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10 CFR 50.90

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May 18, 2007

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

Hope Creek Generating Station
Facility Operating License No. NPF-57
NRC Docket No. 50-354

Subject: Response to Request for Additional Information
Request for License Amendment - Extended Power Uprate

Reference: 1) Letter from George P. Barnes (PSEG Nuclear LLC) to USNRC, September 18, 2006
2) Letter from USNRC to William Levis, PSEG Nuclear LLC, May 17, 2007

In Reference 1, PSEG Nuclear LLC (PSEG) requested an amendment to Facility Operating License NPF-57 and the Technical Specifications (TS) for the Hope Creek Generating Station (HCGS) to increase the maximum authorized power level to 3840 megawatts thermal (MWt).

In Reference 2, the NRC requested additional information concerning PSEG's request. Attachment 1 to this letter restates the NRC questions and provides PSEG's response to each question with the exception of questions 3.66, 3.67, 13.18 and 13.19. PSEG will provide the responses to these questions in a separate transmittal.

PSEG has determined that the information contained in this letter and attachment does not alter the conclusions reached in the 10CFR50.92 no significant hazards analysis previously submitted.

There are no regulatory commitments contained within this letter.

A001

Should you have any questions regarding this submittal, please contact Mr. Paul Duke at 856-339-1466.

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

Executed on 5/18/07
(date)

Sincerely,

Thomas P. Joyce

Thomas P. Joyce
Site Vice President
Salem Generating Station

Attachment: Response to Request for Additional Information

cc: S. Collins, Regional Administrator – NRC Region I
J. Shea, Project Manager - USNRC
NRC Senior Resident Inspector - Hope Creek
K. Tosch, Manager IV, NJBNE

Hope Creek Generating Station
Facility Operating License NPF-57
Docket No. 50-354

Extended Power Uprate

Response to Request for Additional Information

In Reference 1, PSEG Nuclear LLC (PSEG) requested an amendment to Facility Operating License NPF-57 and the Technical Specifications (TS) for the Hope Creek Generating Station (HCGS) to increase the maximum authorized power level to 3840 megawatts thermal (MWt).

In Reference 2, the NRC requested additional information concerning PSEG's request. Each NRC question is restated below followed by PSEG's response, except questions 3.66, 3.67, 13.18 and 13.19. PSEG will provide the responses to these questions in a separate transmittal.

1. Vessels & Internals Integrity Branch (CVIB) (additional question)

1.6 In response to RAI CVIB 1.4(b), the licensee in its letter dated March 13, 2007, stated that for the top guide whose fluence exceeds the irradiated assisted stress corrosion cracking (IASCC) threshold (5×10^{20} n/cm^2) (E > 1 MeV), the grid beams are not required to be inspected. The licensee further states that this is based on the Boiling Water Reactor Vessel Inspection Program (BWRVIP)-26-A, which states that there is no safety consequences resulting from a failure at a single beam intersection, and that a large number of complete separations would need to occur before control rod insertion would be affected. In other words, BWRVIP-26 acknowledges that while there is no safety concern from a single beam failure, multiple beam failures would be a safety concern, as it would compromise the safe shutdown of the reactor.

The NRC notes that multiple failures of the top guide beams are possible when the threshold fluence for IASCC is exceeded. For example, according to BWRVIP-26-A, multiple cracks have been observed in the top guide beams at Oyster Creek. In addition, multiple failures have occurred in other components that have exceeded the threshold fluence for IASCC, such as baffle-former bolts in pressurized-water reactors (PWRs).

The NRC also notes that the BWRVIP has been informed of this issue by NRC letter dated June 10, 2003. This letter recommended that the BWRVIP conduct a comprehensive evaluation of the impact of IASCC and multiple failures of the top guide beams, and that an inspection program for top guide beams that exceed the IASCC threshold fluence for all BWRs should be developed by the BWRVIP to ensure that all BWRs can meet the requirements of 10 CFR Part 54 (continue to perform their intended function under the current licensing basis for the extended period of operation). At the time, the NRC believed that the IASCC would be exceeded during the extended period of operation. However, the NRC now has information that some plants, such as Hope Creek, have already exceeded the IASCC fluence threshold during the current operating period. Therefore, since this degradation mechanism is based on exceeding the IASCC fluence threshold, this issue may also apply to the current operating period. The BWRVIP is working on resolving this issue generically, but until then, a site-specific inspection program is necessary to manage the effects of IASCC in the top guide.

Matrix 1 of RS-001, Revision 0, Review Standard for Extended Power Uprates (December 2003) specifies that the NRC's acceptance criteria for reactor internal and core support materials are based on GDC-1 of Appendix A to 10 CFR Part 50. GDC-1 specifies, "where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function." Therefore, since the current inspection plan of excluding inspections of the top guide beam is not adequate to address the safety concern of multiple grid beam failures impacting the safe shutdown of the reactor, the inspection plan is required by GDC-1 to be supplemented. This modification can be accomplished by providing, for NRC approval, an inspection program to manage this aging effect to preclude loss of the component intended function. An example of an acceptable inspection program is as follows:

> Enhanced visual testing (EVT-1) of the top guide grid beams will be performed in accordance with GE SIL 554 following the sample selection and inspection frequency of BWRVIP-47 for CRD guide tubes. That is, inspections will be performed on 10% of the total population of cells within twelve years, and 5% of the population within six years. The sample locations selected for examination will be in areas that are exposed to the highest fluence. This inspection plan will be implemented beginning with the refueling outage following EPU operation.

Therefore, the licensee is requested to provide an inspection program to manage the IASCC degradation mechanism of the top guide to preclude the loss of component intended function, as required by GDC-1.

<u>Response</u>
Enhanced visual testing (EVT-1) of the top guide grid beams will be performed in accordance with GE SIL 554 following the sample selection and inspection frequency of BWRVIP-47 for CRD guide tubes. That is, inspections will be performed on 10% of the total population of cells within twelve years, and 5% of the population within six years. The sample locations selected for examination will be in areas that are exposed to the highest fluence. This inspection plan will be implemented beginning with the refueling outage following EPU operation.

