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April 22, 2005

Docket No. 50-271
BVY 05-046
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. 28
Extended Power Uprate – Response to Request for Additional Information

References:

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)," April 14, 2005

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 April 14, 2005, (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 the eleven individual RAIs contained in Reference 1.

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.

A001

There are no new regulatory commitments contained in this submittal.

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 April 22, 2005.

Sincerely,

Jay K. Thayer
Jay K. Thayer
Site Vice President
Vermont Yankee Nuclear Power Station

Attachment (1)

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Attachment 1

Vermont Yankee Nuclear Power Station

Proposed Technical Specification Change No. 263 – Supplement No. 28

Extended Power Uprate

Response to Request for Additional Information

Total number of pages in Attachment 1
(excluding this cover sheet) is 23.

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

PREFACE

This attachment is in response to the NRC staff's request for additional information (RAI) dated April 14, 2005. This attachment provides Entergy's response to the eleven 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 stated exactly as provided in NRC's letter of April 14, 2005.

Plant Systems Branch (SPLB)

Balance of Plant Section (SPLB-A)

RAI SPLB-A-14

Spent Fuel Pool (SFP) Cooling and Cleanup System
(Safety Evaluation (SE) Template Section 2.5.3.1)

The licensee's response to request for additional information (RAI) SPLB-A-11, in the supplement dated February 24, 2005, provided information that indicates that the plant licensing basis related to the standby fuel pool cooling subsystem (SFPCS) will change following implementation of the proposed EPU. In particular, Revision 18 of the Updated Final Safety Analysis Report (UFSAR) on page 10.5-9 it states: "These [SFPCS] heat exchangers are each sized to maintain the fuel pool water temperature below 150 °F after a normal refueling. 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. The combined heat removal capability considering both trains (two heat exchangers and two pumps) operating encompasses a full core discharge heat load completely filling the pool with 3,353 spent fuel assemblies. This provides sufficient heat removal capacity to preclude any impact on plant operation due to insufficient spent fuel pool cooling." Additionally, on page 10.5-12 of the UFSAR it states: "At six days decay, a single train of SFPCS is able to remove the decay heat load. For a full-core discharge (abnormal operation)....two trains of SFPCS can remove the decay heat load at 10 days...." These statements are also supported by the information provided in Table 10.5.1, "Heat Removal Capacities," Table 10.5.3, "Comparison of Heat Loads to Heat Removal Capacities with SFP at Capacity," and Table 10.5.4, "Fuel Pool Cooling and Demineralizer System - System Specifications." Based on a review of the February 24, 2005, response to RAI SPLB-A-11, VYNPS will not be able to satisfy the current plant licensing basis as described in the UFSAR (and referred to above) following the proposed EPU. Please describe the changes that are being made to the plant licensing basis in this regard, explain why NRC review and approval is not required pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.59 requirements, and provide a markup of UFSAR Sections 10.5.5 and 10.5.6 and UFSAR Tables 10.5.1, 10.5.3 and 10.5.4, that reflect the changes that are being made.

Response to RAI SPLB-A-14

VYNPS will continue to satisfy the current licensing basis under EPU conditions with respect to the spent fuel pool cooling system. Therefore, no markup of the UFSAR is being provided.

Following EPU operation, VYNPS' standby fuel pool cooling subsystem (SFPCS) will be able to support the spent fuel pool heat loads as stated in the RAI. The following is the decay heat load in the spent fuel pool at 6 days following plant shutdown for the batch off-load scenario and at 10 days following plant shutdown for the full core off-load scenario:

Table SPLB-A-14-1

Off-Load Scenario	Spent Fuel Pool heat load
Batch off-load (136 bundles) – 6 Days after Plant Shutdown	10.46 M BTU/hr
Full core off-load (368 bundles) – 10 Days after plant shutdown	21.78 M BTU/hr

As can be seen from Table SPLB-A-14-1, the spent fuel pool (SFP) heat load is within the capacity of one train of the SFPCS (11 M BTU/hr) for the batch scenario and two trains of the SFPCS (22 M BTU/hr) for the full-core offload scenario (while filling the spent fuel pool with 3,353 spent fuel assemblies). Even if the spent fuel pool gates are installed with an initial SFP temperature of 150°F, which would violate VYNPS administrative procedures, the spent fuel pool temperature will not exceed the acceptance criterion of 150°F since the SFP heat load remains below the heat removal capacity of the SFPCS heat exchangers.

Note that each SFPCS heat exchanger capacity of 11 M BTU/hr is based on a service water heat sink temperature of 85°F and a SFP water inlet temperature of 150°F. The heat removal efficiency of the heat exchanger is reduced when there is a lower differential approach temperature. This is the reason that the response to RAI SPLB-A-11 in the supplement dated February 24, 2005 shows a SFP heat up after the fuel pool gates are installed with an initial SFP temperature of 125°F.

During a conference call between the NRC staff, Entergy and GE on April 13, 2005, a question was raised by the NRC staff regarding a previous RAI response which indicated that the SFP heat load at 6 days following plant shutdown was 14.8 M BTU/hr. A review of previous VYNPS RAI responses indicated that the 14.8 M BTU/hr value is shown in Entergy's response to RAI SPLB-A-9 (Section (a)(ii) on page 20 of 39 of Attachment 2 to BVY 04-074, dated July 30, 2004). It should be noted that the conservative value of 14.8 M BTU/hr used in the alternate cooling system evaluation is the maximum SFP heat load that occurs following a batch off-load for Configuration 1 shown in Table 6-3 of the VYNPS PUSAR, NEDC-33090P. Configuration 1 is an assumed scenario that differs from the scenario postulated in SPLB-A-11[1]. For Configuration 1, the maximum SFP heat load occurs at 35 hours (1.458 days) following plant shutdown. The actual SFP heat load for Configuration 1 shown in Table 6-3 of the VYNPS PUSAR at six days following plant shutdown is 10.34 M BTU/hr. The following Figure SPLB-A-

[1] Configuration 1 postulates a normal batch offload with both trains each of the normal fuel pool cooling subsystem and the standby fuel pool cooling subsystem in service, and the heat load in the reactor pressure vessel cooled by one train of the residual heat removal system in the shutdown cooling mode. Fuel transfer is assumed to commence 24 hours after shutdown.

