impacts on CDF and LERF from internal events for the EPU.

10.4.1.1 Initiating Event Frequency

The licensee identified that the principal change that affects the Level 1 CDF due to initiating events is the potential increase in the frequency of turbine trips. This effect is the result of running the installed spare FW and condensate/booster pumps at EPU conditions. The licensee made the conservative assumption that the loss of any single FW or condensate/booster pump would lead to a reactor low-water-level scram signal. The increase in turbine trip initiating event frequency was determined by evaluating plant-specific data over a seven-year period to identify how many FW and condensate/booster pump trips had occurred that did not result in scrams under the current conditions that would have resulted in scrams under the EPU conditions, without crediting any plant modifications that would reduce the potential for these scrams. Three potentially additional turbine trips were identified over this seven-year period, which results in an increase of about 0.43/year/2 units, or about 0.21 additional turbine trips per year at each unit. Therefore, the turbine trip initiating event frequency was increased to reflect the effect of having to run the installed spare FW and condensate/booster pumps, which increased the turbine trip initiating event frequency from its current value of 1.14/year to the EPU value of 1.35/year. This increase in initiating event frequency is stated by the licensee to result in about a 2.5 percent increase in the base CDF, which is primarily due to anticipated transients without scram (ATWS) sequences.

The licensee, in parallel with the EPU, is performing a plant modification that will initiate a reactor recirculation pump runback on a loss of a single FW or condensate/booster pump in combination with a reactor low level alarm. This modification is expected to prevent reaching the reactor low level scram setpoint for the evaluated EPU conditions. The modification will reduce the trip frequency for EPU conditions by avoiding the “new” scrams, as identified above, that would occur as a result of having to run the installed spare FW and condensate/booster pumps if this modification were not implemented.

However, there is also the potential for introducing additional scrams if the reactor recirculation pump runback control circuitry spuriously actuates. The licensee stated that the reactor recirculation pump runback is designed with an “energize to actuate” logic to reduce the possibility of spuriously causing a RPV water level transient, which would challenge the FW control system. The licensee estimated this spurious runback scram, which must also involve a failure of the FW control system to maintain the RPV level below the high-level scram setpoint (i.e., it fails to match the FW flow with the reduced recirculation flow in sufficient time), to have a frequency of about 1E-4/year. This is more than two orders of magnitude less than the scram reduction that is expected to be achieved by installing the runback circuit.

The staff finds that it is reasonable to conclude that, other than the loss of FW-induced turbine trip, the initiating event frequencies will not change, as long as the operating ranges or limits of equipment are not exceeded. Further, the staff finds that it is reasonable to expect the EPU modeled effects to be conservative since they do not take credit for the plant modification to initiate a reactor recirculation pump runback on the loss of a single FW or condensate/booster pump. However, since the models were developed prior to the completion of the design of the actual runback control circuitry, the staff believes that the licensee should develop and incorporate into the PRA the model that represents the actual designed and installed reactor recirculation pump runback circuitry as part of their PRA model update. The staff believes this update should be performed prior to operating under EPU conditions so that the PRA model, and the associated tools that rely on these models, reflects the as-built, as-operated plant.

Including this plant modification in the PRA model should provide confirmation that the actual designed and installed reactor recirculation pump runback control circuitry is as reliable as was modeled for the EPU license application and is bounded by the modeled turbine trip initiating event frequency, including the consideration of the potential effects and frequency of spurious actuations of this circuitry and, thus, ensure that the impacts on CDF and LERF are still within the RG 1.174 acceptance guidelines.

In addition, as discussed further in Section 10.4.1.2, there is potentially a new means of inducing a LOOP initiating event under EPU conditions. Under specific EPU conditions, there is the potential for overloading the unit auxiliary transformer (UAT) or the reserve auxiliary transformer (RAT). During normal operation the station's auxiliary loads are split between the UAT and the RAT, with each transformer handling the loads for two non-essential 4160V buses. However, if either the UAT or the RAT becomes unavailable during normal operations without a reactor scram, the increased loads for the EPU configuration may result in an overduty condition for the remaining transformer. Thus, the operation of three FW pumps under EPU conditions introduces a potential overduty condition when all the loads are fed through a single source (i.e., either the UAT or the RAT) until the loads are manually shed by the operators. Due to the overduty condition on the remaining transformer, the current plant configuration may not be acceptable under EPU conditions if allowed to exist for an extended period of time without operator actions to mitigate the effects of such an event and may also create a new means of inducing a LOOP initiating event at DNPS that has not been previously analyzed by the licensee. This condition is potentially significant because the currently designed fast transfer feature that responds to a failure of one transformer may actually create a LOOP condition by overloading the remaining transformer. This potential overduty condition on the transformers is the synergistic effect of having to operate the installed spare FW and condensate/booster pumps at EPU levels.

Further, the staff finds that, without operator actions to manually shed loads within a set period of time, the ability of a single transformer to carry the entire plant loads under EPU conditions may not be adequate if allowed to exist for an extended period of time and may create a LOOP initiating event. The licensee has performed a simplified calculation, using generic equipment failure rate information and a screening operator action human error probability (HEP), to show that this new means of inducing a LOOP has a very small impact on CDF, approximately increasing the base CDF by 6E-9/year.

The RAT can also become overloaded following a LOCA with all condensate pumps running because the UAT will deenergize upon the unit trip due to the LOCA and all its loads will transfer to the RAT. Upon the startup of the ECCS pumps, an undervoltage could occur on the 4160V buses causing the FW and condensate pumps to trip. Since the offsite power can still be manually restored to the 4160V buses in this condition, the scenario is bounded by the occurrence of a LOCA coincident with a LOOP. The licensee has designed a plant modification to trip condensate/booster pump D in the event of a LOCA to prevent the overload condition from occurring. The licensee has performed a simplified calculation considering the potential failure to trip condensate/booster pump D following a LOCA and assuming that the overload condition would result in a LOOP. The calculation indicates that this results in a negligibly small impact on CDF; increasing the base CDF by about 1.7E-10/year. In addition, the licensee calculated the potential increase in turbine trip initiating event frequency due to a spurious actuation of the condensate/booster pump D LOCA trip signal, which takes credit for the operation of the recirculation pump runback feature previously described. The results of this calculation indicate that the turbine trip initiating event frequency would increase by about 2E-6/year, which is a negligibly small contributor, given the current initiating event frequency of 1.14/year.

The staff has reviewed the licensee's evaluation of grid stability and related electrical equipment (e.g., transformers) and determined that they are acceptable for EPU. This evaluation included the determination that the UAT and RAT will operate acceptably for EPU in the single transformer operation mode. Therefore, even though these transformers may be operated beyond their current ratings for EPU, the staff has determined that this condition is acceptable and will not appreciably degrade the performance of the transformers. The staff's evaluation is provided in Section 6.1.2.

Similar to the reactor recirculation pump runback circuitry discussed above, since the simplified models and calculations used by the licensee to evaluate this condition were developed prior to the completion of the plant modifications, the staff believes that the licensee should develop and incorporate into the PRA the model that represents the actual installed and implemented plant modifications and proceduralized operator actions as part of the PRA model update. The staff believes that it would have been beneficial to have updated the PRA model prior to operating under EPU conditions so that the PRA model, and the associated tools that rely on these models, reflect the as-built, as-operated plant. Including the plant modification and procedural considerations in the PRA model should provide confirmation that the actual installed and implemented plant modifications and operator actions are as reliable as was considered for the EPU license application and thus, ensure that the impacts on CDF and LERF are still within the RG 1.174 acceptance guidelines.

The licensee's risk evaluation was not based on a detailed model of the actual installed plant modifications and proceduralized operator actions. However, given that the estimated impacts are very small (i.e., a few percent increase in risk), the staff believes that these issues would not significantly alter the overall results (i.e., not raise the change in risk values above the RG 1.174 acceptance guidelines) and thus would not rebut the presumption of adequate protection or warrant denial of the license amendment.

10.4.1.2 Component Reliability

Some of the licensee's evaluations (e.g.,of grid stability and SBO) at EPU conditions as part of the license application identified potential impacts on various components. However, the majority of these components were either shown by analyses to be acceptable under the EPU conditions or were replaced with components qualified for the EPU conditions.

These evaluations did identify a potential for overloading the UAT and the RAT under specific EPU conditions. Though the onsite distribution ratings for safety-related equipment are unchanged for EPU, the operation on a single transformer exceeds the non-safety-related 4160V switchgear short circuit rating. During normal operation the station's auxiliary loads are split between the UAT and the RAT. In the split bus configuration, the current carrying and interrupting capability of the switchgear is maintained within the switchgear rating. The operation of three FW pumps under EPU conditions introduces a potential overduty condition (i.e., excessive short circuit current) on the switchgear when all the loads are fed from a single source (i.e., either the UAT or the RAT). This would occur when either the UAT or RAT is unexpectedly lost during normal operations, which would result in a transfer of loads to the remaining transformer. In that situation, if a three-phase bolted short occurred, the design momentary rating of the switchgear could be exceeded. In addition, under these conditions, the remaining transformer is in an overduty condition, as described above in Section 10.4.1.1, until loads are manually shed by the operators. The RAT can also be in an overduty condition following a LOCA, as previously described in Section 10.4.1.1.

Since the interrupting and momentary rating requirements under EPU conditions are higher than the breaker and switchgear rating, the breaker and switchgear were tested to higher values. The tests indicate that the breaker will interrupt at the higher value but, to meet the momentary current requirements, changes to the bracing or connecting points are needed. The licensee stated that a confirmatory momentary test was planned following the identified modifications. The licensee also indicated that, after successful tests, the bracing in the field would be modified accordingly. The licensee has indicated that they have subsequently performed a successful test of the switchgear and breaker with the modified bracing to demonstrate that they meet the EPU momentary current requirements. Given that the modifications required to achieve a successful test are implemented in the field, it is expected that the reliability of the switchgear and breakers will not differ from the current, pre-uprate plant condition.

The licensee also identified that the probability of having a stuck-open relief valve (SORV) was increased due to the predicted increased number of valve cycles following postulated transients. The increased number of valve cycles is due to the increase in decay heat at EPU conditions. The licensee evaluated this increase in probability and determined that it had a very minor impact on the base CDF, less than 1 percent increase in CDF.

The staff finds that it is reasonable to conclude that equipment reliability will not change, as long as the operating ranges or limits of the equipment are not exceeded. For equipment that is operated within its operating ranges or limits, the staff expects that the licensee’s equipment monitoring programs (e.g., Maintenance Rule program) will detect any significant degradation in equipment performance and the staff expects these programs to maintain the current reliability of the equipment.

For the UAT and RAT and their associated switchgear and breakers, which may be loaded beyond their current ratings, when the appropriate bracing modifications are implemented in the field, the staff finds it reasonable to expect their reliability to be at the same level as for the current, pre-uprate plant condition. However, without the implementation of the appropriate field modifications, there is no direct evidence that the equipment will be as reliable as assumed in the licensee’s PRA under the described overduty conditions.

The staff has reviewed the licensee’s evaluation of grid stability and related electrical equipment (e.g., transformers) and determined that they are acceptable for EPU. This evaluation included the determination that the UAT and RAT will operate acceptably for EPU in the single transformer operation mode. Therefore, even though these transformers may be operated beyond their current ratings for EPU, the staff has determined that this condition is acceptable and will not appreciably degrade the performance of the transformers. The staff’s evaluation is provided in Section 6.1.2.

The licensee has not provided confirmatory responses regarding switchgear and breaker confirmatory tests and resulting field modifications to ensure these components will operate as reliably as assumed under EPU conditions. However, given that the estimated impacts are very small (i.e., less than 1 percent increase in CDF) and the licensee has committed to perform the field modifications to the switchgear and breakers, as appropriate, the staff believes that this issue would not significantly alter the overall results (i.e., not raise the change in risk values above the RG 1.174 acceptance guidelines) and thus would not rebut the presumption of adequate protection or warrant denial of the license amendment.

