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February 24, 2005

Docket No. 50-271
BVY 05-017
TAC No. MC0761

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Subject: **Vermont Yankee Nuclear Power Station**
Technical Specification Proposed Change No. 263 – Supplement No. 23
Extended Power Uprate – Response to Request for Additional Information

Reference: 1) U.S. Nuclear Regulatory Commission (Richard B. Ennis) letter to Entergy Nuclear Operations, Inc. (Michael Kansler), "Request for Additional Information – Extended Power Uprate, Vermont Yankee Nuclear Power Station (TAC No. MC0761), December 21, 2004

2) Entergy letter to U.S. Nuclear Regulatory Commission, "Vermont Yankee Nuclear Power Station, License No. DPR-28 (Docket No. 50-271), Technical Specification Proposed Change No. 263, Extended Power Uprate," BVY 03-80, September 10, 2003

This letter responds to NRC's request for additional information (RAI) of December 21, 2004 (Reference 1) regarding the application by Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc. (Entergy) for a license amendment (Reference 2) to increase the maximum authorized power level of the Vermont Yankee Nuclear Power Station (VYNPS) from 1593 megawatts thermal (MWt) to 1912 MWt.

Attachment 1 to this letter provides Entergy's response to 15 of the 18 individual RAIs contained in Reference 1. Entergy is in the process of preparing a response to the remaining three RAIs and anticipates submitting these responses by March 1, 2005.

Subsequent to the receipt of the RAI, discussions were held with the NRC staff to further clarify the RAIs. In certain instances the RAIs may have been modified based on clarifications and understandings reached during the telecons. The information provided herein is consistent with those understandings.

Attachment 2 provides the "Exhibits" referenced in two of the RAI responses.

There are no new regulatory commitments contained in the responses to the RAIs.

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This supplement to the license amendment request provides additional information to clarify Entergy's application for a license amendment and does not change the scope or conclusions in the original application, nor does it change Entergy's determination of no significant hazards consideration.

If you have any questions or require additional information, please contact Mr. James DeVincentis at (802) 258-4236.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on February 24, 2005.

Sincerely,

Jay K. Thayer
Site Vice President
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Attachments (2)

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Attachment 1

Vermont Yankee Nuclear Power Station

Proposed Technical Specification Change No. 263 – Supplement No. 23

Extended Power Uprate

Response to Request for Additional Information

Total number of pages in Attachment 1 (excludina this cover sheet) is 48.

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION RELATED TO EXTENDED POWER UPRATE REQUEST VERMONT YANKEE NUCLEAR POWER STATION

PREFACE

This attachment is a partial response to the NRC staff's request for additional information (RAI) dated December 21, 2004. This attachment provides Entergy's response to 15 of the 18 individual RAIs. Upon receipt of the RAI, discussions were held with the NRC staff to further clarify the RAI. In certain instances individual RAIs may have been modified based on clarifications reached during these discussions. The information provided herein is consistent with those clarifications.

The individual RAIs are re-stated exactly as provided in NRC's letter of December 21, 2004.

Plant Systems Branch (SPLB)

Balance of Plant Section (SPLB-A)

RAI SPLB-A-10

EPU Transient Testing

As discussed in the NRC's "Review Standard for Extended Power Uprates," RS-001, Safety Evaluation template Section 2.12, "Power Ascension and Testing Plan," the purpose of the EPU test program is to demonstrate that structures, systems, and components (SSCs) will perform satisfactorily in service at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with design criteria at EPU conditions. The NRC's acceptance criteria for the proposed EPU test program are based on 10 CFR Part 50, Appendix B, Criterion XI, which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service. Specific review criteria are contained in NUREG-0800, Standard Review Plan (SRP) Section 14.2.1, "Generic Guidelines for Extended Power Uprate Testing," Draft Revision 0, dated December 2002.

SRP Section 14.2.1 directs the NRC staff to assess the adequacy of the licensee's evaluation of the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to anticipated operational occurrences. The staff's review is intended to ensure that the performance of plant equipment important to safety that could be affected by integrated plant operation or transient conditions is adequately demonstrated prior to extended operation at the requested EPU power level. Licensees may propose a test program that does not include all of the power-ascension testing that would normally be included in accordance with the guidance provided in SRP 14.2.1, provided each proposed test exception is adequately justified. If a licensee proposes to omit a specified transient test from the EPU testing program based on favorable operating experience, the applicability of the operating experience to the specific plant must be demonstrated. Further, the licensee shall address the potential for any new thermal-hydraulic phenomena or system interactions that may be introduced as a result of the EPU or planned modifications. Also, if the basis for elimination of a transient test relies on the use of analytical methods, the licensee should address the conformance to limitations associated with the analytical methods. Plant design details (such as configuration, modifications, and relative changes in setpoints and parameters), equipment specifications, operating power level, test specifications and methods, operating and emergency operating procedures; and adverse operating experience from previous power uprates must be considered and addressed.

Entergy's test program primarily includes steady state testing with some minor load changes, and no large-scale transient testing is proposed. Sufficient information has not been provided to demonstrate that in the absence of large-scale transient testing, the integrated plant response during transient conditions will be as expected. Entergy is therefore requested to either: a) provide additional information in accordance with the guidance provided in SRP Section 14.2.1 that explains in detail how the proposed EPU startup and power ascension test program, in conjunction with the original test results and applicable industry experience, assures the plant will respond as expected during postulated transient conditions following implementation of the proposed EPU given the revised operating conditions that will exist and plant changes that are

being made; or b) describe transient testing that will be included in the power ascension test program in order to provide this assurance, and explain in detail how the proposed transient testing will demonstrate that SSCs will perform satisfactorily in service at the proposed EPU power level.

Response to RAI SPLB-A-10

A. INTRODUCTION AND SUMMARY OF CONCLUSIONS

By letter BVY 03-098, dated October 28, 2003, Entergy, in its request for approval of the extended power uprate (EPU), provided justification for elimination of the requirement for large transient testing upon implementation of the EPU. This response provides further amplification of that justification and addresses the specific acceptance criteria as contained in Standard Review Plan (SRP) 14.2.1, Draft Rev. 0, Section III.C.2, "Use of Evaluation to Justify Elimination of Power-Ascension Tests." Because there are minimal benefits to conducting large transient testing, Entergy concludes that such testing is not warranted.

This response concludes that:

1. The justification provided for elimination of large transient testing is consistent with the justifications provided and approved for other plants implementing EPUs.

2. Operating experience at plants that have implemented EPU and are similar in design to the Vermont Yankee Nuclear Power Station (VYNPS), as well as prior large transient events at VYNPS, demonstrate that the transient analysis results bound the actual transient events. The VYNPS transient events considered include a transient in 2004 that followed installation of many of the EPU modifications (installed during the spring 2004 refueling outage). The response of plant systems to this transient event (which occurred in June 2004) was as expected.

3. EPU does not introduce new thermal-hydraulic phenomena or system interactions that would affect the results or response to plant transients.

4. The VYNPS Power Uprate Safety Analysis Report (PUSAR), NEDC-33090P, Rev. 0, September 2003, section 10.6 addresses operator training for the modified plant and operation at constant pressure power uprate (CPPU) conditions.

5. Any changes in margin do not impact system integrity or significantly affect operator response.

6. The VYNPS license amendment application and request for exception from transient testing is in accordance with General Electric (GE) Company Licensing Topical Report for Constant Pressure Power Uprate (CLTR) Safety Analysis: NEDC-33004P-A, Rev. 4, July 2003.

7. This justification for not performing large transient testing (LTT) does not rely on the guidance provided in SRP 14.2.1 section III.C.2.g.

B. BACKGROUND

From 10 CFR 50, Appendix B, Criterion III, "[The] design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program." [*emphasis added*] For each change to the facility to accommodate CPPU, the design adequacy is verified for VYNPS by means of (a) a combination of design review by VYNPS engineering personnel and its vendors, and evaluation of operational experience at other utilities; (b) calculational modeling of VYNPS-specific changes; and/or, (c) the performance of a suitable testing program for the changes implemented at VYNPS.

From Standard Review Plan 14.2.1, Section III.A.1, "The licensee should provide a comparison of the proposed EPU testing program to the original power-ascension test program performed during initial plant licensing. The scope of this comparison shall include (1) all power-ascension tests initially performed at a power level of equal to or greater than 80 percent of the original licensed thermal power level; and (2) initial power-ascension tests performed at lower power levels if the EPU would invalidate the test results. The licensee shall either reperform initial power-ascension tests within the scope of this comparison or adequately justify proposed deviations." [*emphasis added*]

The CPPU license amendment application was prepared following the guidelines contained in the NRC approved CLTR. In its approval of the CLTR, the NRC staff required, in lieu of generic elimination of large transient testing as presented in the CLTR, that a plant-specific basis be provided for not performing these tests. Therefore, a VYNPS plant-specific basis for exception to performing the large transient tests (i.e., main steam isolation valve (MSIV) closure and turbine generator load rejection) is provided herein.

C. SUMMARY OF EPU MODIFICATIONS

The following Table SPLB-A-10-1 provides (a) a listing of EPU plant modifications, (b) a determination of whether the modifications have been installed during the previous RFO24 (i.e., spring 2004), (c) a determination of whether the modifications have an effect on the plant transient analysis, (d) a determination of whether the plant change is modeled in the transient analyses, (e) an indication of any proposed post modification testing, (f) an indication of subsequent power ascension and/or power operation confirmatory testing and monitoring, and (g) a determination of whether the modified function would be tested/verified during large transient testing. Low power testing and monitoring as are normally conducted during startups has been and will be performed in addition to the testing cited. None of these modifications will introduce any new thermal-hydraulic phenomena as a result of power uprate, nor are any new system interactions during or as the result of analyzed transients introduced. A brief discussion of the modifications, including those that may affect plant transient analyses, follows Table SPLB-A-10-1. It should be noted that incidental modifications associated with EPU, such as alarms, indications, and scaling changes are not included as these changes do not impact transient response.

The modifications listed in Table SPLB-A-10-1 identify those EPU changes currently installed or planned for installation at VYNPS. Further evaluation may identify the need for other changes

or eliminate the need for some pending modifications and tests. Therefore, this listing is not a formal commitment to completely implement the modifications as shown or to, consequently, perform the testing exactly as planned. In addition, construction, installation, and/or pre-operational testing for each modification has been performed in accordance with the VYNPS design process procedures and these tests are not listed herein. The tests listed in Table SPLB-A-10-1 are the final acceptance tests that demonstrate the modifications will perform their function and integrate appropriately within the plant.