14-1 and Table SPLB-A-14-2 show the actual SFP heat load for Configuration 1 shown in Table 6-3 of the VYNPS PUSAR. Note that Case 1 and Configuration 1 are the same.

Figure SPLB-A-14-1

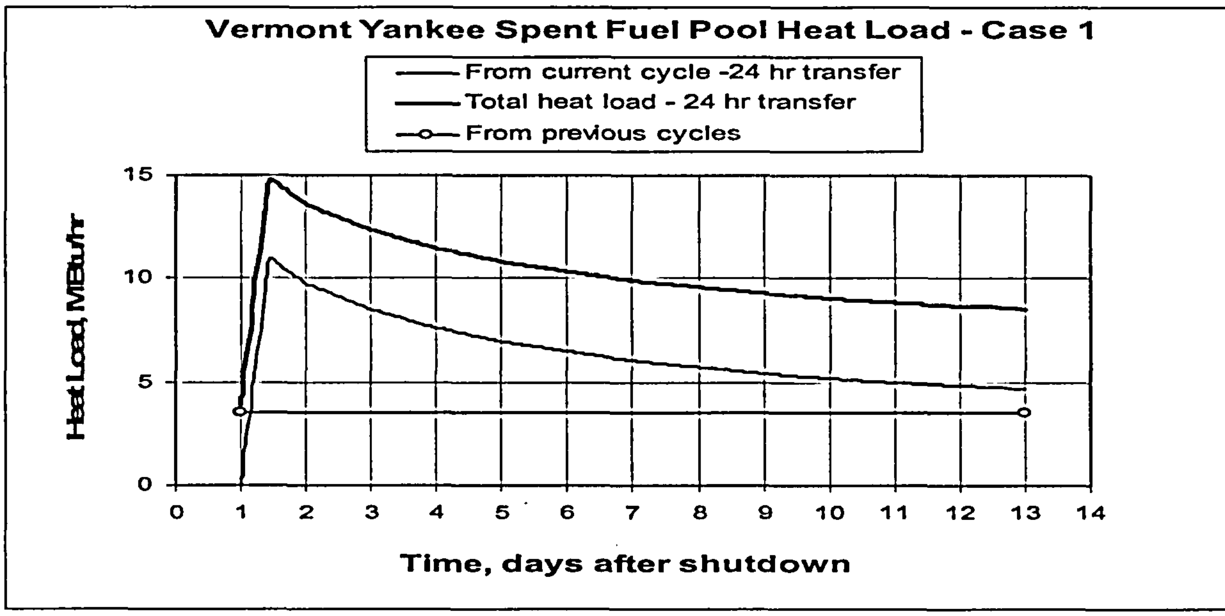

Table SPLB-A-14-2
Heat Loads for Case 1/Configuration 1 - Normal Batch Discharge

Time (days)	Heat Load[1] (M Btu/hr)		
	From Core	In SFP	Total
1	0.00	3.52	3.86
(35 hrs)	10.95	3.52	14.81
2	9.74	3.52	13.60
(51 hrs)[2]	9.59	3.52	13.44
3	8.48	3.52	12.34
4	7.60	3.51	11.46
5	6.95	3.51	10.80
6	6.49	3.51	10.34
7	6.03	3.51	9.88
8	5.73	3.51	9.58
9	5.43	3.50	9.27
10	5.18	3.50	9.02
11	4.99	3.50	8.83
12	4.82	3.50	8.66
13	4.69	3.50	8.53

Notes:
1. Pump heat = 0.34 M Btu/hr
2. Corresponds to peak pool temperature

RAI SPLB-A-15

Station Service Water System
(SE Template Section 2.5.3.2)

The information that was provided in several supplements (e.g., response to RAI questions SPLB-A-9 and SPSB-C-29 in the supplement dated July 30, 2004) indicates that the maximum design-basis service water temperature limit is 85 °F, and this is the maximum temperature that is assumed in the accident analyses and decay heat removal calculations. However, UFSAR Section 10.6.5 describes a higher temperature limit of 88 °F under certain conditions. Explain how the evaluation supporting the UFSAR service water temperature limit of 88 °F was assessed for validity to EPU operation.

Response to RAI SPLB-A-15

The higher service water temperature (i.e., 88°F) discussed in UFSAR section 10.6.5 addresses a unique summer operating condition during hybrid mode of circulating water system operation, which is not applicable under EPU conditions. The design bases analyses that have been revised for EPU conditions assume a service water temperature limit of 85°F. The UFSAR will be updated in conjunction with issuance of the EPU license amendment.

RAI SPLB-A-16

Reactor Auxiliary Cooling Water Systems
(SE Template Section 2.5.3.3)

The cooling function of the alternate cooling system (ACS) is relied upon in the event that the service water system becomes unavailable due to a failure of the Vernon Dam, or due to a fire or flooding in the intake structure. With respect to the response to RAI SPLB-A-9(a), in the supplement dated July 30, 2004, additional information is needed in order to fully demonstrate the capability of the ACS to perform its function for EPU conditions:

a. Describe the extent of changes in the assumptions and methodology used to evaluate the ACS performance at EPU conditions relative to the existing design basis analysis.

b. Confirm that the limiting parameters that were originally assumed relative to cooling tower performance (temperature, humidity, wind, etc.) continue to be "worst-case" based on trending of the meteorological conditions that have existed at VYNPS.

