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

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

References:
1) PSEG letter LR-N05-0258, Request for License Amendment: Extended Power Uprate, November 7, 2005

2) PSEG letter LR-N06-0052, Withdrawal of Request for License Amendment: Extended Power Uprate, February 10, 2006

3) NRC Letter to GE Nuclear Energy, Review of Extended Power Uprates for Boiling Water Reactors, June 25, 2003

4) PSEG letter LR-N05-0328, Supplement No. 1 to Request for License Amendment: Extended Power Uprate, Loss of Coolant Analysis, November 7, 2005

5) PSEG letter LR-N05-0329, Supplement No. 2 to Request for License Amendment: Extended Power Uprate, Stability Reports, November 7, 2005

6) PSEG letter LR-N05-0330, Supplement No. 3 to Request for License Amendment: Extended Power Uprate, Mixed Core Analysis Reports, November 7, 2005

7) PSEG letter LR-N05-0331, Supplement No. 4 to Request for License Amendment: Extended Power Uprate, Fuel Transition Reports, November 7, 2005

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This letter forwards proprietary information in accordance with 10CFR 2.390. The balance of this letter may be considered non-proprietary upon removal of Attachments 4, 15, 20 and 22.

Pursuant to 10 CFR 50.90, PSEG Nuclear LLC (PSEG) hereby requests a revision to the Operating License and Technical Specifications for the Hope Creek Generating Station. In accordance with 10CFR50.91(b)(1), a copy of this submittal has been sent to the State of New Jersey.

The proposed amendment would increase the maximum power level authorized by Section 2.C.(1) of Operating License NPF-57 from 3339 megawatts thermal (MWt) to 3840 MWt, an increase of approximately 15 percent. This request also includes supporting Technical Specification changes necessary to implement the increased power level.

This request for license amendment revises the request submitted previously in Reference 1 and withdrawn in Reference 2. PSEG has evaluated the proposed changes in accordance with 10CFR50.91(a)(1), using the criteria in 10CFR50.92(c), and has determined this request involves no significant hazards considerations. A description of the requested changes and information in support of the no significant hazards consideration determination are provided in Attachment 1 to this letter. The marked up Operating License and Technical Specification pages for the proposed changes are provided in Attachment 2.

Attachment 3 to PSEG's original request for license amendment (Reference 1) contains a supplement to the Hope Creek Generating Station Environmental Report supporting a finding of no significant impact. PSEG performed an assessment of environmental impacts of the proposed uprate from 3339 MWt up to a maximum of 3952 MWt by comparing the impacts of the uprate to those previously evaluated by the NRC staff in the 1984 Final Environmental Statement (FES) associated with the issuance of the Hope Creek Operating License. The comparisons show that the conclusions of the FES and the Environmental Assessment remain valid for operation at 3840 MWt.

The technical bases for this request follow the guidelines contained in the NRC-approved GE Nuclear Energy (GENE) Licensing Topical Reports (LTRs) for extended power uprate (EPU) safety analysis: NEDC-33004P-A, "Constant Pressure Power Uprate," (CLTR); NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1); and NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (ELTR2). Attachment 4 contains NEDC-33076P, Revision 2, "Safety Analysis Report for Hope Creek Constant Pressure Power Uprate," dated August 2006 (i.e., the Power Uprate Safety Analysis Report (PUSAR)). The PUSAR is a summary of the results of the safety analyses performed for the Hope Creek EPU. The PUSAR contains information which GE considers to be proprietary. GE requests that the proprietary information in this report be withheld from public disclosure in accordance with 10 CFR 9.17(a)(4) and 2.390(a)(4). An affidavit supporting this request is included with Attachment 4. A non-proprietary version of the report is provided in Attachment 12.

Attachment 5 provides a list of completed and currently planned modifications necessary to support EPU. The planned modifications are scheduled to be implemented before restart from the refueling outage currently planned for Fall 2007. The list of modifications is subject to change based on component evaluations currently being performed. The modifications listed in Attachment 5 are planned actions which do not constitute regulatory commitments by PSEG. The modifications listed in Attachment 5 are being implemented in accordance with the requirements of 10 CFR 50.59 and do not require NRC review and approval.

Attachment 6 to PSEG's original request for license amendment (Reference 1) provides a description of EPU transient testing. PSEG does not plan to conduct large transient testing requiring an automatic scram from high power (e.g., main steam isolation valve (MSIV) closure). The justification for not performing large transient testing is included in Attachment 6. A non-proprietary version of the report is provided in Attachment 16 to PSEG's original request for license amendment (Reference 1).

Attachment 7 contains a summary of actions completed or currently planned to ensure the integrity of the steam dryer at the EPU condition. A report describing the application of the acoustic circuit model to the Hope Creek steam dryer and main steam line geometry is provided in Attachment 18. A report describing the calculation and evaluation of stresses in the steam dryer at Current Licensed Thermal Power is provided in Attachment 19. The predicted stresses at the EPU condition are provided in Attachment 21. The bounding methodology to predict steam dryer loads from in-plant measurements is described in Attachment 20. A description of the small scale testing program is provided in Attachment 22. Attachments 20 and 22 contain information which Continuum Dynamics, Inc. (CDI) considers to be proprietary. CDI requests that the proprietary information be withheld from public disclosure in accordance with 10 CFR 2.390(a)(4). An affidavit supporting this request is provided in Attachment 24. Attachments 25 and 26 contain non-proprietary versions of the reports in Attachments 20 and 22.

Attachment 8 summarizes the flow induced vibration (FIV) susceptibility review performed to determine systems and components that could be adversely affected by flow-induced vibration under EPU conditions. Attachment 8 also describes the remote vibration monitoring program and baseline results for the main steam, feedwater, and extraction steam piping systems.

Attachment 9 to PSEG's original request for license amendment (Reference 1) provides a summary of grid impact studies which demonstrate that the Hope Creek EPU will not have a significant adverse effect on the reliability or operating characteristics of Hope Creek or on the offsite electrical system.

Attachment 10 to PSEG's original request for license amendment (Reference 1) provides a markup of the review matrices contained in the NRC's "Review Standard for Extended Power Uprates," (RS-001) with cross-references to the Hope Creek PUSAR and other documents submitted in support of this request. Attachment 11 to PSEG's original request for license amendment (Reference 1) provides a markup of the Template Safety Evaluation for Boiling Water Reactor Extended Power Uprate contained in RS-001.

Attachment 13 to PSEG's original request for license amendment (Reference 1) provides marked up TS Bases Pages. These pages are being submitted for information only and do not require issuance by the NRC.

Attachment 14 to PSEG's original request for license amendment (Reference 1) provides a summary of the findings and observations from the PRA Peer Review Certification of the Hope Creek 1999 PRA model with PSEG's response for each item.

To address NRC questions regarding the application of GE's nuclear core and physics analytical methods to EPU conditions, GE submitted Licensing Topical Report (LTR) NEDC-33173P, "Applicability of GE Methods to Expanded Operating Domains," to the NRC on February 10, 2006. The scope of the LTR addresses extended power uprates and is based upon the approach taken during the NRC approval of the Vermont Yankee license application for a constant pressure power uprate. PSEG intends to implement the provisions of NEDC-33173P as part of implementation of EPU at Hope Creek Generating Station. This includes the provision for an adjusted Safety Limit Minimum Critical Power Ratio. Section 3.0 of NEDC-33173P addresses the MELLLA+ operating domain and does not apply to the HCGS EPU.

In the Reference 3 letter, the NRC described additional plant-specific information to be submitted by licensees applying for extended power uprate (EPU) with a core containing non-GE fuel. PSEG plans to implement EPU in a Hope Creek operating cycle in which there will be a combination of GE14 and SVEA 96+ fuel. In the operating cycle in which EPU will be first implemented (Cycle 15), there will be predominately GE14 fuel with some remaining thrice and more burned SVEA 96+ fuel. This SVEA 96+ fuel is currently expected to be operating in this first EPU cycle at fuel bundle powers consistent with reactor operation at Current Licensed Thermal Power. In accordance with the guidance in Reference 3, PSEG has provided the information in References 4, 5, 6 and 7 in support of the NRC's review of the requested License Amendment. The report provided in Attachment 1 to Reference 6 summarizes the results of fuel dependent analyses applicable to Current Licensed Thermal Power operation for the Hope Creek Cycle 13 core composed of GE14 and SVEA 96+ fuel. In addition, the report in Attachment 15 provides a Hope Creek specific supplement to GE Licensing Topical Report NEDC-33173P based on a preliminary EPU core design for Cycle 15. Attachment 15 contains information which GE considers to be proprietary. GE requests that the proprietary information in this report be withheld from public disclosure in accordance with 10 CFR 9.17(a)(4) and 2.390(a)(4). An affidavit supporting this request is included with Attachment 15. A non-proprietary version of the report is provided in Attachment 17.

A description of the planned program for steam dryer and piping system vibration monitoring during power ascension is provided in Attachment 23.

There are no regulatory commitments contained in this letter or attachments.

PSEG plans to implement extended power uprate before restart from the refueling outage currently planned for Fall 2007. Therefore, to support PSEG's schedule for reload core design and outage planning, PSEG requests that the proposed changes be approved by September 18, 2007, with implementation to be completed within 120 days from startup (Mode 2) following refueling outage RF14.

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

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

Executed on 9/18/06
(date)

George P. Barnes
George P. Barnes
Site Vice President – Hope Creek

Attachments (26)

1. Description Of The Requested Changes And Information In Support Of The No Significant Hazards Consideration Determination
2. Marked Up Operating License and Technical Specification Pages
3. [Supplement to the Hope Creek Generating Station Environmental Report submitted in Reference 1]
4. NEDC-33076P, Revision 2, "Safety Analysis Report for Hope Creek Constant Pressure Power Uprate" (Proprietary)
5. Completed and Planned Modifications
6. [EPU Transient Testing (Proprietary) submitted in Reference 1]
7. Steam Dryer Evaluation
8. Flow Induced Vibration
9. [Summary of Grid Impact Studies submitted in Reference 1]
10. [Markup of RS-001 Technical Area Review Matrices submitted in Reference 1]
11. [Markup of RS-001 BWR Template Safety Evaluation submitted in Reference 1]
12. NEDO-33076, Revision 2, "Safety Analysis Report for Hope Creek Constant Pressure Power Uprate"
13. [Markup of TS Bases Pages (Information Only) submitted in Reference 1]
14. [Summary of 1999 PRA Peer Review Findings and Observations submitted in Reference 1]
15. "Interim Methods LTR Supplement for Hope Creek Extended Power Uprate," July 2006 (Proprietary)
16. [EPU Transient Testing - Non-Proprietary Version submitted in Reference 1]

17. "Interim Methods LTR Supplement for Hope Creek Extended Power Uprate," July 2006 (Non-Proprietary Version)
18. "Hydrodynamic Loads on Hope Creek Unit 1 Steam Dryer to 200 Hz," CDI Report 06-17, Revision 2, September 2006
19. "Stress Analysis of the Hope Creek Unit 1 Steam Dryer for CLTP," CDI Report No. 06-24, Revision 3, September 2006
20. "Bounding Methodology to Predict Full Scale Steam Dryer Loads from In-Plant Measurements," CDI Report No. 05-28P, Revision 1, May 2006 (Proprietary)
21. "Stress Analysis of the Hope Creek Unit 1 Steam Dryer Using 1/8th scale Model Pressure Measurement Data," CDI Report No. 06-27, Revision 0, September 2006
22. "Estimating High Frequency Flow Induced Vibration in the Main Steam Lines at Hope Creek Unit 1: A Subscale Four Line Investigation of Standpipe Behavior," CDI Report No. 06-16, Revision 1, September 2006 (Proprietary)
23. Power Ascension Test Plan Overview
24. CDI Request for Withholding
25. "Bounding Methodology to Predict Full Scale Steam Dryer Loads from In-Plant Measurements," CDI Report No. 05-28P, Revision 1, May 2006 (Non-Proprietary)
26. "Estimating High Frequency Flow Induced Vibration in the Main Steam Lines at Hope Creek Unit 1: A Subscale Four Line Investigation of Standpipe Behavior," CDI Report No. 06-16NP, September 2006

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HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

EXTENDED POWER UPRATE

REQUEST FOR CHANGE TO TECHNICAL SPECIFICATIONS EXTENDED POWER UPRATE

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REQUEST FOR CHANGE TO TECHNICAL SPECIFICATIONS EXTENDED POWER UPRATE

1. DESCRIPTION

The proposed amendment increases the Hope Creek Generating Station (HCGS) licensed thermal power level to 3840 megawatts thermal (MWt), approximately 15% above the current rated thermal power (RTP) of 3339 MWt and 16.6% above the original RTP of 3293 MWt.

NRC approval of the requested increase in reactor thermal power level will allow PSEG to implement operational changes to generate and supply a higher steam flow to the turbine generator. Higher steam flow is accomplished by increasing the reactor power along specified control rod and core flow lines. This increase in steam flow will permit an increase in the electrical output of the plant.