10.4.1.3 Success Criteria

The licensee has used the industry-recognized thermal-hydraulic code Modular Accident Analysis Package (MAAP), Version 3.0B, to support the PRA for performing best-estimate calculations. This industry-recognized thermal-hydraulic code has been used to evaluate design basis and beyond-design-basis accidents and was used for the EPU license application to calculate changes in the plant's thermal-hydraulic profile for specific issues, such as boildown time. The boildown time decreases as a result of increasing the power level to 2957 MWt.

The thermal-hydraulic analysis was performed using a value of 2898 MWt, which equates to the desired heat output of 912 MWe. This value comes from the heat balance developed for the EPU conditions. The licensee stated that, for the EPU configuration, the plant will normally be operated at 2898 MWt to achieve the desired output of 912 MWe, though during certain periods of the year, the plant may operate up to the proposed licensed power uprate level of 2957 MWt. Therefore, to reflect the typical plant conditions, the MAAP code runs that were performed to support the EPU used a value of 2898 MWt, instead of the proposed licensed power uprate value of 2957 MWt. For the EPU project, the MAAP evaluations were performed for QCNPS as the base case for both the QCNPS and the DNPS EPU license applications, since the thermal hydraulic parameters are the same for both sites.

For the EPU, the plant-specific parameters in the thermal hydraulic-code that represent the primary system and containment were examined qualitatively to identify those parameters that could modify success criteria, scenario timing, or equipment operability (e.g., NPSH). The result of that qualitative evaluation was the identification of two areas in which the success criteria would change in the Level 1 PRA under EPU conditions:

- The RPV depressurization success criteria changed from requiring one RV or SRV, to two valves.

- The number of S&RVs required to open for overpressure protection under failure to scram conditions increased from 11 to 12.

There are a total of five valves (four RVs and one SRV) used for RPV depressurization for a transient event without a SORV. In the current, pre-uprate plant, any single valve is adequate to achieve successful depressurization, but for the EPU plant conditions two valves are needed. Therefore, failure to depressurize requires failing all five valves in the current plant, but failure of any four valves will fail depressurization for the EPU conditions. The licensee indicated that the sequences involving failure of these valves are dominated by operator action failure and common-cause failure (CCF) of the RVs and/or SRVs to open. Though the CCF contribution increases due to this change in success criteria, the CDF is only increased by about 1 percent due to the large diversity in high pressure makeup systems for QCNPS.

For IORV or SORV sequences, RPV depressurization is not required for the current, pre-uprate configuration because a single open RV or SRV satisfies the current plant success criteria for depressurization. However, for the EPU configuration where two RVs and/or SRV are required to open for success, RPV depressurization still requires at least one RV or SRV to open, in addition to the IORV or SORV. The licensee stated that this additional requirement for the EPU configuration results in an increase in CDF of approximately 5E-8/year, which represents almost a 1 percent increase in the current base CDF.

There are a total of 13 valves (four RVs, one SRV, and eight SSVs) used for RPV overpressure protection for ATWS sequences. In the current, pre-uprate plant, 11 of the 13 valves must open to provide successful overpressure protection, but 12 of the 13 valves must open for the EPU plant conditions. Thus, failure of overpressure protection requires failing any three valves in the current plant, but failure of any two valves to open will fail overpressure protection for the EPU conditions. Similar to RPV depressurization, the contribution from the failure of these valves is dominated by CCF events. The licensee's approach to modeling these CCF events in the current, pre-uprate plant and the EPU condition uses a beta factor approach. However, due to a lack of CCF data for this relief mode of BWR SRVs, the licensee's approach results in the probability of CCF for any two valves to be equal to the probability of CCF for three or more valves. Thus, there is no calculational difference between the current plant and the EPU condition, even though the success criterion have changed. The licensee stated that there was only a negligible impact on CDF because RPV overpressure protection failure is dominated by CCF of these valves to open.

The licensee has indicated that there have been some changes in success criteria under EPU conditions, as discussed above. However, the licensee has shown that these changes do not significantly increase the plant risk from the current, pre-uprate plant. As part of the staff's evaluation, the DNPS IPE system success criteria were reviewed. Though the success criteria for DNPS is not directly comparable with the BWRs analyzed in NUREG-1150, "Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants," and the associated supporting documents (e.g., NUREG/CR-4550), due to the class of plant, the staff did find that the DNPS success criteria did address the critical safety functions for the identified spectrum of initiating events. Based on the staff's review and the evaluations performed by the licensee, the staff finds that it is reasonable that the system success criteria, and the associated change in CDF and LERF, are not expected to be significantly impacted by the proposed EPU.

However, since the licensee's thermal hydraulic analysis used in support of establishing the system success criteria, and the time available for operator actions, used a power level of only 2898 MWt and not the EPU license application value of 2957 MWt, there is some, albeit small, potential for impacts to success criteria and HEPs that have not been evaluated by the licensee. The staff believes that it would have been beneficial for the licensee to evaluate the system success criteria and HEPs at the license application EPU value of 2957 MWt. Performing these evaluations of system success criteria and HEPs at the EPU license application level of 2957 MWt would ensure that the success criteria and HEPs appropriately reflect the potential operating levels and, thus, ensure that the impacts on CDF and LERF are still within the RG 1.174 acceptance guidelines.

The licensee has not provided confirmatory responses to demonstrate that no system success criteria or operator action times, and associated HEPs, are affected by performing the thermal-hydraulic analysis at the EPU license application value of 2957 MWt. The licensee also has not provided additional analysis of the ATWS sequences involving failure of RPV overpressure protection to support the assertion that the impact of EPU is negligible for these sequences. However, given that the evaluated power level is only a couple of percent less than the EPU license application level and the ATWS sequences involving RPV overpressure protection failure are properly modeled for EPU conditions, the staff concludes that these issues would not significantly alter the overall results (i.e., not raise the change in risk values above the RG 1.174 acceptance guidelines) and, thus, would not rebut the presumption of adequate protection or warrant denial of the license amendment.

10.4.1.4 Operator Response

The licensee conducted an evaluation to determine how the proposed EPU would impact operator response capabilities during accidents. The reductions in certain operator action allowable times resulted in changes to HEPs due to the EPU. The actions and allowable times that were determined in the risk assessment to individually cause about a 1 percent or more increase in CDF were identified as significant actions. Each of these significant operator actions and the associated impacts due to the EPU is discussed below.

The time to initiate late standby liquid control SLC injection following an ATWS is reduced from 20 minutes to 16 minutes, which affects the HEP for this action. The base probability for failure to initiate late SLC was 3.3E-2. Due to the decrease in available time, the EPU HEP becomes 5.0E-2, which results in a CDF increase of about 1 percent.

The time to control RPV level following an ATWS decreases from 20 minutes to 16 minutes. The base probability for failure to control RPV level was 3.2E-2. Due to the decrease in available time, the EPU HEP becomes 5.0E-2, which results in a CDF increase of about 1 percent.

The time to inhibit the ADS with FW available following an ATWS decreases from 12 minutes to 10 minutes. The base probability for failure to inhibit ADS was 1.0E-2. Due to the decrease in available time, the EPU HEP becomes 1.3E-2, which results in a CDF increase that is less than 1 percent.

The time to initiate RPV depressurization following an ATWS decreases from 10 minutes to 8.5 minutes. The base probability for failure to initiate RPV depressurization was 1.8E-2. Due to the decrease in available time, the EPU HEP becomes 2.3E-2, which results in a CDF increase that is less than 1 percent.

Initially, a 1 percent increase in CDF was estimated for the decrease in the time available to successfully initiate isolation condenser makeup. However, subsequent analysis by the licensee found that 20 minutes would be available for this action under EPU conditions. This response time is actually longer than that used in the current pre-uprate plant PRA, which used 18 minutes. Therefore, the HEP value used in the current PRA bounds the value that would be calculated for the EPU PRA.

The licensee also identified a number of other operator actions that would be impacted by EPU. However, because the current, pre-uprate plant PRA used conservative or screening values, the EPU HEPs are bounded by these values. These operator actions include (1) failure to reopen turbine bypass valves to restore the main condenser as a heat sink, (2) failure to initiate

SLC makeup to the RPV during isolation condenser operation, and (3) failure to initiate RPV depressurization for medium LOCAs. Other operator actions, such as early SLC initiation, were determined to have at least the same amount of time available under EPU conditions, as for the current, pre-uprate plant conditions. This was, at least for the above operator action, the result of the time available being estimated using generic analysis in the current PRA, while using best-estimate thermal-hydraulic calculations to support EPU conditions.

The licensee did not identify any new risk-significant operator actions as a result of the EPU. However, new operator actions may be necessary to manually load shed equipment so as to avoid overloading the UAT or RAT when they are operating in a single transformer operation mode. This potential EPU condition was described above in Sections 10.4.1.1 and 10.4.1.2. The licensee has performed a simplified calculation, using generic equipment failure rate information and a screening operator action HEP, to show that the potential increase in the frequency of a LOOP initiating event has a very small impact on CDF, an increase in CDF of 6E-9/year. However, this simplified calculation includes the failure of the operators to manually shed loads within 1 hour to avoid overloading the operating transformer. This condition is the synergistic result of having to run the installed spare FW and condensate/booster pumps at EPU levels.

The 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 EPU conditions or are bounded by the values used in the current, pre-uprate plant PRA. However, as presented in Section 10.4.1.3, the staff has identified an issue with the thermal hydraulic analysis used to support the development of system success criteria and the available time for operator actions. In addition, the staff has identified at least one new operator action as a result of the proposed EPU. Since the licensee's simplified calculation for overloading the UAT or RAT credits operator actions, the staff believes that the licensee should develop and incorporate into the next PRA update the actual operator actions and associated HEPs. The staff also believes that it would have been beneficial to perform the PRA update prior to operating under EPU conditions so that the PRA model, and the associated tools that rely on these models, reflect the as-built, as-operated plant. Including these procedural considerations in the PRA model should provide confirmation that the actual operator actions are as reliable as was considered for the EPU license application and thus ensure that the impacts on CDF and LERF are still within the RG 1.174 acceptance guidelines.

The licensee has not provided confirmatory responses to demonstrate that no system success criteria or operator action times, and associated HEPs, are affected by performing the thermal-hydraulic analysis at the EPU license application value of 2957 MWt. However, given that the evaluated power level is only a couple of percent less than the EPU license application level, the staff concludes that this issue would not significantly alter the overall results (i.e., not raise the change in risk values above the RG 1.174 acceptance guidelines) and thus, would not rebut the presumption of adequate protection or warrant denial of the license amendment.

10.4.1.5 Summary of Internal Events Evaluation Results

The licensee indicated that potential impacts of the EPU were identified for the turbine trip initiating event frequency, the probability of occurrence of a SORV, the success criteria for RPV depressurization and ATWS overpressure protection, and selected operator actions due to the decrease in available operator response times. The changes to these conditions, as discussed above, result in an 8 percent increase in internal events CDF to about 2.8E-6/year. This represents an increase of about 2.1E-7/year from the current CDF of about 2.6E-6/year due to internal events.

The Level 2 PRA calculates the containment response under postulated severe accident conditions and provides an assessment of the containment adequacy. Changes of 17 percent in power represent relatively small changes to the overall challenge to containment under severe accident conditions. The licensee indicated that the time to containment failure may be reduced by 5 minutes to 30 minutes as measured over accident times of 6 hours to 30 hours. This is judged to be a minor change in the Level 2 PRA assessment. In addition, the success criteria for RPV depressurization was modified for the Level 2 assessment, similar to the modification in the Level 1 assessment. This change in success criteria has a minor impact on the conservative assessment of Level 2 LERF using the DNPS Level 2 PRA model. Based on the changes to the Level 1 model as input to the Level 2 model, the LERF increased from the base value for the current, pre-uprate plant of about 1.4E-6/year to the EPU LERF of about 1.6E-6/year, an increase in LERF of 1.4E-7/year, or about 10 percent. This increase in LERF is considered conservative by the licensee because of the conservative treatment of the time to initiate isolation condenser make-up that was used in the original amendment request that is still included in their LERF calculation, even though it has been subsequently shown to be the same as for the current, pre-uprate plant, as discussed above in Section 10.4.1.4. In addition, the analysis follows the simplified and conservative approach described in NUREG/CR-6595, “An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events,” and does not credit the use of drywell sprays.