Response to RAI SPLB-A-16

The design basis meteorological conditions assumed for alternate cooling system (ACS) operation under EPU conditions are the same as those used for the original design. The original design used a 1% design wet bulb temperature value of 75°F concurrent with an average maximum dry bulb temperature of 90°F and relative humidity of 50%. This set of conditions conservatively envelopes the composite average of the 1967 American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) data for various weather stations in the Northeast region surrounding Vernon, Vermont. Trending this design value with ASHRAE data published in 1977 and again in 1997 indicates that for all stations surrounding Vernon, the 1% values for these years varied from a high of 74°F to a low of 72°F. This shows that the original design value of 75°F remains a conservative estimate of actual conditions at VYNPS. Additional margin is built into these design basis conditions due to the fact that no credit is taken in the analysis for the lower wet bulb temperatures that would occur during the night time.

Credit for wind conditions are included in cooling pond analyses, but are generally not considered for mechanical draft cooling tower designs. No credit was taken for wind effects in either the original or revised ACS analysis.
The Connecticut River serves as the ultimate heat sink (UHS) for VYNPS, whereas the ACS provides safe shutdown heat removal capability for only a limited set of special events. The design basis requirements for this system were defined during the original licensing of the plant, prior to the issuance of Regulatory Guide 1.27 for UHSs. The criteria of Regulatory Guide 1.27 were not specifically used in analyzing the ACS cooling function.

The following provides a brief description of the ACS analysis methodology. It is presented in three parts (cooling tower capability, heat removal requirements, and inventory loss).

Cooling Tower Capability

The Alternate Cooling Cell is the first cell (cell CT2-1) of the eleven cell west cooling tower (CT-2). In the alternate cooling mode, the water flowrate to the tower is between a nominal 4000 to

8000 gpm, which is significantly less than the cell's normal circulating water flowrate. The cooling tower capability (i.e., defined Merkel number or KaV/L value) used in the ACS analysis is based on test data recorded at the reduced ACS flowrates. The heat load to the tower is time dependent, and at each time step, the analysis determines the heat removed by the cooling tower by an iterative method that solves the Merkel number in accordance with Exhibit SPLB-A-16-1[2] and compares this result with the Merkel number from the VYNPS cooling tower characteristic equation. The cold water return temperature is adjusted until good agreement is achieved between the two Merkel numbers.

Heat Removal Requirements

The ACS analysis includes all required ACS heat loads. The major heat loads include reactor decay heat, spent fuel decay heat, the emergency diesel generators, and various pumps and coolers. To assure adequate heat removal from the ACS, the following acceptance criteria are required to be satisfied.

- Peak torus temperature: 181.7°F (A conservative 176°F limit is used in the analysis)
- Peak spent fuel pool temperature: 150°F
- Peak cooling tower fill temperature: 130°F
- Peak RHR heat exchanger outlet temperature: 150°F

The source of cooling water for the ACS is the west cooling tower's deep basin. The analysis assumes an initial deep basin temperature of 105°F.

Upon initiation of ACS, normal cooling tower operation ceases and the alternate cooling cell is lined-up for the ACS mode of operation. For all ACS cases evaluated, the deep basin temperature returns to less than 90°F within 10 hours and less than 85°F within 48 hours. The analysis evaluated the effects of an initial 105°F cooling water temperature on all equipment cooled by ACS. A summary of this evaluation follows:

- Emergency Diesel Generators (EDGs): A cooling water supply temperature of 105°F is acceptable provided the EDG is maintained ≤ 2500 kW and ACS flow to each operating EDG is at least 575 gpm. The ACS hydraulic analysis and operating procedure assure these requirements are satisfied.

- Residual Heat Removal (RHR) and Spent Fuel Pool Cooling (SFPC) Heat Exchangers: The effect of an initially elevated cooling water supply to RHR and SFPC heat exchangers is addressed within the ACS analysis by assuming a basin temperature initial condition consistent with operating procedure limits (e.g., 105°F for the four RHRSW pump case). The resultant spent fuel pool temperature, suppression pool temperature, and reactor cooldown were verified to be acceptable.

- ECCS Corner Room Coolers: The effect of an initial short-term elevated cooling water supply is acceptable since: (a) the heat load in the lower ECCS pump rooms is significantly less than during a design basis accident, thereby compensating for the ACS cases where two RHRSW pumps are utilized in the upper room, and (b) proceduralized

[2]Cooling Tower Institute, "Cooling Tower Performance Curves," copyright © 1967

manual actions to monitor room temperatures and initiate supplemental cooling if needed.

- RHR Service Water (RHRSW) Pump Net Positive Suction Head (NPSH): The initial 105°F basin temperature has little impact on NPSH margin since the basin level is full when the basin temperature is elevated. The limiting NPSH point for the four RHRSW pump case is at 48 hours—prior to a proceduralized pump/flow reduction.

- Equipment Coolers: An evaluation of the RHRSW pump motor coolers and RHR pump seal coolers confirmed that the expected short term elevated cooling water supply temperature would be acceptable.

- Piping: The effect of short-term elevated cooling water temperature on ACS piping was determined to be acceptable.

Inventory Loss

The ACS analysis is required to demonstrate a seven day deep basin inventory of water. The inventory evaporative loss analysis is performed in conjunction with the thermal analysis described above. For each time step of the analysis, the quantity of evaporative loss is calculated based on a cooling tower mass and energy balance using psychrometric properties of the air-water mixture entering and leaving the tower. The summer design meteorological conditions of 90°F dry bulb and 50% relative humidity are conservatively used throughout the seven day period.

The increased heat load due to EPU is balanced by a modification to recover RHRSW pump motor bearing cooling water, thus preserving inventory margin to pre-EPU levels.