Should the BWRVIP revise BWRVIP-26 or issue new inspection guidelines to include top guide inspections, the BWRVIP recommended inspection program will replace the program described above.

2 Electrical Engineering Branch (EEEB) (additional questions)

2.6 Please provide the existing and the proposed Hope Creek EPU expected uprated power level in MWe.

Response
The existing output is 1139 MWe. The expected output for the first cycle after EPU implementation is 1265.5 MWe.

2.7 Please provide the existing and uprated ratings for the main generator (MVA and power factor and include any effect of the power uprate).

Response
Generator nameplate rating prior to EPU modifications: 1300 MVA, 0.9 pf
Generator nameplate rating after EPU modifications: 1373.1 MVA, 0.94 pf

At EPU, the generator is field current limited at 1265.5 MWe resulting in a 0.931 pf.

2.8 Was the delta portion of the iso-phase bus duct modified for the EPU? Provide the existing and, if necessary, uprated rating (in Amperes).

Response
The cooling system modification for the isolated phase bus system included increased rating for the main and delta sections - they have common air flow paths. Existing and uprated ratings for the delta bus are provided below:

Delta bus original design rating: 18500 A
Delta bus new design rating: 19630 A

2.9 Were any modifications made to the unit auxiliary (UAT)/start-up transformers (SAT)? Provide the existing MVA ratings for the UAT/SAT. Is the total calculated loading on the SAT/UAT within the design ratings?

Response
Hope Creek does not have a unit auxiliary transformer connected to the output of the generator at 25 kV. Hope Creek supplies all of its electrical distribution system from the 500 kV switchyard using 500-14.4 kV station power transformers T1, T2, T3, and T4. These transformers energize a 13.8 kV ring bus used to provide auxiliary station power independent of the main generator operation. There are eight station service transformers supplied by the 13.8 kV ring bus used to supply station switchgear. Two of these transformers, 1AX501 and

1BX501, supply power to Class 1E switchgear 10A401, 10A402, 10A403 and 10A404 as well as Non-1E switchgear 10A101 and 10A102. All transformers supplying the station auxiliary distribution system are adequate for EPU and remain within ratings. No modifications to these transformers are required. Transformers are rated as follows:

T1, T2, T3, T4
42/56/70 MVA, 500-14.4 kV

1AX501, 1BX501
17.4/23.21/29/32.4 MVA, 13.8-4.16 kV

1AX502, 1BX502
15/18.75/25/28 MVA, 13.8-7.2 kV

1CX501
17.4/23.21/29/32.4 MVA, 13.8-4.16 kV

1DX501
17.4/23.21/29/32.5 MVA, 13.8-4.16 kV

1AX503
14.7/19.6/21.95 MVA, 13.8-4.16 kV

1BX503
14.7/19.6/21.95 MVA, 13.8-4.16 kV

4) Operator Lic & Human Performance Branch (IOLB) (additional questions)

4.6 Please clarify that the available times credited in the Hope Creek Updated Final Safety Analysis Report (UFSAR) for manual actions remains the same. In your response to RAI 4.1.c, you stated the times remain the same for manual actions but did not explicitly state that the available times remain unchanged as well.

Response
The times credited in the UFSAR for manual actions are inputs to the analysis in the UFSAR and thus represent the available times to perform those manual actions (time assumed in the analysis from beginning of accident to completion of action). Since the analysis for EPU credits existing manual actions following the same time limits currently credited in the UFSAR, available times remain unchanged.

4.7 In the response to RAI 4.2.c, you stated that "The greater amount of decay heat due to EPU will affect the operator time associated with decay heat removal results only." Please provide further clarification on how the operator times will be affected.

Response
The statement in the response to RAI 4.2.c refers to the effect of EPU on the time required to remove decay heat. Operator times are not affected by EPU; but the time required to reach cold shutdown will increase as a result of the larger decay heat due to EPU.

With the increased decay heat, operators will still be able to reduce reactor coolant system temperature to less than 200°F in less than the required 24 hours. As discussed in the response to NRC question SBPB 7.10 (Reference 3), RCS temperature can be reduced below 200°F under CPPU conditions in 13.5 hours using only one RHR heat exchanger. Prior to CPPU, the calculated time to reach cold shutdown was 9.0 hours.

4.8 PSEG has committed to training licensed operators prior to EPU implementation, however there were no statements concerning the training of non-licensed personnel. Please describe your training plans and commitments for the Hope Creek non-licensed personnel.

Response
The non-licensed operators are trained along with the Licensed Operators on the major changes made to the plant that occur during refueling outages. Likewise, the EPU changes will be addressed by licensed and non-licensed operator training. Test procedures, plant operating limits, operating experience, and areas of increased vigilance in the plant are also among the topics presented to the non-licensed operators.

4.9 Is the verification of successful completion of operator training required as a part of the Hope Creek Design Change Process?

Response
The Design Change Package for EPU Implementation has training department actions assigned for creation and implementation of EPU related training. Completion of operator training is required prior to implementation of the EPU power ascension testing. As this training is completed it is documented; in addition the completion of operations department training is documented in the EPU testing procedure *Extended Power Uprate Power Ascension Testing.*

7) Balance-of-Plant Branch (SBPB) (additional questions)

7.11 Section 10.3.2 of the Hope Creek UFSAR states that the main steam isolation valves (MSIV) and main stop valves (MSVs) can close against maximum steam flow. This licensing basis is partially addressed in the Hope Creek Power Uprate Safety Analysis Report (PUSAR), Attachment 4 of the Hope Creek EPU submittal, Section 3.8 which states that an increase in flow rate assists MSIV closure. However, the PUSAR does not address the capability of the MSVs to close against the new maximum steam flow of CPPU.

Evaluate the effect of the increased steam flow conditions of the proposed Constant Pressure Power Uprate (CPPU) upon the MSVs to close against maximum steam flow.