D. EVALUATIONS OF TESTING EXPERIENCE AND UNPLANNED TRANSIENTS AT OTHER FACILITIES LICENSED FOR EPU OPERATION WITHOUT INCREASE IN REACTOR PRESSURE

The CPPU methodology simplifies the analyses and plant changes required to achieve uprated conditions. Although no plants have yet implemented an EPU using the CLTR, thirteen plants have been licensed for EPU operation without increasing reactor pressure:

- Hatch Units 1 and 2 (from 105% to 113% of Original Licensed Thermal Power (OLTP))
- Monticello (from 100% to 106.3% OLTP)
- Muehleberg (i.e., KKM) (from 105% to 116% OLTP)
- Leibstadt (i.e., KKL) (from 105% to 117% OLTP)
- Duane Arnold (from 105% to 120% OLTP)
- Brunswick Units 1 and 2 (from 105% to 120% OLTP)
- Quad Cities Units 1 and 2 (from 100% to 117% OLTP)
- Dresden Units 2 and 3 (from 100% to 117% OLTP)
- Clinton (from 100% to 120% OLTP)

Data collected from testing and responses to unplanned transients for Hatch Units 1 and 2, Brunswick 2, Dresden 2 and 3, and KKL plants during post-EPU operation have shown that plant response has consistently been as planned (except for the Dresden 3 feedwater level control system (FWLCS) tuning issue discussed below), within expected parameters, and bounded by the plant transient and safety analyses. Based on the similarity in design of these units to VYNPS (as shown for several of these units in Updated Final Safety Analysis Report (UFSAR) Tables 1.7.4, 1.7.5, and 1.7.6), it is reasonable to conclude that the response seen at these units would be comparable to that which would be seen at VYNPS.

Where an unplanned response in another plant's operational experience was encountered, such as with the Dresden Nuclear Power Station Unit 3 (Dresden Unit 3) automatic scram as reported in Licensee Event Report (LER) 05000249/2004-002-00, a specific evaluation was conducted to determine if the effects seen from the Dresden Unit 3 FWLCS would be applicable to VYNPS. In this particular instance, the Dresden Unit 3 FWLCS was not properly tuned such that feedwater flow (including overshoot during regulating valve response to reactor vessel level increase) following a reactor scram would be sufficiently reduced prior to introducing feedwater into the High Pressure Coolant Injection (HPCI) turbine steam line and, subsequently, causing the turbine driven HPCI pumps to become inoperable. The VYNPS HPCI turbine steam line is connected to one of the main steam lines versus connected directly to the reactor vessel in the Dresden 3 design. VYNPS has a digital/analog FWLCS (i.e., digital controller units and digital valve positioners in an otherwise analog control system) that incorporates a push button (PB1) on the controller unit in the control room to provide a manual level setdown for additional margin in level control that will preclude flooding of the main steam lines (and thereby introducing water

to the HPCI turbine steam supply line) by feedwater level overshoot during feedwater regulating valve response. The level setdown reduces the level control setpoint from ~160 inches to 133 inches above the top of the enriched fuel (TEF) and is procedurally used following reactor scrams and anticipated transients without scram scenarios to provide additional (immediate operator action) margin for level control. A reactor vessel high level trip of the feedwater pumps, HPCI pump and Reactor Core Isolation Cooling (RCIC) pump occurs at ≤177 inches, which is well above the level control setpoint and is below the steam line nominal bottom elevation of 235.5 inches. Therefore, the differences in design of the HPCI steam supply line configuration and margins provided by the differences in design of the FWLC System, as well as the procedural response to a reactor trip, a situation as experienced at Dresden Unit 3 wherein feedwater overshoot caused inoperability of the HPCI pump should not occur at VYNPS. Operation of three RFPs at VYNPS during uprated conditions will be further addressed in FWLCS operation to ensure the possibility of the situation as occurred at Dresden 3 will be further reduced at VYNPS.

Analyses for anticipated operational occurrences have been performed by GE for VYNPS using the NRC-approved analysis code, ODYN, which models the direct cycle boiling water reactor (BWR), including the turbine-generator system and the feedwater system functions. The analyses yield the bounding results for anticipated operational transients. These analyses yielded small reductions in margins for these overpressurization transients, but maintain a suitable margin to design limits for the reactor vessel and dome as cited in Section 3.1 of the PUSAR. It is important to note that the bounding analyses were performed considering configurations and component/system failures that are impractical to replicate during a testing program and are unlikely to be seen during actual plant transients.

Entergy's position is that additional MSIV closure and generator load rejection tests are not necessary at VYNPS. If performed, these tests would not confirm any new or significant aspect of performance that is not routinely demonstrated by component level testing. To achieve the bounding conditions to verify results of the analyses, several attributes of the plant (e.g., MSIV limit switches and bypass valves) would need to be defeated, which is an undesirable plant configuration. In addition, industry experience (cited above and discussed in more detail in the following section on industry BWR power uprate experience) has demonstrated plant performance to be bounded by the plant transient analyses, as predicted, under EPU conditions. VYNPS has itself experienced generator load rejections and the loss of the generator that resulted in a turbine trip from 100% current licensed thermal power (see VYNPS Licensee Event Reports (LER) 1991-005-00, 1991-009-00, 1991-014-00, and 2004-003-00). It is important to note that the 2004 transient occurred following implementation of many of the EPU modifications (e.g., HP turbine rotor, Main Generator Stator rewind, new HP feedwater heaters, condenser tube staking, upgraded isophase bus duct cooling, and condensate demineralizer filtered bypass). No significant anomalies were seen in the plant's response to these events. Because EPU does not involve any changes that would significantly affect the plant's response as was seen during previous events (as further demonstrated during the 2004 event wherein many of the EPU modifications were already installed), further testing is not necessary to demonstrate safe operation of the plant at CPPU conditions. Therefore, requiring MSIV isolation or load rejection from high power would result in an unnecessary and undesirable transient cycle on the primary system.

E. EVALUATIONS OF VYNPS RESPONSE TO UNPLANNED TRANSIENTS

VYNPS has previously experienced the following unplanned transients:

1. On March 13, 1991, with reactor power at 100% Rated Thermal Power (RTP), a reactor scram occurred as a result of Turbine/Generator Trip on Generator Load Rejection due to a 345 kV Switchyard Tie Line Differential Fault. This event was reported to the NRC in LER 1991-005-00, dated April 12, 1991.

2. On April 23, 1991, with the reactor at 100% RTP, a reactor scram occurred as a result of a turbine/generator trip on generator load rejection due to the receipt of a 345 kV breaker failure signal. The event included a loss of off site power. This was reported to the NRC in LER 1991-009-00, dated May 23, 1991.

3. On June 15, 1991, during normal operation with reactor power at 100% RTP, a reactor scram occurred due to a Turbine Control Valve Fast Closure on Generator Load Rejection resulting from a loss of the 345 kV North Switchyard bus. This event was reported to the NRC in LER 1991-014-00, dated July 15, 1991.

4. On June 18, 2004, during normal operation with the reactor at 100% RTP, a two phase electrical fault-to-ground caused the main generator protective relaying to isolate the main generator from the grid and resulted in a Generator Load Rejection reactor scram. This was caused by an isophase bus flexible connector failure (not related to the EPU modification) and was reported to the NRC in LER 2004-003-00, dated August 16, 2004. It is important to note that several of the modifications associated with EPU, including the new HP turbine rotor, Main Generator Stator rewind, the new high pressure feedwater heaters, condenser tube staking, an upgraded isophase bus duct cooling system, and condensate demineralizer filtered bypass were already installed at the time of this transient.

No significant anomalies were seen in VYNPS's response to these events. Transient experience at high power and for a wide range of power levels at other operating BWR plants has shown a close correlation of the plant transient data to the predicated response and each response was bounded by the plant safety analyses, as discussed below.

Based on the (a) similarity of the VYNPS design configuration and system functions at pre-CPPU to post-CPPU; (b) results of past transient testing and responses to unplanned transients; (c) the fact that past transient and safety analyses correlate closely to results from actual transients; and, (d) the evaluation of unplanned transients for the pre-CPPU VYNPS and other post-EPU plants that provide favorable comparison of plant responses, it is reasonable and justifiable that the effects at EPU conditions can be analytically determined on a plant specific basis versus actual transient testing. The transient analyses performed for the VYNPS CPPU demonstrate that all safety criteria are met and that the uprate does not cause any previous non-limiting events to become limiting. No safety related systems have been or will be significantly modified for the CPPU. Some instrument setpoints were changed but the setpoints changes themselves do not measurably contribute to the response to large transient events. No physical modification or setpoint changes were made to the Safety Relief Valves (SRVs). No new systems or features were installed for mitigation of rapid pressurization anticipated operational occurrences for CPPU.

As previously stated, a scram from high power results is an undesirable transient cycle on the primary system. Because past testing at VYNPS and evaluation of operational experience at VYNPS and other plants has shown that system and plant response is within the bounds of the

plant transient analyses, additional transient testing involving scram from high power is not justified or necessary. As has been shown, analyses for CPPU provide the necessary assurance that sufficient margins to safety limits are maintained. Should any future large transients occur, VYNPS procedures require evaluation and verification that the actual plant response is in accordance with the predicted response and is within existing accident and transient analyses. Existing in-plant computers are capable of acquiring the necessary data for the evaluation and verification.

Steady state testing confirms the important nuclear characteristics required for transient analyses. Technical Specification required surveillance testing (e.g., component testing, trip logic system testing, simulated actuation testing) demonstrates that the systems, structures and components (SSCs) will perform their functions, including integrated performance for transient mitigation as assumed in the transient analysis. The characteristics and functions of SSCs do not need to be demonstrated further in a large transient test. In addition, the limiting transient analyses (i.e., those that affect core operating and safety limits) are reperformed each cycle and are included as part of the reload licensing analysis.

F. ANALYSIS OF MSIV CLOSURE EVENT

Closure of all MSIVs is an Abnormal Operational Transient as described in Chapter 14 of the VYNPS Updated Final Safety Analysis Report (UFSAR). The transient produced by the fast closure (3.0 seconds) of all main steam line isolation valves represents the most severe abnormal operational transient resulting in a nuclear system pressure rise when direct scrams are ignored. The Code overpressure protection analysis assumes the failure of the MSIV position scram feature. The MSIV closure transient is more significant if the transient is terminated by the backup flux scram than the MSIV position scram. This case has been re-evaluated for CPPU and is presented in Section 3.1 of the PUSAR. Design pressure limits were not violated, though a decrease in margin to these limits was determined.

The CLTR states that: "The same performance criteria will be used as in the original power ascension tests, unless they have been replaced by updated criteria since the initial test program." The MSIV closure test performed during the VYNPS initial test program permitted the scram to be initiated by the MSIV position switches. As such, if the MSIV closure test were re-performed using this same assumption, the results should be less significant than the MSIV closure analysis performed by GE for CPPU.

1. Original MSIV Startup Test Criteria

The MSIV closure test performed during the VYNPS initial startup test program was intended to demonstrate the proper transient response of the plant during and following simultaneous full closure of all MSIVs.

a. Performance Criteria:

   i. Reactor pressure shall be maintained below 1230 psig.
   ii. Maximum reactor pressure should be 35 psi below the first safety valve setpoint. (This is margin for safety valve weeping).
   iii. Functionally check the MSIVs for proper operation and determine MSIV closure time (i.e., closure time between 3 and 5 seconds).