Exhibit SPLB-A-16-1

The Tchebycheff method for numerically evaluating the integral $\int_a^b y\,dx$ uses values of y at predetermined values of x within the interval a to b, so selected that the sum of these values of y multiplied by a constant times the interval $(b-a)$ gives the desired value of the integral. In its four-point form the values of y so selected are taken at values of x of 0.102673 . . . ., 0.406204 . . ., 0.593796 . . ., and 0.897327 . . . of the interval $(b-a)$. For the determination of KaV/L, rounding off these values to the nearest tenth is entirely adequate. The approximate formula becomes:

$$\int_a^b y\,dx = \frac{(b-a)}{4}(y_1 + y_2 + y_3 + y_4) \qquad \ldots (4)$$

where

y_1 = *value of y at* $x = a + 0.1\,(b-a)$
y_2 = *value of y at* $x = a + 0.4\,(b-a)$
y_3 = *value of y at* $x = b - 0.4\,(b-a)$
y_4 = *value of y at* $x = b - 0.1\,(b-a)$

For the evaluation of KaV/L,

$$KaV/L = \int_{T_2}^{T_1} \frac{dT}{h_w - h_a} \cong \frac{T_1 - T_2}{4}\left[\frac{1}{\Delta h_1} + \frac{1}{\Delta h_2} + \frac{1}{\Delta h_3} + \frac{1}{\Delta h_4}\right] \qquad \ldots (5)$$

where

Δh_1 = *value of* $(h_w - h_a)$ *at* $T_2 + 0.1\,(T_1 - T_2)$
Δh_2 = *value of* $(h_w - h_a)$ *at* $T_2 + 0.4\,(T_1 - T_2)$
Δh_3 = *value of* $(h_w - h_a)$ *at* $T_1 - 0.4\,(T_1 - T_2)$
Δh_4 = *value of* $(h_w - h_a)$ *at* $T_1 - 0.1\,(T_1 - T_2)$

EXAMPLE OF KaV/L CALCULATION

Given $T_1 = 110°F$
$T_2 = 84°F$
$WBT = 69°F$
$L/G = 1.3$

From the enthalpy table* at 69°F, $h_1 = 33.25$
$h_2 = h_1 + L/G\,(T_1 - T_2)$
$= 33.25 + 1.3\,(110 - 84) = 67.05$

T, °F	h_w	h_a	$(h_w - h_a)$	$\frac{1}{\Delta h}$
$T_2 = 84.0$		$h_1 = 33.25$		
$T_2 + 0.1\,(T_1 - T_2) = 86.6$	51.41	$h_1 + 0.1L/G\,(T_1 - T_2) = 36.63$	$\Delta h_1 = 14.78$	.0676
$T_2 + 0.4\,(T_1 - T_2) = 94.4$	62.38	$h_1 + 0.4L/G\,(T_1 - T_2) = 46.77$	$\Delta h_2 = 15.61$	.0640
$T_1 - 0.4\,(T_1 - T_2) = 99.6$	71.02	$h_2 - 0.4L/G\,(T_1 - T_2) = 53.53$	$\Delta h_3 = 17.49$	.0571
$T_1 - 0.1\,(T_1 - T_2) = 107.4$	86.43	$h_2 - 0.1L/G\,(T_1 - T_2) = 63.67$	$\Delta h_4 = 22.76$	.0441
$T_1 = 110.0$		$h_2 = 67.05$		

From Equation (5):

$$KaV/L = \frac{(110-84)}{4}(.0676 + .0640 + .0571 + .0441) = 1.51$$

Step 3. The test KaV/L versus L/G point from above Steps 1 & 2 is plotted on Figure 9. The test characteristic curve for the tower is constructed by drawing a line through this point, parallel to the characteristic curve submitted by the manufacturer (see Figure 8). The new curve intersects the 10° approach curve at an L/G of 1.45.

Step 4. The tower capability from paragraph 9 of ATC-105 is:

$$Q = \frac{1.45}{1.37} \times 100 = 105.8\%$$

*For enthalpy data, see Table 1.

RAI SPLB-A-17

Condensate and Feedwater System (CFS)
(SE Template Section 2.5.4.4)

Given the reduction in margin of the CFS for EPU conditions (e.g., use of three reactor feedwater pumps (RFPs) rather than two), explain what impact the EPU will have on the reliability of the CFS.

Response to RAI SPLB-A-17

The overall reliability of the VYNPS CFS is not significantly affected by EPU operation. The use of three reactor feedwater pumps (RFPs) at EPU conditions removes the "spare" RFP that could be available in the event of a single RFP trip. For example the infrequent trip of an operating RFP will result in an automatic plant power level reduction versus an automatic start of a third RFP. This feature will allow, upon a trip of a condensate or feedwater pump, an automatic runback of the recirculation pumps to approximately 60% rated core flow and corresponding reactor power to permit main steam/feedwater flows and reactor vessel water level to be maintained such that neither a reactor trip on low level nor a turbine or feedwater pump trip on high level occurs. The RFP reliability is maintained through monitoring, preventative and on-line maintenance. If needed a RFP can be removed from service during planned power reductions. The automatic runback of the recirculation pumps is designed to prevent of an inadvertent reactor trip on loss of a RFP, thus preserving overall reliability of the plant. During normal EPU operation, the three RFPs will operate at lower capacity (with less stress on pumps and motors) than two RFPs operating at CLTP.

The impact of EPU on current margins in the condensate and feedwater systems is discussed below:

- Flow margin:

  All three VYNPS reactor feedwater pumps (RFPs) and three condensate pumps (CPs) will operate to support the required EPU flows. The total EPU flow rate will be split between the three RFPs and the three CPs. This EPU configuration differs from the current configuration which uses two RFPs with one RFP available as a standby pump. At EPU, each RFP will deliver 5,831 gpm, a decrease of approximately 16% when compared to the calculated at CLTP RFP flow rate of 6,965 gpm. This reduction in individual RFP flow increases the available margin from normal operating flows to runout for the individual pump.