The technical bases for this request follow the guidelines contained in the NRC-approved GE Nuclear Energy (GENE) Licensing Topical Reports (LTRs) for extended power uprate (EPU) safety analysis: NEDC-33004P-A, "Constant Pressure Power Uprate," (CLTR) (Reference 1); NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1) (Reference 2); and NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (ELTR2) (Reference 3).

The proposed amendment also includes supporting changes to the Operating License and Technical Specifications necessary to implement the increased power level.

2. PROPOSED CHANGE

PSEG is requesting an increase in the maximum authorized power level for Hope Creek from 3339 MWt to 3840 MWt. This represents an increase of approximately 15 percent from the current RTP.

Proposed changes to the Operating License and Technical Specifications are listed in Table 1 with a brief description of the basis for the change. The marked up Facility Operating License and Technical Specification pages are included in Attachment 2.

Table 1
Proposed OL and TS Changes

Section	Proposed Change	Justification
Operating License Condition 2.C.(1)	Change the Maximum Power Level to 3840 MWt	Revised maximum licensed power level based on General Electric (GE) report NEDC-33076P, "Safety Analysis Report for Hope Creek Constant Pressure Power Uprate," Rev. 2, (i.e., PUSAR - contained in Attachment 4). Refer to PUSAR Section 1.2.1.
Operating License Condition 2.C.(11)	Change the current License Condition to read as follows: The facility shall not be operated with reduced feedwater temperature for the purpose of extending the normal fuel cycle unless analyses supporting such operation are submitted by the licensee and approved by the staff.	The specified value for feedwater temperature (400°F) is not applicable for EPU. Removal of the specified value will allow reduced feedwater temperature operation to continue for feedwater system maintenance while ensuring that operation with partial feedwater heating to extend the cycle beyond the normal end-of-cycle condition would still be not be permitted without NRC review and approval.
Operating License Condition 2.C.(16)	Add a new License Condition to allow leak rate tests required by Surveillance Requirement 4.6.1.2.a to be considered to be performed per SR 4.0.1, upon implementation of the license amendment approving the proposed EPU, until the next scheduled performance.	The proposed change precludes having to perform these affected leak rate tests before their next scheduled performance solely for the purpose of documenting compliance. This does not supercede that aspect of SR 4.0.1 that governs cases where it is believed that, if the SR were performed, it would not be met. Performance of the leak rate tests merely to document compliance would unnecessarily divert resources, interfere with plant operations, potentially incur additional personnel dose, and would not improve plant safety.
TS 1.35 - RATED THERMAL POWER	Change RATED THERMAL POWER to 3840 MWt	Revised maximum licensed power level based on GE report NEDC-33076P. Refer to PUSAR Section 1.2.1.

Section	Proposed Change	Justification
TS 2.1.1 - THERMAL POWER, Low Pressure, or Low Flow, and the associated Action	Revise the value of the thermal monitoring thresholds to 24%.	The existing 25% of RTP limit for the TS Safety Limit is based on generic analyses, evaluated up to approximately 50% of original RTP for the plant design with highest average bundle power (the BWR6) for all of the BWR product lines. This average bundle power (at 100% RTP) was 4.8 MWt. For the Hope Creek EPU, the average bundle power is 5.03 MWt. Therefore, the Safety Limit % RTP basis for EPU conditions is reduced to 24% RTP. Refer to PUSAR Section 9.1.1
Table 2.2.1-1 - Reactor Protection System Instrumentation Setpoints, Functional Unit 2.a	Revise the APRM Neutron Flux - Upscale, Setdown Trip Setpoint to 14%. Revise the Allowable Value to 19%.	Refer to PUSAR Section 5.3.7 and Table 5-1.
Table 2.2.1-1 - Reactor Protection System Instrumentation Setpoints, Functional Unit 2.b.1	Revise the APRM Flow-Biased Simulated Thermal Power – Upscale Trip Setpoint to: $\leq 0.57\ (w - \Delta w) + 58\%$. Revise the Allowable Value to: $\leq 0.57\ (w - \Delta w) + 61\%$.	Refer to PUSAR Section 5.3.3 and Table 5-1
LCO 3.1.4.1 - Rod Worth Minimizer, Applicability	Revise the value of the thermal power level for required RWM operability to 8.6%	Refer to PUSAR Section 5.3.4 and Table 5-1

Section	Proposed Change	Justification
LCO 3.2.1 - APLHGR, Applicability; LCO 3.2.1 - APLHGR, Action; and SR 4.2.1.a	Revise the Average Planar Linear Heat Generation Rate (APLHGR) RTP thermal monitoring threshold value to 24%	The existing 25% of RTP limit for the LCO Applicability is based on generic analyses, evaluated up to approximately 50% of original RTP for the plant design with highest average bundle power (the BWR6) for all of the BWR product lines. This average bundle power (at 100% RTP) was 4.8 MWt. For the Hope Creek EPU, the average bundle power is 5.03 MWt. Therefore, the LCO Applicability for EPU conditions is reduced to 24% RTP. The proposed changes to the Action and SR maintain consistency with the change to the LCO Applicability. Refer to PUSAR Section 9.1.1.
LCO 3.2.3 - MCPR, Applicability; LCO 3.2.3 - MCPR, Action b; and SR 4.2.3.a	Revise the Minimum Critical Power Ratio (MCPR) RTP thermal monitoring threshold value to 24%	The existing 25% of RTP limit for the LCO Applicability is based on generic analyses, evaluated up to approximately 50% of original RTP for the plant design with highest average bundle power (the BWR6) for all of the BWR product lines. This average bundle power (at 100% RTP) was 4.8 MWt. For the Hope Creek EPU, the average bundle power is 5.03 MWt. Therefore, the LCO Applicability for EPU conditions is reduced to 24% RTP. The proposed changes to the Action and SR maintain consistency with the change to the LCO Applicability. Refer to PUSAR Section 9.1.1.

Section	Proposed Change	Justification
LCO 3.2.4 - LHGR, Applicability; LCO 3.2.4 - LHGR, Action; and SR 4.2.4.a	Revise the Linear Heat Generation Rate (LHGR) RTP thermal monitoring threshold value to 24%	The existing 25% of RTP limit for the LCO Applicability is based on generic analyses, evaluated up to approximately 50% of original RTP for the plant design with highest average bundle power (the BWR6) for all of the BWR product lines. This average bundle power (at 100% RTP) was 4.8 MWt. For the Hope Creek EPU, the average bundle power is 5.03 MWt. Therefore, the LCO Applicability for EPU conditions is reduced to 24% RTP. The proposed changes to the Action and SR maintain consistency with the change to the LCO Applicability. Refer to PUSAR Section 9.1.1.
Table 3.3.1-1 - Reactor Protection System Instrumentation Table Notations, Note (j)	Revise the RTP value to 24%. Remove the values for turbine first stage pressure.	Refer to PUSAR Section 5.3.2 and Table 5-1 for change to RTP value. Modifications to the high pressure turbine will change the relationship of turbine first stage pressure to reactor power. The turbine first stage pressure setpoint will be controlled in accordance with plant procedures and will be verified during post-installation testing. The turbine first stage pressure values are details of system design that will be adequately controlled outside the TS. Removal of the turbine first stage pressure values from the TS is consistent with NUREG-1433, "Standard Technical Specifications, General Electric Plants, BWR/4."

Section	Proposed Change	Justification
Table 4.3.1.1-1, Reactor Protection System Instrumentation Surveillance Requirements, Note (d)	Change the APRM CHANNEL CALIBRATION RTP threshold value to 24%.	The proposed change maintains consistency with the changes to TS 2.1.1 and LCOs 3.2.1, 3.2.3 and 3.2.4. Refer to PUSAR Section 9.1.1.
Table 3.3.2-2 - Isolation Actuation Instrumentation Setpoints, Trip Function 3.d	Revise the Main Steam Line Flow – High Trip Setpoint to 162.8 psid and the AV to 169.3 psid	The analytical limit in percent of rated steam flow is unchanged. Refer to PUSAR Section 5.3.1.
LCO 3.3.4.2 - End-of-Cycle Recirculation Trip System Instrumentation, Applicability	Revise the End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation RTP thermal monitoring threshold value to 24%.	The proposed change is consistent with the changes to TS 2.1.1 and LCOs 3.2.1, 3.2.3 and 3.2.4. Refer to PUSAR Section 5.3.2 and Table 5-1
Table 3.3.4.2-1 - EOC-RPT Trip System Instrumentation, Note (b)	Revise the automatic bypass RTP value to 24%. Remove the values for turbine first stage pressure.	Refer to PUSAR Section 5.3.2 and Table 5-1 for change to RTP value. Modifications to the high pressure turbine will change the relationship of turbine first stage pressure to reactor power. The turbine first stage pressure setpoint will be controlled in accordance with plant procedures and will be verified during post-installation testing. The turbine first stage pressure values are details of system design that will be adequately controlled outside the TS. Removal of the turbine first stage pressure values from the TS is consistent with NUREG-1433, "Standard Technical Specifications, General Electric Plants, BWR/4."
Table 3.3.6-2 - Control Rod Block Instrumentation Setpoints, Trip Function 2.a	Revise the APRM Flow Biased Neutron Flux – Upscale Trip Setpoint to $\leq 0.57\ (w - \Delta w) + 53\%$. Revise the allowable value to: $\leq 0.57\ (w - \Delta w) + 56\%$.	Refer to PUSAR Section 5.3.3 and Table 5-1.

Section	Proposed Change	Justification
Table 3.3.6-2 - Control Rod Block Instrumentation Setpoints, Trip Function 2.d	Revise the APRM Neutron Flux-Upscale, Startup (Rod Block) Setpoint to 11%. Revise the Allowable Value to 13%.	The proposed changes maintain the existing margin to the APRM Neutron Flux - Upscale, Setdown Trip Setpoint. Refer to PUSAR Section 5.3.7 and Table 5-1.
LCO 3.3.11 - Oscillation Power Range Monitor Instrumentation, Applicability; and LCO 3.3.11, Action c	Change 25% RTP to 24% RTP	The proposed change maintains consistency with the changes to TS 2.1.1 and TS 3.2.3.
SR 4.3.11.5	Change 30% RTP to 26.1% RTP	The proposed change maintains the same absolute power/flow region boundaries for the Oscillation Power Range Monitor (OPRM) trip-enabled region.
LCO 3.4.1.1 - Recirculation Loops, Action a.1.b; and SR 4.4.1.1.1.a	Change the maximum power for single loop operation to 60.86%.	The proposed changes maintain the existing licensed region for single loop operation. Refer to PUSAR Section 3.6.
LCO 3.4.1.2 - Jet Pumps, SRs 4.4.1.2.a and 4.4.1.2.c	Change 25% RTP to 24% RTP.	The proposed changes are consistent with changes to the applicability of power distribution limits for ECCS performance analyses.
LCO 3.6.1.2.c - Primary Containment Leakage Table 3.6.3-1 - Primary Containment Isolation Valves, Note 3	Change 48.1 psig to 50.6 psig.	The proposed change reflects the updated containment pressure response. Refer to PUSAR Section 4.1.1.
LCOs 3.6.1.2.d and 3.6.1.2.e-Primary Containment Leakage SR 4.6.1.2.g Table 3.6.3-1 - Primary Containment Isolation Valves, Notes 2 and 4	Change 52.9 psig to 55.7 psig.	The proposed changes reflect the updated containment pressure response. Refer to PUSAR Section 4.1.1.
LCO 3.7.7 - Main Turbine Bypass System, Applicability and Action	Change 25% RTP to 24% RTP.	The proposed change maintains consistency with the changes to TS 2.1.1 and LCOs 3.2.1, 3.2.3 and 3.2.4. Refer to PUSAR Section 9.1.1
LCO 3.10.2 - Rod Worth Minimizer	Change 10% RTP to 8.6% RTP.	Proposed change maintains consistency with proposed changes to LCO 3.1.4.1.

Section	Proposed Change	Justification
TS 6.8.4.f - Primary Containment Leakage Rate Testing Program	Change 48.1 psig to 50.6 psig.	The proposed change reflects the updated containment pressure response. Refer to PUSAR Section 4.1.1.

Selected TS references to RTP that are not being changed are listed in Table 2 with the bases for not changing the current TS values.