2. Reactor Transient Behavior to MSIV Closure Event

For this event, the closure of the MSIVs causes a reactor vessel pressure increase and an increase in reactivity. The negative reactivity of the scram from MSIV position switches offsets the positive reactivity of the pressure increase such that there is a minimal increase in heat flux. Therefore, the thermal performance during the proposed MSIV closure test is less limiting than the MSIV closure transient re-evaluated in the PUSAR. The results of BOP plant performance is not needed in this transient. CPPU will have minimal impact on the components important to achieving the desired thermal performance. Reactor Protection System (RPS) logic is unaffected and, with the uprate being a constant pressure uprate, overall control rod insertion times will not be significantly affected. MSIV closure speed is controlled by adjustments to the actuator and is considered very reliable as indicated below.

a. Reactor Vessel Pressure and Relationship to Safety Valve Setpoint

Due to the minimal nature of the flux transient for MSIV closure with scram from the MSIV position switches, the expected reactor vessel pressure rise, Item 1 above, is largely dependent on SRV setpoint performance (i.e., SRVs not lifting below their specified setpoint). It has been the maintenance practice at VYNPS to replace each of the four SRVs with a re-furbished and pre-tested valve during each refueling outage. After the refueling outage, the removed valves are sent offsite for testing and recalibration for installation in the following refueling outage. Over the past ten years there have been twenty five (25) SRV tests performed. In those twenty five tests only one as-found setting was outside the Technical Specification (TS) current allowable tolerance of ±3%. This valve was found to deviate by 3.4% of its nominal lift setpoint. Note that this is bounded by the VYNPS design analysis for peak reactor vessel pressure which assumes one of the four SRVs fails to open (one SRV out of service). Given the historical performance of the VYNPS SRVs, performance of an actual MSIV closure test would provide little benefit for demonstrating vessel overpressure protection that is not already accomplished by the component level testing that is routinely performed in accordance with the VYNPS TSs.

Because rated reactor vessel steam dome pressure is not being increased and SRV setpoints are not being changed, there is no increase in the probability of leakage after a SRV lift. Since SRV leakage performance is considered acceptable at the current conditions, which match CPPU conditions with respect to steam dome pressure and SRV setpoints, SRV leakage performance will continue to be acceptable at CPPU conditions. An MSIV closure test would provide no significant additional confirmation of Item 1 performance criteria beyond the routine component testing performed in accordance with the VYNPS TS.

b. MSIV Closure Time

Because steam flow assists MSIV closure, the focus of Item 2 was to verify that the steam flow from the reactor was not isolated faster than assumed (i.e., 3 seconds). During maintenance and surveillance, MSIV actuators are evaluated and adjusted as necessary to control actuator speed and valve closure time, and VYNPS test performance has been good. To account for minor variations in stroke times, the calibration test procedure for MSIV closure requires an as left fast closure time of 4.0 ±0.2 seconds. The MSIVs were evaluated for CPPU. The evaluation included the limiting MSIV closure time and determined that the MSIVs are acceptable for CPPU operation (see PUSAR section 3.8). Industry experience, including VYNPS, has shown that there are no significant generic problems with actuator design that

would affect actuator performance. Based on Entergy's evaluation confidence is very high that MSIV minimum stroke time will not be less than assumed by the analysis.

3. Other Plant Systems and Components Response

The MSIV limit switches that provide the scram signal are highly reliable devices that are suitable for this application, including environmental requirements. There is no direct effect by any CPPU changes on these switches. There may be an indirect impact caused by slightly higher ambient temperatures (i.e., < 1°F), but the increased temperatures will still be below the qualification temperature. Therefore, the switches are expected to be equally reliable before and after CPPU.

The RPS and Control Rod Drive (CRD) components that convert the scram signals into CRD motion are not directly affected by any CPPU changes. Minor changes in pressure drops across reactor vessel components may result in very slight changes in control blade insertion rates. These changes have been evaluated and determined to be insignificant. The ability to meet the scram performance requirement is not affected by CPPU. Technical Specification (TS) requirements for these components will continue to be met.

Feedwater System operation for CPPU will require operation of all three Reactor Feedwater Pumps (RFP) at CPPU conditions (unlike CLTP conditions wherein only two of the RFPs, with the third RFP in standby, were required). Operation of the additional RFP will not affect plant response to an MSIV closure transient. As stated previously, the level control setpoint is, by procedural requirements, manually reduced from ~160 inches to 133 inches above TEF following a reactor scram. The RFP, the HPCI turbine and the RCIC turbine receive trip signals prior to reactor vessel water level reaching 177 inches. Overfill of the reactor vessel after a trip would only occur if level exceeded 235.5 inches (nominal bottom elevation of the steam lines). Since the RFPs, the HPCI turbine, and the RCIC turbine all receive trip signals prior to level reaching 177 inches, a substantial margin exists. VYNPS operating history has demonstrated that this margin exceeds reactor vessel level overshoot during transient events. Operation of three RFPs at VYNPS during uprated conditions is addressed in FWLCS operation to ensure the margins for vessel level overshoot are maintained. Based on this, there is adequate confidence that the reactor vessel water level will remain well below the main steam lines under CPPU conditions. The HPCI and RCIC pump trip functions are routinely verified as required by TSs and are considered very reliable.

The modification adding a recirculation pump runback following a RFP or condensate pump trip at high power will not affect the plant response to this transient. The reactor scram signal from the MSIV limit switches will result in control rod insertion prior to any manual or automatic operation of the RFPs. The RFPs will then respond to maintain reactor vessel water level.

The prior installation of an additional unpiped Spring Safety Valve (SSV) (added for implementation of License Amendment No. 219, ARTS/MELLLA during the spring 2004 refueling outage) does not affect the plant response to this transient. The third SSV has the same lift setpoint as the two original SSVs. This transient does not result in an opening of a SSV, nor is credit taken for SSV actuation.

G. ANALYSIS OF GENERATOR LOAD REJECTION AND TURBINE TRIP WITHOUT BYPASS EVENT

"Generator load rejection from high power without bypass" (GLRWB) is an abnormal operational transient as described in Chapter 14 of the VYNPS UFSAR. This transient competes with the turbine trip without bypass as the most limiting overpressurization transient that challenges thermal limits for each cycle. The GLRWB analysis assumes that the transient is initiated by a rapid closure of the turbine control valves. It also assumes that all bypass valves fail to open. Therefore the relative reduced bypass capability (from approximately 109% OLTP to 89% at the licensed power uprate (LPU)) is not an issue.

The CLTR states that: "The same performance criteria will be used as in the original power ascension tests, unless they have been replaced by updated criteria since the initial test program." The initial startup test at VYNPS for generator load reject allowed the select rod insert feature to reduce the reactor power level and, in conjunction with bypass valve opening, control the transient such that the reactor does not scram. Current VYNPS design does not include the select rod insert feature. The plant was also modified to include a scram from the acceleration relay oil pressure of the turbine control system. Under current plant design, the generator load reject test as originally planned during the initial test program cannot be re-performed. If a generator load reject with bypass test were performed in the current plant configuration, the results would be less significant than the generator load reject without bypass closure analysis performed for CPPU.

1. Original GLRWB Startup Test Criteria

   The original generator load reject test conducted during initial plant startup was intended to demonstrate reactor response to a generator trip, with particular attention to the rates of changes and peak values of power level, reactor steam pressure and turbine speed.

   The initial startup test criteria were:

   a. All test pressure transients must have maximum pressure values below 1230 psig.
   b. Maximum reactor pressure should be 35 psi below the first safety valve setpoint. (This is margin for safety valve weeping).
   c. The select rod insert feature shall operate and in conjunction with proper bypass valve opening, shall control the transient such that the reactor does not scram.

Due to the plant modification discussed above, criterion (c) above would no longer be applicable for a generator load reject test. The initial generator load reject startup test was performed at 93.7% power; however, a reactor scram occurred during testing and invalidated the test. A design change to initiate an immediate scram on generator load reject was implemented and this startup test was subsequently cancelled since it was no longer applicable. Therefore, no data related to criteria (a) or (b) was collected.

2. Analysis of Reactor Response

   a. Thermal Response

For a generator load reject with bypass event, given current plant design, the fast closure of the Turbine Control Valves (TCVs) causes a trip of the acceleration relay in the turbine control system. The acceleration relay trip initiates a full reactor scram. The bypass valves open sequentially to bypass steam. The negative reactivity of the TCV fast closure scram from the acceleration relay offsets the positive reactivity of the pressure increase such that there is a minimal increase in heat flux. Therefore, the thermal performance during a generator load rejection test would be much less limiting than any of the transients routinely re-evaluated (i.e., MSIV closure). CPPU will have minimal impact on the components important to achieving the desired thermal performance. Reactor Protection System (RPS) logic is unaffected and, with constant steam dome pressure, overall control rod insertion times will not be significantly affected. A channel and alarm functional test of the turbine control valve fast closure scram is performed every three months in accordance with VYNPS TS. Based on operating experience this trip function is considered very reliable.

b. Reactor Vessel Pressure

Due to the minimal nature of the flux transient and the expected reactor vessel pressure rise, criteria (a) and (b) above, SRVs are not expected to open.

A generator load rejection test would provide no significant additional confirmation of performance criteria (a) and (b) than is provided by the routine component testing performed every cycle, in accordance with the VYNPS TSs.

3. Other Plant Systems and Components Response

The turbine control system acceleration relay hydraulic fluid pressure switches that provide the scram signal are highly reliable devices that are suitable for this application including environmental requirements. There is no direct effect by any CPPU changes on these pressure switches. These switches are expected to be equally reliable before and after CPPU.

The reactor protection system (RPS) and control rod drive (CRD) components that convert the scram signals into CRD motion are not directly affected by any CPPU changes. Minor changes in pressure drops across reactor pressure vessel components could result in very slight changes in control rod insertion rates. These pressure drop changes have been evaluated and determined to be insignificant relative to CRD system operation and the ability to meet the scram performance requirement. Therefore, TS requirements for these components will continue to be met.

As previously described, feedwater system operation will require all three RFPs at CPPU conditions. Operation of the additional RFP will not affect plant response to this transient. As stated above, the level control setpoint is, by procedural requirements, manually reduced to 133 inches above TEF following a reactor scram. The RFPs, the HPCI turbine and RCIC turbine receive trip signals prior to reactor vessel water level reaching 177 inches. Overfill of the vessel after a trip would only occur if level exceeded 235.5 inches (nominal bottom elevation of the steam lines). Since the RFPs, the HPCI turbine, and the RCIC turbine all receive trip signals prior to level reaching 177 inches, a substantial margin exists. VYNPS operating history has demonstrated that this margin exceeds vessel level overshoot during transient events. Operation of three RFPs at VYNPS during uprated conditions is addressed in FWLCS operation to ensure the margins for vessel level overshoot are maintained. Based on this, there is adequate confidence that the vessel level will remain well below the main steam lines under

CPPU conditions. The HPCI and RCIC pump trip functions are routinely verified as required by TSs and are considered very reliable.

HP Turbine modification changes the steam flow path but will not affect the turbine control system hydraulic pressure switches that provide the turbine control valve fast closure scram signal to the RPS system.

H. INDUSTRY BOILING WATER REACTOR POWER UPRATE EXPERIENCE

Southern Nuclear Operating Company's (SNOC) application for EPU of Hatch Units 1 and 2 was granted without requirements to perform large transient testing. VYNPS and Hatch are both BWR/4 plants with Mark I containments (refer to UFSAR Tables 1.7.4 and 1.7.5 for comparison of the VYNPS and Hatch designs). Hatch Unit 2 experienced an unplanned event that resulted in a generator load reject from approximately 111% OLTP (98% of uprated power) in the summer of 1999. As noted in SNOC's LER 1999-005-00, no anomalies were seen in the plant's response to this event. Hatch 2 also experienced a reactor trip on high reactor pressure as a result of MSIV closure (from 113% OLTP (100% of uprated power)) in 2001. As noted in SNOC's LER 2001-003-00, systems functioned as expected and designed, given the conditions experienced during the event. In addition, Hatch Unit 1 has experienced two turbine trips from 112.6% and 113% of OLTP (99.7% and 100% of uprated power) as reported in LERs 2000-004-00 and 2001-002-00, respectively. Again, the behavior of the primary safety systems was as expected. No new plant behaviors for either plant were observed. This indicates that the analytical models being used are capable of modeling plant behavior at EPU conditions.