Based on the reported analyses and results, the 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. However, a number of issues have been identified in Section 10.4.1 of this SE. The staff believes that the licensee should address these issues by updating the plant PRA models and the supporting thermal-hydraulic analysis for EPU operations so that they accurately reflect the as-built, as-operated conditions.

The licensee has not provided confirmatory responses to further demonstrate the overall risk acceptability, including addressing the above identified issues. However, given that the estimated impacts associated with these issues are a few percent, the staff concludes that these issues would not significantly alter the overall results (i.e., not raise the change in risk values above the RG 1.174 acceptance guidelines) and conclusions of this specific license application and thus would not rebut the presumption of adequate protection or warrant denial of the license amendment.

10.4.2 External Events

The NRC SE on the DNPS IPEEE concludes, based on the staff's screening review, that the licensee's process is capable of identifying the most likely severe accidents and severe accident vulnerabilities and that DNPS has therefore met the intent of Supplement 4 to GL 88-20. For the IPEEE seismic analysis, DNPS is categorized as a 0.3g focused-scope plant, per NUREG-1407. The licensee performed the DNPS seismic evaluation using the EPRI SMA methodology, as described in EPRI NP-6041-SL. For the IPEEE fire analysis, the licensee performed a fire PRA based on the EPRI FIVE methodology, as described in EPRI TR-100370, and the EPRI FPRAIG, as described in EPRI TR-105928. For the IPEEE evaluation of HFO external events, the licensee used the progressive screening approach consistent with the guidance of NUREG-1407.

Because the licensee used the EPRI SMA methodology, they did not quantify a seismic CDF. However, the licensee states in the supplemental information for the EPU license amendment that the conclusions and results of the SMA were judged to be unaffected by the EPU. Further, the licensee states that the EPU has no impact on the seismic qualifications of the systems, structures, and components. Specifically, the EPU results in additional thermal energy stored in the RPV, but the additional blowdown loads on the RPV and containment given a coincident seismic event are judged not to alter the results of the SMA.

The NRC SE on the DNPS IPEEE indicates that the licensee had implemented a number of improvements during the resolution of USI A-46 and that a number of additional improvements were still under consideration. In particular, the SE states that the licensee was developing a concept for providing a seismically-qualified/verified make-up path to each unit's isolation condenser. The SE also notes that the licensee was planning to perform a study to confirm that the torus would not reach unacceptably high temperatures following a small LOCA with no torus cooling, but with the isolation condenser in operation. The licensee indicated that any necessary design changes to address these items would be completed in conjunction with the approved schedule for resolution of the USI A-46 outliers, which is the fall of 2003. The DNPS IPEEE SMA took credit for the plant modifications and related operational changes needed to implement the seismically-qualified/verified isolation condenser makeup feature and assumed that the torus temperature would be acceptable for the small LOCA scenario. However, these plant modifications and the small LOCA confirmatory study had not been performed or implemented at the time of their original EPU license amendment submittal. Thus, it appears that the IPEEE SMA does not accurately represent the as-built, as-operated plant as RG 1.174 requires for justification of risk-informed licensing actions. Therefore, the staff requested that the licensee augment their IPEEE SMA by performing some simplified seismic risk evaluations of the current and EPU plant configurations for the two outlier scenarios (i.e., non-seismically qualified isolation condenser make-up sources and potential unacceptability of the seismically-induced small LOCA).

Both scenarios involve a seismic event that is followed by the failure of the Dresden Lock and Dam, which has a high confidence of a low probability of failure (HCLPF) value of 0.1g, and both rely on the availability of the isolation condenser. In the first scenario, the operators must align a makeup source to the isolation condenser from one of many different sources within about 20 minutes and a number of hours later may have to realign the isolation condenser to another longer-term source. For this scenario, although the DNPS IPEEE indicates that it is a 0.3g focused-scope SMA, the scenario involves equipment with HCLPF values that are much lower than 0.3g. The most notable of these are the isolation condenser make-up sources, for which the clean demineralized water tank (CDWT) and the 1A condensate storage tank (CST) have HCLPF values of 0.15g. Since the 1A CST is normally cross-connected to the 2/3A and 2/3B CSTs (which have higher HCLPF values), the limiting HCLPF was used to model the entire CST array. The results indicate that the current, pre-uprate plant and the EPU plant CDF values for this scenario are both about 1.0E-5/year, with a change in risk due to the uprate of about 1E-8/year.

Based on the staff's independent verification of the licensee's results, using the same input parameters, it is worth noting that these results are dominated by sequences that involve failure of the CST (i.e., the inventory of the 1A, 2/3A, and 2/3B CSTs), which represent the long-term makeup supply to the isolation condenser, and the risk estimates are primarily associated with seismic events between 0.2g and 0.6g. The change in risk from current conditions to EPU conditions is solely the result of the increase in the HEP value associated with the long-term alignment of the CST to the isolation condenser when the CDWT and CST are both initially available. The licensee assumed that this long-term alignment HEP value doubled from the current pre-uprate value of 5E-4 to the EPU value of 1E-3. Due to the relatively low HCLPF values of these tanks and the fact that the change in risk is driven by the change in HEP value, the change in risk is primarily associated with seismic events between 0.1g and 0.4g.

Subsequent to the licensee's original EPU submittal, the small LOCA confirmatory study was completed. The analysis demonstrated that the isolation condenser and available emergency core-cooling systems, such as HPCI and LPCI, are sufficient to mitigate a seismically-induced small LOCA for a 24-hour period. However, the study also showed that additional equipment, specifically a cooling water supply to the CCSW heat exchangers, will be required shortly after 24 hours to supply SPC. The licensee has developed a concept for providing this supply, which involves the use of large portable pumps and operator actions. However, this concept has not been implemented, but is planned to be completed (fall of 2003) on the same schedule as the modification to provide a seismically-qualified makeup path to the isolation condenser. Thus, the licensee performed a simplified seismic risk evaluation for the current and EPU condition prior to the installation of the above described modification.

For this scenario, the licensee assumed core damage occurred if a small-break LOCA or SORV occurred. The licensee's simplified seismic risk evaluation indicates that the current, pre-uprate plant CDF value for this scenario is about 2.2E-6/year and the EPU plant CDF value is about 2.3E-6/year, with a change in risk due to the uprate of about 6E-8/year.

As before, the staff independently verified these results performing its own calculations using the same input parameters. Due to the relative seismic robustness of the recirculation piping, the simplified risk evaluations indicate that the risks are dominated by high g-level seismic events (i.e., greater than 0.3g with the highest contribution at 1.0g). The change in risk is dominated solely by the increased probability of a SORV due to the increased number of valve cycles at EPU conditions. As this increased probability is not directly affected by the magnitude of the earthquake, but is driven by the decay heat levels under EPU conditions, the change in risk for this scenario is primarily associated with lower g-level earthquakes (i.e., 0.1g to 0.4g).

As stated previously, both scenarios rely on the assumed availability of the isolation condenser. Based on the staff's independent calculations using the same input values from the licensee, the CDF associated with the seismically-induced failure of the isolation condenser is estimated to be about 2.4E-6/year and is primarily driven by higher g-level earthquakes (i.e., greater than 0.3g with the highest contribution from 1.0g). It is noted that the seismically-induced failure of the isolation condenser coincident with dam failure is not affected by the power level (i.e., there is no difference between the current, pre-uprate plant and the EPU plant results).

To address the impacts of the EPU on the fire analyses, the licensee performed an estimate of the top 10 fire scenarios in terms of CDF contribution for each unit. In each case, it was concluded that the EPU would have only a minor effect on the current IPEEE fire risk. The dominant DNPS scenario in terms of fire risk is a severe Control Room fire with evacuation. Analyses performed for EPU indicate that the time available for the operator to initiate the isolation condenser for this fire is reduced from 35 minutes to 32 minutes. The fire risk update assumed that the conditional core damage probability (CCDP) for the Control Room evacuation scenario was 0.5, which is considered to be a very conservative assumption. Although the specific HEP may increase slightly due to the reduction in operator response time, such an increase would have no effect on fire risk because of the conservative CCDP used in the IPEEE, which would bound any realistic HEP. The fire risk for non-Control Room evacuation scenarios is dominated by loss of DHR sequences. The operator action important for mitigating these scenarios are long-term and the EPU would have only a minor impact on the time available for these actions. The current, pre-uprate plant contribution to CDF from fires is approximately 1.7E-5/year for Unit 2 and 3.0E-5/year for Unit 3. Based on the above licensee analyses, the licensee states that the effects of fires on the base CDF for EPU conditions are negligible.

The licensee did not quantitatively estimate the CDF contribution from HFO events since these events were screened out using their progressive screening approach. Therefore, under EPU conditions, the licensee states that there are no impacts on these other external events.

The staff finds that the increase in CDF from fire and HFO external events due to the proposed EPU appears to be negligibly small and within the guidelines provided in RG 1.174. In addition, based on the licensee’s simplified seismic risk evaluations that augments their IPEEE SMA, the staff finds that the seismic outliers do not exceed the baseline acceptance guidelines delineated in RG 1.174 and that the change in risk associated with the EPU for these scenarios is negligibly small. However, it should be noted that these results reflect simplified evaluations that contain large uncertainties and should not be the sole basis for the staff’s decision on the acceptability of the existing conditions. The licensee has indicated that the plan is to implement plant modifications by the fall of 2003 so as to be able to provide a seismically-qualified/verified makeup path to the isolation condenser and to provide a means to supply cooling water to the CCSW heat exchangers. The staff believes these modifications are prudent and as such believes they should be implemented as scheduled to ensure the seismic capability of the plant and to bring the plant within its IPEEE SMA.

The licensee has not evaluated the current plant capability and, as appropriate, designed and implemented the necessary plant and operational modifications to achieve the IPEEE SMA criteria for a 0.3g focused-scope plant. However, because of the licensee’s simplified seismic risk evaluations as independently verified, and the licensee’s previous commitment to resolve these USI A-46 outlier issues by the fall of 2003, the staff concludes that this issue would not significantly alter the overall results (i.e., not raise the change in risk values or the base risk values above the RG 1.174 acceptance guidelines) and conclusions of this specific license application and thus would not rebut the presumption of adequate protection or warrant denial of the license amendment.

10.4.3 Shutdown Risk

The licensee indicated that it evaluated the CDF and LERF changes due to the EPU using the insights derived from the shutdown risk management tool used at DNPS and the insights gained in the application of a quantitative shutdown risk model to the site. The conclusion from these insights is that the changes in CDF and LERF due to EPU are negligible compared with the shutdown risk levels that are present in the current, pre-uprate case.

The following qualitative discussion applies to the shutdown conditions of hot shutdown (Mode 3), cold shutdown (Mode 4), and refueling (Mode 5). The EPU risk impact during the transitional periods such as from at-power (Mode 1) to hot shutdown and from startup (Mode 2) to at-power are considered subsumed by the at-power Level 1 PRA.

The functional impacts of the EPU on shutdown risk are similar to the impacts on the at-power Level 1 PRA, with the exception that reactivity additions are different in the shutdown condition than in the at-power condition. The risk contributors include the loss of SDC, RPV water makeup/injection failures, and reactivity control failures. The first two functional challenges are similar in nature to the at-power risk assessment. The reactivity control functional impact at shutdown is related to misloaded fuel or mislocated fuel, as opposed to the failure to scram issues for the at-power evaluation. The shutdown reactivity control issues are not a function of the EPU and, therefore, their contribution to changes in CDF or LERF was assessed by the licensee to be zero.

The other areas of licensee review for the shutdown risk evaluation included initiating events, success criteria, and human reliability analysis (HRA). Important initiating events for shutdown include RPV draindown and loss of SDC. However, no new initiating events or increased potential for initiating events during shutdown (e.g., loss of a DHR train) has been identified based on the EPU configuration. The at-power change that leads to a possible increase in the turbine trip initiating event frequency, as discussed above in Section 10.4.1.1, due to the need to operate the installed spare FW and condensate/booster pumps, does not apply during shutdown conditions because the turbine has been tripped already. Further, with the reactor at low power, the plant is expected to be operating in the current, pre-uprate configuration with two of the three FW pumps and three of the four condensate/booster pumps operating. For this configuration, if a pump trips, the standby pump will automatically start and a low RPV level scram will be avoided. Thus, there is no change in risk at low power from the current, pre-uprate plant operations. The low power configuration also means that the UAT and RAT will not experience an overduty condition if only one transformer is operable. Thus, for low power and shutdown operations there is no potential for an increase in the LOOP initiating event frequency due to transformer overloading.