Table 2
Unchanged TS References to % RTP

Section	Bases for No Change
Table 2.2.1-1 - Reactor Protection System Instrumentation Setpoints, Functional Unit 2.b.2	APRM Flow Biased Simulated Thermal Power High Flow Clamped Trip Setpoint and Allowable Value are not changed since the function is not credited in any transient analyses. Refer to PUSAR Section 5.3.3.
Table 2.2.1-1 - Reactor Protection System Instrumentation Setpoints, Functional Unit 2.c	APRM Fixed Neutron Flux - Upscale Trip Setpoint and Allowable Value are not changed because the Analytical Limit is not changed.
SR 4.1.3.2, maximum control rod scram insertion time	The 40% RTP used in the surveillance requirement is a value chosen for convenience, sufficiently higher than the Rod Worth Minimizer low power setpoint to minimize the need for out-of-sequence rod withdrawals while ensuring the SR is performed within a reasonable time after startup from a refueling outage or a shutdown lasting more than 120 days.
LCO 3.1.4.3 - Rod Block Monitor, Applicability	The Rod Block Monitor is not credited in the evaluation of the control rod withdrawal error.
Table 4.3.1.1-1, Reactor Protection System Instrumentation Surveillance Requirements, Note (d)	The 2% RTP value used for the CHANNEL CALIBRATION Surveillance Requirement is a tolerance value and does not need to be rescaled.
Table 3.3.2-1 - Isolation Actuation Instrumentation, Note ##	The Note restricts operation of the hydrogen water chemistry system to power levels greater than or equal to 20% of RTP. Leaving the value unchanged is conservative.
Table 3.3.2-2 - Isolation Actuation Instrumentation Setpoints, Note ###	The Note restricts operation of the hydrogen water chemistry system to power levels greater than or equal to 20% of RTP. Leaving the value unchanged is conservative.
Table 3.3.6-1 - Control Rod Block Instrumentation, Note *	The Rod Block Monitor is not credited in the evaluation of the control rod withdrawal error.
Table 3.3.6-2 - Control Rod Block Instrumentation Setpoints, Trip Function 1	The Rod Block Monitor is not credited in the evaluation of the control rod withdrawal error.

Section	Bases for No Change
Table 3.3.6-2 - Control Rod Block Instrumentation Setpoints, Trip Function 2.c	Leaving the APRM Control Rod Block Downscale Trip Setpoint and Allowable Value unchanged is conservative because it results in the trip function occurring at a higher absolute power.
LCO 3.4.1.1 - Recirculation Loops, Action 1.g and SR 4.4.1.1.2	As noted in Reference 4, thermal stratification during single loop operation is known not to be a concern at power levels above 38%. Leaving the value unchanged is conservative.
LCO 3.6.6.2 - Drywell and Suppression Chamber Oxygen Concentration, Applicability and SR 4.6.6.2	15% RTP establishes the 24 hour windows for inerting and de-inerting the containment during plant startups and shutdowns. The sequence of operations during plant startups and shutdowns is substantially unchanged by the EPU. Therefore, the current TS value does not need to be changed.
LCO 3.10.4 - Recirculation Loops; and SR 4.10.4.2	The 5% RTP value is high enough to allow PHYSICS TESTS to be performed yet still below RWM / APRM upscale – setdown, etc., and well below ECCS design basis concerns relative to flow mismatch.

3. BACKGROUND

Hope Creek was originally licensed to operate at a maximum power level of 3293 MWt. In 2001, the authorized maximum power level was increased to 3339 MWt (Amendment No. 131, TAC No. MB0644).

An increase in the electrical output of a BWR plant is accomplished primarily by generating and supplying higher steam flow to the turbine-generator. As currently licensed, most BWR plants, including Hope Creek, have an as-designed equipment and system capability to accommodate steam flow rates above the original rating. In addition, continuing improvements in the analytical techniques (computer codes and data) based on several decades of BWR safety technology, plant performance feedback, and improved fuel and core designs have resulted in a significant increase in the design and operating margins between calculated safety analysis results and the licensing limits. These available safety analyses differences, combined with the excess as-designed equipment, system and component capabilities, provide BWR plants the capability to achieve an increase in their thermal power ratings of between 5 and 20% without major nuclear steam supply system (NSSS) hardware modifications.

In March 2003, the NRC approved the use of the Constant Pressure Power Uprate (CPPU) LTR (CLTR) as a basis for power uprate license amendment requests, subject to limitations specified in the CLTR and in the associated NRC safety evaluation. The limitations relate to license amendment requests that may not be pursued concurrently with the power uprate request. In addition, licensees proposing to utilize fuel designs other than GE fuel, up through GE 14 fuel, may reference the CPPU LTR as a basis for their power uprate for areas other than those involving reactor systems and for fuel issues which are not impacted by the fuel design. The NRC's approvals of ELTR1 (Reference 2) and ELTR2 (Reference 3) do not include similar specific limitations on fuel type. In Reference 5, the NRC described plant-specific information that licensees must submit, in addition to the information routinely submitted, for an extended power uprate application with a mixed core.

A higher steam flow is achieved by increasing the reactor power along specified control rod and core flow lines. A limited number of operating parameters are changed, some setpoints are adjusted and instruments are recalibrated. Plant procedures are revised, and tests similar to some of the original startup tests are performed. Modifications to some non-safety power generation equipment will be implemented over time, as needed.

Detailed evaluations of the reactor, engineered safety features, power conversion, emergency power, support systems, environmental issues, and design basis accidents were performed. These evaluations demonstrate that Hope Creek can safely operate at 3840 MWt.

Need for Proposed Change to Operating License Condition 2.C.(11)
In addition to prohibiting plant operation with reduced feedwater temperature for the purpose of extending the normal fuel cycle without prior NRC review and approval, Operating License Condition 2.C.(11) also prohibits plant operation with a feedwater heating capacity that would result in a rated power feedwater temperature less than 400°F. The 400°F limit was based on the NRC staff's application of a BWR/6 reduced feedwater temperature analysis to Hope Creek operation (Reference 11). With the increase in licensed thermal power, rated feedwater temperature will increase. A specified limit of 400°F in the Operating License would allow greater operating flexibility after the increased power level is implemented than has been evaluated for EPU operation.

4. TECHNICAL ANALYSIS

The safety analysis report in Attachment 4 summarizes the results of the significant safety evaluations performed that justify uprating the licensed thermal power at Hope Creek.

Modification Summary
The generation and supply of higher steam flow for the turbine generator accomplishes an increase in electrical output of a BWR plant. Most BWR plants, including Hope Creek, as currently licensed, have an as-designed equipment and system capability to accommodate steam flow rates at least 5% above the original rating. In addition, continuing improvements in the analytical techniques (computer codes and data) based on several decades of BWR safety technology, plant performance feedback, and improved fuel and core designs have resulted in a

significant increase in the design and operating margins between calculated safety analysis results and the licensing limits. These available safety analyses differences, combined with the excess as-designed equipment, system and component capabilities, provide BWR plants the capability to achieve an increase in their thermal power ratings of between 5 and 20% without major nuclear steam supply system (NSSS) hardware modifications, and to provide for power increases to 20% with limited non-safety hardware modifications, with no significant increase in the hazards presented by the plant as approved by the NRC at the original license stage.

The plan for achieving higher power is to extend the power to flow map along the standard Maximum Extended Load Line Limit Analysis (MELLLA) power to flow upper boundary. The extension of the power to flow map does not require an increase in the maximum core flow limit or operating pressure over the pre-CPPU values.

Discussions of Issues Being Evaluated
Hope Creek performance and responses to hypothetical accidents and transients have been evaluated for a CPPU license amendment. This safety assessment summarizes the safety significant plant reactions to events analyzed for the licensing of Hope Creek, and the potential effects on various margins of safety, and thereby concludes that no significant hazards consideration will be involved.

CPPU Analysis Basis
Hope Creek is currently licensed for operation up to 3339 MWt, and most of the current safety analyses are based on this value. The Cycle 13 ECCS-LOCA analyses are based on 1.02 times the current licensed thermal power (CLTP). However, the containment safety analyses are based on a power level of 1.02 times the original licensed power level. The CPPU RTP level included in this evaluation is 115% of the current licensed thermal power level. The CPPU safety analyses are based on a power level of at least 1.02 times the CPPU power level unless the Regulatory Guide 1.49 two percent power uncertainty factor is already accounted for in the analysis methods.

Cycle-Specific Confirmations
Some evaluation items in the PUSAR dispositioned based on experience or on equilibrium cycle evaluations will be confirmed during cycle-specific evaluations for the EPU implementation cycle and subsequent cycles because they are sensitive to the specific core design.

PSEG's reload design and licensing process, including reload design meetings with the fuel vendor, will be used to ensure cycle specific evaluations address PUSAR dispositions that are sensitive to the specific core design. The process is controlled by administrative procedures that provide the sequence of events and requirements for implementing a cycle specific reload core design. NF-AA-100 defines responsibilities and requirements for establishing the reload design schedule and specification, for addressing licensing, configuration management and industry operating experience, for analysis activities that support the reload design and licensing effort, for addressing the impact on the reload core design and licensing basis of concurrent plant design and licensing changes, for interfacing with and reviewing the nuclear fuel vendor activities and information, for providing training to operations and reactor engineering, and for maintaining documentation. NF-AA-100 requires input from functional groups that may be impacted by the reload core design, such as chemistry, operations, and reactor engineering. NF-AA-100 also requires senior management approval for significant changes in reload core design or operating strategy.

The NRC most recently evaluated PSEG's reload core design and licensing process in 1998 and concluded that PSEG maintained acceptable control over reload core design (Reference 6). The reload design and licensing process in place today is fundamentally the same as the process that was evaluated in 1998, except for the incorporation of enhancements or best practices such as those associated with INPO SOER 03-02, "Managing Core Design Changes."

Nuclear Fuels personnel participate in several forms of communications with the fuel vendor that can be considered reload design meetings. Nuclear Fuels supervision and core design and safety analyses staff have direct input and review / concurrence / approval responsibilities when participating in these meetings. Once a reload design and licensing campaign is initiated, frequent (typically weekly) phone calls are held to discuss requirements, issues and schedule. During the reload campaign, design review meetings are held in addition to the weekly phone calls for key activities, such as the eigenvalue review at the initiation of the core design or the transient selection review prior to reload safety analysis work initiating. Prior to the fuel vendor issuing the Supplemental Reload Licensing Report (SRLR), a final reload design and licensing review meeting is held that addresses all aspects of the activities that will result in the fuel vendor issuing the SRLR for HCGS acceptance.

Fuel Thermal Limits
No new fuel design is required for CPPU. No change in the specified acceptable fuel design limits is required for CPPU. The current fuel design limits will continue to be met at the CPPU RTP. Analyses for each fuel reload will continue to meet the criteria accepted by the NRC as specified in NEDO-24011, "GESTAR II" or otherwise approved in the Technical Specifications. Future fuel designs will meet acceptance criteria approved by the NRC.

Makeup Water Sources
The BWR design concept includes a variety of ways to pump water into the reactor vessel to mitigate all types of events. There are numerous safety-related and non-safety-related cooling water sources. The safety-related cooling water sources alone would maintain core integrity by providing adequate cooling water.

CPPU does not result in an increase or decrease in the available water sources, nor does it change the selection of those assumed to function in the safety analyses. NRC-approved methods were used for analyzing the performance of the Emergency Core Cooling Systems (ECCS) during loss-of-coolant-accidents.

CPPU results in an increase in decay heat, and thus, the time required to cooldown to cold shutdown conditions increases. This is not a safety concern, and the existing cooling capacity can bring the Hope Creek unit to cold shutdown within a time span that continues to meet current licensing requirements.

Design Basis Accidents
Design Basis Accidents (DBAs) are very low probability hypothetical events whose characteristics and consequences are used in the design of the plant, so that the plant can mitigate their consequences to within acceptable regulatory limits. For BWR licensing evaluations, capability is demonstrated for coping with the range of hypothetical pipe break sizes in the largest recirculation, steam, and feedwater lines, a postulated break in one of the ECCS lines, and the most limiting small lines. This break range bounds the full spectrum of large and small line breaks; and ensures the success of plant systems to mitigate the accidents, while accommodating a single active equipment failure in addition to the postulated LOCA. Several of the most significant licensing assessments are made using these LOCA ground rules. These assessments are:

1. **Challenges to Fuel**
   Emergency Core Cooling Systems (ECCS) are described in Section 6.3 of the Hope Creek Updated Final Safety Analysis Report (UFSAR). The ECCS Performance Evaluation described in Attachment 4, Section 4.3 demonstrates the continued conformance to the acceptance criteria of 10 CFR 50.46. As mentioned above, a complete spectrum of pipe breaks is investigated from the largest recirculation line down to the most limiting small line break. As shown in Attachment 4, Table 4-2, the licensing safety margin is not affected by CPPU. The increased peak cladding temperature (PCT) consequences for CPPU are insignificant compared to the large amount by which the results are below the regulatory criteria. Therefore, the ECCS safety margin is not affected by CPPU.

2. **Challenges to the Containment**
   Attachment 4, Table 4-1 provides the results of analyses of the Hope Creek containment response to the most severe LOCAs. The effect of CPPU on the peak values for containment pressure and temperature confirms the suitability of the plant for operation at CPPU RTP. Also, the effects of CPPU on the conditions that affect the containment dynamic loads are determined, and the plant is judged satisfactory for CPPU operation. Where plant conditions with CPPU are within the range of conditions used to define the current dynamic loads, current safety criteria are met and no further structural analysis is required. The change in short-term containment response is negligible.