Response
EPU will not adversely affect the ability of the MSVs to close. The increased flow rate will actually assist in MSV closure. EPU provides increased pressure drop across the valves thereby assisting valve closure.

7.12 Section 7.4.2 of the PUSAR states that two independent hydraulic analyses were performed to account for feedwater demand transients in a 3 primary condensate pump (PCP), 3 secondary condensate pump (SCP), 3 reactor feedwater pump (RFP) lineup. The purpose of the analyses is to ensure that adequate margin above CPPU FW flow is available. The PUSAR stated that the predicted operating parameters from the two hydraulic analyses were acceptable.

a) For the two independent analyses, please state in more specific terms what transients were analyzed, what were the results, and what are the conclusions.

Response
See the response to question 7.13 below. The independent analyses are described under the heading "Analysis Models". The analyzed transients are discussed in the sections titled "Reactor Feed Pumps", "Secondary Condensate Pumps", and "Primary Condensate Pumps". Further details can be found in Tables 7.13-1 through 7.13-6.

b) Describe the impact of the loss of a PCP and/or SCP upon the RFPs at CPPU. How are the margins to RFP trips affected? Are any changes required to achieve acceptable performance?

Response
The impacts of pump losses, along with available margins, are discussed in the response to question 7.13 below in the sections titled "Reactor Feed Pumps", "Secondary Condensate Pumps", and "Primary Condensate Pumps". Margins to trips are discussed in the response to question 7.13 below, following Table 7.13-5. A change to the SCP suction trip time delay is discussed with the trip of the primary condensate pump.

c) Describe the impact of the loss of a RFP upon the remaining RFPs at CPPU. How are the margins to RFP trips affected? Are any changes required to achieve acceptable performance?

Response
Impact of loss of a feed pump is discussed in the response to question 7.13 below under the section titled "Reactor Feed Pumps". No RFP changes are required to achieve acceptable performance.

7.13 Section 10.4.7.2 of the Hope Creek UFSAR for the Condensate and Feedwater Systems describes each primary condensate pump (PCP), secondary condensate pump (SCP), and reactor feedwater pump (RFP) as one-third capacity pumps for operation at the current licensed power level.

Section 10.4.7.1 of the UFSAR states that:

"The condensate and feedwater systems are designed to permit continued operation of the plant at reduced power without reactor trip on loss of one of the three primary condensate pumps, one of the three secondary condensate pumps, one of the three reactor feed pumps, or one of the three strings of feedwater heaters."

Section 7.4 of the PUSAR does not describe any modifications to these pumps for CPPU that would suggest a decrease in the marginal performance for EPU operation.

a) For EPU operating conditions, describe how the PCP, SCP, and RFP normal operating parameters will change as compared to plant operation at the current licensed power level, including a comparison of pump suction pressures, discharge pressures, and margin to pump run out. Also, identify what the minimum allowable pump suction pressures are, what the pump suction pressure trip set points are, and how these trip set points will change for EPU operation.

b) Describe in detail the modeling that was used, analytical methods, assumptions, and analyses that have been completed (including results) that conclusively demonstrate that the plant design basis as described in Section 10.4.7.1 of the UFSAR will continue to be satisfied for the transient plant response that will occur following EPU implementation, including a bounding estimate of the total amount of uncertainty that exists and specifically what the uncertainties are and how they were determined. Also, describe how the accuracy of this analytical approach was validated for use at the uprated power level, along with the results of an analysis that examines the sensitivity of parameters to scaling effects when extrapolating the analytical methods for use at the uprated power level.

c) For a postulated trip of a PCP, SCP, and RFP (each taken individually), provide the following information for each of the pump trip scenarios:

1. a description of the most limiting case scenario that will result in the lowest RFP suction pressure, either as a direct consequence of the postulated pump trip or as a consequence of other PCP or SCP trips that occur as a result of the transient, and identify what minimum RCP suction pressure will be reached (corrected to account for the total amount of uncertainty that exists);

2. compare the minimum transient RFP suction pressure to the RFP suction pressure trip set point (corrected to compensate for allowable tolerances) and determine the minimum margin that will exist to RFP trip for the transient, and compare this margin to the minimum margin that exists for the current licensed power level.

d) Describe any transient testing that will be completed to confirm that the analytical results are sufficiently conservative and representative of transient EPU operation.

Note that as an alternative to the information referred to above, transient testing that adequately demonstrates that the plant design basis as described in UFSAR Section 10.4.7.1 will be maintained for EPU operation, similar to the pump trip testing that was specified for the Browns Ferry EPU (Accession No: ML062360160) and for the Vermont Yankee EPU (Accession No: ML060050028), is considered to be acceptable.

Response

UFSAR paragraph 10.4.7.1 (Design Basis) provides numerous statements related to the design of the feed and condensate systems. The licensing bases of the feed and condensate systems, however, are given in UFSAR paragraph 10.4.7.3 (Safety Evaluation) which states that the systems are not safety related, not required to be operable following a LOCA, and that system failure does not compromise any safety-related system or component, or prevent plant safe shutdown. These statements remain true at CPPU and are consistent with the original plant licensing basis as documented in the Hope Creek Safety Evaluation Report (NUREG-1048). Section 10.4.7 of NUREG-1048 concludes "The feedwater system is not required to transfer heat under accident conditions; therefore, GDC 44, 45, and 46 are not applicable."

Additional clarification of the HCGS feedwater and condensate systems design with regard to anticipated operational occurrences is provided in UFSAR Section 7.7.2.6, that pertains to control systems not required for safety and states, in part:

> "The recirculation runback feature of the HCGS is primarily an operational device to increase plant availability. It reduces the incidence of scrams from low vessel water level due to mis-operations of the feedwater system. Although the recirculation runback feature is simulated in the analyses of a complete loss of feedwater flow, as described in Section

15.2.7, the analyses show it does not make a significant contribution to the mitigation of this event."

PUSAR Section 9.1.1 demonstrates that reactor water level is automatically maintained above the top of active fuel (TAF) at CPPU conditions, during a loss of feedwater event with failure of the HPCI system.