The KKL power uprate implementation program was performed during the period from 1995 to 2000. Power was raised in steps from its previous operating power level of 104.2% OLTP to 116.7% OLTP. Uprate testing was performed at 110.5% OLTP in 1998, 113.5% OLTP in 1999 and 116.7% OLTP in 2000.

KKL testing for major transients involved turbine trips at 110.5% OLTP and 113.5% OLTP and a generator load rejection test at 104.2% OLTP. The KKL turbine and generator trip testing demonstrated the performance of equipment that was modified in preparation for the higher power levels. Equipment that was not modified performed as before. The reactor vessel pressure was controlled at the same operating point for all of the uprated power conditions. These large transient tests at KKL demonstrated the response of the equipment and the reactor response. The close correlation to the predicted response provides additional confidence that the uprate licensing analyses consistently reflected the behavior of the plant.

Progress Energy's Brunswick Units 1 and 2 were licensed to 120% of OLTP and was granted the license amendment without requirements to perform large transient testing. VYNPS and Brunswick are BWR/4 plants with Mark I containments. Brunswick Unit 2 experienced an unplanned event that resulted in a generator/turbine trip due to loss of generator excitation from 115.2% OLTP (96% of uprated thermal power) in the fall of 2003. As noted in Progress Energy's LER 2003-004-00, no anomalies were experienced in the plant's response to this event. No unanticipated plant response was observed. This indicates that the analytical models being used are capable of modeling plant behavior at EPU conditions.

Exelon Generation Company's applications for EPU for Quad Cities Units 1 and 2, and Dresden Units 2 and 3 were granted without the requirements to perform large transient testing. VYNPS, Quad Cities and Dresden units are similar plants with Mark I containments. Dresden 3 has

experienced several turbine trips and a generator load rejection from high uprated power conditions. In January of 2004, Dresden 3 experienced two turbine trips from 112.3% and 113.5% of OLTP (96% and 97% of uprated power) as reported in LERs 2004-001-00 and 2004-002-00, respectively. The plant response was as expected and no new plant behaviors were observed, except for the FWLCS tuning issue as discussed above. This indicates that the analytical models used for transient analyses are capable of modeling plant behavior at EPU conditions. In May 2004, Dresden-3 also experienced a loss of offsite power which resulted in a turbine trip on Generator Load Rejection from 117% of OLTP (100% of uprated power). Control rods fully inserted, and system and containment isolations occurred as expected. Manual initiations proceeded in accordance with procedures. Plant response indicates that the analytical models being used are capable of modeling plant behavior at EPU conditions; however, there were incidental component failures involving the standby gas treatment system and an emergency diesel generator output breaker that were not related to the analysis models or EPU. This was reported in Dresden-3 LER 2004-003-00.

I. DESCRIPTION OF VYNPS PLANT MODELING, DATA COLLECTION, ANALYSES, AND USE OF POWER ASCENSION EXPERIENCE

From the power uprate experience discussed above, it can be concluded that large transients, either planned or unplanned, have confirmed predicted plant response from transient modeling. Since the VYNPS uprate does not involve reactor pressure changes, this experience is applicable to VYNPS.

The safety analyses performed for VYNPS used the NRC-approved ODYN transient modeling code. The NRC accepts this code for GE BWRs with a range of power levels and power densities that bound the requested power uprate for VYNPS. The ODYN code has been benchmarked against BWR test data and has incorporated industry experience gained from previous transient modeling codes. ODYN uses plant specific inputs and models the essential physical phenomena for predicting integrated plant response to the analyzed transients. The MSIV Closure pressurization transient analysis (that bounds the load reject without bypass pressurization event) has been performed for VYNPS at CPPU power level using the ODYN code. The evaluation of this transient and the Load Reject Without Bypass showed the MSIV Closure transient to be the most limiting event with respect to reactor overpressure. The results of these analyses have shown the response of the plant to this bounding transient to be acceptable. No new information with regard to transient modeling or the analysis results are expected to be gained from performing these large transient tests. As stated above, the performance of the large transient tests will necessarily be less severe than the transients analyzed because the analyses assume worse conditions than would be applied during testing.

The power ascension at VYNPS following uprate, as cited in Entergy letter BVY 04-129, dated December 9, 2004, will provide a controlled and systematic power ascension program for the power levels above OLTP to LPU. The ascension program provides for 2.5% power level increases with stabilization and hold times at the end of each power level increase to allow plant systems and components (most notably the steam dryer) performance to be assessed. In this way, in conjunction with the normal system and component surveillance testing, the systems and components are further assured of performing as designed and within the bounds of the transient analyses. Thus, the controlled startup program provides further justification that large transient testing will not yield any new information from that analyzed or experienced at VYNPS or other plants previously.

Plant operator training is conducted for the modified and uprated plant as described in Section 10.6 of the PUSAR.

J. CONCLUSIONS

The above justification concludes the following:

1. **Previous operating experience**

   Operating experience at other plants that have implemented a EPU have shown that the transient analysis results indeed bound the operational transients experienced; and that this operating experience is applicable to the VYNPS CPPU based on the similarity in design of the plants to VYNPS.

   Previous operating experience at VYNPS for large transient events has shown the plant has performed as expected and the transient analyses bound the transients experienced. This includes a transient event in 2004 which occurred following installation of many of the EPU modifications that further demonstrates that the modifications do not affect plant response to transient conditions.

2. **Introduction of new thermal-hydraulic phenomena or identified system Interactions**

   The operation of VYNPS at EPU will result in different conditions (e.g., feedwater flow, moisture carryover) but will not result in any new thermal-hydraulic phenomena as a result of plant transients. Modifications performed for EPU that provide for new system interactions (e.g., recirculation pump runback) do not impact the plant response to transient conditions. The modifications have no significant effect on plant transient analysis because the uprate is a constant pressure uprate wherein the operational effect on a majority of plant systems is minimal.

3. **Facility conformance to limitations associated with analytical analysis methods**

   VYNPS's conformance with any limitations of the GE methodology is being addressed by RAI SRXB-A-6.

4. **Plant staff familiarization with facility operation and trial use of operating and emergency operating procedures**

   PUSAR Section 10.6 describes the training of plant operators on the modified and uprated plant. As stated above, several of the modifications required for EPU have been installed and have been in service since the spring 2004 refueling outage.

5. **Margin reduction in safety analysis results for anticipated operational occurrences**

   Plant transient analyses results have shown that reductions in margin are small (e.g., reactor vessel and vessel dome pressure), or plant modifications have been performed to restore margin. Any changes in margin do not impact system integrity or significantly affect operator response.

6. **Guidance contained in vendor topical reports**

The VYNPS license amendment application and request for exception from transient testing is in accordance with General Electric (GE) Company Licensing Topical Report for Constant Pressure Power Uprate (CLTR) Safety Analysis: NEDC-33004P-A Rev. 4, July 2003. This topical report justified, based on the characteristics of the CPPU, that large transient testing was not required on a generic basis. However, the NRC's Safety Evaluation Report approving the Topical Report required plant-specific exception to this requirement, which is satisfied by this response.

7. **Risk implications**

The application for extended power uprate is not a risk informed licensing action; therefore, utilizing risk as a basis for elimination of large transient testing is not applicable.

8. **Benefits of large transient testing**

Based on the above considerations, Entergy concludes that the benefits of large transient testing would be minimal.

TABLE SPLB-A-10-1
SUMMARY OF EPU MODIFICATIONS
A. No Potential Impact on Transient Response

Modification	Modification Installed?	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Test	EPU Startup Testing	Further Tested by Load Reject Without Bypass / Main Steam Isolation Valve Closure
Main turbine – LP diaphragm replacement	• No	• Replace 8th stage diaphragm of LP turbine	No	No	• Vibration baseline measurements	• Vibration monitoring	• NA
Main turbine cross-around relief valves (CARVs) and Discharge Piping	• Yes	• Install higher capacity relief valves	No	No	• Valves shop tested • In-service Leak check	• Monitor temperature downstream of CARVs	• No
Main generator - rewind	• Yes • Yes	• Rewind/upgrade main generator for CPPU conditions. • Replace generator hydrogen coolers with upgraded coolers	No	No	• Performance test • AC Hi-Pot test each phase • Pressure and vacuum testing • Winding resistance • Meggering	• Monitor generator and cooling	• No
Main condenser	• Yes	• Stake main condenser tubing to reduce the effects of flow induced vibration	No	No	• Leak check tubes • Monitor chemistry	• Monitor chemistry	• No
Feedwater heater 4A/B shell side relief valve	• Yes	• Replace relief valves with larger capacity relief valve to accommodate increased feedwater flow	No	No	• Bench test valves, • Leak test installation	NA	• No

TABLE SPLB-A-10-1
SUMMARY OF EPU MODIFICATIONS
A. No Potential Impact on Transient Response

Modification	Modification Installed?	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Test	EPU Startup Testing	Further Tested by Load Reject Without Bypass / Main Steam Isolation Valve Closure
Steam dryer cover plate strengthening	• Yes • Yes • Yes • Yes • Yes	• Replace lower cover plates with thicker plates • Add reinforcing stiffeners at lower cover plates and vertical hood sides • Remove internal brackets in top inside corners of outer hoods • Replace vertical hood and hood top plates with thicker plates • Replace/Upgrade tie bars	No	No	• Inspection	• Vibration and moisture carryover monitoring during power ascension per power ascension test plan (PATP)	• No
Isolated phase bus duct cooling	• Yes	• Install a new isolated phase bus duct cooling system to remove bus duct heat under CPPU conditions	No	No	• Monitor bus duct cooling • Flow tests	• Performance monitoring	• No
HP feedwater heater replacement	• Yes	• #1A, #1B, #2A, and #2B feedwater heater replacement	No	No	• Pressure test • Visual inspection • Magnetic particle testing • Radiography • In-service inspection • Thermal performance demonstration	• Performance monitoring	• No

TABLE SPLB-A-10-1
SUMMARY OF EPU MODIFICATIONS
A. No Potential Impact on Transient Response

Modification	Modification Installed?	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Test	EPU Startup Testing	Further Tested by Load Reject Without Bypass / Main Steam Isolation Valve Closure
Residual heat removal service water (RHRSW) system	• No	• Modify RHRSW pumps (Train A and B) Motor Bearing Oil Coolers piping to recover Service Water flow from the coolers	No	No	• Visual Inspection • Particle Testing • Ultrasonic Flow Testing • In-Service Inspection	NA	• No
NSSS/torus attached piping	• Yes	• Upgrade particular NSSS and torus attached piping supports	No	No	• Welds to be examined by visual, liquid penetrant, magnetic particle, as applicable	NA	• No
Flow induced vibration (FIV)	• No	• Install FIV instrumentation	No	No	• Verify installation	• Collect EPU data and analyze	• No
Reactor recirculation (RR) system runback	• Yes	• Provide rapid runback of RR pump from high power on trip of condensate or feedwater pump	No	No	• Channel Calibration • Test with breakers in "test" and RR system not operating	NA	• No
Condensate demineralizer	• Yes	• Install condensate demineralizer filtered bypass strainer to permit one demineralizer to be removed under CPPU conditions	No	No	• Monitor chemistry • Establish flow baseline measurements	• With filtered bypass in service, monitor flows under various EPU conditions • Monitor reactor water chemistry	• No