Because there will be more residual heat with CPPU, the containment long-term response slightly increases. However, containment pressures and temperatures remain below their design limits following any design basis accident, and thus, the containment and its cooling systems are judged to be satisfactory for CPPU operation. The small increase in the calculated post LOCA suppression pool temperature above the currently assumed peak temperature was evaluated and determined to be acceptable.

3. **Design Basis Accident Radiological Consequences**
The Hope Creek UFSAR provides the radiological consequences for each DBA. The magnitude of the potential consequences is dependent upon the quantity of fission products released to the environment, the atmospheric dispersion factors and the dose exposure pathways. The atmospheric dispersion factors and the dose exposure pathways do not change. Therefore, the only factor, which could influence the magnitude of the consequences, is the quantity of activity released to the environment. This quantity is a product of the activity released from the core and the transport mechanisms between the core and the effluent release point.

License Amendment No. 134 (Reference 7) approved changes to the TS based on full implementation of an alternative source term (AST) pursuant to 10CFR50.67 using the guidance provided in Regulatory Guide (RG) 1.183.

For CPPU, the Control Rod Drop Accident (CRDA), Loss-of-Coolant Accident (LOCA), Fuel Handling Accident (FHA), Main Steamline Break Accident (MSLBA) and instrument line break accident (ILBA) are reanalyzed.

For an ILBA, the transport mechanism potentially influenced by an increase in reactor power is the quantity of coolant mass discharged to the environment. For the ILBA, increased mass loss will occur if the operating pressure is increased. However, the requested CPPU does not need or include an increase in operating pressure, and thus, the consequences of an ILBA do not change. The ILBA is not a limiting event.

For the MSLBA and ILBA, the primary coolant activity used in the evaluation of these postulated events is unaffected by CPPU. The primary coolant activity is based on Technical Specification limits, which remain unchanged for CPPU.

For the remaining DBAs, the only parameter of importance is the activity released from the fuel. Because the mechanism of fuel failure is not influenced by CPPU, the only parameter of importance is the actual inventory of fission products in the fuel rod. If the only parameter affecting fuel is an increase in thermal power, then the increase in the quantity of fission products can be assumed to be proportional to the increase in power.

The DBA that has historically been limiting from a radiological viewpoint is the LOCA, for which USNRC Regulatory Guide 1.183, Appendix A guidance has been applied. Adherence to the guidance in RG 1.183, and the use of the specific values/limits contained in the Technical Specifications with as-tested post-accident performance of the safety grade engineered safety functions (ESF), provide the assurance for sufficient safety margin, including a margin to account for analysis uncertainties. It is, therefore, concluded that the existing LOCA radiological consequences, as a result of CPPU, are increased proportional to the increase in power, and, as shown in Section 9.2 of the PUSAR, these consequences remain below regulatory guidelines. The CPPU LOCA evaluation results include the 2% power uncertainty factor from Regulatory Guide 1.49.

The results of all radiological analyses remain below the allowable limits of 10 CFR 50.67 and Table 6 in Regulatory Guide 1.183. Therefore, all radiological safety margins are maintained.

Anticipated Operational Occurrence Analyses

The effects of Anticipated Operational Occurrences (AOO) are evaluated by investigating a number of disturbances of process variables and malfunctions or failures of equipment according to a scheme of postulating initiating events. These events are primarily evaluated against the Safety Limit Minimum Critical Power Ratio (SLMCPR) and other applicable Specified Acceptable Fuel Design Limits (SAFDLs) such as the avoidance of fuel centerline melting and not exceeding 1% fuel cladding plastic strain. Compliance with SLMCPR and with the other applicable SAFDLs has been determined using NRC-approved methods. As described in Section 9.1 of Attachment 4, the limiting AOOs have been evaluated for the CPPU RTP conditions. No change to the basic characteristic of any of the limiting events is caused by the CPPU. The results of the CPPU AOO evaluations demonstrate that CPPU RTP operation can be safely implemented consistent with the bases for the Technical Specification Power Distribution Limits. Licensing acceptance criteria are not exceeded. Continued compliance with the SLMCPR and other applicable Specified Acceptable Fuel Design Limits will be confirmed on a cycle specific basis. Therefore, the margin of safety is not affected by CPPU.

Combined Effects

DBAs are postulated using deterministic regulatory criteria to evaluate challenges to the fuel, containment, and off-site radiation dose limits. The off-site dose evaluation performed in accordance with Regulatory Guide 1.183 calculates more severe radiological consequences than the combined effects of bounding DBAs that produce the greatest challenge to the fuel and containment. In contrast, the DBA that produces the highest PCT does not result in damage to the fuel equivalent to the assumptions used in the off-site dose evaluation, and the DBA that produces the maximum containment pressure, does not result in leak rates to the atmosphere equivalent to the assumptions used in the off-site dose evaluation. Thus, the off-site doses calculated in conformance with Regulatory Guide 1.183 are conservative compared to the combined effect of the bounding DBA evaluations.

Equipment Qualification
Hope Creek safety related electrical and mechanical equipment was evaluated against the criteria appropriate for operation at EPU. Changes in environmental conditions due to EPU will not adversely affect existing equipment qualifications.

Balance-of-Plant
Balance-of-plant (BOP) systems and equipment have been reviewed for CPPU. CPPU operation for BOP systems and equipment is justified by generic or Hope Creek specific evaluations, which include the limited modifications that were or will be made to BOP components.

Core Thermal Power Measurement
The current licensed thermal power level (3339 MWt) is based on reduced uncertainty in core thermal power measurement achieved with the Crossflow ultrasonic flow measurement system as described in Reference 8. If the Crossflow system becomes unavailable, plant operation at 3339 MWt may continue for 24 hours after the last valid correction factor was obtained from the Crossflow system. Procedural guidance directs that reactor power be reduced to a level less than or equal to the previously licensed power level (3293 MWt) if the Crossflow system cannot be restored to operation within 24 hours. Core power is then maintained at a level less than or equal to 3293 MWt until the Crossflow system is returned to service and a heat balance in accordance with SR 4.3.1.1 is performed with updated correction factors from the Crossflow system.

Analyses for the proposed CPPU are based on a power level at least 1.02 times the CPPU power level unless the Regulatory Guide 1.49 two percent power uncertainty factor is already accounted for in the analysis methods. Therefore, following NRC approval of the proposed amendment, plant procedures will no longer direct that power be reduced if the Crossflow system becomes unavailable.

Probabilistic Risk Assessment
Attachment 4, Section 10.5 describes the results of Level 1 and Level 2 Probabilistic Risk Assessments (PRAs) performed for the CPPU. When compared to the risk-acceptance guidelines presented in Regulatory Guide 1.174, the calculated changes in core damage frequency (CDF) and large early release frequency (LERF) are very small. The CLTP and CPPU CDFs are both well below 1E-4 events per year for the internal events. The change in CDF associated with CPPU implementation is 6.8E-7/yr. The CLTP and CPPU LERFs are both well below 1E-5 events per year for the internal events. The change in LERF associated with CPPU implementation is 6.1E-8/yr.

Primary Containment Leakage Rate Testing Program
Surveillance Requirement 4.6.1.2.a requires that primary containment leakage rates be demonstrated in accordance with the Primary Containment Leakage Rate Testing Program. The testing program is required by 10 CFR 50.54(o) and 10 CFR 50 Appendix J and is described in Technical Specification 6.8.4.f. Test intervals are established on a performance basis in accordance with 10 CFR 50 Appendix J, Option B.

The Type A integrated leak rate test and the Type B and C local leak rate tests are performed at the calculated peak containment pressure (Pa). Pa increases to 50.6 psig for the EPU; and Technical Specification 6.8.4.f is being revised to reflect the change. However, with substantial margin to the leakage rate acceptance limits based upon current leak rate test results, it is not necessary to reperform all of the leak rate tests at the higher Pa before implementation of the EPU.

Proposed License Condition 2.C.(16) would allow leak rate tests required by Surveillance Requirement 4.6.1.2.a to be considered to be performed per SR 4.0.1, upon implementation of the license amendment approving the proposed EPU, until the next scheduled performance. This would preclude having to perform the affected leak rate tests before their next scheduled performance solely for the purpose of documenting compliance. The allowance provided in License Condition 2.C.(16) would not supercede that aspect of SR 4.0.1 that governs cases where it is believed that, if the SR were performed, it would not be met. Performance of the leak rate tests merely to document compliance would unnecessarily divert resources, interfere with plant operations, potentially incur additional personnel dose, and would not improve plant safety.

Ultimate Heat Sink
No changes to the TS ultimate heat sink (UHS) limits are required for EPU implementation.

The UHS for engineered safety feature (ESF) components is the Delaware River. The UHS is the source of cooling water to the Safety Auxiliaries Cooling System (SACS) heat exchangers through the Station Service Water System (SSWS). The SACS, in turn, provides demineralized cooling water in a closed loop to the ESF components.

LCO 3.7.1.3 includes a limit of 85ºF on river water temperature. When river water temperature exceeds 85ºF, continued plant operation is permitted provided that both SSWS emergency discharge valves are open and emergency discharge pathways are available. With the river water temperature in excess of 88.0°F, continued plant operation is permitted provided that all of the following additional conditions are satisfied: UHS temperature is at or below 89.0°F, all SSWS pumps are operable, all SACS pumps are operable, all emergency diesel generators (EDGs) are operable and the SACS loops have no cross-connected loads (unless they are automatically isolated during a LOP and/or LOCA).

The design calculation for UHS temperature limits was revised to reflect heat loads associated with EPU conditions. With all SSWS pumps, SACS pumps and EDGs operable, the current TS UHS temperature limit is 89°F. Under EPU conditions, for a loss of offsite power (LOP) event coincident a safe shutdown earthquake (SSE) and the failure of one emergency diesel generator (EDG), the calculated limit for UHS temperature is 91.4°F, which bounds the current TS limit. The LOP/SSE scenario is the same scenario used to establish the basis for the current 89°F limit (References 9 and 10).

The UHS temperature limit for conditions resulting from combinations of design basis failures concurrent with equipment outages permitted by Technical Specification AOT Action Statements with only one (1) SACS pump per loop and two (2) SACS heat exchangers per loop is 88.3°F, which bounds the current Technical Specification limit of 88°F.

The basis for the current TS limits was submitted in Reference 9 and was reviewed and approved by the NRC in Reference 10. The significant changes to the design calculation for UHS temperature limits are summarized below:

- The revised UHS temperature limit calculation includes the heat loads associated with Extended Power Uprate conditions corresponding to a rated thermal power of 3840 MWt. The LOCA RHR heat exchanger heat load is increased to 127.1 MBTU/hr from the current 123.8 MBTU/hr. The LOP RHR heat exchanger heat load is decreased to 127.1 MBTU/hr from the current 132.5 MBTU/hr. The revised RHR heat exchanger heat loads bound those resulting from the maximum predicted suppression pool temperatures analyzed at 102% of 3840 MWt (212.3°F for a LOCA and 213.6°F for a LOP). Use of these heat loads is conservative because the peak suppression pool temperatures occur late in the event (approximately 8-9 hours), after many near-term loads (e.g., ECCS pump/cooler) would have been secured. The required RHR heat exchanger performance (307 BTU/sec-°F) is unchanged from that calculated in support of the current TS UHS limits (References 9 and 10).

  The EPU LOP/SSE RHR heat exchanger heat load (127.1 MBTU/hr) bounds the heat load resulting from the maximum predicted suppression pool temperature for that event. The higher LOP RHR heat exchanger heat load (132.5 MBTU/hr) used in the previous UHS analysis was obtained from a now superceded suppression pool temperature analysis whose purpose was to determine the minimum RHR heat exchanger heat load required to maintain suppression pool temperatures within the limits for SRV discharge specified in NUREG-0783 in the event of a loss-of-offsite power and a fire in a SACS pump room which incapacitates one SACS/RHR loop. The calculation assumed that realignment of the one available RHR loop from suppression pool cooling to shutdown cooling would be completed within approximately one hour of the event. The calculation did not consider that, upon a loss of offsite power, shutdown cooling could not be placed in service since it is isolated by the de-energized NSSSS system. Therefore, the high heat rejection loads are not experienced (heat load is function of pool temperature, not RCS temperature).

As noted in PUSAR section 4.1.1.1, the local suppression pool temperature for plant transients involving SRV discharge was evaluated for EPU and determined to meet the NUREG-0783 criteria.

- For the LOP/SSE event, SSWS flow to the nonsafety-related Reactor Auxiliaries Cooling System (RACS) heat exchangers is assumed to be isolated, either automatically (by actuation of the RACS room flooding isolation logic) or by operator action in accordance with plant procedures within one hour from the event. Existing plant procedures direct operators to reduce SSWS flow to the RACS heat exchangers if SACS temperatures cannot be maintained below 95°F.

  The LOP/SSE event is evaluated in two parts: 1) assuming SSWS flow is supplied to RACS for up to one-hour and 2) after one-hour with SSWS to RACS isolated. When SSWS flow is provided to the RACS heat exchangers, the assumed RHR heat exchanger heat load is based on a suppression pool temperature (186°F) which bounds the post-LOP predicted suppression pool temperature one hour into the event.