  Each CP will be required to provide the increased flow associated with EPU operation with the same number of pumps (i.e., three) currently being used. The CP flow margin between the EPU conditions and the runout with three RFPs and three CPs will be approximately 7% greater than the required EPU flow. Industry criteria typically recommend a 5% margin. As such, the available margin exceeds that typically required by industry.

- Operating considerations:

  A recirculation system runback will be initiated when any reactor feedwater or condensate pump breaker is opened when operating at power levels that cannot be supported with two RFPs. The runback will automatically reduce recirculation flow to a value that has been pre-selected so that the expected core flow will be outside of the power/flow map exclusion and buffer region. This will automatically result in a reduction in reactor power that can be supported by the remaining running pumps. Transient analysis of the single feedwater pump trip event shows that there is margin to the low reactor water level scram setpoint.

- Motor Horsepower Impact:

  RFP

  The reduced individual pump flowrate resulting from three pump operation versus two pump operation will result in the calculated EPU operating point RFP motor requirements being reduced to 4,200 hp from 4,600 hp at CLTP conditions. Thus, EPU operation has the impact of increasing the horsepower margin to nameplate rating on the RFP motors, which is 5,500 horsepower per pump motor.

  CP

  The calculated CP motor requirements at EPU will increase to approximately 1,500 hp from 1,410 hp calculated at CLTP. The CP motors were evaluated by the motor manufacturers and found to have sufficient design margin to allow operation at the EPU horsepower requirements.

- Suction pressure trip setpoint:

  Prior to the current operating cycle (cycle-24), all of the RFP low suction pressure trip setpoints were 150 psig decreasing with a two second time delay. During the last refueling outage (RFO 24), the RFP low suction pressure trip setpoint was reduced to 98 psig decreasing and staggered time delays of 30, 40, and 45 seconds to provide RFP protection for NPSH events. A RFP low-low suction pressure trip with a setpoint of 90 psig decreasing and a time delay of one second was provided to prevent feedwater and condensate system water hammer events. The minimum calculated RFP suction pressure following the trip of one CP at EPU will be approximately 124 psig.

  There is sufficient margin between the minimum transient RFP suction pressure and the current RFP suction pressure trip setpoint to ensure RFP operation during normal operation and the loss of one CP transient.

- Pump Room Heatup:

  Conservative estimates indicate that operating three RFPs at EPU versus two pumps currently, the RFP room temperature will increase approximately 7.6°F over the current predicted RFP room temperature, conservatively resulting in a peak RFP room temperature of 112.6°F. The impact of this higher room temperature on the motor and related equipment inside the RFP room was evaluated and considered to be acceptable.

Similarly, the increased CP motor horsepower requirements result in a peak room temperature conservatively estimated to be 122.5°F at EPU. The impact of this higher room temperature on the motor and related equipment inside the CP room was evaluated and considered to be acceptable.

Conclusion:

Based on the above discussion, the impact on CFS operation resulting from EPU is balanced by EPU design modifications implemented during the past refuel outage. The impacts of EPU on reliable operation of the condensate and feedwater systems have been fully evaluated and are acceptable.

RAI SPLB-A-18

CFS
(SE Template Section 2.5.4.4)

Describe the extent of post-modification testing that will be completed to demonstrate acceptable performance for the reactor recirculation system runback modification and the RFP suction pressure trip modification.

Response to RAI SPLB-A-18

The reactor recirculation system runback modification was installed during the last refueling outage and was post modification tested as part of the modification process. The testing included complete logic verification from the initiation signal to movement of the actuating device (scoop tube positioner). Instrumentation was calibrated and recirculation motor-generator set operation was simulated. The required fluid coupler actuator changes were observed to take place in response to simulated plant inputs. The runback function is not currently armed and the EPU-analyzed plant conditions do not exist at the current licensed power (i.e., the function is not armed until approximately 89% of EPU rated steam flow).

This recirculation pump runback feature was provided to prevent an inadvertent reactor trip following the loss of a feedwater or condensate pump at EPU conditions. This runback feature is not required for plant safety as the plant is analyzed for a complete loss of feedwater.

For the feedwater pump low suction pressure modification, a similar approach was used. Instrumentation was calibrated and the breakers for the feedwater pumps were placed in the TEST position. The required breaker trips were observed in response to simulated plant inputs. Low suction pressure trip setpoint and time delay changes were made to minimize the possibility of multiple feed pump trips following the loss of one condensate pump at EPU conditions while ensuring pump protection. The setpoints are not challenged following the loss of one of the three running condensate pumps at the current licensed power.

An analysis was performed to demonstrate that the reactor recirculation runback upon loss of one feedwater pump would limit reactor power sufficiently to ensure the reactor did not scram on low water level. The analysis was performed at 1912 MWt (100% EPU rated power) at core flows of 38.4 Mlb/hr (80% rated core flow) and 51.36 Mlb/hr (107% rated core flow). While the 80% rated core flow analysis is for a condition not allowed during EPU operation, it bounds the 47.52 Mlb/hr (99% rated core flow) lower flow boundary for EPU operation at rated power. The reactor recirculation runback is assumed to terminate at a core flow of approximately 28.8 Mlb/hr (60% rated core flow).

The analysis was performed for both three element and single element feedwater level control. Further, each of these control logics was evaluated with nominal and diminished responsiveness. For the nominal responsiveness cases, feedwater flow was assumed to decrease to 70% of EPU rated feedwater flow in 2.0 seconds after pump trip, then increase to 80% of rated feedwater flow in 7.0 seconds after pump trip. Since the remaining pumps would be pumping against less resistance after the pump trip, it is expected that they would be capable of producing more flow earlier in the event. Additionally, the feedwater level control system is expected to be even more responsive than modeled.