TABLE SPLB-A-10-1
SUMMARY OF EPU MODIFICATIONS
A. No Potential Impact on Transient Response

Modification	Modification Installed?	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Test	EPU Startup Testing	Further Tested by Load Reject Without Bypass / Main Steam Isolation Valve Closure
Feedwater system suction pressure trip	• Yes • Yes	• Protect feed pumps (RFP) with two sequential levels of low suction pressure trips at various time delays to ensure only one pump trips at a time and for high power RR pump runback to ~60% on loss of a Feed Pump • Modify trip logic to prevent common mode failure due to loss of RFP low flow circuits	No	No	• Channel calibration • Test with breakers in "Test" position	NA	• No
Cooling tower/fan motors	• No (in progress)	• Replace fan blades with more efficient blades and drive motors with upgraded higher performance motors	No	No	• Cooling tower performance monitoring	NA	• No
EQ Upgrades	• Yes	• Reroute feed to SRV monitor to new breaker	No	No	• Voltage check and megger	NA	• No

TABLE SPLB-A-10-1
SUMMARY OF EPU MODIFICATIONS
A. No Potential Impact on Transient Response

Modification	Modification Installed?	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Test	EPU Startup Testing	Further Tested by Load Reject Without Bypass / Main Steam Isolation Valve Closure
Grid Stability	• Yes • Yes • No • Yes • Yes • Yes • Yes	• Increase the rating (million volt-ampere (MVA)) of the Vermont Yankee-Northfield 345kV line from 896 MVA to a minimum rating of 1075 MVA. • Increase MVA rating on the Ascutney-Coolidge 115 kV line from 205 MVA to 240 MVA • Addition of 60 MVAr of shunt capacitors at the Vermont Yankee 115 kV bus. • Modification to provide a second primary protection scheme on the Vermont Yankee north bus • Addition to provide a second primary protection scheme on the Vermont Yankee main generator • Independent pole tripping on the Vermont Yankee 381 breaker • Addition of out of step protection for the Vermont Yankee generator	No	No	• Voltage checks • Logic checks • Relay calibration	• In-service testing of the 345kV and 115 kV primary/ secondary protective relay, line carrier system (Monthly)	• No

TABLE SPLB-A-10-1
SUMMARY OF EPU MODIFICATIONS
A. No Potential Impact on Transient Response

Modification	Modification Installed?	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Test	EPU Startup Testing	Further Tested by Load Reject Without Bypass / Main Steam Isolation Valve Closure
Main turbine – HP flow path	• Yes • Yes • Yes • No • No	• Replace HP Turbine steam path (new HP diaphragms and rotor) • New control cams, camshafts and hydraulics • New control valve settings • Modify control valve operating mechanism with 5% margin above CPPU • Modify turbine control and overspeed setpoint for CPPU conditions.	No	No	• Factory 120% trip test • Overspeed testing • Control and stop valve response testing • Vibration baseline measurements • EPR and MPR tuning	• Overspeed testing • Vibration monitoring • EPR and MPR Testing per Power Ascension Test Plan (PATP) • Control and stop valve testing	• No.

TABLE SPLB-A-10-1
SUMMARY OF EPU MODIFICATIONS
B. Potentially Impacting Transient Response

Modification	Modification Installed?	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Test	EPU Startup Testing	Further Tested by Turbine Trip / Main Steam Isolation Valve *Closure*
Electronic pressure regulator (EPR) setpoint change	• Yes • Yes • Yes • Yes • Yes	• Change in EPR setpoint control range and zero power setpoint based on higher steam line differential pressure (dp). • Rescale bypass relay to account for bypass valve capability of 89% of total steam flow • Expand EPR control band from current range of 900 to 1000 psig a new range of 850 to 1000 psig, • Install signal isolators to minimize EPR output test wiring fault from negatively affecting EPR operation • *Add second notch* filter function to programmable logic controller (PLC) software and tune to *remove an 8.8* Hz signal	Yes	Yes	• Wire continuity checks • PLC calibration • EPR and MPR tuning	• EPR and MPR testing per PATP	• No.

TABLE SPLB-A-10-1
SUMMARY OF EPU MODIFICATIONS
B. Potentially Impacting Transient Response

Modification	Modification Installed?	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Test	EPU Startup Testing	Further Tested by Turbine Trip / Main Steam Isolation Valve Closure
Main steam line high flow setpoint	• No • No • No • No	• Respan transmitters to encompass new 140% steam flow values • Replace the 4 transmitters used to provide 40% setpoint for MSL high flow reduced function with more accurate transmitters. • Setpoint changes for 140% isolation at new steam flows • Install new indicators on master trip units	Yes	Yes	• Channel calibration • Test circuit logic	• TS required channel check and calibration	• No.
Neutron monitoring setpoints – APRM and RBM	• No • No • No	• APRM flow biased scram setpoints and rod block limits require changes due CPPU • APRMs require recalibration reflecting CPPU rated power operation • RBMs require recalibration reflecting CPPU rated power operation	Yes	Yes	• Channel calibration • Test circuit logic	• TS required channel check and calibration	• No.
Rod worth minimizer (RWM) - setpoint	• No	• Setpoint change to maintain the setpoint at the same absolute value of steam flow due to the range changes of the associated instruments.	Yes	Yes	• Channel calibration • Test circuit logic	• TS required channel check and calibration	• No.

TABLE SPLB-A-10-1
SUMMARY OF EPU MODIFICATIONS
B. Potentially Impacting Transient Response

Modification	Modification Installed?	Description	Potential Impact on Transient Response	Modeled in Transient Analysis	Post Mod Test	EPU Startup Testing	Further Tested by Turbine Trip / Main Steam Isolation Valve Closure
Turbine first stage pressure	• No	• Setpoint changes for the scram bypass	Yes	Yes	• Channel calibration • Test circuit logic	• No. (TS required channel check and calibration)	• No

A. Modifications with No Significant Impact on Transient Analyses

Main Turbine LP Replacement

The 8th stage diaphragms will be replaced during the fall 2005 refueling outage to upgrade the turbine to accommodate the increased steam flow for power uprate. This change increases the structural integrity of the diaphragms and has no impact on performance under normal or transient conditions. The change has no impact on the integrated plant response during transient conditions.

Main Turbine Cross-Around Relief Valves and Discharge Piping

The main turbine cross-around relief valves and discharge piping have been modified to increase the pressure in the cross-around piping to the low pressure turbine. This change has no effect on the integrated plant response to transient conditions as all transients/tests assume turbine control valves or Main Steam Isolation Valves close.

Main Generator Stator Rewind

The main generator stator was rewound in place. The scope of the activity was a complete replacement of the generator stator bars and a design uprate to 684,000 KVA @ 0.9593 power factor. The scope also included an increased capacity for the Generator hydrogen cooling system. Generator output has no significant effect on the integrated plant response during transient conditions.

Main Condenser Tube Staking

Additional support staking of the main condenser tubes was performed to minimize potential effects of flow induced vibration. This modification has an insignificant impact on the thermal performance of the condenser. Therefore, this change to the condenser has no impact on the integrated plant response during transient conditions.

Feedwater Heater 4A/B Shell Side Relief Valve

Because the EPU will increase the feedwater mass flow through the heat exchanger tubes by 20%, the relief valves on the shell side, per the ASME Code, must be capable of relieving pressure to avoid overpressure of the heat exchangers in case of an internal failure. The cause of the overpressure would be the failure of the heat exchanger tubes. The relief valves on feedwater heaters 4A/B have been replaced with higher capacity relief valves. These relief valves or heat exchangers have no effect on the integrated response of the plant during transient conditions.

Steam Dryer Strengthening

Strengthening of the steam dryer was performed to reduce the effect from flow induced vibration. This modification has no impact on the integrated response of the plant to transient conditions.

Isolation Phase Bus Duct Cooling

A modification was made to the isophase bus duct cooling system to provide additional cooling capacity associated with the power uprate. Although the modified system was installed when the flexible connector failed that resulted in the generator load rejection as reported in LER 2004-003-00, the failure did not result from the effects of the modification for power uprate nor does it affect its performance for power uprate. This change has no impact on the integrated plant response during transient conditions.

High Pressure Feedwater Heater Replacement

The four (4) high pressure feedwater heaters have been replaced to accommodate the increased flow and pressure conditions of power uprate, as well as to provide more erosion resistant material for operating life. This change has no impact on the integrated plant response during transient conditions.

Residual Heat Removal Service Water (RHRSW) Pump Bearing Oil Cooling Piping Design

The redesign of the RHRSW pump bearing oil cooling piping design was implemented to recover the bearing oil cooling water during the alternate cooling system (ACS) mode of operation for the pumps. Because the EPU will increase the decay heat rate and increased evaporative losses from the deep basin, the return of the cooling water from the bearing oil coolers is necessary for the deep basin water inventory while maintaining acceptable design margins. This change has no impact on the integrated plant response during transient conditions while in ACS mode.

Nuclear Steam Supply System (NSSS)/Torus Attached Piping (TAP) Supports

Main steam line supports in the drywell and the RCIC line support in the RCIC room were upgraded based on temperature considerations. These changes reestablished the design margins for the piping and support configurations. This change has no impact on the integrated plant response during transient conditions.

Reactor Recirculation (RR) System Runback

This modification added a rapid RR pump runback to approximately 60% of rated core flow on low feedwater flow (armed at approximately 89% of licensed uprated power (LPU) steam flow) following a feedwater pump (RFP) or condensate pump trip at high power but does not affect the plant response to transient conditions for MSIV closure and GLRWB. This modification allows power level and core flow to be reduced outside the power/flow exclusion and buffer region such that the feedwater and condensate systems can maintain feedwater/main steam flows and reactor vessel water level conditions, and an inadvertent reactor trip on low level can be prevented. However, a reactor scram signal from turbine control valve fast closure will result in control rod insertion prior to any manual or automatic operation of the RFPs. The feedwater level control system and operator actions to lower the level control setpoint will function as designed to maintain reactor vessel water level below the high level trip setpoint. Therefore, this change has no impact on the integrated plant response during transient conditions.

Condensate Demineralizer Filtered Bypass

Operation at EPU conditions with increased condensate/feedwater flow will require operation of the five (5) condensate demineralizer vessels. During backwash and precoat operations when one demineralizer is removed from service, the remaining four (4) demineralizers do not have the capacity for full condensate flow, thus requiring bypass flow path around the demineralizers and increasing the potential for debris to be passed from the condenser to the reactor. The new bypass filter provides the means of limiting debris passage by filtering the bypassed flow during demineralizer backwash operations. This change has no impact on the integrated plant response during transient conditions.