- The Filtration, Recirculation, and Ventilation System (FRVS) and Emergency Core Cooling System (ECCS) cooler heat loads in the current UHS temperature limit calculation are based on an updated reactor building GOTHIC model analysis. In the evaluation submitted in Reference 9, these loads were based on a reactor building model that was built in a spreadsheet. The GOTHIC model provides a more accurate representation of actual conditions.

The maximum allowable UHS temperatures are calculated assuming the SSWS discharge path is through the safety-related emergency overboard lines (EOBs) rather than the normal discharge path to the cooling tower basin. The SSWS flow rates through the normal discharge path are significantly higher than the flow rates through the EOBs.

The revised design calculation for UHS temperature limits accounts for instrumentation inaccuracies, model uncertainty, heat load uncertainty and pump degradation to ensure the TS limits are not exceeded.

The existing UHS system provides a sufficient quantity of water at temperatures within the current TS limits to perform its safety related functions at EPU conditions.

Operating License Condition 2.C.(11)
The specified value for feedwater temperature (400°F) in License Condition 2.C.(11) is not applicable for EPU. It was based on the NRC staff's application of a BWR/6 reduced feedwater temperature analysis to Hope Creek operation (Reference 11).

As the NRC staff acknowledged in Reference 11, reduced feedwater temperature operation is possible during normal operation. Feedwater temperature drops with decreasing power while all feedwater heaters are in service. Feedwater temperature is also reduced when feedwater heaters are removed from service during maintenance. A summary of reduced feedwater heating effects and analyses performed is provided below.

Feedwater temperature is a plant parameter that primarily affects the plant heat balance and reactor thermal-hydraulic conditions. Typically, a design feedwater temperature is established based on the overall plant heat cycle design. Actual plant operating feedwater temperature may vary slightly from the design value due to performance variations from the as-built plant or from potential system performance issues (e.g., feedwater heater(s) out-of-service for maintenance). For a given reactor power level, the actual feedwater temperature will impact the reactor heat balance, and thus the reactor thermal-hydraulic conditions. These reactor thermal-hydraulic conditions establish the initial conditions for the plant safety analysis. Based on past analysis experience, most plant safety analyses are not sensitive to small (e.g., +/- 10 deg. F) variations in feedwater temperature.

The HCGS design feedwater temperature at CPPU conditions is 431.6 deg. F (Attachment 4, Table 1-3). HCGS has been evaluated for operation with a feedwater temperature reduction of approximately 23 deg. F from the design feedwater temperature (minimum assumed feedwater temperature of 409 deg. F). The safety analyses impacted by this feedwater temperature reduction, and a brief discussion of the impact, are provided below. All analyses continue to meet the required licensing acceptance criteria.

1. Stability – A reduction in feedwater temperature may increase the calculated core decay ratio and impact the region boundaries of the stability exclusion regions for Backup Stability Protection (BSP). The BSP exclusion regions are implemented in the case that the Oscillation Power Range Monitor (OPRM) system is determined to be inoperable. Attachment 4, Section 2.4.1, describes the results of the BSP exclusion region analysis. The BSP exclusion regions have been determined including the effect of reduced feedwater temperature.

2. Reactor Internal Pressure Differences (RIPDs) - A reduction in feedwater temperature will increase the reactor vessel subcooling and reduce initial steam flow. These changes may impact the blowdown rate of assumed piping breaks and /or the change in reactor steam flow during postulated events and therefore impact the calculated RIPDs and associated reactor internal component loads/stresses. Attachment 4, Section 3.3 and the Fuel Transition Report

(including supplement 1), Section 4, describe the results of the analysis of the RIPDs and reactor internal component loads. The RIPD and reactor internal component loads have been determined including the effect of reduced feedwater temperature.

3. Containment Evaluation - A reduction in feedwater temperature will increase the subcooling in the reactor vessel and attached piping (i.e., feedwater lines and recirculation lines). These changes may impact the blowdown rate of assumed piping breaks into containment. Attachment 4, Section 4.1, describes the results of the containment response analysis. The containment pressure and temperature responses have been determined including the effect of reduced feedwater temperature.

4. Containment Dynamic Loads (Subcompartment Pressurization) - A reduction in feedwater temperature will increase the subcooling in the reactor vessel and attached piping (i.e., feedwater lines and recirculation suction line). These changes may impact the blowdown rate of the assumed piping breaks and therefore impact the calculated subcompartment (annulus) pressurization loads. Attachment 4, Section 4.1.2.3, describes the results of the analyses of the subcompartment pressurization loads. The subcompartment pressurization loads analyses have been performed including the effect of reduced feedwater temperature.

5. Transient Analysis - A reduction in feedwater temperature will increase the reactor vessel subcooling and thus change the reactor thermal-hydraulic initial conditions. These changes may impact the response of key reactor parameters during postulated transient events and therefore may impact the calculated consequences. Attachment 4, Section 9.1, describes the results of the transient analysis. The transient analysis has been performed including the effect of reduced feedwater temperature.

6. High Energy Line Break (HELB) - A reduction in feedwater temperature will increase the subcooling in the reactor vessel and attached piping (i.e., feedwater and reactor water cleanup lines). These changes may impact the blowdown rate of the assumed high energy line breaks and therefore impact the calculated mass and energy releases. Attachment 4, Section 10.1.2, describes the results of the HELB analyses. The HELB analyses have been performed including the effect of reduced feedwater temperature.

The analyses performed and documented in Attachment 4 support operation with reduced feedwater temperature and allow continued operation during feedwater system maintenance, if required. For future operating cycles, the reload process will continue to address the effects of reduced feedwater temperature on the cycle specific safety analyses. HCGS will not operate with reduced feedwater temperature for the purpose of extending cycle energy capability beyond the normal end-of-cycle condition without prior NRC review and approval.

With the increase in licensed thermal power, rated feedwater temperature will increase. A specified limit of 400°F in the Operating License would allow greater operating flexibility after the increased power level is implemented than has been evaluated for EPU operation. The proposed change to the License Condition will allow reduced feedwater temperature operation to continue for feedwater system maintenance while maintaining the prohibition on plant operation with partial feedwater heating to extend the cycle beyond the normal end-of-cycle condition.

Changes to Technical Specification Setpoints

The proposed changes to the Technical Specification (TS) setpoints do not involve limiting safety system settings for variables on which a safety limit (SL) has been placed. The basis for this determination is provided below.

10 CFR 50.36, "Technical Specifications," requires that the TS include safety limits (SL), limiting safety system settings (LSSS), and limiting conditions for operation (LCO) among other items. 10 CFR 50.36(c)(1)(i)(A) sets forth the criteria for safety limits, and 10 CFR 50.36(c)(1)(ii)(A) sets forth the criteria for LSSS.

- 10 CFR 50.36(c)(1)(i)(A) states "Safety limits for nuclear reactors are limits upon important process variables that are found to be necessary to reasonably protect the integrity of certain of the physical barriers that guard against the uncontrolled release of radioactivity."

- 10 CFR 50.36(c)(1)(ii)(A) states "Limiting safety system settings for nuclear reactors are settings for automatic protective devices related to those variables having significant safety functions. Where a limiting safety system setting is specified for a variable on which a safety limit has been placed, the setting must be so chosen that automatic protective action will correct the abnormal situation before a safety limit is exceeded."

As required by 10 CFR 50.36, the Hope Creek SLs and LSSS are defined in the TS. The Hope Creek SLs are defined in TS Section 2.1 as follows:

- TS SL 2.1.1 requires that the THERMAL POWER shall not exceed 25% (pre-EPU) of rated thermal power with the reactor steam dome pressure less than 785 psig or core flow less than 10% of rated core flow.

- TS SL 2.1.2 requires that the minimum critical power ratio (MCPR) shall be greater than or equal to 1.06 (pre-EPU) for two recirculation loop operation and greater than or equal to 1.08 (pre-EPU) for single recirculation loop operation, with the reactor steam dome pressure greater than 785 psig and core flow greater than 10% of rated core flow.

- TS SL 2.1.3 requires that the reactor steam dome pressure shall not exceed 1325 psig.

- TS SL 2.1.4 requires that the reactor vessel water level shall be above the top of the active irradiated fuel.

PSEG has evaluated the proposed TS changes to determine if any of these changes affect a limiting safety system setting for a variable on which a safety limit (SL) has been placed as discussed in 10 CFR 50.36(c)(1)(ii)(A).

Based on the definition of an LSSS as provided in 10 CFR 50.36, the settings that are to be classified as an LSSS in TS shall protect the SLs contained in TS Section 2.1. The trip setpoint values for these parameters must be directly associated with an SL for the parameter to be an LSSS. The general results of the evaluation of the proposed TS changes against the above SLs are provided below.

Reactor Core Safety Limits (Thermal Power & MCPR)
SLs as defined in TS Sections 2.1.1 and 2.1.2 are protected by the settings associated with certain RPS functions. The RPS LSSS, in combination with other LCOs, are designed to prevent any anticipated combination of transient conditions for reactor coolant system water level, pressure, and thermal power level that would result in exceeding the MCPR SL. A reactor scram is initiated by these RPS functions to ensure that fuel limits are not exceeded. The proposed TS changes do not change the specified LSSS of any of the parameters assumed to perform a mitigating safety function protecting the MCPR SL in the plant safety analyses.

Reactor Coolant System Pressure SL
TS SL 2.1.3 is protected by the RPS reactor vessel steam dome pressure-high scram function and the RPS APRM fixed neutron flux-upscale scram function as well as the pressure relief function of the safety/relief valves, which are defined as LSSS. The proposed TS changes do not change the specified LSSS of any of these parameters.

Reactor Vessel Water Level SL
The top of active fuel SL (TS SL 2.1.4) is protected by both the RPS low level scram function and the low level initiation of the ECCS. Establishment of ECCS initiation setpoints higher than this SL provides margin such that the SL will not be reached or exceeded.

The Hope Creek ECCS consists of High Pressure Coolant Injection, Automatic Depressurization System, Low Pressure Coolant Injection, and Core Spray. In addition, the Hope Creek design includes the Reactor Core Isolation Cooling (RCIC) system. Analysis has demonstrated that the RCIC system alone is capable of maintaining reactor level above the top of active fuel SL during a postulated loss of all feedwater flow. If the RCIC system were to fail, the ECCS systems would provide the required protection of the SL. These systems have initiation signals based on low reactor pressure vessel water level, which are required to protect the SL. Based on this, the associated ECCS settings are considered as LSSS in the Hope Creek

TS. The proposed TS changes do not change the specified LSSS of any of these parameters.

The specific proposed changes to TS values associated with the Hope Creek EPU submittal are listed in Table 1 of this Attachment. This table has been replicated below with a statement included to define whether or not each changed setpoint is a LSSS for a variable on which a Safety Limit (SL) has been placed. Table 1 included changes to a number of Limiting Conditions for Operation (LCOs). Since LCOs are not "automatic protective devices", are not directly associated with a SL and do not produce an "automatic protective action" as defined in 10CFR 50.36 (c)(1)(ii)(A), they are not considered LSSS and have been removed from the table for simplification.

Table 3
Proposed TS Changes

Section	Proposed Change	SL-Related Basis
TS 1.35 - RATED THERMAL POWER	Change RATED THERMAL POWER to 3840 MWt	**Not SL-Related** This parameter is not associated with an "automatic protective device" and does not produce an "automatic protective action" as defined in 10CFR 50.36 (c)(1)(ii)(A).
TS 2.1.1 - THERMAL POWER, Low Pressure, or Low Flow, and the associated Action	Revise the value of the thermal monitoring thresholds to 24%.	**Not SL-Related** This parameter is not associated with an "automatic protective device" and does not produce an "automatic protective action" as defined in 10CFR 50.36 (c)(1)(ii)(A).
Table 2.2.1-1 - Reactor Protection System Instrumentation Setpoints, Functional Unit 2.a	Revise the APRM Neutron Flux - Upscale, Setdown Trip Setpoint to 14%. Revise the Allowable Value to 19%.	**Not SL-Related** This parameter is associated with the Control Rod Drop accident (CRDA) and Continuous Rod Withdrawal Error (RWE) at low power. This parameter provides a backup to the IRM scram function. Furthermore, for these events, the scram function helps to limit fuel peak enthalpy within specified design limits. Fuel peak enthalpy is not a SL as described in TS 2.1. This parameter is not required to protect any SL as described in TS 2.1. Therefore, this parameter is not SL-Related.