The statement in UFSAR paragraph 10.4.7.2 that the RFPs, SCPs, and PCPs are one-third capacity pumps was intended to indicate that three pumps each are required to support normal plant operations at 100% RTP (both at CLTP and CPPU). However, procedural power limitations and actual capacities of these pumps at CPPU are shown in Tables 7.13-1a and 7.13-1b below. Tables 7.13-2 through 7.13-6 provide additional CPPU and CLTP information.

Table 7.13-1a - Procedural Limits with Pumps Out of Service

PCP/SCP/RFP	% of CLTP	% of CPPU*
3/3/2	100%	89.5%
3/2/3	86.9%	75%
2/3/3	87.3%	87%

* Includes 5% margin for transient events

Table 7.13-1b - Feed and Condensate Pump Capacities

Pump	% of CPPU Full Power*	Limitation
RFP	48.5% each	Available NPSH
RFP	44.7% each	Current speed clamp setting of 5480 rpm
SCP	46.5% each	Available NPSH
PCP	46.0% each	Available NPSH

* Procedural limits with pumps out of service are shown in Table 7.13-1a. However, Table 7.13-1b provides actual pump capabilities under CPPU conditions.

Table 7.13-2 - Pump Parameters at CPPU (Normal Operations)

Primary Condensate Pumps	Units	CLTP	CPPU*
Flow Rate (each of 3 pumps)	gpm	9,700	11,150
Suction Pressure	psia	9.6	9.6
Discharge Pressure	psig	195	155.5
Run-Out Margin	gpm	5,300 (35%)	3,850 (25.6%)
Secondary Condensate Pumps			
Flow Rate	gpm	9,700	11,150
Suction Pressure**	psig	124	78.2**
Prefilter/Demineralizer d/p	psid	38	51
Discharge Pressure	psig	586	506
Run-Out Margin	gpm	5,300 (35%)	3,850 (25.6%)
Reactor Feed Pumps			
Flow Rate	gpm	10,915	12,550
Suction Pressure***	psig	470	361***
Discharge Pressure	psig	1080	1114
Run-Out Margin	gpm	4785 (30%)	3150 (20%)

* CPPU values based on degraded pumps.

** SCPs trip at suction pressure = 30 ±3.3 psig (CPPU margin to trip = 48.2 psid). These trips are currently set with 1-second time-delays, which are being changed to ≤15 seconds for CPPU.

*** RFPs trip on suction pressure =230 ±9.6 psig (CPPU margin to trip = 131 psid). These trips are currently set with 10-second time-delays, which will remain the same for CPPU.

Table 7.13-3 - RFP NPSH Required

GPM	9000	10,000	11,000	11,500	12,000	12,500	13,000	14,000
FT	118	130	150	160	170	180	192	218
PSIG	36.3	41.5	50.2	54.5	58.8	63.1	68.3	79.5

Table 7.13-4 - SCP NPSH Required

GPM	9000	10,000	11,000	11,500	12,000	12,500	13,000	14,000
FT	61	65	75	87	98	110	130	185
PSIG	11.7	13.4	17.7	22.9	27.7	32.9	41.5	65.3

Table 7.13-5 - Pump Comparisons

Description	CLTP	CPPU	Original Design
Reactor Feed Pumps (each)	4.78×10^6 lbm/hr	5.58×10^6 lbm/hr	
Reactor Feed Pumps (each)	10,915 gpm	12,550 gpm	13,000gpm
$NPSH_R$	49.5 psig	63.6 psig	
Pump Efficiency	86.0%	88.5%	
Secondary Condensate (each)	9,700 gpm	11,150 gpm	11,400gpm
$NPSH_R$	12.9 psig	19.3 psig	
Pump Efficiency	88.0%	88.0%	
Primary Condensate Pumps (each)	9,700 gpm	11,150 gpm	12,300gpm
Pump Efficiency	84.0%	87.5%	

As can be seen above, the RFP 230 psig trip (with 10 second time delay) is well above the NPSH requirement for the RFPs, both at CLTP and at CPPU. Since NPSH available exceeds NPSH required under all operating conditions, the 230 psig RFP low suction pressure trip was based on the limiting combination of operating pumps. The minimum value was calculated to be 247 psia and was based on a 3/2/3 (PCP/SCP/RFP) combination at 100% of original licensed thermal power (OLTP). The 230 psig trip also provides a 45% margin to the saturation temperature at CLTP (based on 370°F), which is reduced to 27% at CPPU (based on 380°F). The 230 psig low-suction pressure trip remains acceptable at CPPU and no change to the trip set point is planned.

For the SCP, the 30 psig (with 1 second time delay) trip set point is based on NPSH required, since the saturation pressure for temperatures below 140°F are sub-atmospheric. The 30 psig set point provides a margin to NPSH (required) of 130% at CLTP and 55% at CPPU. This margin is also considered acceptable and no changes to the set point are recommended. However, as discussed below, the 1 second time delay will be increased to improve plant reliability at CPPU.

As stated in PUSAR section 7.4.2, the Hope Creek plant automatically runs back at CPPU on loss of PCP or SCP to approximately 70% power and 60% core flow. Consequently, potential for total loss of feedwater is eliminated because the runback reduces power levels to within the capabilities of the remaining pumps. It should be noted that original plant design documents make the following statements regarding SCP or PCP trips. Design calculations indicate that the original design anticipated that power level would have to be reduced (below 100% OLTP) in the event of an SCP or PCP trip.

> "Should any one of the primary or secondary condensate pumps trip, and total feedwater demand exceeds the maximum capacity of the remaining pumps, an automatic reduction in reactor power to reduce feedwater demand will be initiated. This is accomplished by a runback of the recirculation pump speed, which decreases reactor power level and feedwater demand to within the capabilities of the remaining pumps."