The impact of the EPU on the success criteria during shutdown is similar to the Level 1 PRA. The increased power level decreases the time to boildown. However, because the reactor is already shutdown, the boildown times are relatively long compared to the at-power PRA. The boildown time is approximately 1 hour at 2 hours after shutdown (e.g., time of hot shutdown) and approximately 2 hours to 4 hours at 12 hours to 24 hours after shutdown (e.g., time of cold shutdown). The changes in the boildown time when comparing the current, pre-uprate cases with the EPU cases are small fractions of the total boildown time. These small changes in boil down time have a negligible effect on the calculated HEPs, which are predominately cause-based as opposed to being driven by the available time for the action.

The increased decay heat loads associated with the EPU impacts the time when low-capacity DHR systems, such as FPC and RWCU, can be considered successful alternate DHR systems. The EPU condition delays the time after shutdown when FPC or RWCU may be used as an alternative to SDC. However, shutdown risk is dominant during the early time frame soon after shutdown, when the decay heat level is high and FPC and RWCU would not be viable DHR systems for either the current or the EPU conditions. At DNPS the time in each outage when various DHR systems are available is assessed. The RWCU and FPC systems would not be included in the defense-in-depth evaluation until the EPU decay heat level was sufficiently low for these systems to be successful alternatives. Therefore, the impact of the EPU on the FPC and RWCU success criteria has a negligible risk impact.

It is recognized in the shutdown risk quantifications that the SDC equipment is operating continuously for a significant portion of the outage. Therefore, for the EPU condition, SDC would be required to run for a longer time than in the current, pre-uprate case before other systems with lower heat removal capacity are adequate for DHR. These later times are generally very low risk periods during the outage. Therefore, for those low risk situations when FPC or RWCU could provide a backup in the current case, they would become marginal in the EPU case for some additional short period of time. The time differential between the current and the EPU conditions when FPC and RWCU may not be adequate alone as DHR methods is approximately 12 days in the time frame from 26 days to 38 days following a shutdown based on conservative assumptions (e.g., no decay heat loss to structures or the environment). Because the shutdown risk profile is dominated by the risk at early times in the outage (e.g., 0 days to 10 days), increasing the time when SDC is the only adequate DHR system, during which the risk is low due to low decay heat, has a minor impact on the overall shutdown risk. With DNPS outages lasting less than 20 days, this change in success criteria has no impact on the integrated shutdown risk. Other success criteria are marginally impacted by the EPU. The EPU has a minor impact on shutdown RPV inventory makeup requirements because of the low makeup requirements associated with the low decay heat level. The heat load to the suppression pool is also lower because of the low decay heat level, such that the margins for the SPC capacity are adequate for the EPU condition. The EPU impact on the success criteria for blowdown loads, RPV overpressure margin, and SRV actuation is estimated to be minor because of the low RPV pressure and low decay heat level during shutdown.

Similar to the at-power Level 1 PRA, the decreased boildown time decreases the time available for operator actions. The significant, time-critical operator actions impacted in the at-power Level 1 PRA are related to RPV depressurization, SLC injection, and SLC level control. These operator actions do not directly apply to shutdown conditions because the RPV is at low pressure and the reactor is subcritical.

The risk-significant operator actions during shutdown conditions include recovering a failed DHR system or initiating alternate DHR systems. However, the typically long boildown times during shutdown (e.g., hours as opposed to minutes) result in the EPU having only a minor impact on the shutdown HEPs associated with recovering or initiating DHR systems. Because the available time is relatively long and the HEPs are dominated by the cause-based HRA performance shaping factors, the increased decay heat levels during shutdown for the EPU conditions will not appreciably impact the HEPs.

Based on a review of the potential impacts on initiating events, success criteria, and operator response times, the EPU configuration will have a minor impact on shutdown risk. Any quantitative impact of the EPU on shutdown risk is evaluated using the deterministic Outage Risk Assessment and Management (ORAM) software. The ORAM software evaluates the planned plant configuration, including systems available, RPV water level, RPV and containment status, and decay heat level, which is used for calculating time-to-boil or time-to-uncover-fuel. The ORAM software evaluates the planned outage schedule to ensure that adequate defense-in-depth is maintained throughout the outage. With respect to the EPU, based on the increased decay heat level, ORAM will be able to identify how much longer SDC needs to operate before alternative DHR systems could be placed in service.

Based upon the above risk management process, the licensee indicates that the EPU will 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 staff finds that the impact on shutdown risk due to the proposed EPU will be 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 licensee'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 staff's decision. In this case, the licensee is not requesting relaxation of any deterministic requirements for the proposed EPU and the staff's approval is primarily 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 staff evaluated the information provided by the licensee in its submittal and considered the review findings on the original DNPS IPE and IPEEE, as well as the fact that the DNPS PRA has been through two peer reviews as part of the BWR Owners Group PRA certification program. In addition, in July 2001, the NRC staff reviewed the DNPS PRA maintenance and update procedures and processes to support its review of the licensee's proposed EPU. The staff's evaluation of the licensee's submittal focused on the capability of the licensee's PRA model to analyze the risks stemming from both the current, pre-uprate plant operations and the EPU conditions. The staff's evaluation did not involve an in-depth review of the licensee's PRA.

The licensee stated in its supplemental information and in response to staff requests for additional information associated with the DNPS EPU license application that it maintains and updates each of its PRAs to be representative of the respective as-built, as-operated plant and that the PRA update process is formalized by procedure. The licensee also stated that this procedure defines the process for regular and interim updates for issues identified as potentially affecting the PRA and that this process assures that the present PRA reflects the current plant configuration and plant procedures. The licensee's risk management processes are stated as providing for ongoing review of plant design changes, procedure changes, and formal calculations, to ensure that PRA personnel are aware of actual and pending changes to the plant. Plant changes with the potential to impact the PRA are recorded in a database, along with an assessment of whether immediate model changes are required. None of the items currently in the database have been identified as having a major impact on the PRA and none have required an immediate model change.

In response to a RAI from the staff, the licensee stated that it used the EPRI methodology, (described in technical bulletins 96-11-01, “Monitoring Reliability for the Maintenance Rule,” and 97-3-01, “Monitoring Reliability for the Maintenance Rule – Failures to Run”) to assure that the assumptions in the PRA were consistent with the NRC Maintenance Rule reliability performance criterion (RPC). The methodology statistically determines when a failure rate experienced in the plant is significantly outside the expected failure rate used in the PRA. If the licensee considers higher RPCs for the plant, PRA sensitivity studies are used. The licensee stated that since the EPU has a small impact on PRA parameters, the EPU will have a negligible impact on the Maintenance Rule performance criteria. In addition, the licensee stated that plant engineers trend overall risk as part of the Maintenance Rule program, performing quarterly evaluations of the 12-month rolling average CDF. Risk increases or decreases with respect to the base CDF are evaluated. To date, the evaluation has indicated that the trends are non-risk-significant. The licensee asserts that this indicates that the PRA model adequately reflects the current maintenance practices. Further, the licensee stated that during the next scheduled PRA model update, the latest unavailability data from the Maintenance Rule will be used for risk-significant equipment. Thus, the licensee has a process in place that enables them to update their equipment unavailabilities in the PRA models to reflect the current plant maintenance practices.

The NRC SE on the DNPS IPE was issued in October 1997 and concluded that the licensee had met the intent of GL 88-20. The licensee has significantly upgraded the DNPS PRA models since the staff review relative to GL 88-20 and has addressed the staff’s concerns identified in the NRC SE on the DNPS IPE, specifically regarding CCF values and its containment analysis. The latest DNPS PRA models have been used to support a license application for establishing a risk-informed inservice inspection program. The DNPS PRA has been through two peer reviews as part of the BWR Owners Group PRA certification process. The first peer review, which was performed in January 1998, resulted in a major upgrade of the PRA models. The second peer review, which was performed in November 2000, concluded that the DNPS PRA was adequate to support regulatory applications when combined with deterministic insights.

The recently completed NRC SE on the DNPS IPEEE concludes, based on the staff’s screening review, that the licensee’s process is capable of identifying the most likely severe accidents and severe accident vulnerabilities and that the DNPS IPEEE has therefore met the intent of Supplement 4 to GL 88-20. For the IPEEE, the licensee performed the DNPS seismic evaluation using the EPRI SMA methodology, as described in EPRI NP-6041-SL. For the IPEEE fire analysis, the licensee performed a fire PRA based on the EPRI FIVE methodology, as described in EPRI TR-100370, and the EPRI FPRAIG, as described in EPRI TR-105928. For the IPEEE evaluation of HFO external events, the licensee used the progressive screening approach consistent with the guidance of NUREG-1407.

The NRC SE on the DNPS IPEEE indicates that the licensee had implemented a number of improvements during the resolution of USI A-46 and that a number of additional improvements were still under consideration. In particular, the SE states that the licensee was developing a concept for providing a seismically-qualified/verified makeup path to each unit's isolation condenser. The SE also indicates that the licensee was planning to perform a study to confirm that the torus would not reach unacceptably high temperatures following a small LOCA with no torus cooling, but with the isolation condenser in operation. The licensee indicated that any necessary design changes to address these items would be completed in conjunction with the approved schedule for resolution of the USI A-46 outliers. The DNPS IPEEE SMA took credit for the plant modifications and related operational changes needed to implement the seismically-qualified/verified isolation condenser makeup feature and assumed that the torus temperature would be acceptable for the small LOCA scenario. However, these plant modifications and the small LOCA confirmatory study had not been performed or implemented at the time of the original EPU license amendment submittal. Therefore, the IPEEE SMA does not accurately represent the as-built, as-operated plant as RG 1.174 requires for justification of risk-informed licensing actions.

The staff is aware that the licensee's PRA management and control processes continue to evolve and improve and have benefitted from the BWR Owners Group PRA peer review and certification process. The staff finds that the licensee has provided sufficient information to indicate the adequacy of the quality of their internal events PRA and fire analysis for this specific license application. However, the staff also finds that the licensee's SMA, as presented in the DNPS IPEEE, does not reflect the existing plant conditions or capabilities and takes credit for plant modifications that have not occurred. Therefore, the staff requested that the licensee augment their IPEEE SMA by performing some simplified seismic risk evaluations of the current and EPU plant configurations for the two outlier scenarios (i.e., non-seismically qualified isolation condenser make-up sources and potential unacceptability of the seismically-induced small LOCA). As described in Section 10.4.2, these simplified evaluations indicate that the seismic outliers do not exceed the baseline acceptance guidelines delineated in RG 1.174 and that the change in risk associated with the EPU for these scenarios is negligibly small. However, it should be noted that these results reflect simplified evaluations that contain large uncertainties and should not be the sole basis for the staff's decision of acceptability of the existing conditions. The licensee has indicated that they plan to implement plant modifications by the fall of 2003 so as to be able to provide a seismically-qualified/verified makeup path to the isolation condenser and to provide a means to supply cooling water to the CCSW heat exchangers. The staff believes these modifications are prudent, will ensure the seismic capability of the plant, and will bring the plant within its IPEEE SMA.

Finally, given the number of plant and operational modifications related to, or being performed at the same time as, the EPU, the staff believes that it would be beneficial for the licensee to expedite the next DNPS PRA update and not wait until the next scheduled update. The licensee has indicated they plan for both Dresden and Quad Cities updates to be completed as scheduled in the first 6 months of 2002. By updating the PRA to reflect the current plant modifications and plant-specific operating information, the PRA, and the tools (e.g., Maintenance Rule, shutdown risk monitor), that rely on or use the PRA models, will more accurately reflect the as-built, as-operated plant. The updates would confirm that the simplified models, simplified calculations, and analysis limitations (e.g., thermal hydraulic analysis at a power level less than 2957 MWt) associated with the EPU license amendment are bounding and/or assure that the overall risk impacts of the EPU and related modifications, reflecting the actual installed modifications or revised operations, remain within the acceptance guidelines provided in RG 1.174.