Section	Proposed Change	SL-Related Basis
Table 2.2.1-1 - Reactor Protection System Instrumentation Setpoints, Functional Unit 2.b.1	Revise the APRM Flow-Biased Simulated Thermal Power – Upscale Trip Setpoint to: $\leq 0.57\ (w - \Delta w) + 58\%$. Revise the Allowable Value to: $\leq 0.57\ (w - \Delta w) + 61\%$.	**Not SL-Related** This parameter provides an RPS actuation (scram) on Simulated Thermal Power – Upscale. However, this function is not credited as a protective action in the plant safety analyses. Therefore, this parameter is not SL-Related.
Table 3.3.1-1 - Reactor Protection System Instrumentation Table Notations, Note (j)	Revise the RTP value to 24%. Remove the values for turbine first stage pressure.	**Not SL-Related** This parameter is used to reduce (disable) scrams and recirculation pump trips at low power levels. Therefore, this parameter is not an "automatic protective device" and does not produce an "automatic protective action" as defined in 10CFR 50.36 (c)(1)(ii)(A).
Table 4.3.1.1-1, Reactor Protection System Instrumentation Surveillance Requirements, Note (d)	Change the APRM CHANNEL CALIBRATION RTP threshold value to 24%.	**Not SL-Related** This parameter is not associated with an "automatic protective device" and does not produce an "automatic protective action" as defined in 10CFR 50.36 (c)(1)(ii)(A).
Table 3.3.2-2 - Isolation Actuation Instrumentation Setpoints, Trip Function 3.d	Revise the Main Steam Line Flow – High Trip Setpoint to 162.8 psid and the AV to 169.3 psid	**Not SL-Related** This parameter provides an isolation signal to the MSIVs to limit the released activity (from the coolant) during a Main Steam Line Break Accident (MSLBA) outside containment. No fuel damage occurs during a MSLBA. This parameter is not required to protect any SL as described in TS 2.1. Therefore, this parameter is not SL-Related.

Section	Proposed Change	SL-Related Basis
Table 3.3.4.2-1 - EOC-RPT Trip System Instrumentation, Note (b)	Revise the automatic bypass RTP value to 24%. Remove the values for turbine first stage pressure.	**Not SL-Related** This parameter is used to reduce (disable) scrams and recirculation pump trips at low power levels. Therefore, this parameter is not an "automatic protective device" and does not produce an "automatic protective action" as defined in 10CFR 50.36 (c)(1)(ii)(A).
Table 3.3.6-2 - Control Rod Block Instrumentation Setpoints, Trip Function 2.a	Revise the APRM Flow Biased Neutron Flux – Upscale Trip Setpoint to $\leq$ 0.57 (w - Δw)+ 53%. Revise the allowable value to: $\leq$ 0.57 (w - Δw) + 56%.	**Not SL-Related** This parameter provides an RPS actuation (rod withdrawal block) on Neutron Flux – Upscale. However, this function is not credited as a protective action in the plant safety analyses. Therefore, this parameter is not SL-Related.
Table 3.3.6-2 - Control Rod Block Instrumentation Setpoints, Trip Function 2.d	Revise the APRM Neutron Flux-Upscale, Startup (Rod Block) Setpoint to 11%. Revise the Allowable Value to 13%.	**Not SL-Related** This parameter is associated with the Continuous RWE at low power. This parameter provides a backup to the IRM rod block function during an RWE. Furthermore, the rod block function helps to limit fuel peak enthalpy within specified design limits. Fuel peak enthalpy is not a SL as described in TS 2.1. This parameter is not required to protect any SL as described in TS 2.1. Therefore, this parameter is not SL-Related.
SR 4.3.11.5	Change 30% RTP to 26.1% RTP	**Not SL-Related** This parameter establishes a surveillance threshold above which the Oscillation Power Range Monitor (OPRM) system is required to be trip-enabled. This parameter is not an "automatic protective device" and does not produce an "automatic protective action" as defined in 10CFR 50.36 (c)(1)(ii)(A).

5. REGULATORY SAFETY ANALYSIS

5.1 No Significant Hazards Consideration

PSEG Nuclear LLC (PSEG) has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment" as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The probability (frequency of occurrence) of Design Basis Accidents occurring is not affected by the increased power level, because Hope Creek continues to comply with the regulatory and design basis criteria established for plant equipment. A probabilistic risk assessment demonstrates that the calculated core damage frequencies do not significantly change due to constant pressure power uprate (CPPU). Scram setpoints (equipment settings that initiate automatic plant shutdowns) are established such that there is no significant increase in scram frequency due to CPPU. No new challenges to safety-related equipment result from CPPU.

   The changes in consequences of hypothetical accidents, which would occur from 102% of the CPPU (rated thermal power) RTP compared to those previously evaluated, are in all cases insignificant. The CPPU accident evaluations do not exceed any of the NRC-approved acceptance limits. The spectrum of hypothetical accidents and transients has been investigated, and are shown to meet the plant's currently licensed regulatory criteria. In the area of fuel and core design, for example, the Safety Limit Minimum Critical Power Ratio (SLMCPR) and other applicable Specified Acceptable Fuel Design Limits (SAFDLS) are still met. Continued compliance with the SLMCPR and other SAFDLs will be confirmed on a cycle specific basis consistent with the criteria accepted by the NRC as specified in NEDO-24011, "General Electric Standard Application for Reactor Fuel, GESTAR II."

   Challenges to the Reactor Coolant Pressure Boundary were evaluated at CPPU conditions (pressure, temperature, flow, and radiation) and were found to meet their acceptance criteria for allowable stresses and overpressure margin.

   Challenges to the containment have been evaluated, and the containment and its associated cooling systems continue to meet 10 CFR 50 Appendix

A Criterion 38, Long Term Cooling, and Criterion 50, Containment. The small increase in the calculated post LOCA suppression pool temperature above the currently assumed peak temperature was evaluated and determined to be acceptable.

Radiological release events (accidents) have been evaluated, and shown to meet the guidelines of 10 CFR 50.67.

Therefore, the proposed change does not involve a significant increase in the probability or radiological consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

Equipment that could be affected by CPPU has been evaluated. No new operating mode, safety-related equipment lineup, accident scenario or equipment failure mode was identified. The full spectrum of accident considerations has been evaluated, and no new or different kind of accident has been identified. CPPU uses developed technology, and applies it within the capabilities of existing plant equipment in accordance with presently existing regulatory criteria to include NRC approved codes, standards and methods. No new power dependent accidents have been identified.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

Response: No.

The CPPU affects only design and operational margins. Challenges to the fuel, reactor coolant pressure boundary, and containment were evaluated for CPPU conditions. Fuel integrity is maintained by meeting existing design and regulatory limits. The calculated loads on all affected structures, systems and components, including the reactor coolant pressure boundary, will remain within their design allowables for all design basis event categories. No NRC acceptance criterion will be exceeded. Because the Hope Creek configuration and responses to transients and hypothetical accidents do not result in exceeding the presently approved NRC acceptance limits, CPPU does not involve a significant reduction in a margin of safety.

Based on the above, PSEG concludes that the proposed changes present no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements/Criteria

10 CFR 50.36 (c)(2)(ii) Criterion 2, requires that TS LCOs include process variables, design features, and operating restrictions that are initial conditions of design basis accident analysis. The Technical Specifications ensure that the Hope Creek system performance parameters are maintained within the values assumed in the safety analyses. The Technical Specification changes justified by the safety analyses are made in accordance with methodology approved for Hope Creek and continue to provide a comparable level of protection as Hope Creek Technical Specifications previously issued by the NRC. Applicable regulatory requirements and significant safety evaluations performed in support of the proposed changes are described in Attachment 4.

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

6. ENVIRONMENTAL CONSIDERATION

The proposed TS changes required for implementation of EPU meet the requirements for an environmental review as set forth in 10 CFR 51.20, "Criteria For And Identification Of Licensing And Regulatory Actions Requiring Environmental Impact Statements." A supplement to the Hope Creek Environmental Report in Attachment 3 to PSEG's original request for license amendment (Reference 12) concludes that worker radiation exposures will continue to be significantly less than the limits established by federal regulation. The evaluation described in Attachment 3 supports increases in the licensed power level up to 3952 MWt, which bounds the proposed increase to 3840 MWt.

7. REFERENCES

1. GE Nuclear Energy, "Constant Pressure Power Uprate," Licensing Topical Report NEDC-330004P-A, Revision 4, July 2003

2. GE Nuclear Energy, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," Licensing Topical Report NEDC-32424P-A, February 1999

3. GE Nuclear Energy, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," Licensing Topical Reports NEDC-32523P-A, February 2000; NEDC-32523P-A, Supplement 1 Volume I, February 1999; and Supplement 1 Volume II, April 1999

4. HC License Amendment No. 63, Single Loop Operation Instrumentation (TAC No. M85771)

5. NRC letter dated June 25, 2003, "Review of Extended Power Uprates for Boiling Water Reactors"

6. NRC Inspection Report 50-354/98-09, October 2, 1998

7. HC License Amendment No. 134

8. HC License Amendment No. 131

9 PSEG letter LR-N98274, "Request for Change to Technical Specifications: Ultimate Heat Sink Temperature Limits," June 12, 1998

10. HC License Amendment No. 120, Ultimate Heat Sink Temperature Limits (TAC No. MA2060)

11. NUREG-1048, Supplement No. 6, Safety Evaluation Report related to the Operation of Hope Creek Generating Station, July 1986

12. PSEG letter LR-N05-0258, Request for License Amendment: Extended Power Uprate, November 7, 2005

HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
REVISIONS TO THE TECHNICAL SPECIFICATIONS

FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATION PAGES WITH PROPOSED CHANGES

The following sections of Facility Operating License No. NPF-57 are affected by this change request:

FOL Paragraph	Page
2.C.(1)	3
2.C.(11)	5
2.C.(16)	7

The following Technical Specifications for Facility Operating License No. NPF-57 are affected by this change request:

Technical Specification	Page
1.35	1-6
2.1.1	2-1
Table 2.2.1-1	2-4
3/4.1.4	3/4 1-16
3/4.2.1	3/4 2-1
3/4.2.3	3/4 2-3
3/4.2.4	3/4 2-5
Table 3.3.1-1	3/4 3-5
Table 4.3.1.1-1	3/4 3-8
Table 3.3.2-2	3/4 3-22

Technical Specification	Page
3/4.3.4	3/4 3-45
Table 3.3.4.2-1	3/4 3-47
Table 3.3.6-2	3/4 3-59
3/4.3.11	3/4 3-110
3/4.4.1	3/4 4-1 3/4 4-2a 3/4 4-4
3/4.6.1	3/4 6-2 3/4 6-4
Table 3.6.3-1	3/4 6-42
3/4.7.7	3/4 7-21
3/4.10.2	3/4 10-2
6.8.4.f	6-16b

Insert 1

(16) Leak rate tests required by Surveillance Requirement 4.6.1.2.a to be performed in accordance with the Primary Containment Leakage Rate Testing Program are not required to be performed until their next scheduled performance, which is due at the end of the first test interval that begins on the date the test was last performed prior to implementation of Amendment No. [XXX].

(4) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(5) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(6) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

3840

PSEG Nuclear LLC is authorized to operate the facility at reactor core power levels not in excess of 3339 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. , and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into the license. PSEG Nuclear LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Inservice Testing of Pumps and Valves (Section 3.9.6, SSER No. 4)*

This License Condition was satisfied as documented in the letter from W. R. Butler (NRC) to C. A. McNeill, Jr. (PSE&G) dated December 7, 1987. Accordingly, this condition has been deleted.

*The parenthetical notation following the title of many license conditions denotes the section of the Safety Evaluation Report and/or its supplements wherein the license condition is discussed.

(8) <u>Solid Waste Process Control Program (Section 11.4.2, SER; Section 11.4, SSER No. 4)</u>

PSEG Nuclear shall obtain NRC approval of the Class B and C solid waste process control program prior to processing Class B and C solid wastes.

(9) <u>Emergency Planning (Section 13.3, SSER No. 5)</u>

In the event that the NRC finds that the lack of progress in completion of the procedures in the Federal Emergency Management Agency's final rule, 44 CFR Part 350, is an indication that a major substantive problem exists in achieving or maintaining an adequate state of emergency preparedness, the provisions of 10 CFR Section 50.54(s)(2) will apply.

(10) <u>Initial Startup Test Program (Section 14, SSER No. 5)</u>

Any changes to the Initial Startup Test Program described in Section 14 of the FSAR made in accordance with the provisions of 10 CFR 50.59 shall be reported in accordance with 50.59(b) within one month of such change.

(11) <u>Partial Feedwater Heating (Section 15.1, SER; Section 15.1, SSER No. 5; Section 15.1, SSER No. 6)</u>

The facility shall not be operated with reduced feedwater temperature for the purpose of extending the normal fuel cycle ~~After the first operating cycle, the facility shall not be operated with a feedwater heating capacity that would result in a rated power feedwater temperature less than 400°F~~ unless analyses supporting such operation are submitted by the licensee and approved by the staff.

(12) <u>Detailed Control Room Design Review (Section 18.1, SSER No. 5)</u>

a. PSE&G shall submit for staff review Detailed Control Room Design Review Summary Reports II and III on a schedule consistent with, and with contents as specified in, its letter of January 9, 1986.

b. Prior to exceeding five percent power, PSE&G shall provide temporary zone markings on safety-related instruments in the control room.