Feedwater System Suction Pressure Trip

The EPU requires that the three currently installed RFPs and the three currently installed condensate pumps be operating to achieve power uprate to 1912 MWt. In the pre-EPU configuration for this operation, upon a trip of a condensate pump, the suction pressure to the RFPs would drop such that the three RFP would trip based on a single 150 psig low pressure suction trip. Therefore, this modification provided staggered sequential time delay tripping of the RFPs such that suction pressure could recover to preclude tripping of all the RFPs. In addition, at EPU conditions with the trip of a condensate pump or RFP, the steam/feedwater flow mismatch would result in a reactor trip on low level if power/steam flow were not rapidly reduced to levels that could be supported by the operating pumps. Therefore, at EPU conditions, a rapid RR pump runback of both RR pumps to a core flow and power level (approximately 60% of rated core flow) outside of the power/flow exclusion and buffer region has been added. This runback is armed at approximately 89% of LPU steam flow. As with the discussion of the RR pump runback cited above, a reactor scram signal from turbine control valve fast closure will result in control rod insertion prior to any manual or automatic operation of the RFPs. The feedwater level control system and operator actions to lower the level control setpoint will function as designed to maintain reactor vessel water level below the high level trip setpoint. Therefore, this change has no impact on the integrated plant response during transient conditions.

Cooling Tower Fans/Motors

The cooling tower fan blades and motors have been replaced with higher efficiency blades and higher horsepower pumps to provide for cooling tower plume control (environmental and aesthetic issues). Other than CT-2-1 (which is required for alternate cooling system operation and is not being modified), the cooling towers perform no safety related function. Therefore, these changes have no effect on the plant response to transient conditions.

SRV Monitor Power Feed Relocation to New Breaker

Based on evaluations conducted for EPU, the breaker that fed the SRV monitor panel was not environmentally qualified to the new environment. This modification rerouted the power feeding the panel to a new breaker that is located in a mild environment. This change has no effect on the plant response to transient conditions.

Grid Stability

The Grid Stability study identified several changes required for the grid to accept the uprated power. These are:

- Increase the pre-contingency MVA rating on the Vermont Yankee-Northfield 345kV line (Section 381) from the current rating of 896 MVA to a minimum rating of 1075 MVA by replacing the limiting line relay equipment.
- Increase the post-contingency MVA rating on the Ascutney-Coolidge 115 kV line from the current long term emergency (LTE) rating of 205 MVA to 240 MVA by replacing approximately 25 feet of limiting rise conductor.
- Ensure that the Vermont Yankee 345 kV pre-contingency bus voltage is not degraded as a result of the uprate project by the addition of 60 MVA of shunt capacitors at the Vermont Yankee 115 kV bus.
- Provide a modification to add a second primary protection scheme on the Vermont Yankee north bus to achieve acceptable performance in response to the normal contingency fault NC14. (This reliability upgrade is required to mitigate pre-existing contingency conditions and is not prompted by uprate, but is required for the uprate.)
- Provide a modification to add a second primary protection scheme on the Vermont Yankee main generator to achieve acceptable performance in response to normal contingency fault NC15. (This reliability upgrade is required to mitigate pre-existing contingency conditions and is not prompted by uprate, but is required for the uprate.)
- Replace the Vermont Yankee 381 breaker to provide independent pole tripping to achieve acceptable performance in response to the extreme contingency fault EC8.
- Add an out of step protection to the Vermont Yankee generator to ensure acceptable performance in response to several extreme contingencies.

These changes support maintaining grid reliability and they have no effect on the plant response to transient conditions.

HP Turbine Steam Path Replacement

The high pressure turbine rotor has been replaced with a monoblock rotor with six (6) stages of buckets, 1st stage nozzle diaphragm, and five (5) associated diaphragms. To support the rotor installation, the shell was repaired or reworked, as required, to accommodate the new rotor and diaphragms. Hydraulic coupling bolt sleeves for connecting the LP-A rotor to the HP turbine, and new control valve camshafts, cams and hydraulics were installed. No changes were required to the steam supply, governor, or throttle valves. Turbine control valve modifications were made to accommodate power uprate, but turbine control system hydraulic pressure switches that provide the turbine control valve fast closure scram signal to the RPS system are not affected.

The rotational inertia due to the turbine rotor replacement does not affect the turbine overspeed transient. (See the response to RAI SPLB-A-12.) Thus, this change has no impact on the integrated plant response during transient conditions.

B. Modifications with Potential Effect on Transient Analyses

Electronic Pressure Regulator (EPR) Setpoint Change

The EPR is part of the mechanical hydraulic pressure control system for the turbine generator. It provides a signal to the control valves to maintain steam pressure at a desired setpoint. The EPR setpoint control range and zero power setpoint have been lowered based on the increase in steam line pressure drop at EPU steam flows. In addition, to account for EPU bypass valve capability of 89% of total LPU steam flow, the bypass relay was required to be rescaled. The control band has been rescaled to accommodate the lower control setpoint for human factors reasons. Signal isolators have been installed to minimize the EPR output test wiring from negatively affecting EPR operation, and a second notch filter function was installed in the PLC software and tuned to remove an 8.8 Hz signal that could affect proper EPR operation at uprated steam flows. The EPR is not actually modeled in the transient analyses but the parameters that it controls (steam flow and pressure to the main turbine and steam bypass) are reflected in the analyses. Therefore, the EPR setpoints and limits incorporated into the analyses are reflective of the plant configuration at EPU. The relative reduction in steam bypass capability has no effect on transients because the bypass capability is assumed to fail in the most limiting cases. For those cases (such as the load reject with bypass), bypass capability is adequate in that bypass valves will open sequentially during the transient as bypassed steam flow increases; however, since steam production drops dramatically during the transient, it is not expected that all bypass valves will be required. Therefore, the change in the EPR has no effect on the large transient tests.

Main Steam Line High Flow Setpoint

The main steam line high flow setpoint was previously 140% of the OLTP steam flow. For EPU, the setpoint is still 140% of the full power steam flow but is a higher absolute flow setpoint because steam flow has increased. These transmitters are being respanned to provide the new 140% flow. The transmitters for the high steam flow with the mode switch "Not in Run" were replaced to accommodate the new range of the steam flow, and the indicator scales were respanned to accommodate the increased steam flow. The higher steam flow high setpoint has an effect on the transient analysis in that MSIV isolation occurs at a higher flow for EPU. This closure signal isolates containment by initiating a Group 1 Isolation. This has been analyzed by GE, but has no effect on the large transient tests.

Neutron Monitoring Setpoints – APRM and RBM

The APRM flow biased scram and Rod Block setpoints are changed due to EPU. This change will also require that the Flow Control Trip Reference cards be reprogrammed for EPU. The APRMs and RBMs will be recalibrated to reflect the new 100% power level. The revised limits and setpoints are included in the transient analyses and have been evaluated as acceptable for EPU operation.

Rod Worth Minimizer – Setpoint

The rod worth minimizer low power setpoint is used to bypass the rod pattern constraints for the Control Rod Drop Accident (CRDA) at greater than a pre-established low power level, and is based on feedwater and steam flow. The setpoint is maintained at the same absolute power level for EPU as OLTP. This setpoint maintains a sufficient margin to the CRDA limit and rod

withdrawal error at startup criteria. The setpoint is used in the analysis for the CRDA, and is applicable only at very low power levels. The CRDA is not a part of the large transient tests, and therefore, the change to the RWM low power setpoint has no effect on large transient tests.

Turbine First Stage Pressure

The turbine first stage pressure setpoint is used to reduce scrams and reactor recirculation pump trips at low power levels where the turbine steam bypass system is effective for turbine trips and generator load rejections. In the safety analysis, this trip bypass only applies to events at low power levels that result in a turbine trip or load rejection. The setpoint for EPU is maintained at the same absolute pressure as OLTP, thereby maintaining the same transient analysis and scram avoidance range of the bypass valves. Since this only affects the low power transient analysis, this change has no effect on the transients at increased output levels.

RAI SPLB-A-11

Followup on Response to RAI SPLB-A-7, Item b
(Spent Fuel Pool Cooling - Heat Removal Capability and Limiting Case for Core Offload)

The licensee was requested to address the limiting cases for normal batch offload and full core offload in accordance with the Updated Final Safety Analysis Report (UFSAR), Section 10.5.5, which states: "Considering one train (one heat exchanger and one pump), this heat removal capability encompasses the normal maximum heat load from completely filling the pool with 3,353 spent fuel assemblies from the last normal discharge..."

In its response the licensee stated that, "...., the configurations presented in the VYNPS UFSAR, Section 10.5, Page 10.5-9, present scenarios more conservative than SRP Section 9.1.3 in that the batch offload configuration assumes more than a single failure (failure of both the NFPCS [normal fuel pool cooling system] trains and the failure of one SFPCS)..."

The licensee has not adequately considered and addressed the plant licensing basis as reflected in the UFSAR. Because the NFPCS is not safety-related, it is not credited in the limiting case. This is consistent with the guidance provided in SRP 9.1.3. Therefore, the licensee is requested to address the question as originally posed by the staff in RAI SPLB-A-7, Item b.

Response to RAI SPLB-A-11

The extended power uprate fuel pool heat-up calculations, assuming no credit for the normal fuel pool cooling subsystem, have been completed. These calculations address the UFSAR assumptions for fuel pool heat-up contained in UFSAR Section 10.5.5. The following initial conditions and assumptions were used for these two new cases.

- The initial fuel pool temperature is conservatively assumed to be at the UFSAR specified administrative limit (125°F) and remains at that temperature until the fuel pool gates are installed (6 days for batch offload and 10 days for full core offload cases). This assumption is conservative because the VYNPS administrative procedures preclude installation of the fuel pool gates if the fuel pool temperature is above the administrative limit.
- Once the fuel pool gates are installed, the only fuel pool cooling available consists of one train of SFPCS for the batch offload scenario, and two trains of SFPCS for the full core offload scenario.
- The acceptance criterion is that the bulk fuel pool temperature is maintained below the VYNPS Technical Specification limit of 150°F.

The following peak fuel pool temperature results were obtained:

- Partial core (i.e., a 136 bundle batch) offload with one train of SFPCS for heat removal
    - o Peak Bulk Pool Temperature = 140.6°F at 7.5 days after shutdown (i.e., 1.5 days after the fuel pool gates are installed).
- Full core offload with two trains of SFPCS for heat removal

- Peak Bulk Pool Temperature = 145.7°F at 11 days after shutdown (i.e., 1 day after the fuel pool gates are installed).

For both cases, the licensing acceptance criterion of less than 150°F is met.

RAI SPLB-A-12

Followup on Response to RAI SPLB-A-3
(Turbine Overspeed)

The increase in main steam flow rate and rotor inertia considerations increase the likelihood that the main turbine speed will overshoot and exceed design specifications during postulated events. Identify the worst-case scenario that could lead to main turbine overspeed and discuss in detail what measures will been taken to assure that this condition will not occur, including testing that will be completed to confirm that the combination of increased main steam flow and inertial effects will not cause the turbine design specifications to be exceeded.

Response to RAI SPLB-A-12

It is true that the latest high pressure (HP) turbine replacement adds to steam flow and turbine power output (~20% higher), but together with the previous monoblock low pressure (LP) rotor replacements, the total rotor inertia has also increased more than 20%. Thus, the net effect on overspeed is virtually unchanged from the initial conditions, i.e., original licensed power steam flow with the original LP and HP rotors. In fact, the anticipated peak speed following a full load rejection under the present configuration, i.e., extended power uprate steam flow and the replacement HP/LP rotors, is slightly less than the original peak speed. Consequently, the overspeed trip device setting can remain unchanged at 110.5 – 111.5% of rated speed.