Table 7.13-6 - Design Parameters under Uprate for the Feed and Condensate Systems

Parameter	Units	CLTP	CPPU
Feedwater Mass Flow Rate (total)	lb_m/hr	14,349,300	16,741,000
Maximum Feedwater Temperature	°F	420.7	431.6
Maximum Allowable Condensate Demin/Prefilter differential-pressure	psid	50	68
Feedwater Flow (per pump)	gpm	10,915	12,550
Condensate Flow (per pump)	gpm	9,700	11,150
Pressure at Secondary Condensate Pump Suction	psig	112 (Trip 30 psig with 1-sec. TD)	60* (Trip 30 psig with ≤15-sec. TD)
Pressure at Feedwater Pump Inlet	psig	470 (Trip 230 psig with 10-sec. TD)	332* (Trip 230 psig with 10-sec. TD)
Pressure at Feedwater Pump Discharge	psig	1080	1114
RFP Running Speed	rpm	4400 (Clamp 5480) (4816 PCP Trip) (4961 SCP Trip)	5050* (Clamp 5480) (4816 PCP Trip) (4961 SCP Trip)
Condenser Pressure	Inches Hg (a)	5.0	5.0**

* Predicted pressures and speed assume a 3/3/3 pump configuration and operation with a maximum combined prefilter/demineralizer allowable pressure drop of 68 psid. Normal post-CPPU combined DP is expected to be approximately 51 psid; thus, a corresponding increase of pressure would be expected at the secondary condensate pump suctions under normal conditions. In addition, procedures will restrict reactor power at high filter/demineralizer differential pressures to maintain adequate suction pressure margins.

** For a given set of conditions, an increase of approximately 0.7"Hg (a) is expected due to the increase in condenser heat duty. Per current plant procedures, operation without de-rate is allowed up to a condenser pressure of 5.5"Hg (a).

Reactor Feed Pumps

Trip of a reactor feed pump (at CPPU) will not cause loss of any other feed or condensate pump, and does not cause a reactor trip. This event has been analyzed and is documented in Attachment 6 to LCR H05-01. Attachment 6 provides comparisons of CPPU analyses to plant data and actual plant events, including an event in May of 1993 during which two of the three RFPs tripped.

Attachment 6 shows that the trip of a single RFP at CPPU is bounded by the 1993 event and that further testing of the RFP trip is not warranted.

<u>Secondary Condensate Pumps</u>
Trip of a secondary condensate pump at CPPU triggers an immediate recirculation (RR) system runback and also initiates an immediate reduction of RFP speed from a nominal 5050 rpm to 4961 rpm. As shown in Table 7.13-2, steady-state RFP suction pressures are well above the 230 psig RFP suction pressure trip (131 psid or 57% margin). Under these conditions, dynamic analyses (described below) indicate that RFP suction pressures remain well above the 230 psig trip set point following an SCP pump trip, with no delays in the runback or RFP speed change. With a more realistic delay in RFP speed reduction and runback effectiveness, suction pressures may momentarily drop below the 230 psig trip set point but recover well within the existing 10-second time delay. Available margins and plant experience from past events indicate that an SCP trip at CPPU will not cause a loss of all feedwater. Hence, trip testing of SCPs is not warranted.

<u>Primary Condensate Pumps</u>
Of the three sets of pumps, trip of a PCP results in the lowest margin to suction pressure limits (i.e. SCP trip set point). Trip of a primary condensate pump at CPPU also triggers both an RR runback and RFP speed reduction (from 5050 rpm to 4816 rpm). In the case of the PCPs, however, steady-state SCP suction pressures at CPPU are approximately 78 psig. Dynamic analyses indicate that SCP suction pressures remain above 60 psig following a PCP trip with no relative delay in the RR runback. When a 4-second delay was imposed on the RR runback (to evaluate possible loop-logic time delays), SCP suction pressure dropped to 39 psig (only 9 psi above the 30 psig trip set point) following the PCP trip. In view of the low margin and in view of the sensitivity of the start of the RR runback, the 30 psig SCP trip set point time-delay (currently 1-second) is being increased to ≤15-seconds for CPPU.

The increased time delay will assure that SCP pumps will not trip following the trip of a PCP at CPPU because the combination of the RR runback and the RFP speed reductions will recover SCP suction pressures prior to any consequential pump trips. Dynamic analyses show that the SCP suction pressures recover in a matter of seconds such that the ≤15-second delay would be sufficient to preclude trip actuation. Also, power restrictions will be procedurally imposed under off-normal plant conditions to assure that transient margins are maintained.

In February 2006, an actual PCP trip occurred during which the RR runback was effective and no significant plant challenges occurred. The plant historian data from this trip has been compared to the dynamic analysis models and has been shown to be comparable to the model predictions. During the February 2006 event, a 60 psi margin to the SCP suction pressure trip was observed. In view of the above and the empirical data from the February 2006 pump trip, no further testing of PCPs is warranted.

Analysis Models
As discussed in PUSAR section 7.4.2, hydraulic analyses to confirm availability of a 105% of CPPU (4032 MWt) and 108% of CPPU (4147 MWt) feedwater flow rate for transients were performed independently by General Electric and Sargent and Lundy Engineers. These analyses demonstrated sufficient steady-state flow margins (5% minimum) to accommodate transient conditions at CPPU. Subsequent to PUSAR submittal, dynamic analyses were performed to confirm original conclusions as further discussed below.

For uniformity and clarification in reading this response, the following definitions are provided:

Steady State: Plant operating conditions with constant reactor power, pressure, core flow, feedwater flow, and temperature.

Transient: The difference in operating conditions between two steady state reactor operating conditions. Transient margin does not imply that a time-dependent transient calculation has been performed, only that an evaluation at greater than steady state power and flow has been performed to ensure that sufficient steady state capacity exists to provide reactor vessel level control capability. A 5% criterion is applied generically across all major operating parameters as a screening criterion.

Dynamic: A time-dependent transient calculation or computer analysis that predicts various plant parameters as a function of time following an initiating event, such as loss of a condensate pump.