4) The trust agreement shall not be modified in any material respect without prior written notification to the Director, Office of Nuclear Reactor Regulation.

5) The trustee, investment advisor, or anyone else directing the investments made in the trust shall adhere to a "prudent investor" standard, as specified in 18 CFR 35.32(3) of the Federal Energy Regulatory Commission's regulations.

c. PSEG Nuclear LLC shall not take any action that would cause PSEG Power LLC or its parent companies to void, cancel, or diminish the commitment to fund an extended plant shutdown as represented in the application for approval of the transfer of this license from PSE&G to PSEG Nuclear LLC.

INSERT 1

D. The facility requires exemptions from certain requirements of 10 CFR Part 50 and 10 CFR Part 70. An exemption from the criticality alarm requirements of 10 CFR 70.24 was granted in Special Nuclear Material License No. 1953, dated August 21, 1985. This exemption is described in Section 9.1 of Supplement No. 5 to the SER. This previously granted exemption is continued in this operating license. An exemption from certain requirements of Appendix A to 10 CFR Part 50, is described in Supplement No. 5 to the SER. This exemption is a schedular exemption to the requirements of General Design Criterion 64, permitting delaying functionality of the Turbine Building Circulating Water System-Radiation Monitoring System until 5 percent power for local indication, and until 120 days after fuel load for control room indication (Appendix R of SSER 5). Exemptions from certain requirements of Appendix J to 10 CFR Part 50, are described in Supplement No. 5 to the SER. These include an exemption from the requirement of Appendix J, exempting main steam isolation valve leak-rate testing at 1.10 Pa (Section 6.2.6 of SSER 5); an exemption from Appendix J, exempting Type C testing on traversing incore probe system shear valves (Section 6.2.6 of SSER 5); an exemption from Appendix J, exempting Type C testing for instrument lines and lines containing excess flow check valves (Section 6.2.6 of SSER 5); and an exemption from Appendix J, exempting Type C testing of thermal relief valves (Section 6.2.6 of SSER 5). These exemptions are authorized by law, will not present an undue risk to the public health and safety, and are consistent with the common defense and security. These exemptions are hereby granted. The special circumstances regarding each exemption are identified in the referenced section of the safety evaluation report and the supplements thereto. These exemptions are granted pursuant to 10 CFR 50.12. With these exemptions, the facility will operate, to the extent authorized herein, in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission.

PROCESS CONTROL PROGRAM

1.33 The PROCESS CONTROL PROGRAM (PCP) shall contain the current formulas, sampling, analyses, test, and determinations to be made to ensure that processing and packing of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61, and 71, State regulations, burial ground requirements, and other requirements governing the disposal of solid radioactive waste.

PURGE - PURGING

1.34 PURGE or PURGING shall be the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.35 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3339 MWT. 3840

REACTOR PROTECTION SYSTEM RESPONSE TIME

1.36 REACTOR PROTECTION SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by any series of sequential, overlapping or total steps such that the entire response time is measured.

REPORTABLE EVENT

1.37 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

ROD DENSITY

1.38 ROD DENSITY shall be the number of control rod notches inserted as a fraction of the total number of control rod notches. All rods fully inserted is equivalent to 100% ROD DENSITY.

2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

THERMAL POWER, Low Pressure or Low Flow

2.1.1 THERMAL POWER shall not exceed ~~25%~~ 24% of RATED THERMAL POWER with the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With THERMAL POWER exceeding ~~25%~~ 24% of RATED THERMAL POWER and the reactor vessel steam dome pressure less than 785 psig or core flow less than 10% of rated flow, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

THERMAL POWER, High Pressure and High Flow

2.1.2 With reactor steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow:

The MINIMUM CRITICAL POWER RATIO (MCPR) shall be ≥ 1.06 for two recirculation loop operation and shall be ≥ 1.08 for single recirculation loop operation.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With reactor steam dome pressure greater than 785 psig and core flow greater than 10% of rated flow and the MCPR below the values for the fuel stated in LCO 2.1.2, be in at least HOT SHUTDOWN within 2 hours and comply with the requirements of Specification 6.7.1.

REACTOR COOLANT SYSTEM PRESSURE

2.1.3 The reactor coolant system pressure, as measured in the reactor vessel steam dome, shall not exceed 1325 psig.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3 and 4.

ACTION:

With the reactor coolant system pressure, as measured in the reactor vessel steam dome, above 1325 psig, be in at least HOT SHUTDOWN with reactor coolant system pressure less than or equal to 1325 psig within 2 hours and comply with the requirements of Specification 6.7.1.

TABLE 2.2.1-1

REACTOR PROTECTION SYSTEM INSTRUMENTATION SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Intermediate Range Monitor, Neutron Flux-High	≤ 120/125 divisions of full scale	≤ 122/125 divisions of full scale
2. Average Power Range Monitor:		
a. Neutron Flux-Upscale, Setdown	≤ ~~15%~~ 14% of RATED THERMAL POWER	≤ ~~20%~~ 19% of RATED THERMAL POWER
b. Flow Biased Simulated Thermal Power-Upscale		
1) Flow Biased	0.57(w-Δw)+58% ≤ ~~0.66(w-Δw)+66%~~** with ~~a maximum of~~	0.57(w-Δw)+61% ≤ ~~0.66(w-Δw)+69%~~** ~~with a maximum of~~
2) High Flow Clamped	≤ 113.5% of RATED THERMAL POWER	≤ 115.5% of RATED THERMAL POWER
c. Fixed Neutron Flux-Upscale	≤ 118% of RATED THERMAL POWER	≤ 120% of RATED THERMAL POWER
d. Inoperative	NA	NA
3. Reactor Vessel Steam Dome Pressure - High	≤ 1037 psig	≤ 1057 psig
4. Reactor Vessel Water Level - Low, Level 3	≥ 12.5 inches above instrument zero*	≥ 11.0 inches above instrument zero
5. Main Steam Line Isolation Valve - Closure	≤ 8% closed	≤ 12% closed

*See Bases Figure B 3/4 3-1.

**The Average Power Range Monitor Scram function varies as a function of recirculation loop drive flow (w). Δw is defined as the difference in indicated drive flow (in percent of drive flow which produces rated core flow) between two loop and single loop operation at the same core flow. Δw = 0 for two recirculation loop operation. Δw = 9% for single recirculation loop operation.

3/4.1.4 CONTROL ROD PROGRAM CONTROLS

ROD WORTH MINIMIZER

LIMITING CONDITION FOR OPERATION

3.1.4.1 The Rod worth minimizer (RWM) shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2*#, when THERMAL POWER is less than or equal to ~~10%~~ 8.6% of RATED THERMAL POWER, minimum allowable low power setpoint.

ACTION:

a. With the RWM inoperable after the first 12 control rods are fully withdrawn, operation may continue provided that control rod movement and compliance with the prescribed control rod pattern are verified by a second licensed operator or other technically qualified member of the unit technical staff who is present at the reactor control console.

b. With the RWM inoperable before the first twelve (12) control rods are fully withdrawn, one startup per calendar year may be performed provided that the control rod movement and compliance with the prescribed control rod pattern are verified by a second licensed operator or other technically qualified member of the unit technical staff who is present at the reactor control console.

c. Otherwise, control rod movement may be only by actuating the manual scram or placing the reactor mode switch in the Shutdown position.

SURVEILLANCE REQUIREMENTS

4.1.4.1 The RWM shall be demonstrated OPERABLE:

a. In OPERATIONAL CONDITION 2 within 8 hours prior to withdrawal of control rods for the purpose of making the reactor critical, and in OPERATIONAL CONDITION 1 within 8 hours prior to RWM automatic initiation when reducing THERMAL POWER, by verifying proper indication of the selection error of at least one out-of-sequence control rod.

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* Entry into OPERATIONAL CONDITION 2 and withdrawal of selected control rods is permitted for the purpose of determining the OPERABILITY of the RWM prior to withdrawal of control rods for the purpose of bringing the reactor to criticality.

See Special Test Exception 3.10.2.

3/4.2 POWER DISTRIBUTION LIMITS

3/4.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.1 All AVERAGE PLANAR LINEAR HEAT GENERATION RATES (APLHGRs) shall be less than or equal to the limits specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER.

ACTION:

With an APLHGR exceeding the limits specified in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore APLHGR to within the required limits within 2 hours or reduce THERMAL POWER to less than ~~25%~~ 24% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.1 All APLHGRs shall be verified to be equal to or less than the limits specified in the CORE OPERATING LIMITS REPORT:

a. Once within 12 hours after THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER and at least once per 24 hours thereafter.

b. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for APLHGR.

3/4.2.3 MINIMUM CRITICAL POWER RATIO

LIMITING CONDITION FOR OPERATION

3.2.3 The MINIMUM CRITICAL POWER RATIO (MCPR) shall be equal to or greater than the MCPR limit specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER.

ACTION:

a. With the end-of-cycle recirculation pump trip system inoperable per Specification 3.3.4.2, operation may continue and the provisions of Specification 3.0.4 are not applicable provided that, within 1 hour, MCPR is determined to be greater than or equal to the EOC-RPT inoperable limit specified in the CORE OPERATING LIMITS REPORT.

b. With MCPR less than the applicable MCPR limit specified in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore MCPR to within the required limit within 2 hours or reduce THERMAL POWER to less than ~~25%~~ 24% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.3 MCPR, shall be determined to be equal to or greater than the applicable MCPR limit specified in the CORE OPERATING LIMITS REPORT:

a. Once within 12 hours after THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER and at least once per 24 hours thereafter.

b. Initially and at least once per 12 hours when the reactor is operating with a LIMITING CONTROL ROD PATTERN for MCPR.

POWER DISTRIBUTION LIMITS

3/4.2.4 LINEAR HEAT GENERATION RATE

LIMITING CONDITION FOR OPERATION

3.2.4 The LINEAR HEAT GENERATION RATE (LHGR) shall not exceed the limit specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER.

ACTION:

With the LHGR of any fuel rod exceeding the limit specified in the CORE OPERATING LIMITS REPORT, initiate corrective action within 15 minutes and restore the ~~LHGR to~~ within the limit within 2 hours or reduce THERMAL POWER to less than ~~25%~~ 24% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.4 LHGR's shall be determined to be equal to or less than the limit specified in the CORE OPERATING LIMITS REPORT:

a. Once within 12 hours after THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER and at least once per 24 hours thereafter.

b. Initially and at least once per 12 hours when the reactor is operating on a LIMITING CONTROL ROD PATTERN for LHGR.

TABLE 3.3.1-1 (Continued)

REACTOR PROTECTION SYSTEM INSTRUMENTATION

TABLE NOTATIONS

(a) A channel may be placed in an inoperable status for up to 6 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter.

(b) This function shall be automatically bypassed when the reactor mode switch is in the Run position.

(c) Unless adequate shutdown margin has been demonstrated per Specification 3.1.1, the "shorting links" shall be removed from the RPS circuitry prior to and during the time any control rod is withdrawn*.

(d) The non-coincident NMS reactor trip function logic is such that all channels go to both trip systems. Therefore, when the "shorting links" are removed, the Minimum OPERABLE Channels Per the Trip System are 4 APRMS, 6 IRMS and 2 SRMS.

(e) An APRM channel is inoperable if there are less than 2 LPRM inputs per level or less than 14 LPRM inputs to an APRM channel.

(f) This function is not required to be OPERABLE when the reactor pressure vessel head is removed per Specification 3.10.1.

(g) This function shall be automatically bypassed when the reactor mode switch is not in the Run position.

(h) This function is not required to be OPERABLE when PRIMARY CONTAINMENT INTEGRITY is not required.

(i) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

delete

24%

(j) This function ~~shall be~~ automatically bypassed when turbine first stage pressure is ~~$\leq$ 159.7 psig~~ equivalent to THERMAL POWER less than ~~30%~~ of RATED THERMAL POWER. ~~To allow for instrument accuracy, calibration, and drift, a setpoint of $\leq$ 135.7 psig is used.~~

delete

(k) Also actuates the EOC-RPT system.

*Not required for control rods removed per Specification 3.9.10.1 or 3.9.10.2.

TABLE 4.3.1.1-1 (Continued)
REACTOR PROTECTION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL FUNCTIONAL TEST	CHANNEL CALIBRATION	OPERATIONAL CONDITIONS FOR WHICH SURVEILLANCE REQUIRED
8. Scram Discharge Volume Water Level - High				
a. Float Switch	NA	Q	R	1, 2, 5(j)
b. Level Transmitter/Trip Unit	S	Q(k)	R	1, 2, 5(j)
9. Turbine Stop Valve - Closure	NA	Q	R	1
10. Turbine Control Valve Fast Closure Valve Trip System Oil Pressure - Low	NA	Q	R	1
11. Reactor Mode Switch Shutdown Position	NA	R	NA	1, 2, 3, 4, 5
12. Manual Scram	NA	W	NA	1, 2, 3, 4, 5

(a) Neutron detectors may be excluded from CHANNEL CALIBRATION.