Due to inherent modeling uncertainties, diminished responsiveness, which assumes the increase to 80% feedwater flow occurs in 20 seconds after pump trip, was also analyzed. The results of these analyses indicate that a minimum level margin of 16.2 inches to the low water level scram occurs during single element degraded responsiveness condition initiated at 51.36 Mlb/hr (107% rated core flow). Therefore, the analysis confirmed the acceptability of the reactor recirculation runback to ensure the reactor did not scram on low water level upon the loss of one feedwater pump.

RAI SPLB-A-19

Emergency Diesel Engine Fuel Oil Storage and Transfer System
(SE Template Section 2.5.6.1)

Explain how the limiting emergency diesel generator fuel oil consumption rate and duration that were established for the current licensed power level will remain bounding for EPU operation.

Response to RAI SPLB-A-19

The minimum emergency diesel generator (EDG) fuel oil storage tank capacity of 36,000 gallons required by Technical Specification (TS) 3.10.C is adequate for EPU operation. Because loading of the EDGs does not increase for EPU operation, the fuel oil consumption rate at a nameplate continuous duty rating of 2750 kW for seven continuous days of operation will remain the TS basis. For additional information, see Power Uprate Safety Analysis Report section 6.1 (proprietary information version).

RAI SPLB-A-20

Power Ascension and Testing
(SE Template Section 2.12)

The licensee's response to RAI SPLB-A-10, in the supplement dated February 24, 2005, indicated that analyses of anticipated operational occurrences have been performed by General Electric for VYNPS using the NRC-approved ODYN code, which models the direct-cycle boiling-water reactor, including the turbine-generator system and the feedwater system functions. Additional information is required to explain in detail how the balance-of-plant (BOP) transient response to postulated events and anticipated operational occurrences was evaluated and determined, including:

a. a discussion of the BOP transient response criteria that are important for assuring reactor safety and for minimizing challenges to plant safety systems;

b. the nature, capability, applicability, accuracy, and sensitivity of the analytical modeling and methods that were used, including limitations and restrictions that apply, and sensitivities and uncertainties associated with extrapolating the use of these methods to encompass EPU conditions;

c. measures that have been taken to confirm and assure that the analytical models and methods accurately represent the BOP transient response and a description of how well predicted performance compares with actual performance, including to what extent analytical models and methods have been updated and corrected to reflect VYNPS behavior following plant transients that have occurred, the extent that BOP features are actually modeled and an explanation for why this is sufficient, and consideration of plant modifications and setpoint adjustments that have been made subsequent to plant transients that have occurred such that the effects of these changes are not represented by the existing plant response data;

d. the impact of plant modifications, setpoint adjustments and parameter changes that are planned on the validity, accuracy, sensitivity, and uncertainty of the analytical methods being used;

e. a comparison of the analytical results (as adjusted to account for uncertainties in the analytical modeling and analyses) to the acceptance criteria that have been established for BOP transient performance; and

f. measures that are included in the power ascension test program that will confirm the validity, accuracy, and sensitivity of the analytical results.

Response to RAI SPLB-A-20

A conference call was held between NRC staff, Entergy, and GE on April 11, 2005 to clarify the RAI question. During the conference call the NRC staff clarified that the purpose of the RAI was to determine if any of the original VYNPS balance of plant (BOP) startup testing transient response criteria were affected by the full MSIV closure or generator load rejection transients initiated at EPU conditions. In accordance with that understanding, this response provides the information requested.

The functions important to safety associated with anticipated operational occurrences (AOOs) were evaluated as part of the VYNPS EPU analyses. BOP parameter data used in these analyses were integral to the evaluation of these functions. The effects of large transients on BOP systems were not specifically evaluated because the BOP systems do not constitute functions important to safety.

The ODYN code acceptability for modeling the reactor system response for pressurization transients, such as full main steam isolation valve (MSIV) closure and generator load rejections was previously approved in the NRC safety evaluations for the ODYN licensing topical report, NEDO-24154-A. The models and methods used in these analyses are described in and licensed for use by GE and Global Nuclear Fuels (GNF) in the GESTAR II topical report (NEDE-24011-P-A), which has been approved for this use by NRC. The use of these methods for EPU application was approved by the NRC in the safety evaluation for ELTR-1 and the constant pressure power uprate (CPPU) LTR.

The original VYNPS startup test program for full MSIV closure testing and generator load rejection did not have any acceptance criteria for the BOP transient response. This continues to be the case for these large transients analyzed at EPU conditions. The BOP response is a second or third order effect in pressurization events and the predicted performance is not critical to the results. As such, there were no Level 1 or Level 2 acceptance criteria for BOP system performance during original plant startup large transient tests. BOP performance was validated during system checkout and other power ascension tests (e.g. recirculation pump trip and feedwater pump trip).

The analyses of AOOs performed by GE model some BOP systems or component actions (e.g., feedwater level control, pressure regulator performance, stop valve closure) as inputs to the analysis of safety system performance. The BOP input assumptions are modeled to assure reactor safety and not to evaluate BOP response to AOOs.

The VYNPS EPU will be done at constant pressure per the CPPU LTR. Because there are no significant operating system pressure changes, no new thermal-hydraulic phenomena are introduced.

For any setpoint changes made as a result of power uprate, verification of setpoints will be conducted per plant design procedures. Monitoring of BOP systems and component performance (e.g., monitoring and verification of feedwater level control within reactor vessel water level limits, monitoring and verification of pressure regulator performance within primary and secondary limits) will be performed during EPU power ascension testing to ensure that systems and components are operating per design.