Similar to other non-safety related design calculations performed in support of BOP systems and other non-essential systems at HCGS, the hydraulic models developed to address condensate and feedwater system performance were not built with the detailed and in-depth treatment of instrument accuracies (e.g., sum of the squares methods applied to all pressure, flow and temperature devices used to benchmark the models), that would be required of safety-related analyses such as ECCS and/or ultimate heat sink type calculations. As provided in Section 1.1, Scope, of ANSI N45.2.11, Quality Assurance Requirements for the Design of Nuclear Power Plants, since the condensate and feedwater systems are not relied upon to "prevent accidents that could cause undue risk to the health and safety of the public; or to mitigate the consequences of such accidents if they were to occur," a lesser standard can be applied. This "lesser standard" which does not even require design verification is typically employed throughout the industry for similar type calculations.

The THOR-BOP models are state-of-the-art, two-phase, non-equilibrium models available for the balance of plant (BOP) systems. The Hope Creek simulator software was upgraded to THOR-BOP specifically to simulate EPU BOP conditions. THOR-BOP is now used to model the secondary plant, i.e. main steam, moisture separator, turbines, main condensers, condensate, feed, extraction steam and drain systems.

To analyze BOP transients under CPPU conditions, HCGS used three dynamic models (PROTO-FLO, THOR-BOP, and GE-SAFER) and one steady-state/transient model (FATHOM), as well as empirical data from an actual plant trip of a PCP (2/4/06) at CLTP. The THOR-BOP model is a powerful simulator code that is benchmarked against both plant data and the 110% CPPU thermal kit, and simulates recirculation (RR) runbacks and RFP speed clamps. The FATHOM and PROTO-FLO models do not have the capabilities to include plant RR runback logic. However, the FATHOM and PROTO-FLO codes are approved models per the HCGS design engineering process/procedures. THOR-BOP results, therefore, were supplemented by PROTO-FLO sensitivity analyses and empirical plant data to confirm the adequacy of the THOR-BOP conclusions.

Steady-state conditions prior to initiation of one of the SCP trips are shown below. At CPPU (115% CLTP), predicted RFP THOR-BOP speeds were 5000 rpm. RFP suction pressure was approximately 360 psia, SCP suction pressure 78 psia, and PCP discharge pressure 166 psia. A comparison of the pre-trip THOR-BOP predicted conditions to the steady-state models is shown in Table 7.13-7 below.

Table 7.13-7 – Pre SCP Trip Steady-State Conditions

Model	SCP Suction	RFP Suction	RFP Speed	PreFilter/Demin DP
THOR-BOP	78 psia	360 psia	5000 rpm	80 psid
PROTO-FLO	85 psia	344 psia	4950 rpm	68 psid
FATHOM	74 psia	348 psia	5100 rpm	70 psid

The HCGS dynamic analysis evaluates BOP conditions and therefore relies primarily on codes and models that are benchmarked to actual plant data rather than incorporating numerous artificial conservatisms that would detract from the ability to reproduce realistic plant conditions. At the same time, numerous sensitivity runs were performed at extremely high differential pressures (e.g., across condensate pre-filters and demineralizers) and with different simulated leakage rates to establish plant responses under these conditions. Based on the results of these runs and analyses, high confidence has been established that trip of an RFP, SCP, or PCP will not result in a plant trip or loss of feed event once the SCP suction trip time delay is extended and based upon procedural restrictions for off-normal alignments.

As stated in PUSAR Section 7.4.2, Transient Operation, the ability of the feedwater and condensate systems to respond to large transients will be confirmed as part of the power ascension test plan. While designed for a 5% flow margin at EPU conditions, the test plan includes the performance of large (10%, referenced to total EPU flow) step changes into each of the three feed pumps at each of the power plateaus up to 110% CLTP. Such testing will confirm the reserve capacity of the pumps and digital feedwater system response to large level transients. To verify the maximum FW runout capability, the pressure, flow and controller data will be measured during power ascension testing and compared against acceptance criteria. In addition during power ascension, critical parameters such as demineralizer differential pressures, and pump suction pressures will be compared to model predicted results and trended via System Performance Monitoring & Analysis plans, which will be developed for each significant EPU affected system.

The plant response at CPPU to loss of a feed or condensate pump is bounded by the complete loss of feed transient event (LOFW) with a coincident loss of HPCI. As stated above, the LOFW analysis determined that minimum level is reached in the RPV upper plenum above the top of active fuel (TAF).

Since feed and condensate pumps at HCGS were originally oversized, these pumps will be operating at the same or better efficiency points at CPPU than at CLTP. With these pumps operating closer to their best efficiency points under steady state operation at CPPU, the probability of mechanical failures will remain the same or slightly improve based on operating closer to optimum design conditions. Hence, the frequency of a BOP pump trip, and with the available margins a loss of feed event, does not increase at CPPU and is bounded by original plant analyses.

In view of the foregoing, the frequency and consequences of a loss-of-feedwater event do not increase with CPPU. The original design/licensing basis bounding event, loss of all feedwater, has not changed for CPPU. Also, the original licensing basis (as stated in the UFSAR) that the systems are not safety related, not required to operate following a LOCA, and that system failure does not compromise any safety-related system or component, or prevent plant safe-shutdown remains valid for CPPU. Risks to the health and safety of the public have not changed. The original plant test requirements, which did not include condensate pump trip testing, should be applied to CPPU conditions.

7.14 UFSAR Section 10.2.[2].6, "Overspeed Protection," states that the turbine has two electrical trips, specifically : 1) A primary electrical overspeed trip that is initiated if the turbine speed reaches approximately 8 percent above rated speed, and 2) An emergency electrical overspeed trip that serves as a backup to the primary trip that is initiated at approximately 10 percent above rated speed.

UFSAR Table 10.2-1 states that the overspeed trip is 110% and the backup is 112% of rated speed. The table refers to the overspeed trip as a mechanical trip. The description of the overspeed trip devices in Table 10.2-1 does not appear to be consistent with the description of the overspeed devices in UFSAR Section 10.2.[2].6.