The replacement HP turbine rotor was factory tested to 120% of synchronous speed before its installation during the spring 2004 refueling outage. Pre-operational testing after the rotor installation included normal post maintenance type tests of the turbine, turbine auxiliaries, and protective trip features and an overspeed trip test. Once in service, turbine vibration data were taken to ensure that vibration is within specification. During EPU power ascension, turbine vibration data and turbine performance data will be gathered. This testing adequately verifies that the HP turbine replacement has been completed properly.

Main Turbine Overspeed Transient

A main turbine overspeed transient can only occur during times when the main generator is not synchronized to the electrical grid. The most likely scenario is during a sudden loss of load transient. Should the load be lost due to an electrical fault which causes the main generator to trip, the same relays which trip the generator also simultaneously trip the main turbine and cause an automatic reactor scram if the turbine trip occurs above 25 percent of EPU core thermal power. This avoids a challenge to the turbine overspeed trip. Note that the power level for automatic scram upon turbine trip is at the same absolute reactor power level for original licensed thermal power and for EPU thermal power.

Should the turbine load be lost due to a grid disturbance, the main turbine control system speed governor would react quickly to the initial overspeed to rapidly close the HP turbine control valves (upstream of the HP turbine inlet) and intercept control valves (upstream of the LP turbine inlet), thereby preventing the peak speed from reaching the overspeed trip setting range of 110.5 – 111.5%.

As stated in the previous response to RAI SPLB-A-3, in the unlikely event that the turbine control system speed governor fails or if there was a failure of the HP control valves and intercept control valves, the next line of defense is the overspeed trip setting of 110.5 – 111.5% of rated speed. Initiation of the overspeed trip will cause a rapid closure of the turbine HP and intermediate stop valves. As stated in the response to RAI SPLB-A-3, the emergency overspeed of the unit at EPU operation will still not exceed the limit of 120% of rated speed.

The evaluation of the peak turbine normal overspeed and emergency overspeed discussed in the response to RAI SPLB-A-3 included the speed overshoot upon a loss of load. The speed overshoot is a product of the delays in the protective actuations, the time for the turbine valves to close, the residual steam in the steam path and turbine, and the rotational inertia of the turbine generator. EPU effects no changes to the trip circuitry, control oil system, or turbine valves. Thus, the time delays from these components are unchanged. Additionally, the steam flow path up to and downstream of the main turbine, including the turbine casing, remain unchanged. The replacement HP rotor has approximately 1% more rotational inertia than the original HP rotor. However, the existing LP rotors have approximately 20% more rotational inertia than the original LP rotors. The higher inertia of the HP and LP rotors essentially negates an increase in overspeed from a load rejection at EPU conditions.

No tests were performed during the initial startup testing to demonstrate or qualify the main turbine overspeed overshoot. Performance of such a test at the Vermont Yankee Nuclear Power Station would require defeating multiple, preemptive protective features. Unlike the normal overspeed trip test with no load on the turbine, a test to determine the main turbine overspeed overshoot would require a rapid transient, which once initiated would no longer be under the control of the operator. Such a test is neither prudent nor warranted. With the preemptive trips defeated, the consequence of a failure of the emergency overspeed trip could be catastrophic. Sufficient margin exists in the design of the HP and LP rotors relative to high-speed durability, and engineering analysis demonstrates that an overspeed event will remain within design. The replacement HP turbine, in concert with the previously replaced LP rotors, will reduce, not increase the magnitude of overspeed overshoot from that of the originally installed HP and LP turbines. Therefore, a test to demonstrate main turbine overspeed overshoot would not confirm any new or significant aspect of performance that has not already been adequately evaluated and does not justify the risk inherent with such a test.

Section 7.1 of the CLTR addresses turbine overspeed trip protection.

RAI SPLB-A-13

High Energy Line Breaks (HELBs)

Referring to Section 10.1.2 of NEDC-33090P, additional discussion is needed to explain why safety-related SSCs will not be affected due to postulated HELBs at the proposed EPU conditions. Specifically, the section titled "Liquid Line Breaks" should state a conclusion regarding the ability of safety-related SSCs to perform as intended at the proposed EPU conditions.

Response to RAI SPLB-A-13

Liquid high energy lines consist of feedwater and reactor water cleanup (RWCU) system piping. The effects of these liquid high energy line breaks (HELBs) on safety-related structures, systems, and components (SSCs) have been evaluated in three areas:

1. HELB transient pressure loading on building structures,
2. HELB harsh environments, and
3. HELB pipe whip and jet impingement

These evaluations, summarized below, assure the ability of potentially impacted safety-related SSCs to perform as intended at the proposed EPU conditions.

HELB Pressure Loading

The currently licensed thermal power (CLTP) limiting HELB for steam tunnel pressurization is a combined main steam and feedwater HELB. The CLTP structural analysis for this event uses a 6.1 psid differential pressure to evaluate the main steam tunnel concrete and steel floor framing. The CLTP calculated differential pressure for this event is 4.97 psid. The constant pressure power uprate (CPPU) calculated differential pressure for this event is 5.92 psid, which is bounded by the existing structural analysis.

The CLTP structural analysis uses the nuclear system design pressure of 1250 psig to determine main steam and feedwater jet forces on structures. The CLTP analysis bounds CPPU conditions since the CPPU main steam and feedwater operating pressures are well below the 1250 psig design value.

Finally, the CLTP HELB design differential pressures between the steam tunnel and the control rod drive (CRD) maintenance room main concrete wall, as well as the CLTP HELB design differential pressure loads acting on all safety related reactor building masonry block walls, bound the CPPU calculated differential pressure loads for the limiting liquid line breaks.

HELB Harsh Environments

The CPPU HELB peak temperatures increase for the RWCU, combined RWCU-feedwater, and the combined main steam-feedwater HELBs. Table 10-2 of NEDC-33090P[1] summarizes the CPPU effect on HELB temperatures. Safety-related electrical equipment in areas affected by

[1] That is, the Power Uprate Safety Analysis Report submitted as part of Entergy's September 10, 2003, application for a license amendment.

higher CPPU HELB temperatures have been identified and evaluated for impact on their equipment qualification. One modification was implemented to remove a vital AC circuit breaker from the harsh environment caused by the new CPPU HELB conditions. Other electrical components with higher CPPU HELB peak temperatures are qualified for the higher temperature without requiring any modification.

HELB pipe whip and jet impingement

As described in Section 10.1.2 of NEDC-33090P, pipe whip and jet impingement loads resulting from high energy pipe breaks are directly proportional to system pressure. Because CPPU conditions do not result in an increase in pressure considered in high-energy piping evaluations, there is no increased pipe whip or jet impingement loads on HELB targets or pipe whip restraints. The pipe stress evaluations of high energy piping systems at CPPU conditions did not result in the identification of any new pipe break locations.

Based on these evaluations and the modification described above, safety-related SSCs will not be affected due to postulated HELBs at the proposed EPU conditions and will continue to perform their intended safety functions.

Probabilistic Safety Assessment Branch (SPSB)

Containment and Accident Dose Assessment Section (SPSB-C)

RAI SPSB-C-34

What is the temperature criterion for piping attached to the torus? Is this criterion satisfied under power uprate conditions?

Response to RAI SPSB-C-34

The temperature criterion for piping attached to the torus is 195°F.[2] This criterion is satisfied because the maximum torus temperature under power uprate conditions is 194.7°F.[3]

[2] See Power Uprate Safety Analysis Report (PUSAR), Section 3.5.2, page 3-20.
[3] See PUSAR, Table 4-1.

RAI SPSB-C-37

Staff calculations indicate that it is not necessary to credit the reduced values of required NPSH given in Curves E12.5.522-1B and E12.5.522-2B in Attachment 5 of calculation VYC-0808, Revision 8. Using the long-term required NPSH values given in Table SPSB-C-12-1 (from the July 2, 2004 response to staff RAIs), the containment accident pressure that must be credited is slightly higher than the values calculated in Tables 4.1, 4.4 and 4.5, but still sufficiently below the conservatively calculated pressure shown to be available. Please justify use of the reduced values of required NPSH and assess the use of the values given in Table SPSB-C-12-1 of your July 2, 2004, letter instead.

Response to RAI SPSB-C-37

Entergy concurs with the NRC staff's conclusion that it is not necessary to credit reduced values of required net positive suction head (NPSH) for the short-term loss-of-coolant accident (LOCA) analysis (i.e., during the first 10 minutes post-LOCA), summarized in Table 4.1 in calculation VYC-0808, Rev. 8, because containment accident pressure will exceed the required containment overpressure (COP) during this time period. However, this does not invalidate the conclusion in VYC-0808, Rev. 8, page 31, that there is no need for COP credit in the first 10 minutes because the use of the reduced values of required NPSH is acceptable during this time period.

The reduced values of required NPSH given in Curves E12.5.522-1B and E12.5.522-2B of Attachment 5 to VYC-0808, Rev. 8 are the pump vendor's recommended minimum values. The vendor concluded that pump operation at the reduced values of required NPSH is acceptable assuming a ramp up in available NPSH after seven hours as indicated on the referenced curves.

The reduced values of required NPSH are used in the NPSH analyses for currently licensed thermal power (CLTP), both for the short-term (first 10 minutes) and at the time of the peak torus temperature during the long-term. The reduced values of required NPSH are used in the short-term analysis for power uprate. Higher-than-required values were used in the long-term LOCA case for power uprate to provide a bounding calculation of the required COP.

As for the other cases cited, Table 4.4 in VYC-0808, Rev. 8 is a "General Profile" which is not related to a specific event scenario. It provides the results of a sensitivity study on the effects of torus temperature, pump flow rate, and minimum and maximum required NPSH. The results (which are plotted on Figures 4.4-1 through 4.4-4) do not include a head loss term for debris on the emergency core cooling system (ECCS) suction strainers, nor do they account for a change in elevation head due changes in suppression pool mass.

Furthermore, Table 4.5 in VYC-0808, Rev. 8 provides a tabulation of NPSH margin for the pumps operating under minimum flow conditions. The flow rates and corresponding required NPSH values for the minimum flow conditions are summarized on pages 8 and 9 of VYC-0808, Rev. 8. These flow rates are lower than the flow rates evaluated in Table 4.1. Therefore, the reduced values of required NPSH from Curves E12.5.522-1B and E12.5.522-2B in Attachment 5 of calculation VYC-0808, Rev. 8 are not applicable to the results in Table 4.5.

RAI SPSB-C-38

Describe the worst-case single failure assumed for the NPSH calculations and the basis for this assumption.

Response to RAI SPSB-C-38

The worst case single failure assumed in the calculation of net positive suction head (NPSH) for emergency core cooling system (ECCS) pumps is the loss of one of the two residual heat removal (RHR) system heat exchangers (due to an assumed active failure of the heat exchanger outlet valve). This case produces the highest suppression pool temperature for the design-basis loss-of-coolant accident. The highest suppression pool temperature is produced for this case because:

1. The availability of normal auxiliary power results in the maximum amount of hot feedwater (from motor-driven feedwater pumps) being delivered to the reactor, and

2. The availability of normal auxiliary power also results in all low pressure ECCS pumps starting and operating for the first 10 minutes of the accident, then all but one RHR pump operating after 10 minutes, which maximizes the amount of pump heat added to the pumped fluid.

By maximizing the heat transferred to the reactor coolant via these mechanisms, combined with the assumed loss of a RHR heat exchanger, the highest suppression pool temperature is produced.