RAI SPLB-A-21

Power Ascension and Testing
(SE Template Section 2.12)

As discussed in the licensee's response to RAI SPLB-A-10, in the supplement dated February 24, 2005, the performance criteria that were established for the main steam isolation valve closure event and the turbine load reject and turbine trip without bypass both included: a) reactor pressure shall be maintained below 1230 psig; and b) maximum reactor pressure should be 35 psi below the first safety valve setpoint. Additional information is required to demonstrate that these criteria will continue to be satisfied for EPU operation, including a discussion of how these determinations were made, uncertainties that are inherent in the analyses that were completed, and how these uncertainties were accounted for in demonstrating acceptable results.

Response to RAI SPLB-A-21

The original VYNPS startup tests performed for the main steam isolation valve closure (MSIV) closure, turbine trip, and generator load reject events, applied a Level 1 acceptance criterion of reactor pressure vessel (RPV) peak pressure less than or equal to 1230 psig to ensure the safety valves did not open during testing. At that time, the opening setpoint for the first safety valve was 1230 psig. A Level 2 startup test acceptance criterion was established to ensure the peak pressure was at least 35 psi (30 psi for turbine trip test) below the safety valve setpoint, or 1195 psig (1200 psig for turbine trip test), and was meant as margin to prevent safety valve leakage or weeping. It should be noted that the original turbine trip and generator load reject startup tests allowed operation of the turbine bypass valves. Generator load reject without bypass and turbine trip without bypass events were not simulated during startup testing.

Prior to extended power uprate operation, cycle-specific reload analyses were performed confirming at least 25 psi margin to unpiped spring safety valve (SSV) lift for infrequent events. The infrequent events, which are expected to occur less than once during plant life, include the generator load reject without bypass and turbine trip without bypass events.

Beginning with EPU, consistent with industry practice, it was decided to change the analysis basis to maintain a 60 psi margin to unpiped SSV lift for the more realistic moderate frequency events. Moderate frequency events are those events with an expected frequency of more than once in plant life. The 60 psi margin, relative to the current nominal SSV lift setpoint of 1240 psig leads to an analysis objective of ensuring pressure remains less than or equal to 1180 psig during moderate frequency events. This value is more stringent than the acceptance criterion associated with the initial startup tests. The limiting moderate frequency event with regard to margin to unpiped SSV lift is the main steam isolation valve closure with direct scram (MSIVD) event.

As noted in PUSAR Section 3.1, the MSIVD event was analyzed for EPU conditions. The results show that there is an 88.9 psi margin to the lifting of unpiped SSVs—greater than the recommended margin of 60 psi. The analysis was performed for a representative EPU core, assuming one safety relief valve (SRV) out-of-service with the remaining SRVs assumed to lift at their nominal setpoints plus 3% uncertainty. The SRV that is assumed to be out-of-service is the one with the lowest nominal setpoint. The analysis is reperformed for each fuel cycle.

For comparison purposes, the Cycle 23 core analysis of the MSIVD event at the original licensed thermal power of 1593 MWt, resulted in a 97.3 psi margin to unpiped SSV lift, while the Cycle 24 core analysis at the EPU licensed thermal power of 1912 MWt, showed a margin of 84 psi to SSV lift. (Note: VYNPS is currently in Cycle 24).

RAI SPLB-A-22

Power Ascension and Testing
(SE Template Section 2.12)

The licensee indicated in the response to RAI SPLB-A-10, in the supplement dated February 24, 2005, that: "Operation of three RFPs at VYNPS during uprated conditions is addressed in FWLCS [feedwater level control system] operation to ensure the margins for vessel level overshoot are maintained." Additional information is required to explain specifically how FWLCS operation for uprated conditions will assure the margins for vessel level overshoot are maintained, including the need for any adjustments and how they were determined, and how FWLCS modeling and tuning for VYNPS differs from Dresden such that FWLCS performance in accordance with predictions is assured.

Response to RAI SPLB-A-22

An evaluation was conducted to determine if the effects seen from the Dresden Unit 3 feedwater level event[3] would be applicable to VYNPS.

The Dresden Unit 3 event resulted from the digital feedwater level control system (FWLCS) not being properly optimized and tuned for the specified reactor vessel level setdown setpoint and operation at the increased feedwater flow for EPU. This led to a feedwater regulating valve response to a reactor vessel level change that resulted in excessive feedwater injection and introduced water into the high pressure coolant injection (HPCI) system turbine steam line. The water entrainment into the HPCI steam line caused the turbine driven high pressure injection pump to become inoperable. Apparently, the Dresden Unit 3 FWLCS was programmed to execute feedwater regulating valve position in a stepped sequence, and the inherent delays in this sequencing, in conjunction with the reactor vessel level setdown setpoint, resulted in the overshoot event.

The VYNPS FWLCS is a digital/analog system (i.e., digital controller units and digital valve positioners in an otherwise analog control system) that incorporates a push button on the controller unit in the control room to provide a manual level setdown (for reduction of the reactor vessel level control setpoint from ~160 inches to 133 inches from the top of the enriched fuel during reactor trip and anticipated transient without scram scenarios) for an expanded margin in level control. These design and operating differences will preclude flooding of the main steam lines (which could introduce water to the HPCI turbine steam supply line) in the event of feedwater level overshoot during feedwater regulating valve response. The feedwater regulating valve control from the FWLCS at VYNPS does not provide for an automatic stepped sequence control following an upset condition but rather automatic/manual controlled adjustment of feedwater flow.

In addition and of significant note, the VYNPS HPCI turbine steam line is connected to one of the main steam lines (main steam line bottom elevation of 235.5 inches) versus directly connected to the reactor vessel as with the Dresden Unit 3 design. Unlike VYNPS, the Dresden Unit 3 HPCI turbine steam line is located approximately 50 inches below the main steam line,

[3] See Licensee Event Report 2004-002-00 for Dresden Unit 3 (NRC Docket No. 50-249) describing the January 30, 2004, reactor trip.

which significantly compresses the available overshoot margin. This design difference provides another significant preclusion to flooding of the HPCI turbine steam supply line due to feedwater level overshoot concerns.