Additionally, Attachment 10 of the CPPU submittal, in the notes of Matrix 5, refers only to a mechanical trip that is set at 109.9% - 110.4% with a "normal overspeed" of 109.2% and an "emergency overspeed" value of 119.35%.

Please explain these apparent inconsistencies, and describe how the main turbines will be protected from overspeed conditions following CPPU implementation such that design limitations will not be exceeded. Also, please describe testing that will be completed to assure acceptable performance of the main turbine overspeed protective features.

Response

UFSAR Section 10.2.2.6, "Overspeed Protection," correctly documents the methods used to protect the turbine generator against overspeed. These changes were implemented with the Digital Electro-Hydraulic Control (DEHC) system installed in RF12 (completed in February 2005). The two trip devices are:

1. A primary electrical overspeed trip that is initiated if the turbine speed reaches approximately 8 percent above rated speed.

2. An emergency electrical overspeed trip that serves as a backup to the primary trip that is initiated at approximately 10 percent above rated speed.

UFSAR Table 10.2-1 is incorrect and will be revised to reflect DEHC implementation. The reference to mechanical trip settings in the note to Matrix 5 is also incorrect. The function of the mechanical overspeed trip is now performed by the emergency electrical overspeed trip. A station corrective action item has been initiated to track and correct the discrepancies.

The normal overspeed (NOS) and emergency overspeed (EOS) values are calculated as described in the note to Matrix 5. The NOS and EOS values remain within limits for CPPU; therefore the main turbine will continue to be protected from overspeed conditions following CPPU implementation such that design limitations will not be exceeded.

Testing of both the primary overspeed trip and the emergency electrical overspeed trip were satisfactorily completed as a part of the site acceptance test for the DEHC implementation. Steps for testing both of the overspeed trips while online and during refueling outages have been incorporated into Operations procedures and are already being utilized.

7.15 Please clarify your RAI response to RAI 7.5 regarding Post EPU SFP Heat Load. The values in the table of your response specify a normal fuel off load. Whereas, the PUSAR on page 6-7, bottom paragraph, says the Safety Auxiliaries Cooling System Loss of Coolant Accident heat load calculation used a full fuel offload. Should you be considering the full offload condition?

<u>Response</u>
Spent fuel pool (SFP) heat load calculations, both for CLTP and CPPU, consider normal fuel off-loads when evaluating post-LOCA conditions. Maximum post-accident SACS heat loads are based on a design basis LOCA, which occurs during full-power operations with maximum core power history and other design basis conditions. In this case, if a refueling outage had recently been completed and even if a full-core offload had been performed during the outage, at least 2/3 of the core would have been reloaded into the reactor vessel (along with a batch of new fuel) prior to plant startup. Consequently, the maximum amount of recently discharged fuel remaining in the SFP for cooling by SACS would be a normal refueling batch (approximately 1/3 core).

During normal refueling outages, an entire core is not replaced with a complete core of new fuel such that the plant would return to power with a recently discharged full-core remaining in the SFP. If that were to occur for some unforeseen reason, the new core would have an insufficient power history (immediately after the outage) to generate the mass-and-energy release assumed in a design basis LOCA event. The words "full fuel offload" in the PUSAR (last paragraph of page 6-7) do not refer to a full-core offload. The design basis SFP heat load (with a recent batch offload) does consider all other pool fuel racks to be full with expended fuel (minus one complete core).

The following additional information is being provided in response to an NRC staff request for clarification during a telephone conference call on May 11, 2007.

The table supplied with the response to question 7.5 (showing 98 hours after shutdown and 12 days after shutdown) is the result of analyses done to support the PUSAR. These analyses demonstrate the feasibility of maintaining the current temperature limits for the spent fuel pool but do not directly correlate to the Hope Creek current licensing basis. Subsequent to preparation of the PUSAR, HCGS design and licensing basis fuel pool calculations were revised to reflect CPPU heat loads and to provide a basis for CPPU UFSAR changes.

As discussed in our response to question 7.1, the licensing basis for the spent fuel offloads to the fuel pool remain unchanged (except for the additional CPPU heat) as shown in the following table. In all cases, SACS inlet temperature is assumed to be at 95°F. For the full-core offload, one RHR heat exchanger in

SFP cooling assist mode is assumed to be in operation. The CPPU heat loads will be inserted into the USFAR as the new licensing-basis heat loads for the HCGS fuel pool.

8) SG Tube Integrity & Chem. Eng Br (CSGB)

8.21 Please provide the pre-EPU flow accelerated corrosion (FAC) rates for comparison purposes as an additional column to the After Uprate table provided in your response to RAI 8.18.

Response

The "After Uprate" table in the response to RAI 8.18 has been modified to include comparison FAC rates for pre-EPU operating conditions. In addition, a typographical error in the post-120% EPU wear rate for 1-AD-031-S01-N1 (3A Feedwater Heater to 4A Feedwater Heater) has been corrected.

After Uprate#

System	Line Name	Component ID	Description	Wear Rate /Year (mil) Pre 120%	Wear Rate /Year (mil) Post 120%
Seal Steam	Steam Supply to Steam Seal Evaporator	1-AF-004-S05-P1	Pipe	22.7	25.9
Heater Drains	FWH 4B to FWH 3B	1-AF-109-S01-L1	Elbow	14.2	16.1
Condensate	Secondary Condensate Pump Discharge Header	1-AD-111-S01-N1	Nozzle	14.4	15.8
Condensate	3A Feedwater Heater to 4A Feedwater Heater	1-AD-031-S01-N1	Nozzle	13.2	15.3
Heater Drains	3A Feedwater Heater to 2A Feedwater Heater	1-AF-141-S02-L2	Elbow	10.8	13.6
Heater Drains	5C Feedwater Heater to 4C Feedwater Heater	1-AF-095-S03-L1	Elbow	11.2	12.3
Condensate	2A Feedwater Heater to #2 Feedwater Heater Header	1-AD-062-S01-L1	Elbow	8.7	10.2

Pre 120% figures based on RF10 (Autumn 2002) input data and Cycle 10 operating conditions. After uprate wear rates are based on the operating conditions of the 120% OLTP uprate. Selections for this table were based on the high predicted wear rate of the component after the 120% uprate.