RAI SPSB-C-39

Explain why the emergency operating procedure (EOP) NPSH curves are still valid without change for the power uprate conditions. Are accident-generated debris included in the calculations? Is credit taken for the minimum available NPSH shown in curves on pages 18 and 19 of 19 of Attachment 5 to calculation VYC-0808, Revision 8? Were the EOP curves calculated with the same computer program used to calculate the temperatures and pressures used in VYC-0808, Revision 8?

Response to RAI SPSB-C-39

EOP NPSH curves are independent of specific event scenarios; therefore, they do not have to be changed as a result of power uprate conditions. The EOP curves provide torus (suppression pool) temperature limits as a function of pump flow rate and torus overpressure.

The debris head loss term assumed in the EOP NPSH calculation is conservatively assumed to be twice the value used in calculation VYC-0808, Rev. 8.

Credit is taken for the minimum available NPSH shown in the curves on pages 18 and 19 of Attachment 5 to VYC-0808, Rev. 8.

As noted above, the EOP curves are not based on specific event scenarios; therefore, the temperatures and pressures are not based on the computer programs used for the loss-of-coolant accident and anticipated transient without scram pressures and temperatures used in VYC-0808, Rev. 8.

RAI SPSB-C-40

The response to SPSB-C-10, dated July 2, 2004, contains a calculation which shows that with two heat exchangers operating but all other conservative assumptions of the licensing basis calculation unchanged, the suppression pool temperature is reduced from 194 F to 169 F. Is the flow through each heat exchanger due to just one residual heat removal (RHR) pump and one service water pump? Under what conditions would the operator actually use both trains of RHR to cool the suppression pool as opposed to using one train to cool the suppression pool and one train to inject water into the reactor vessel? The RAI response states that the calculation was not performed to QA program requirements. The staff requests that this calculation be verified according to the VYNPS Appendix B program.

Response to RAI SPSB-C-40

The flow through each heat exchanger is due to just one residual heat removal (RHR) pump and one RHR service water pump. The conditions for using two trains (with both heat exchangers) of RHR to cool the suppression pool would be a best estimate where the ECCS is fully available and core spray adequately maintains core cooling. The initial sensitivity calculation was performed to address a question from the State of Vermont. The calculation has subsequently been performed to QA requirements and documented in the Engineering Report VY-RPT-05-00003 (see Exhibit 1).

RAI SPSB-C-41

The minimum required NPSH values recommended by the pump vendor were based on operating conditions supplied by the licensee (Page 6 of 19 of Attachment 5 and Page 8 of 58 of calculation VYC-0808, Revision 8). If these suppression pool temperature values were based on pre-power uprate temperatures, why are the recommended times at minimum required NPSH still valid?

Response to RAI SPSB-C-41

The information provided to the pump vendor illustrated how the available NPSH varied over time following a design-basis loss-of-coolant accident under current licensed thermal power operating conditions. The available NPSH did not include containment overpressure; therefore, it is a conservative representation of the available NPSH, but consistent with the current licensing basis.

The pump vendor developed a time-dependent required NPSH curve that bounded the minimum available NPSH provided to them. As noted on page 10 of 19 of Attachment 5 to calculation VYC-0808, the minimum NPSH recommendation was based on (1) no permanent pump damage due to cavitation, (2) operation above the "knee" of the pump curve, and (3) conformance to original pump requirements and extrapolated requirements, as defined in Attachment 5 to VYC-0808, Rev. 8.

With containment overpressure credit, the available NPSH exceeds the required NPSH under power uprate operating conditions; therefore, pump requirements are satisfied even though suppression pool temperatures are higher under extended power uprate accident conditions.

RAI SPSB-C-42

Calculation VYC-0808, Revision 8, Attachment 5, Page 7 of 19, states that the RHR pumps were run for only a few minutes at reduced NPSH. Please explain why this is sufficient time to observe pump behavior at reduced NPSHA, as stated in the Attachment.

Response to RAI SPSB-C-42

Attachment 5 to VYC-0808 is the pump vendor's report on NPSH characteristics of the pumps in question. The vendor was commenting on the nature of the witness tests performed for all four RHR pumps; the purpose of which, as noted on Page 6 of 19, was "to demonstrate that the pump met the contractual requirements." The pump vendor's comment that there was sufficient time to observe pump behavior stands on its own merits based on the expertise of the pump vendor.

The vendor did provide further guidance, however, on the amount of time that the pump could be operated at reduced NPSH, which was not available from the witness test results. This guidance is summarized in Attachment 5 to VYC-0808.

Attachment 5 supplements the original witness test results with additional test data on the actual pumps delivered to VY[4] and from testing performed on pumps of similar design. The vendor also considered the minimum available NPSH over the extended time period following a design-basis loss-of-coolant accident. As noted on Page 10 of 19, the final recommended minimum NPSH is based on:

1. No permanent pump damage due to cavitation
2. Operation above the "knee" of the pump curve
3. Conformance to the original pump requirements and extrapolated requirements, as defined herein (i.e., as defined in Attachment 5 to VYC-0808).

Therefore, the relatively short period of time at reduced NPSH during the witness tests is neither a shortcoming in the original witness tests nor an indication of lack of adequate testing in general.

[4] One of the four RHR pumps (Pump No. 270840) was subjected to a more complete NPSH testing prior to final impeller trimming (see page 6 of 19). Pump No. 270840 was tested at 6300, 8065, and 9502 gpm with 5 to 8 test points at each capacity "to establish the slope and shape of NPSH vs. Head."

RAI SPSB-C-43

Regarding calculation VYC-0808 Revision 8, Attachment 5 Page 8 of 19, and Page 6 of 58, Section 2.1, what is the "minimum operational NPSH"?

Response to RAI SPSB-C-43

"Minimum operational NPSH" is the term used on the RHR pump curves from the witness tests, which were performed, as noted on VYC-0808, Rev. 8[5], Attachment 5, Page 6 of 19, "to demonstrate that the pump met the contractual requirements." The minimum operational NPSH is plotted on Curve No. Ic, page 13 of 19, Attachment 5, VYC-0808, Rev. 8.

[5] Calculation VYC-0808, Rev. 8 was provided as part of Entergy's letter of October 5, 2004 (BVY 04-106), extended power uprate license amendment request supplement 18.

RAI SPSB-C-44

Regarding calculation VYC-0808 Revision 8, Page 8 of 58, what is the basis for the limit of 8000 hours on impeller life? What is the licensing basis time the pumps must operate after a postulated design-basis LOCA? To what measured percentage reduction in pump discharge head does the value of minimum available NPSH after 100 hours correspond?

Response to RAI SPSB-C-44

The pump vendor based 8000 hours on their evaluation methodology to determine acceptable impeller vane erosion considering pumpage, temperature, impeller material, suction specific speed, and NPSH margin.

There is no specified licensing basis for pump operating time after a postulated design-basis LOCA. The long-term containment analysis is typically carried out to 1,000,000 seconds (approximately 278 hours) after the postulated design-basis LOCA. At this point in time, the available NPSH would exceed the minimum NPSH assumed in the impeller life evaluation.

By inspection of Curve No. Ic (page 13 of 19, Attachment 5, VYC-0808, Rev. 8), the minimum available NPSH after 100 hours (page 18 of 19, VYC-0808, Rev. 8) falls between the curves labeled "NPSHR-1%" and "NPSHR-3%". Thus, the percentage reduction in head corresponds to between 1% and 3%.

RAI SPSB-C-45

The response to RAI SPSB-C-1 provided in Attachment 2 to Supplement 8 indicates that pumps taking suction from the suppression pool have adequate NPSH without requiring credit for containment accident pressure when best-estimate assumptions are used. The response to RAI SPSB-8 provided in Attachment 2 to Supplement 5, Table RAI#8-1, indicates that, as modeled in the PRA, the operators have more than 24 hours to initiate suppression pool cooling (event KOPACTFL). Please submit the thermal-hydraulic analyses (both the containment response analysis and the NPSH calculation) that support these statements. Also, please discuss how much time the operator would realistically take to: (a) diagnose the need for suppression pool cooling and; (b) implement suppression pool cooling once the diagnosis is complete. What is the basis for these times (e.g., operator talk-through, simulator exercises)?

Response to RAI SPSB-C-45

The response to RAI SPSB-C-1[6] indicated that pumps have adequate NPSH without requiring credit for containment accident pressure when the design basis loss-of-coolant accident (LOCA) suppression pool calculation is performed when best-estimate assumptions are used. The response to RAI SPSB-A-8[7] indicated that, as modeled in the probabilistic risk assessment (PRA), the operators have more than 24 hours to initiate suppression pool cooling (event KOPACTFL) for the general transient initiating event class. These two events are unrelated.

The MAAP thermal-hydraulic analysis for the containment response and the NPSH calculations is documented in Exhibit 2, "VY MAAP4 Analysis of Adequate NPSH in a LBLOCA." This best-estimate thermal-hydraulic analysis, assuming the initiating event was a large break LOCA, concludes that the operators would have on the order of 4 hours to establish suppression pool cooling using a single loop of RHR prior to exceeding NPSH limitations. This is based on a conservative assessment of the energy added to the containment due to continued feedwater system operation. A more realistic assessment of the feedwater coastdown would extend this available time by an additional 45 minutes. These results demonstrate there is a high likelihood of success for the operators to mitigate this accident prior to exceeding pump NPSH limitations. The report also includes a discussion on operator action and realistic time to initiate suppression pool cooling.

[6] See Entergy's letter dated July 2, 2004 (BVY 04-058), extended power uprate license amendment request supplement 8.
[7] See Entergy's letter dated January 31, 2004 (BVY 04-008), extended power uprate license amendment request supplement 5.

RAI SPSB-C-46

Regarding the response to SPSB-C-29 in Attachment 2 to Supplement 10, please explain why the total heat sink area given in Table SPSB-C-29-1 is less for the SHEX calculation than for the MAAP calculation. Shouldn't SHEX assume more heat transfer to the heat sinks?

Response to RAI SPSB-C-46

As shown in Table SPSB-C-29-1[8] Item (h), "Total Containment Concrete Heat Sink Area," the concrete heat sink area used in the SHEX analysis (i.e., 2,068 ft^2) is significantly less than that used in the MAAP analysis (i.e., 20,419 ft^2). Footnote (4) to Table SPSB-C-29-1 was intended to explain the reason for the difference in the total containment concrete heat sink area between MAAP and SHEX. The MAAP code includes the concrete surface area surrounding the drywell steel shell, and the drywell steel is modeled as a liner to the concrete for heat sink purposes. The SHEX code does not apply this modeling technique. SHEX models the exposed drywell concrete as well as the drywell steel shell. Note that Item (i) of Table SPSB-C-29-1 shows that the total containment steel heat sink area are in close agreement between MAAP and SHEX.

Table SPSB-C-32-1[9], "Inputs to Containment Analyses for Peak Drywell Pressure and for Evaluation of NPSH" contains the SHEX inputs. The SHEX analysis for NPSH used the heat sinks as described in the Heat Structure Properties section of Table SPSB-C-32-1.

[8] See Entergy's letter dated July 30, 2004 (BVY 04-074), extended power uprate license amendment request supplement 10.
[9] See Entergy's letter dated August 12, 2004 (BVY 04-081), extended power uprate license amendment request supplement 11.