The licensee has not evaluated the current plant seismic capability and, as appropriate, designed and implemented the necessary plant and operational modifications to achieve the IPEEE SMA criteria for a 0.3g focused-scope plant. In addition, the licensee has not provided confirmatory responses regarding the risk acceptability of the actual installed plant modifications and proceduralized operator actions performed as part of, or in parallel with, the EPU. Also, the licensee has not updated the plant PRA and supporting thermal hydraulic analysis prior to operating at EPU levels. However, as previously stated, the staff believes that these issues would not significantly alter the overall results (i.e., not raise the change in risk values above the RG 1.174 acceptance guidelines) and conclusions of this specific license application and thus would not rebut the presumption of adequate protection or warrant denial of the license amendment.

10.4.5 Risk Evaluation Conclusions

The staff finds that changes may occur as a result of the DNPS EPU for the turbine trip and LOOP initiating event frequencies, the probability of occurrence of a SORV, the success criteria for RPV depressurization and ATWS overpressure protection, and the time available for a number of operator responses.

However, the staff concludes that the increase in the turbine trip initiating event frequency will be offset by the plant modification to initiate a reactor recirculation pump runback on the loss of a single FW or condensate/booster pump and that the increase in LOOP initiating event frequency will be small and mitigated by operator actions to shed loads manually following the fast transfer of all loads to a single transformer. Further, the staff finds that the impacts on plant risk from the increased probability of a SORV and the changes in success criteria will be small and/or within the conservatisms of the current, pre-uprate plant analysis. Finally, the staff finds that the risk increases due to the reduced operator response times available under the EPU conditions are small and within the acceptance guidelines of RG 1.174.

The staff finds that the licensee has a process for managing plant risk during shutdown operations and that the risk impact due to the EPU during these operations will be negligible. The staff also finds that the risk increases from external events under EPU conditions will be negligibly small and within the acceptance guidelines of RG 1.174.

Based on the licensee's reported analyses and results and the staff's own verification calculations, the staff concludes that the increases in CDF and LERF from internal, external, and shutdown events due to the proposed EPU will be small and that the risk impacts will be within the acceptance guidelines provided in RG 1.174. However, the staff has identified a number of issues associated with the licensee's supporting risk analysis. These issues are the use of simplified models that were developed in parallel with the design of the plant modifications and/or procedures (e.g., recirculation pump runback control circuitry and manual load shedding UAT or RAT following a fast transfer without scram), the use of simplified calculations (e.g., LOOP initiation frequency due to overduty of UAT or RAT and risks associated with IPEEE seismic outliers), and limitations in the supporting analysis (e.g., thermal hydraulic analysis performed at a power level less than the EPU license application power level of 2957 MWt). The staff believes that, prior to operating under EPU conditions, the licensee should confirm that the current analyses and PRA models, upon which the licensee based its conclusions regarding plant risk, bound the potential impacts of the actual designed and installed plant modifications and operational/procedural modifications that are being implemented as part of, or in parallel with, the EPU.

Given the number of plant and operational modifications related to, or being performed at the same time as, the EPU, the staff believes that the licensee should expedite the next DNPS PRA update and not wait until the next scheduled update, which may be as much as 2 years in the future based on the DNPS PRA maintenance and update procedures. By updating the PRA to reflect the current plant modifications and plant-specific operating information, the PRA, and the tools (e.g., Maintenance Rule, shutdown risk monitor) that rely on or use the PRA models, will more accurately reflect the as-built, as-operated plant. By updating the PRA before operating the plant at EPU levels, the licensee can confirm that the simplified models, simplified calculations, and analysis limitations of the EPU license amendment are bounding and/or assure that the overall risk impacts of the EPU and related modifications, reflecting the actual installed modifications or revised operations, remain within the acceptance guidelines provided in RG 1.174.

In conclusion, during the course of its review, the staff identified a number of issues associated with risk analysis supporting the EPU. However, the staff, recognizing that this submittal is not a risk-informed license application, believes the identified issues will not rebut the presumption that the licensee has provided adequate protection by meeting the deterministic requirements and regulations. This conclusion is based on the facts that the estimated impacts due to EPU are small (i.e., increase in risk by only a few percent) and the licensee has committed to perform the identified plant modifications associated with the identified issues, as appropriate. Therefore, the staff believes that the identified issues do not warrant denial of the license application.

10.5 Human Factors

This evaluation is limited to the effect of the increased maximum power level on operator performance. It covers required changes to operator actions, human-system interface, procedures, and training as a result of the increased maximum power level. The evaluation is based on the licensee's responses to five broad questions regarding human performance.

The 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," ANSI/ANS-58.8, "Time Response Design Criteria for Safety-Related Operator Actions," 1984, and NUREG-0800, SRP, Chapter 18 (draft), "Human Factors Engineering."

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

In its submittal of February 12, 2001 (Reference 8), the licensee stated that emergency operating procedure changes are limited to revisions to numerical values such as maximum core thermal power and heat capacity temperature limit of the suppression pool, and that operator actions remain unchanged. Two abnormal operating procedures (AOPs) will change as a result of modifications to equipment. First, the required actions following a FW pump trip will be changed to reflect the installation of an automatic recirculation system runback. The second AOP change reflects the modifications to the condensate pump circuitry to trip the fourth running pump during a loss-of-coolant accident to prevent an electrical overload. EGC stated that these emergency and abnormal procedure changes will be addressed during operator training sessions prior to operation at EPU conditions. The staff is satisfied with this response as the changes are minimal and EGC has committed to provide the necessary training.

Question 2 - Describe any new risk-important operator actions as a result of the proposed power uprate. Describe changes to any current risk-important operator actions that will occur as a result of the uprate. Explain any changes in plant risk that result from changes in risk-important operator actions. That is, identify operator actions that will require additional response time or will have reduced time available; identify any operator actions that are being automated as a result of the power uprate; and provide justification for the acceptability of these changes.

The licensee responded that no new risk-important operator actions were identified as a result of EPU for DNPS.

For DNPS, seven current operator actions were identified in which the available time to complete the action will be reduced as a result of EPU. In the two worse-case actions, the time available to complete the action will be reduced from 20 minutes to 16 minutes. These are initiating SLC injection following an ATWS and controlling reactor vessel level following an ATWS. Based on the criteria of ANSI/ANS 58.8, 16 minutes is sufficient time to accomplish either task, but EGC determined that this reduction in time available would increase HEP enough to increase CDF by approximately 1 percent for each sequence.

Question 3 - Describe any changes the proposed power uprate will have on operator interfaces for control room controls, displays, and alarms. For example, what zone markings (e.g., normal, marginal and out-of-tolerance ranges) on meters will change? What set points will change? How will the operators know of the changes? Describe any controls, displays, and alarms that will be upgraded from analog to digital instruments as a result of the proposed power uprate and how operators were tested to determine they could use the instruments reliably.

The licensee stated in its submittal of February 12, 2001, that no major physical changes to control room controls, displays, or alarms are required as a result of the EPU. Some changes are required to indicator spans, alarm settings, and automatic actuation setpoints to accommodate increased process conditions. Existing zone banding on all control board indications will be reviewed for acceptability and revised as necessary prior to EPU operation.

EGC listed the control board changes and additions to be made and the setpoints to be changed as a result of the EPU. EGC stated that these changes are being implemented as design changes in accordance with approved change control procedures. The procedures include an impact review by operations and training personnel.

The staff is satisfied that the control room changes are minor and that they will be implemented by approved design change procedures including an impact review by operations and training personnel.

Question 4 - Describe any changes the proposed power uprate will have on the safety parameter display system. How will the operators know of the changes?

The licensee stated that the analog and digital inputs to the safety parameter display system (SPDS) are not affected. One alarm is changed to reflect the revised low reactor water level scram function (which was approved under a separate amendment). The setpoint changes are listed in Reference 8. EGC has committed to complete these changes to the SPDS prior to power ascension to EPU conditions and to discuss these changes as part of the operator training program for EPU. Based on these commitments, the staff finds that the licensee's consideration of the effect of EPU on SPDS is satisfactory.

Question 5 - Describe any changes to the operator training program and the plant reference control room simulator as a result of the proposed power uprate, and provide the implementation schedule for making the changes.

In its February 12, 2001, submittal, EGC stated that an operator lesson plan will be developed to teach plant changes as a result of the EPU and existing lesson plans will be revised to reflect the changes. The EPU lesson plan will be presented to all licensed and certified operations personnel before startup for operating at extended power conditions. EPU changes will be incorporated in continuing-training lesson plans as applicable.

Operator training for power uprate conditions will be performed on the simulator prior to operating at EPU conditions. This training will consist of comparisons of plant conditions between the current maximum power level and the uprated power level, the normal operating procedure actions to achieve the uprated level, and selected transients and accidents that present the greatest change from previous power levels.

A simulator software module reflecting the major plant systems and reactor changes as a result of the EPU will be implemented prior to the operator training session before the EPU is initiated. Simulator performance validation will be conducted in accordance with ANSI/ANS 3.5-1985. It will be performed in two stages. First, the simulator performance will be validated against the EPU expected system response. Second, post-startup data will be collected and compared with simulator performance data, allowing any necessary adjustments to be made to the simulator model.

Based on these commitments, the staff is satisfied that the operators will be sufficiently trained and qualified in the EPU conditions.

The staff concludes that the review topics associated with the operator's integration into the proposed extended power uprated system have been satisfactorily addressed by the licensee. The staff further concludes that the proposed EPU should not adversely affect operator performance and minimally increases HEP based on reduced time available for several risk-important operator actions. The impact of these operator actions on plant risk is discussed in Section 10.4.

11.0 CHANGES TO FACILITY OPERATING LICENSE, CHANGES TO TECHNICAL SPECIFICATIONS, AND COMMITMENTS

11.1 Changes to Facility Operating License

The licensee proposed to make the following conforming changes to the DNPS Unit 2 Facility Operating License DPR-19 and DNPS Unit 3 Facility Operating License DPR-25 to reflect the proposed EPU:

(1) DPR-19, paragraph 2.C.(1), and DPR-25, paragraphs d. and 3.A: The maximum power level is revised to be 2957 MWt.

Justification for Change: The new maximum licensed power level is 2957 MWt as evaluated in this SE.

(2) DPR-19, Appendix B, and DPR-25, Appendix B: The first condition in Appendix B is revised and relocated to paragraph 2.C.(17) in DPR-19 and to paragraph 3.X. in DPR-25. This condition specifies the amount of containment overpressure credit allowed.

Justification for Change: The new containment overpressure credit was reviewed and found to be acceptable by the staff as described in Section 4.2.5 of this SE.

11.2 Changes to Technical Specifications

The licensee proposed to make the following conforming changes to the DNPS, Unit 2 and 3, TS to reflect the proposed EPU:

(1) TS table of contents, page i: Section 3.2.4 is removed from the table of contents.

Justification for Change: Section 3.2.4, Average Power Range Monitor (APRM) Gain and Setpoint, is being removed from TS as described in Item (5) of this section. This change to the table of contents is consistent with the removal of Section 3.2.4 from TS.

(2) TS Section 1.1, Definitions, page 1.1-3: Fuel Design Limiting Ratio for Centerline Melt (FDLRC) and it’s definition are removed from Section 1.1.

Justification for Change: Because the analyses performed for the EPU are based on DNPS ARTS, use of FDLRC as a fuel thermal limit is no longer required. FDLRC is removed from TS by removal of TS 3.2.4. Section 3.2.4, Average Power Range Monitor (APRM) Gain and Setpoint, is being removed from TS as described in Item (5) of this section. This change to the TS definitions is consistent with the removal of Section 3.2.4 from TS.

(3) TS Section 1.1, Definitions, page 1.1-4: Maximum Fraction of Limiting Density (MFLPD) and it’s definition are removed from Section 1.1.

Justification for Change: Because the analyses performed for the EPU are based on DNPS ARTS, use of MFLPD as a fuel thermal limit is no longer required. MFLPD is removed from TS by removal of TS 3.2.4. Section 3.2.4, Average Power Range Monitor

(APRM) Gain and Setpoint, is being removed from TS as described in Item (5) of this section. This change to the TS definitions is consistent with the removal of Section 3.2.4 from TS.