13) Containment and Ventilation Branch (SCVB) (additional question)

13.17 Pleased provide a reference to NRC staff approval of hydrodynamic loads issues for Hope Creek.

Response
NRC staff review and approval of the Hope Creek Plant Unique Analysis Report is documented in Appendix N to Supplement 3 and in Supplement 4 to NUREG-1048, "Safety Evaluation Report Related to Operation of Hope Creek Generating Station."

13.20 The Hope Creek response to GL 97-04 shows that although adequate available net positive suction head (NPSH) existed, the NPSH margin was less than 1 foot for both the core spray and the residual heat removal (RHR) pumps (December 30, 1997 letter to NRC Page 4/5). Was there any change to the NPSH methods described in the Hope Creek response to GL 97-04 for the EPU? If not, how was the increase in suppression pool temperature accommodated?

Response
NPSH calculation methodology has not changed for CPPU. However as discussed below, original NPSH margins were based upon conservative NPSH specifications from the NSSS vendor rather than actual pump vendor requirements. CPPU NPSH margins are based on actual vendor requirements.

Original design basis NPSH calculations were performed by Bechtel Power Corporation in the 1984/ 1985 time frame. These calculations determined NPSH available and concluded that NPSH was acceptable because the available NPSH exceeded specifications provided by the NSSS vendor (GE). The GE specifications included the pump vendor's NPSH required and also included margins added by GE, most likely to account for unknowns during the design phase. The Bechtel calculations demonstrated the following margins to the GE specifications. These values were subsequently reported to the NRC in response to GL 97-04.

- RHR satisfied by about 1.5 feet (over GE spec of 9 feet)
- CS satisfied by about 1.2 feet (over GE spec of 10 feet)

New ECCS suction strainers were installed in 1997/1998 time frame. The pressure drop for the new strainers was approximately 1 foot greater than the pressure drop from the previous strainers (old strainer 1 foot; new strainer 2.04 feet). This reduced the apparent NPSH margins by approximately one foot, as shown below. These values were also subsequently reported to the NRC in response to GL 97-04.

- Approximately 1/2 foot for RHR (over the GE spec of 9 feet)
- Approximately 1/4 foot for CS (over the GE spec of 10 feet).

In 2000, new NPSH calculations were prepared using benchmarked PROTO-FLO models of the RHR and CS systems including the same debris loading calculation for the new suction strainers as described above (2.04 feet per strainer). These calculations, for the first time, provided the actual margins to the pump vendor NPSH (required) for the RHR and CS pumps at CLTP conditions, as shown in the table below. These values were not reported to the NRC since they demonstrated more margin than had been reported in response to GL 97-04. As can be seen below, PROTO-FLO calculated available NPSH similar to the original Bechtel results.

CLTP NPSH Margins

Pump	NPSH (Required)	NPSH (Available)	NPSH Margin
RHR A	3.0 feet	11.17 feet	8.17 feet
RHR B	3.5 feet	11.29 feet	7.79 feet
RHR C	3.0 feet	10.09 feet	7.09 feet
RHR D	4.0 feet	10.11 feet	6.11 feet
CS A	5.6 feet	11.3	5.7 feet
CS B	5.6 feet	11.3	5.7 feet
CS C	5.6 feet	11.3	5.7 feet
CS D	5.6 feet	11.3	5.7 feet

In 2005, the PROTO-FLO calculations were revised for CPPU to accommodate a bounding suppression pool temperature increase from 212°F to 218°F (with no credit for containment pressure). These calculations are identical to the 2000 calculations except for the temperature increase. The increase from 212°F to 218°F reduces available margins by the change in vapor pressure (1.85 psid or 4.5 feet). In view of this bounding change, the available NPSH margins at CPPU are shown below:

CPPU NPSH Margins

Pump	NPSH Margin
RHR A	3.7 feet
RHR B	3.4 feet
RHR C	2.6 feet
RHR D	1.7 feet
CS A to D	1.2 feet

13.21 Please confirm: The peak bulk pool temperature in Table 4-1 of the PUSAR of 201°F is calculated at 2% above 3339 MWt. The peak bulk pool temperature of 212.3°F is calculated at 2% above 3840 MWt. The peak wetwell air space pressure of 27.6 psig is calculated at 2% above 3339 MWt and the peak wetwell airspace pressure of 27.7 psig is calculated at 2% above 3840 [MWt].

Response
The following temperatures are confirmed below:

Parameter	Description	Basis	Staff Understanding
201 °F	Peak Bulk Pool Temperature at CLTP	2% above 3339 MWt	Correct
212.3 °F	Peak Bulk Pool Temperature at CPPU	2% above 3840 MWt	Correct
27.6 psig	Peak Wetwell Air Space Pressure at CLTP	2% above 3339 MWt	Correct
27.7 psig	Peak Wetwell Air Space at CPPU	2% above 3952 MWt	Different. See footnote 1 to Table 4-1.

13.22 The response to RAI 13.9 listed the maximum temperatures for various systems attached to the torus. It is not clear from the response what the temperature limit is for the attached piping to demonstrate that the calculated temperatures at EPU conditions are acceptable, please clarify this temperature limit.

Response
Only the RHR and Core spray piping are required to operate when the suppression pool temperature is at the maximum calculated temperature of 213.6°F. Two trains of RHR suction piping and Core spray piping are analyzed below 213.6°F. A review of the margins of the affected stress and support calculations concluded that the small increase of 1.6°F will have a negligible effect at EPU conditions on the existing design calculations. This negligible effect is acceptable.

References

1. PSEG letter LR-N06-0286, Request for License Amendment: Extended Power Uprate, September 18, 2006

2. NRC letter, Hope Creek Generating Station - Request for Additional Information Regarding Request for Extended Power Uprate (TAC NO. MD3002), May 17, 2007

3. PSEG letter LR-N07-0099, Response to Request for Additional Information, April 30 2007