At VYNPS, a reactor vessel high level trip of the feedwater, HPCI and reactor core isolation cooling (RCIC) pumps occurs at 177 inches, which is well above the level control setpoint and is well below the steam line bottom elevation of approximately 235.5 inches. In addition, plant procedures for off-normal reactor vessel water level increases instruct operators to ensure that feedwater pumps, HPCI pump (if running), and the RCIC pump (if running) are tripped prior to exceeding 173 inches.

For EPU, VYNPS does not plan to change the response or the tuning of the FWLCS. While VYNPS uses digital devices in the FWLCS, it is not the same as a digital control system as is in use at Dresden Unit 3. At VYNPS the system response is very close to the original analog system response. When the system was modified, startup testing was performed at power to verify that the system would respond properly. The testing is scheduled to be repeated as part of the EPU power ascension test program.

Based on (a) the margins provided by the differences in design of the HPCI steam supply line configuration and the feedwater control system; (b) the procedural response to a reactor trip; and (c) the startup testing previously performed and to be performed during the EPU Power Ascension Test Program, the increase in feedwater flow by approximately 20% at VYNPS should not cause a feedwater overshoot situation as experienced at Dresden Unit 3.

RAI SPLB-A-23

Internally Generated Missiles
(SE Template Section 2.5.1.2.1)

The Vermont Yankee Notes - Matrix 5, for SE Section 2.5.1.2.1, "Internally Generated Missiles (Outside Containment)," in Supplement No. 4 dated January 31, 2004, indicate that the "CPPU [constant pressure power uprate] will not result in increases in system pressures or configurations that would affect the impact of internally generated missiles on SSCs [structures, systems, and components] important to safety. The VYNPS CPPU does not result in any condition (system pressure increase or equipment overspeed) that could result in an increase in the generation of internally generated missiles." However, seemingly inconsistent with this conclusion, the high pressure feedwater heaters must be replaced in order to accommodate higher extraction pressures and EPU operation will require increased feedwater system flow and possibly higher feedwater system pressure. Also, it is not clear to what extent transient conditions were considered in assessing the impact of the EPU on the likelihood and consequences of internally generated missiles. Please provide additional information to address these considerations. Note, if SSCs important to safety are not located within the missile strike zone of a particular missile hazard, specific analysis of these particular hazards are not required.

Response to RAI SPLB-A-23

The constant pressure power uprate of VYNPS does not result in increases in system pressures or configurations that would affect the impact of internally generated missiles (outside containment) on structures, systems, or components (SSCs) important to safety. The new high pressure turbine installed at VYNPS during the spring 2004 refueling outage resulted in higher extraction steam pressures and flows. Replacement of the four high pressure feedwater heaters during the spring 2004 outage was required to ensure adequate margin for shell side material erosion due to increased extraction steam velocities.

The design of the new feedwater heaters incorporated enhancements in design margin including increased shell side pressure ratings. With respect to the pressure increase in the extraction lines to the high pressure feedwater heaters (i.e., E-1-1A&B and E-2-1A&B), there are no SSCs important to safety located in the vicinity of these lines. Hence, no specific analysis for a potential extraction line missile hazard was required to be evaluated.

The feedwater piping system was evaluated for changes in operating parameters that resulted from EPU conditions. With respect to the pressure of the feedwater system, the design pressure will not be increasing as a result of EPU. The flow rate increase for the feedwater system was evaluated to assess its potential impact on flow induced fluid transient loads in the piping system. The evaluations performed indicated that because the feedwater system does not contain any fast closing valves, the flow rate increase was acceptable. Hence, no new missile concerns for the feedwater system will result due to the implementation of EPU.

With respect to transient conditions that were assessed in the EPU piping evaluations, and subsequently in potential missile generation issues, systems experiencing flow rate increases were evaluated to determine the potential impact of the flow rate increase on flow induced fluid transient loads in the piping system. A detailed evaluation of the main steam system was performed to assess the higher system flow rate and its impact on turbine stop valve closure event transient loads. The evaluations performed concluded that no new postulated pipe break locations for the main steam piping will result due the implementation of EPU. Hence, no new missile concerns for the main steam system are present due to the implementation of EPU. For the remaining piping systems which will experience flow rate increases, it was also concluded that no new missile concerns will result due to the implementation of EPU.

RAI SPLB-A-24

Liquid Waste Management Systems
(SE Template Section 2.5.5.2)

The CPPU topical report indicates that review of liquid waste management systems should be completed on a plant-specific basis, and RS-001 includes additional review considerations that are not specifically recognized by the CPPU topical report. In order to fully address these considerations, additional information is required. Section 8.1 of the CPPU Safety Analysis Report (Attachment 6 to the application dated September 10, 2003) indicates that the total volume of liquid processed waste will not increase appreciably as a result of the EPU. Please explain how much liquid waste processing capacity is needed for EPU and how this determination was made relative to the VYNPS licensing basis criteria, and compare this capacity to the actual capacity that is available.

Response to RAI SPLB-A-24

The current quantity of liquid radwaste processed is 9,491,000 gallons/year. The increase due to EPU was calculated to be 109,557 gallons/year for a total of 9,600,557 gallons/year. This represents an increase of approximately 1.15%.

The volume of liquid radwaste calculated for EPU conditions is well within the designed system capacity of 10,585,000 gallons/year.

The increase due to EPU was determined by evaluating the increase from the two major sources of additional liquid waste: the Cleanup Phase Separators (CPS) backwash and the Condensate Filter Demineralizer (F/D) backwash. The increase corresponding to the CPS backwash is assumed to be proportional to the reactor water cleanup system conductivity increase. The increase corresponding to the condensate F/D backwash is assumed to be proportional to the feedwater flow increase.