(4) TS Section 1.1, Definitions, page 1.1-5: The Rated Thermal Power (RTP) definition is changed to 2957 MWt.

Justification for Change: The new RTP is 2957 MWt as evaluated in this SE.

(5) TS 3.2.4, pages 3.2.4-1 and 3.2.4-2: Section 3.2.4, Average Power Range Monitor (APRM) Gain and Setpoint, is removed from TS.

Justification for Change: With DNPS ARTS, monitoring to ensure that the SLMCPR is not exceeded is performed with ARTS power-dependent and flow-dependent thermal limits. The ARTS power- and flow-dependent limits replace the APRM trip setdown (gain and setpoint) requirements of TS 3.2.4 which are therefore deleted from TS. The staff reviewed and approved the licensee's thermal limits assessment as described in Section 2.2 of this SE. Implementation of DNPS ARTS in place of the APRM trip setdown was reviewed and found to be acceptable by the staff as described in Sections 3.4, 9.1, and 9.2 of this SE.

(6) TS 3.3.1.1, Required Action E.1, SR 3.3.1.1.14, and Table 3.3.1.1-1 Functions 8 and 9, pages 3.3.1.1-2, 3.3.1.1-6, and 3.3.1.1-10: The power level where the direct RPS scrams on TSV or TCV fast closure are automatically bypassed is changed from 45% to 38.5% RTP.

Justification for Change: The turbine bypass capacity is not being changed by this EPU. The new percent RTP (38.5%) is required to maintain the actual value of reactor power consistent with the pre-uprate value. 45% of pre-uprate RTP is essentially the same steam flow as 38.5% of post-uprate RTP. These changes in TS were reviewed and found to be acceptable by the staff as described in Sections 5.3.2, 7.3, and 9.2.1 of this SE.

(7) TS 3.3.1.1, SR 3.3.1.1.2, page 3.3.1.1-4: The gain adjustment required by TS 3.2.4 is removed.

Justification for Change: The staff reviewed and found this change to be acceptable as described in Sections 5.3.1 and 9.2.1 of this SE.

(8) TS 3.3.1.1, Table 3.3.1.1-1, Function 2b and Footnote (b), page 3.3.1.1-8: The flow biased portion of the AV for TLO APRM flow biased - high RPS trip is changed to .56W + 67% RTP and the clamped portion of the AV is changed to 122% RTP. The flow biased portion of the AV for SLO APRM flow biased - high RPS trip is changed to .56W + 63.2% RTP.

Justification for Change: During operation, the neutron flux varies with recirculation drive flow. At lower core flows, the flow biased portion of this AV is reduced as core flow is reduced but this AV is clamped at an upper limit that is equivalent to the APRM Fixed Neutron - High Function AV. The flow biased portion of this AV is revised consistent with ELTR1, ELTR2 and the MELLLA. This change to the flow biased portion of this AV was reviewed and found to be acceptable by the staff as described in Sections 2.3.1 and 5.3.3 of this SE. The change in the clamped portion, the APRM Fixed Neutron - High Function AV, is described below in 11.2 (9).

(9) TS 3.3.1.1, Table 3.3.1.1-1, Function 2c, page 3.3.1.1-9: The AV for APRM fixed - high RPS trip is increased from 120% to 122% RTP.

Justification for Change: The AV of 120% was derived previously based on the methodology that used FDLRC. As described in 11.2 (2), FDLRC is being removed from TS. The new AV of 122% is determined by APRM setpoint calculations using MELLLA. This change to the APRM fixed - RPS trip AV was reviewed and found to be acceptable by the staff as described in Sections 2.3.1 and 5.3.3 of this SE.

(10) TS 3.3.1.1, Table 3.3.1.1-1, Function 10, page 3.3.1.1-10: The AV for turbine condenser vacuum - low RPS trip is changed from ≥21.15 inches Hg vacuum to ≥21.4 inches Hg vacuum.

Justification for Change: The AV is being increase to maintain adequate margin between the setpoint and the expected condenser pressure at EPU conditions. This change was reviewed and found to be acceptable by the staff as described in Section 5.3.5 of this SE.

(11) TS 3.3.5.2, SR 3.3.5.2.3, page 3.3.5.2-2: The AV for the IC automatic initiation time delay is reduced from ≤17 to ≤15 seconds.

Justification for Change: The IC initiation time delay is provided to avoid unnecessary actuations of the IC. Analysis of the LOFW transient event was performed using a time delay of 15 seconds. The IC automatic initiation time delay is reduced to 15 seconds to ensure compliance with the transient analysis. This change was reviewed and found to be acceptable by the staff as described in Sections 3.8, 5.1, and 5.3.6 of this SE.

(12) TS 3.3.6.1, Table 3.3.6.1-1, Function 1a, page 3.3.6.1-5: The AV for the main steam line isolation on reactor water level - low low is decreased from ≥ minus 56.77 inches to ≥ minus 56.34 inches.

Justification for Change: Recalculating the AV for this function using the same temperature ranges that were used for other instruments in this loop results in a decrease in the AV. This change was reviewed and found to be acceptable by the staff as described in Section 5.3.7 of this SE.

(13) TS 3.3.6.1, Table 3.3.6.1-1, Function 1d, page 3.3.6.1-5: The AV for the main steam line isolation on main steam line flow - high is changed for DNPS Unit 2 from ≤160.5 psid to ≤259.2 psid and for DNPS Unit 3 from ≤117.1 psid to ≤252.6 psid.

Justification for Change: The AV is being increased to maintain adequate margin between the setpoint and the increase full power steam flow. This was reviewed and found to be acceptable by the staff as described in Sections 3.7 and 5.3.8 of this SE.

(14) TS 5.5.12, primary containment leakage rate testing program pressure, page 5.5-11: The containment test pressure is reduced from 48 psig to 43.9 psig.

Justification for Change: Analyses show that the peak containment pressure following a DBA LOCA will be 43.9 psig for EPU conditions, using a new analysis methodology. This was reviewed and found to be acceptable by the staff as described in Section 4.1.1.3 of this SE.

(15) TS 5.6.5, core operating limits report (COLR), page 5.6-3: The LHGR and transient linear heat generation rate limits for TS 3.2.4 are removed from the COLR.

Justification for Change: This requirement is no longer applicable since, as discussed in Item (5) of this section, TS 3.2.4 is removed from TS.

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.

11.3 Commitments

In support of this amendment the licensee made several commitments that the staff relied upon in reaching the conclusions of this SE. These are therefore considered to be regulatory commitments. These regulatory commitments are discussed in the following sections of this SE:

3.5.1 Piping modifications will be completed prior to implementation of this EPU. Supports, structural attachments, and supporting steel modifications will be completed prior to implementation of this EPU.

3.5.2 The reactor vessel moisture separation equipment will be modified prior to implementation of this EPU. The FAC predictive model will be enhanced and the FAC inspection program will be modified prior to implementation of this EPU.

5.1 The modifications and changes to devices that need to be made will be completed prior to implementation of this EPU.

6.1.1.1 Resolution of issues discovered during the Transmission and Distribution Entity reviews will be completed prior to implementation of this EPU.

6.1.1.2.2 The bus duct cooling will be upgraded prior to implementation of this EPU.

6.1.2 The procedurally controlled load-shedding scheme will be instituted prior to implementation of this EPU. This approach will be confirmed by thermal analysis or an engineering evaluation. The alarm response procedures will be modified to require operator action to reduce transformer load within one hour when all loads are fed from the UAT. The bracing of the switchgear for the load cubicles will be modified to reflect the tested configuration prior to implementation of this EPU.

6.2 Modification of the main feed cables to the reactor building dc panels will be completed prior to implementation of this EPU.

6.3 Procedural controls to ensure reactor building conditions are consistent with conditions assumed in the evaluation of credited evaporative cooling capacity will be implemented. The same methods and acceptance criteria used for the existing analysis will be applied in evaluating planned offloads that are not bounded by the existing analysis.

9.4.1 DNPS Unit 3 SLC capability will be confirmed prior to EPU. Valve reseat pressure and lack of valve chatter will be verified at the next refueling outage for each unit.

10.2.1.2 The items remaining to be qualified for EPU conditions will be qualified prior to implementation of this EPU.

10.3 The testing program committed to will be completed. A summary report will be submitted after completion of the EPU test program.

10.5 Training will be provided on the emergency and abnormal operating procedures. The changes to the operator training program, operator training, and plant control room simulator changes will be completed prior to implementation of this EPU.

The NRC staff finds that reasonable controls for the implementation and for subsequent evaluation of proposed changes pertaining to the above regulatory commitment(s) are best provided by the licensee's administrative processes, including its commitment management program. The above regulatory commitments do not warrant the creation of regulatory requirements (items requiring prior NRC approval of subsequent changes).

12.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Illinois State official was notified of the proposed issuance of the amendments. 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 November 16, 2001 (66 FR 57750). 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 December 20, 2001 (66 FR 65752). Accordingly, based upon the environmental assessment, the Commission has determined that issuance of these amendments 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 amendments will not be inimical to the common defense and security or to the health and safety of the public.

15.0 REFERENCES

1. Letter from Commonwealth Edison Company to Nuclear Regulatory Commission, “Dresden Nuclear Power Station, Units 2 and 3, and Quad Cities Nuclear Power Station, Units 1 and 2, Request for License Amendment: Power Uprate Operation,” December 27, 2000, with attachments, RS-00-0167.

2. GE Nuclear Energy, “Safety Analysis Report for Dresden 2 & 3 Extended Power Uprate,” Licensing Topical Report, NEDC-32962P (Proprietary), December 2000.

3. GE Nuclear Energy, “Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate,” (ELTR1), Licensing Topical Report NEDC-32424P-A (Proprietary), February 1999, and NEDC-32424 (Nonproprietary), April 1995.

4. Nuclear Regulatory Commission, letter to General Electric Company, “Staff Position Concerning General Electric Boiling Water Reactor Extended Power Uprate Program,” February 8, 1996.

5. GE Nuclear Energy, “Generic Evaluation of General Electric Boiling Water Reactor Extended Power Uprate (ELTR2),” Licensing Topical Report NEDC-32523P-A (Proprietary), February 2000, NEDC-32523P-A Supplement 1, Volume 1 (Proprietary), February 1999, and NEDC-32523P-A Supplement 1, Volume II (Proprietary), April 1999.

6. Nuclear Regulatory Commission, letter to General Electric Company, “Safety Evaluation by the Office of Nuclear Reactor Regulation Related to General Electric Licensing Topical Report NEDC-32523P,” September 14, 1998.

7. Nuclear Regulatory Commission, “Standard Review Plan,” NUREG-0800, April 1996.

8. Letter from R. M. Krich, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Supplemental Information for Request for License Amendment for Power Uprate Operation,” February 12, 2001, RS-01-023.

9. Letter from R. M. Krich, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Electrical Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Plant,” April 6, 2001, RS-01-052.

10. Letter from R. M. Krich, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Supplement to Request for License Amendment for Power Uprate Operation,” April 13, 2001, RS-01-083.

11. Letter from R. M. Krich, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Environmental Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” May 3, 2001, RS-01-089.

12. Letter from R. M. Krich, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Testing Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” May 18, 2001, RS-01-104.

13. Letter from R. M. Krich, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Health Physics Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” May 29, 2001, RS-01-108.

14. Letter from R. M. Krich, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Fluence Information Supporting the License Amendment Request to Permit Uprated Power,” June 5, 2001, RS-01-107.

15. Letter from J. A. Benjamin, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Materials Information Supporting the License Amendment Request to Permit Uprated Power Operation,” June 7, 2001, RS-01-113.

16. Letter from R. M. Krich, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Instrumentation and Controls Information Supporting the License Amendment Request to Permit Uprated Power Operation,” June 15, 2001, RS-01-116.

17. Letter from R. M. Krich, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Offsite Dose Information Supporting the License Amendment Request to Permit Uprated Power Operation,” July 6, 2001, RS-01-124.

18. Letter from R. M. Krich, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Electrical Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” July 23, 2001, RS-01-143.

19. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” August 7, 2001, RS-01-151.

20. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," August 8, 2001, RS-01-157.

21. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Reactor Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” August 9, 2001, RS-01-158.

22. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," August 13, 2001, RS-01-162.

23. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” August 13, 2001, RS-01-161.

24. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” August 14, 2001, RS-01-167.

25. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” August 14, 2001, RS-01-168.

26. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Supplement to Request for License Amendment for Power Uprate Operation,” August 29, 2001, RS-01-175.

27. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Radiation Dose Information Supporting the License Amendment Request to Permit Uprated Power Operation,” August 31, 2001, RS-01-183.

28. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Safety Analysis Reports Supporting the License Amendment Request to Permit Uprated Power Operation,” August 31, 2001, RS-01-180.

29. GE Nuclear Energy, Safety Analysis Report for Dresden 2 & 3 Extended Power Uprate, NEDO-32962, Revision 1, August 2001.

30. GE Nuclear Energy, Safety Analysis Report for Dresden 2 & 3 Extended Power Uprate, NEDC-32962P, Revision 2, (Proprietary), August 2001.

30. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation,” September 5, 2001, RS-01-186.

31. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station,” September 5, 2001, RS-01-187.

33. Letter from R. M. Krich, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Request for License Amendment for Pressure Temperature Limits,” June 26, 2001.

34. Letter from L. W. Rossbach (USNRC) to O. D. Kingsley (EGC), “Dresden Nuclear Power Station, Units 2 and 3 - Report On Results of Staff Audit Conducted On March 29-31, 1999, of Dresden Nuclear Power Station’s Resolution of Issues Identified in NRC Bulletin 96-03 (TAC NOS. M96142 and M96143),” August 10, 2001.

35. General Electric, “General Electric Standard Application for Reactor Fuel,” GESTAR II, NEDE-24011-P-A-14, July 2000.

36. General Electric, “GE Fuel Bundle Design,” NEDE-31152P, Volumes 1, 2, and 3, December 1988.

37. General Electric Nuclear Energy, “BWR Owners Group Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology and Reload Applications,” Licensing Topical Report NEDO-32465-A, August 1996.

38. BWROG-94078, “BWR Owners Group Guidelines for Stability Interim Corrective Action,” June 1994

39. General Electric Nuclear Energy, “General Electric Instrument Setpoint Methodology,” NEDC-31336P-A, September 1996.

40. Commonwealth Edison Company, “Analysis of Instrument Channel Setpoint Error and Instrument Loop Accuracy,” NES -EIC-20.04, Rev. 3.

41. General Electric Nuclear Energy, “ATWS Rule Issues Relative to BWR Core Thermal-Hydraulic Stability,” NEDO-32047-A, June 1995.

42. General Electric Nuclear Energy, “BWR Owners Group Long-term Stability Solution Licensing Methodology,” NEDO-31960-A and Supplement 1, April 1996.

43. General Electric, “Assessment of BWR Mitigation of ATWS, Volume II” (NUREG-0460 Alternative No. 3), NEDE-24222, December 1979.

44. Nuclear Regulatory Commission, “Power Oscillation in Boiling Water Reactors (BWRs),” Bulletin Number 88-07, Supplement 1, December 1988.

45. Letter from Stuart A. Richards, Nuclear Regulatory Commission, “Review of NEDC-32992P ODYSY Application for Stability Licensing Calculation,” Safety Evaluation, April 20, 2001.

46. Letter from G.G. Benes (ComEd) to USNRC, “LaSalle County Nuclear Power Station Units 1 and 2, Application for Amendment Request to Facility Operating Licenses NPF-11 and NPF-18, Appendix A, Technical Specifications Partial ARTS Implementation NRC Docket Nos. 50-373 and 50-374,” June 9, 1994.

47. Letter from W.D. Reckley (USNRC) to D.L. Farrar (ComEd), “Issuance of Amendments (TAC Nos. M89631 and M89632),” April 13, 1995.

48. Letter from T. W. Simpkin, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station,” September 14, 2001, RS-01-194.

49. Letter from T. W. Simpkin, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” September 19, 2001, RS-01-200.

50. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Supplement to Request for License Amendment for Power Uprate Operation,” September 25, 2001, RS-01-206.

51. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Testing Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” September 27, 2001, RS-01-209.

52. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” September 27, 2001, RS-01-210.

53. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station,” September 26, 2001, RS-01-208.

54. Letter from K. A. Ainger, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Revision to Proprietary Designation - Additional Testing Information Supporting the License Amendment Request to Permit Uprated Power Operation,” October 17, 2001, RS-01-228.

55. Letter from P. R. Simpson, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station, Units 2 and 3 and Quad Cities Nuclear Power Station, Units 1 and 2,” November 2, 2001, RS-01-249.

56. Letter from K. R. Jury, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Electrical Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” November 16, 2001, RS-01-263.

57. Letter from K. R. Jury, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station, Units 2 and 3, Quad Cities Nuclear Power Station, Units 1 and 2,” November 30, 2001, RS-01-275.

58. Global Nuclear Fuel, to Nuclear Regulatory Commission, “GEXL14 Correlation for GE14 Fuel, NEDC-32851P Revision 2, and GEXL10 Correlation for GE12 Fuel with Inconel Spacer, NEDC-32464P Revision 2,” September 25, 2001.

59. Letter from P. O’Connor (USNRC) to L. DelGeorge (Commonwealth Edison Company), Dresden 2 Nuclear Generating Station, Safety Evaluation of Hydrology SEP Topics II-3.A, II-3.B, II-3.B.1, and II-3.C,” June 21, 1982.

60. Boiling Water Reactor Owners Group (BWROG), Utility Resolution Guidance for ECCS Suction Strainer Blockage, Boiling Water Owner’s Group, NEDO-32686A, October 1998.

61. Letter from K. R. Jury, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Information Supporting the License Amendment Request to Permit Uprated Power Operation,” December 10, 2001, RS-01-289.

62. Letter from K. R. Jury, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Revision to Proprietary Designation - Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station and Quad Cities Nuclear Power Station,” dated December 17, 2001, RS-01-303

63. Letter from K. R. Jury, Exelon Generation Company, LLC, to Nuclear Regulatory Commission, “Additional Information Supporting the License Amendment Request to Permit Uprated Power Operation,” dated December 18, 2001, RS-01-306

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Date: December 21, 2001

EPU ONSITE AUDIT REVIEWS

During the weeks of March 26 and June 16, 2001, members of the NRC Reactor Systems Branch (SRXB) staff visited the Global Nuclear Fuel (GNF) engineering and manufacturing facility at Wilmington, North Carolina. The purpose of these visits was to perform onsite audit reviews of selected safety analyses and system and component performance evaluations used to support EPU license submittals. The March audit focused on the Duane Arnold Energy Center (DAEC) EPU, and the June audit was related to the DNPS EPU submittal. The areas covered by these audits are related to the following sections of the licensee's SAR and are discussed accordingly:

2.0 Reactor Core and Fuel Performance

2.1 Fuel Design and Operation
2.2 Thermal Limits Assessment
2.3 Reactivity Characteristics
2.4 Stability

9.0 Reactor Safety Performance Evaluations

9.1 Reactor Transients
9.3 Design Basis Accidents
9.4 Special Events

Review areas from the DAEC audit that also apply to Dresden and Quad Cities are included here. In each section, the areas reviewed are identified and grouped by a bullet listing. The audit reviews resolved a number of questions as discussed below. Several open items were identified, which were addressed by requests for additional information (RAIs) and resolved later, by licensee responses summarized below.

2.0 REACTOR CORE AND FUEL PERFORMANCE

2.1 Fuel Design and Operation

The SRXB staff audit covered the following areas:

- Followup issue addressed in RAI Question 3:

  In 1992, following an NRC team audit of the GE-11 (9x9, part-length rods) fuel design compliance with Amendment 22 of NEDE-20411-PA, GE (now GNF) was encouraged to develop a procedure for implementing Amendment 22 criteria for new CPR correlation development as defined in GESTAR II. This procedure is documented in GNF Technical Design Procedure (TDP) 0117, Rev. 2, page 8. Explain how this procedure was applied in the development of the GEXL14 correlation for use with GE-14 (10x10, part-length rods) fuel at Quad Cities and Dresden, especially with regard to items 1 and 2 of the TDP, given the apparent absence of raw experimental data points for upskew and downskew power profiles. Provide technical justification if the criteria of Amendment 22 process criteria were not met.

The licensee response to RAI Question 3 states:

"TDP-0117, Rev. 2, Sections 5.3 and 5.4 describes the test matrix for the ATLAS testing for the development of the GEXL correlation. This process was used, as described in GEXL14 Correlation for GE14 Fuel, NEDC-32851, Revision 1, September 1999. NEDC-32851, Rev. 1 also provides the process that was used to develop the uncertainties for GEXL14, using the COBRAG code to simulate the upskew and downskew power shape effects."

As discussed in the response to RAI Question 1 below, the GEXL correlation will be re-evaluated based on experimental test data alone. This includes data characterizing the trend with axial power shape. See also the response to RAI Question 2. With this action, the GEXL correlations for GE14 10x10 fuel will be in full compliance with Amendment 22 to GESTAR II, and the application of the approved Amendment 22 process documents the safety of the GE-14 fuel design.

- GE-14 fuel design compliance with respect to the GESTAR Amendment 22 process and applicable approved topical reports

  In addition to the followup issue discussed above, the staff reviewed the GE-14 fuel design compliance with the Amendment 22 process and with the approved topical reports, NEDC-32601P, NEDC-32694P, and NEDC-32502P, Rev. 1. To facilitate the review, the process was compared with previous compliance reviews of the GE-11 and GE-12 fuel designs. The reviewers questioned several aspects of the documentation, but judged that the intent of the process was largely met. There are no remaining issues, and GNF will document the generic responses for future reference to support the TS amendment.

- Fuel performance information for 10x10 fuel lattice design (GE-14) fuel used for DNPS, including available post-irradiation examination (PIE) data

  GNF staff presented a summary of recent fuel performance information for 9x9 and 10x10 fuel designs and discussed the schedule for collecting future PIE data for the 10x10 fuel "lead use" assemblies and reload batches. The results generally showed increased fuel reliability in the recent designs. The staff is satisfied with the results and planned inspection schedules.

- Analyses of DNPS first transition GE-14 reload core design, in comparison with equilibrium GE-14 core discussed in the licensee's SAR, with respect to operating T/H limits.

  Analyses performed for the first GE-14 transition reload core were reviewed by examination of the design record files for DNPS Cycle 18, and by discussions with Exelon and GNF engineering personnel involved in the analyses.

2.2 Thermal Limits Assessment (Critical Power Performance)

The SRXB audit covered the following areas:

- Experimental data base for 10x10 fuel lattice designs, used to develop the GEXL14 CPR correlation for GE-14 fuel, for DNPS reloads
- Range of CPR experimental data and correlation fit with respect to DNPS EPU operating power, flow, and temperature requirements
- Statistical aspects of experimental data base and correlation, (design of experiment, goodness of fit, uncertainty analysis) to support DNPS applications

Critical Power Performance

The staff reviewed the experimental data base used for the development of the GEXL14 CPR correlation for the GE14 (10x10) fuel lattice design.

As indicated, in the followup issue discussion above, the staff questioned the adequacy of the testing of the new 10x10 GE14 fuel (and GE-12 fuel) to determine their respective CPR correlations. No power upskew or downskew experimental data was collected to develop and validate the GEXL10 or the GEXL14 correlations for use in the US fuel/spacer designs. The staff requested (RAI Question 2) the licensee to provide additional data and analyses to substantiate and validate the GEXL10 and GEXL14 correlation uncertainties in the upskew and downskew regions. RAI Question 2 stated:

Describe the testing of the new GE14 fuel that was conducted to test the respective CPR correlations. Identify any additional data, available or planned, to substantiate and validate the correlations. Provide upskew or downskew data that has been collected to validate the GEXL10 or the GEXL14 correlations for use at Quad Cities, Units 1and 2, and Dresden, Units 2 and 3.

In response to RAI Question 2, the licensee stated:

"The GEXL14 correlation for GE-14 fuel was based on full-scale ATLAS test points, all of which were cosine axial power shape. Since the original GE14 testing was performed, additional testing has been performed in the ATLAS facility for the GE14 fuel design for both cosine and inlet-peaked power shape. An additional set of test points were obtained, of which some points were for a cosine axial power shape and the remaining points were for an inlet-peaked power shape. Thus, there are substantial experimental data points available to re-evaluate the GEXL14 critical power correlation. The response to RAI Question 1 discusses the re-evaluation."

RAI Question 1 is as follows:

The COBRAG computer code is the critical power ratio (CPR) methodology used to predict critical power behavior throughout the core. The NRC staff has not reviewed this code. We understand that COBRAG uses first principle models to predict boiling transition and the details of the flow field. Justify the adequacy of the COBRAG code in predicting, from “first principles,” boiling transition phenomenon in the upper portion of GE14 fuel and, if applicable to Quad Cities or Dresden, for GE12 (10x10) fuel.

In response to RAI Question 1 the licensee stated:

“For GE14, the GEXL14 correlation was developed from full-scale critical power data for cosine axial power shape and COBRAG-predicted critical power trends versus axial power shape. Comparison of the GEXL correlation to more recently performed full-scale testing for GE14 fuel for cosine and inlet peaked power shapes have shown that the GEXL14 correlation predicts the trend with respect to axial power shape and, therefore, the GEXL14 correlation is considered to be adequate. The correlation uncertainty for the GEXL14 correlation is being re-evaluated based on data alone and the COBRAG-generated data is being removed from the correlation uncertainty calculations. The capability of the GEXL correlations for GE14 fuel to predict the axial power shape effect is being re-evaluated based solely on the full scale ATLAS test data.”

As indicated in the licensee response above, GNF has agreed to remove the COBRAG calculated points from the GEXL14 data base. This resolves the question of COBRAG applicability.

The staff reviewed the range of experimental data versus the operating power, mass flow, and temperature conditions required for the DNPS EPU operation.

The data range for the cosine axial power shape was judged to cover the EPU operating range requirements for DNPS.

The staff reviewed the statistical aspects of the CPR experimental data base, the correlation development and validation, and the uncertainty analyses. The statistical techniques and application to the cosine data for the GEXL correlation determination were judged to be sufficient, with the exceptions noted above.

2.4 Stability

The SRXB audit covered the following areas:

- operating experience relative to T/H compatibility of different DNPS fuel types at low-flow/high-power conditions with off-normal void distribution

- clarification of applicability of Solution III to DNPS transition mixed cores

- evaluation of stability impact of changes due to DNPS mixed core with respect to restrictions in operating region and scram due to instability

The application of the ODYSY code to the Interim Corrective Action (ICA) stability solution was reviewed by discussions with GNF staff. At the time of the audit, the ODYSY stability application licensing topical report (NEDC-32992P) was under review and was subsequently approved as discussed in Section 2.4 of this SE.

In reviewing the applicability of the long-term Solution I-D option for DAEC application, the staff questioned whether the generic DIVOM curve for core wide mode and regional mode stabilities was applicable for EPU operation. The DIVOM (Delta CPR over initial minimum critical power ratio [IMCPR] versus oscillation magnitude) curves are normalized curves of CPR performance versus the hot bundle OM. Two generic curves are used to specify core wide oscillation and regional mode oscillation. The regional mode 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 MCPR safety limit protection against core wide instability. The staff reviewed the DNPS EPU and transition Cycle 18 analyses to determine the applicability of the generic curves for EPU operation. GE provided the staff with a February 19, 2001, “Interim Corrective Action Request,” which indicated that for 20 percent EPU, the generic DIVOM curve may not be bounding for regional mode oscillations. The internal corrective action report stated that the generic DIVOM curves are acceptable for 5 percent power uprate. In June 29, 2001, GE issued a 10 CFR Part 21 report on the potential nonconservatism and provided a figure of merit to be applied to the both core wide and regional DIVOM curves. This resolved the staff’s questions regarding the applicability of the generic DIVOM curves for EPU operations at DNPS as discussed in Section 2.4 of this SE.

9.0 REACTOR SAFETY PERFORMANCE EVALUATIONS

9.1 Reactor Transients

Dresden and Quad Cities design record files and Project Task Report T0900, “Transient Analysis,” report were reviewed during the audit. No problems were found, and the discussion of limiting transients is included in the appropriate sections of this SE.

9.2 Design Basis Accidents

The SRXB audit covered the DNPS LOCA analysis for pre- and post-uprate conditions.

The staff reviewed the DNPS LOCA analyses for pre- and post-uprate operating conditions by discussions of design record files with Exelon and GNF engineering personnel involved in the analyses. One item was questioned and resolved by RAI.

RAI Question 4 was as follows:

The LOCA analysis of off-rated conditions (specifically, SLO) assumes that the statistical adders developed for the SAFER code at rated conditions will apply. Justify the use of these adders for SLO at Quad Cities and Dresden.

In response to RAI Question 4 the licensee stated:

“The maximum average planar linear heat generation rate (MAPLHGR) multiplier for single-loop operation (SLO) is set at a value that keeps the nominal SLO peak cladding temperature (PCT) below the nominal two-loop PCT for the design basis accident (DBA). The upper bound PCT is then calculated for the limiting two-loop DBA case. This process assumes that the two-loop upper bound PCT would bound an explicit SLO upper bound PCT calculation. Inherent in this process is the assumption that the upper bound adder terms used in the two-loop calculations are bounding for SLO conditions.

“The SLO PCT is first peak limited; 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 and include core uncovery, vessel refilling, spray and steam cooling, core reflooding, and quenching, along with any residual effects from the first peak heatup. 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. Therefore, the assumption that the upper bound adder terms used in the two-loop calculation are bounding for SLO is valid.”

9.4 Special Events

The only special event was the post-uprate anticipated transient without scram (ATWS) analysis for DNPS EPU operating region.

Dresden and Quad Cities design record files and the Project Task Report T0902, “Anticipated Transient Without Scram,” were reviewed during the audit. The following section, 9.4.1, addresses a generic item identified during the DNPS audit, regarding SLC system performance.

9.4.1 Anticipated Transient Without Scram (ATWS)

As a result of the audit, the staff requested and received additional information from the licensee on the ATWS/SLC events that were analyzed at the EPU conditions.

The limiting events for each of the five ATWS acceptance criteria in Section 9.4.1 of the licensee’s SAR are identified as the PRFO for Criteria 1,2, and 3, and the MSIVC for Criteria 4 and 5. The licensee confirmed that the operator response to an ATWS event is not being modified from that described in Section L.3.2, “Operator Actions,” of ELTR1. The licensee confirmed that for all limiting ATWS events, the SLC system for DNPS, Unit 2 will be able to inject at the appropriate time without lifting the SLC bypass RV. The cycle-specific reload analysis for DNPS Unit 3, and for QCNPS, Units 1 and 2, will confirm the SLC capability or will identify required system modifications. The licensee also confirmed that the SLC system meets the ATWS acceptance criteria for DNPS and QCNPS even if the operator requests SLC actuation before the time assumed in the analysis, and the RV lifts and remains open until the valve inlet pressure decreases to the valve reseat pressure. The licensee will verify the valve reseat pressure and the lack of valve chatter upon reseat at the next refueling outage for each unit. The licensee’s response to the staff’s questions was summarized in a letter dated November 2, 2001 (Reference 55).

Conclusions

The SRXB staff audit, conducted during the week of June 16, 2001, covered the areas of the licensee's SAR being reviewed by SRXB. As stated, most questions were resolved during the audit, and the rest were covered by RAIs and the licensee responses. All open items were addressed. Based on the audit and the licensee response to the RAIs, the staff finds that all issues have been satisfactorily resolved.

LIST OF ACRONYMS

AC - alternating current
ADS - automatic depressurization system
AL - analytical limit
ALARA - as low as reasonably achievable
ANSI - American National Standards Institute
AOO - anticipated operational occurrence
AOP - abnormal operating procedure
APC - availability performance criteria
APRM - average power range monitor
ART - adjusted reference temperature
ARTS - averabe power range monitor/rod block monitor technical specification
ASME - American Society of Mechanical Engineers
ATWS - anticipated transient without scram
AV - allowable value
BOP - balance-of-plant
BWR - boiling water reactor
BWROG - Boiling Water Reactor Owners Group
CAD - containment atmosphere dilution
CC - containment cooling
CCF - common cause failure
CDF - core damage frequency
CGCS - combustible gas control system
COLR - Core Operating Limits Report
CPR - critical power ratio
CRD - control rod drive
CRDA - control rod drop accident
CRDM - control rod drive mechanism
CREV - control room emergency ventilation
CS - core spray
CSC - containment spray cooling
CUF - cumulative usage factor
DAEC - Duane Arnold Energy Center
DBA - design-basis accident
DC - direct current
DGCW - diesel generator cooling water
DHR - decay heat removal
DRF - design record file
ECCS - emergency core cooling system
EFPY - effective full power years
ELLLA - extended load limit line analysis
EPU - extended power uprate
EQ - environmental qualification
FHA - fuel-handling accident

FIV - flow-induced vibration
FIVE - fire-induced vulnerability evaluation
FPC - fuel pool cooling
FPCCS - fuel pool cooling and cleanup system
FW - feedwater
GDC - general design criteria
GE - General Electric
GIP - generic implementation procedure
GNF - Global Nuclear Fuel
GL - generic letter
HCLPF - high confidence of a low probability of failure
HCU - hydraulic control unit
HELB - high-energy line break
HEP - human error probability
HEPA - high-efficiency particulate air
HPCI - high-pressure coolant injection
HVAC - heating, ventilation, and air conditioning
IMPCR - initial minimum critical power ratio
IORV - inadvertently opened relief valve
IPE - individual plant examination
IPEEE - individual plant examination of external events
ISTS - Improved Standard Technical Specification
LERF - large early release frequency
LFWH - loss of feedwater heating
LOCA - loss-of-coolant accident
LHGR - linear heat generation rate
LLRW - low-level radioactive waste
LOOP - loss of offsite power
LOFWF - loss-of-feedwater flow
LPCI - low-pressure coolant injection
LTR - Licensing Topical Report
MAPLHGR - maximum average planar linear heat generation rate
MCPR - minimum critical power ratio
MCRACS - main control room atmosphere control system
MELLLA - maximum extended load limit line analysis
MOV - motor-operated valves
MSIV - main steam isolation valve
MSLB - main steam line break
NPSH - net positive suction head
NRC - U.S. Nuclear Regulatory Commission
NSSS - nuclear steam supply system
OL - operating limit
ORNL - Oak Ridge National Laboratory
ORTP - original rated thermal power
PCT - peak cladding temperature
PRA - probabilistic risk assessment
QCNPS - Quad Cities Nuclear Power Station
RAI - request for additional information
RAT - reserve auxiliary transformer

RBCCW - reactor building closed cooling water
RBM - rod block monitor
RG - regulatory guide
RCIC - reactor core isolation cooling
RCPB - reactor coolant pressure boundary
RCS - reactor coolant system
RHR - residual heat removal
RPS - reactor protection system
RPT - recirculation pump trip
RPV - reactor pressure vessel
RTP - rated thermal power
RV - relief valve
RWCU - reactor water cleanup
RWE - rod withdrawal error
S&RVs - safety and relief valves
SAFDL - specified acceptable fuel design limit
SAR - safety analysis report
SBO - station blackout
SDC - shutdown cooling
SE - safety evaluation
SER - safety evaluation report
SFP - spent fuel pool
SGTS - standby gas treatment system
SLC - standby liquid control
SLMCPR - safety limit minimum critical power ratio
SLO - single-loop operation
SORV - stuck-open relief valve
SPC - suppression pool cooling
SPDS - safety parameter display system
SSE - safe-shutdown earthquake
SRM - source range monitor
SRP - Standard Review Plan
SRV - safety/relief valve
SSV - spring-actuated safety valve
TASC - Technical Activity Steering Committee
TBCCW - turbine building closed cooling water
TCV - turbine control valve
TER - technical evaluation report
TS - technical specification
TSC - technical support center
TSV - turbine stop valve
TTNBP - turbine trip with bypass failure
UAT - unit auxiliary transformer
UFSAR - updated final safety analysis report
UHS - ultimate heat sink
USE - upper shelf energy
USI - unresolved safety issue