(b) The IRM and SRM channels shall be determined to overlap for at least 1/2 decades during each startup after entering OPERATIONAL CONDITION 2 and the IRM and APRM channels shall be determined to overlap for at least 1/2 decades during each controlled shutdown, if not performed within the previous 7 days.

(c) DELETED

(d) This calibration shall consist of the adjustment of the APRM channel to conform to the power values calculated by a heat balance during OPERATIONAL CONDITION 1 when THERMAL POWER ≥ 25% ≥24% of RATED THERMAL POWER. Adjust the APRM channel if the absolute difference is greater than 2% of RATED THERMAL POWER.

(e) This calibration shall consist of the adjustment of the APRM flow biased channel to conform to a calibrated flow signal.

(f) The LPRMs shall be calibrated at least once per 1000 effective full power hours (EFPH).

(g) Verify measured core flow (total core flow) to be greater than or equal to established core flow at the existing recirculation loop flow (APRM % flow).

(h) This calibration shall consist of verifying the 6 ± 0.6 second simulated thermal power time constant.

(i) This item intentionally blank

(j) With any control rod withdrawn. Not applicable to control rods removed per Specification 3.9.10.1 or 3.9.10.2.

(k) Verify the tripset point of the trip unit at least once per 92 days.

(l) Not required to be performed when entering OPERATIONAL CONDITION 2 from OPERATIONAL CONDITION 1 until 12 hours after entering OPERATIONAL CONDITION 2.

TABLE 3.3.2-2

ISOLATION ACTUATION INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. PRIMARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level		
1) Low Low, Level 2	≥ -38.0 inches*	≥ -45.0 inches
2) Low Low Low, Level 1	≥ -129.0 inches*	≥ -136.0 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Reactor Building Exhaust Radiation - High	≤ 1×10^{-3} µCi/cc	≤ 1.2×10^{-3} µCi/cc
d. Manual Initiation	NA	NA
2. SECONDARY CONTAINMENT ISOLATION		
a. Reactor Vessel Water Level - Low Low, Level 2	≥ -38.0 inches*	≥ -45.0 inches
b. Drywell Pressure - High	≤ 1.68 psig	≤ 1.88 psig
c. Refueling Floor Exhaust Radiation - High	≤ 2×10^{-3} µCi/cc	≤ 2.4×10^{-3} µCi/cc
d. Reactor Building Exhaust Radiation - High	≤ 1×10^{-3} µCi/cc	≤ 1.2×10^{-3} µCi/cc
e. Manual Initiation	NA	NA
3. MAIN STEAM LINE ISOLATION		
a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -129.0 inches*	≥ -136.0 inches
b. Main Steam Line Radiation - High, High###	≤ 3.0 X full power background	≤ 3.6 X full power background
c. Main Steam Line Pressure - Low	≥ 756.0 psig	≥ 736.0 psig
d. Main Steam Line Flow - High	≤ ~~108.7~~ 162.8 psid	≤ ~~111.7~~ 169.3 psid

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.4.2 The end-of-cycle recirculation pump trip (EOC-RPT) system instrumentation channels shown in Table 3.3.4.2-1 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3.4.2-2 and with the END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM RESPONSE TIME as shown in Table 3.3.4.2-3.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to ~~30%~~ 24% of RATED THERMAL POWER.

ACTION:

a. With an end-of-cycle recirculation pump trip system instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3.4.2-2, declare the channel inoperable until the channel is restored to OPERABLE status with the channel setpoint adjusted consistent with the Trip Setpoint value.

b. With the number of OPERABLE channels one less than required by the Minimum OPERABLE Channels per Trip System requirement for one or both trip systems, place the inoperable channel(s) in the tripped condition within 12 hours.

c. With the number of OPERABLE channels two or more less than required by the Minimum OPERABLE Channels per Trip System requirement for one trip system and:

1. If the inoperable channels consist of one turbine control valve channel and one turbine stop valve channel, place both inoperable channels in the tripped condition within 12 hours.

2. If the inoperable channels include two turbine control valve channels or two turbine stop valve channels, declare the trip system inoperable.

d. With one trip system inoperable, restore the inoperable trip system to OPERABLE status within 72 hours or take the ACTION required by Specification 3.2.3.

e. With both trip systems inoperable, restore at least one trip system to OPERABLE status within one hour or take the ACTION required by Specification 3.2.3.

TABLE 3.3.4.2-1

END-OF-CYCLE RECIRCULATION PUMP TRIP SYSTEM INSTRUMENTATION

TRIP FUNCTION	MINIMUM OPERABLE CHANNELS PER TRIP SYSTEM[a]
1. Turbine Stop Valve - Closure	2[b]
2. Turbine Control Valve-Fast Closure	2[b]

[a] A trip system may be placed in an inoperable status for up to 6 hours for required surveillance provided that the other trip system is OPERABLE.

delete ≤

[b] This function shall be automatically bypassed when turbine first stage pressure is ~~≤ 159.7 psig~~ equivalent to THERMAL POWER less than ~~30%~~ 24% of RATED THERMAL POWER. ~~To allow for instrument accuracy, calibration and drift, a setpoint of ≤ 135.7 psig is used.~~

delete

TABLE 3.3.6-2
CONTROL ROD BLOCK INSTRUMENTATION SETPOINTS

TRIP FUNCTION	TRIP SETPOINT	ALLOWABLE VALUE
1. ROD BLOCK MONITOR		
a. Upscale		
i. Flow Biased	≤ 0.66 (w-Δw) + 65%*	≤ 0.66 (w-Δw) + 68%*
ii. High Flow Clamped	≤ 116%	≤ 119%
b. Inoperative	NA	NA
c. Downscale	≥ 5% ~~of RATED THERMAL POWER~~	≥ 3% ~~of RATED THERMAL POWER~~
2. APRM		
a. Flow Biased Neutron Flux - Upscale	0.57(w − Δw) + 53% ≤ ~~0.66 (w-Δw) + 57%*~~	0.57(w − Δw) + 56% ≤ ~~0.66 (w-Δw) + 60%*~~
b. Inoperative	NA	NA
c. Downscale	≥ ~~4% of~~ RATED THERMAL POWER	≥ 3% of RATED THERMAL POWER
d. Neutron Flux - Upscale, Startup	≤ ~~12%~~ 11% of RATED THERMAL POWER	≤ ~~14%~~ 13% of RATED THERMAL POWER
3. SOURCE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	≤ 1.0 x 10^5 cps	≤ 1.6 x 10^5 cps
c. Inoperative	NA	NA
d. Downscale	≥ 3 cps	≥ 1.8 cps
4. INTERMEDIATE RANGE MONITORS		
a. Detector not full in	NA	NA
b. Upscale	≤ 108/125 divisions of full scale	≤ 110/125 divisions of full scale
c. Inoperative	NA	NA
d. Downscale	≥ 5/125 divisions of full scale	≥ 3/125 divisions of full scale
5. SCRAM DISCHARGE VOLUME		
a. Water Level-High (Float Switch)	109'1" (North Volume) 108'11.5" (South Volume)	109'3" (North Volume) 109'1.5" (South Volume)
6. REACTOR COOLANT SYSTEM RECIRCULATION FLOW		
a. Upscale	≤ 111% of rated flow	≤ 114% of rated flow
b. Inoperative	NA	NA
c. Comparator	≤ 10% flow deviation	≤ 11% flow deviation
7. REACTOR MODE SWITCH SHUTDOWN POSITION	NA	NA

* The rod block function is varied as a function of recirculation loop flow (w) and Δw which is defined as the difference in indicated drive flow (in percent of drive flow which produces rated core flow) between two loop and single loop operation at the same core flow.

3/4.3.11 OSCILLATION POWER RANGE MONITOR

LIMITING CONDITION FOR OPERATION

3.3.11 Four channels of the OPRM instrumentation shall be OPERABLE*. Each OPRM channel period based algorithm amplitude trip setpoint (Sp) shall be less than or equal to the Allowable Value as specified in the CORE OPERATING LIMITS REPORT.

APPLICABILITY: OPERATIONAL CONDITION 1, when THERMAL POWER is greater than or equal to ~~25%~~ 24% of RATED THERMAL POWER.

ACTIONS

a. With one or more required channels inoperable:
   1. Place the inoperable channels in trip within 30 days, or
   2. Place associated RPS trip system in trip within 30 days, or
   3. Initiate an alternate method to detect and suppress thermal hydraulic instability oscillations within 30 days.

b. With OPRM trip capability not maintained:
   1. Initiate alternate method to detect and suppress thermal hydraulic instability oscillations within 12 hours, and
   2. Restore OPRM trip capability within 120 days.

c. Otherwise, reduce THERMAL POWER to less than ~~25%~~ 24% RTP within 4 hours.

SURVEILLANCE REQUIREMENTS

4.3.11.1 Perform CHANNEL FUNCTIONAL TEST at least once per 184 days.

4.3.11.2 Calibrate the local power range monitor once per 1000 Effective Full Power Hours (EFPH) in accordance with Note f, Table 4.3.1.1-1 of TS 3/4.3.1.

4.3.11.3 Perform CHANNEL CALIBRATION once per 18 months. Neutron detectors are excluded.

4.3.11.4 Perform LOGIC SYSTEM FUNCTIONAL TEST once per 18 months.

4.3.11.5 Verify OPRM is enabled when THERMAL POWER is ≥ ~~30%~~ 26.1% RTP and recirculation drive flow ≤ the value corresponding to 60% of rated core flow once per 18 months.

4.3.11.6 Verify the RPS RESPONSE TIME is within limits. Each test shall include at least one channel per trip system such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip system. Neutron detectors are excluded.

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* When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated ACTIONS may be delayed for up to 6 hours, provided the OPRM maintains trip capability.

3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 RECIRCULATION SYSTEM

RECIRCULATION LOOPS

LIMITING CONDITION FOR OPERATION

3.4.1.1 *Two reactor coolant system recirculation loops shall be in operation.*

APPLICABILITY: OPERATIONAL CONDITIONS 1* and 2*.

ACTION:

a. With one reactor coolant system recirculation loop not in operation:

1. Within 4 hours:

   a) Place the recirculation ~~flow~~ control system in the Local Manual mode, and 60.86%

   b) Reduce THERMAL POWER to ≤ ~~70%~~ of RATED THERMAL POWER, and

   c) Increase the MINIMUM CRITICAL POWER RATIO (MCPR) Safety Limit per Specification 2.1.2, and

   d) Reduce the AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR) limit to a value specified in the CORE OPERATING LIMITS REPORT for single loop operation, and

   e) Reduce the LINEAR HEAT GENERATION RATE (LHGR) limit to a value specified in the CORE OPERATING LIMITS REPORT for single loop operation, and

   f) Limit the speed of the operating recirculation pump to less than or equal to 90% of rated pump speed, and

   g) Perform surveillance requirement 4.4.1.1.2 if THERMAL POWER is ≤ 38% of RATED THERMAL POWER or the recirculation loop flow in the operating loop is ≤ 50% of rated loop flow.

2. Within 4 hours, reduce the Average Power Range Monitor (APRM) Scram Trip Setpoints and Allowable Values to those applicable for single recirculation loop operation per Specification 2.2.1; otherwise, with the Trip Setpoints and Allowable Values associated with one trip system not reduced to those applicable for single recirculation loop operation, place the affected trip system in the tripped condition and within the following 6 hours, reduce the Trip Setpoints and Allowable Values of the affected channels to those applicable for single recirculation loop operation per Specification 2.2.1.

3. Within 4 hours, reduce the APRM Control Rod Block Trip Setpoints and Allowable Values to those applicable for single recirculation loop operation per Specification 3.3.6; otherwise, with the Trip Setpoint and Allowable Values associated with one trip function not

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*See Special Test Exception 3.10.4.

SURVEILLANCE REQUIREMENTS

4.4.1.1.1 With one reactor coolant system recirculation loop not in operation at least once per 12 hours verify that:

a. Reactor THERMAL POWER is ≤ ~~70%~~ 60.86% of RATED THERMAL POWER, and

b. The recirculation flow control system is in the Local Manual mode, and

c. The speed of the operating recirculation pump is less than or equal to 90% of rated pump speed.

4.4.1.1.2 With one reactor coolant system recirculation loop not in operation, within no more than 15 minutes prior to either THERMAL POWER increase or recirculation loop flow increase, verify that the following differential temperature requirements are met if THERMAL POWER is ≤ 38% of RATED THERMAL POWER or the recirculation loop flow in the operating recirculation loop is ≤ 50% of rated loop flow:

a. ≤ 145°F between reactor vessel steam space coolant and bottom head drain line coolant, and

b. ≤ 50°F between the reactor coolant within the loop not in operation and the coolant in the reactor pressure vessel, and

c. ≤ 50°F between the reactor coolant within the loop not in operation and the operating loop.

The differential temperature requirements or Specifications 4.4.1.1.2b and 4.4.1.1.2c do not apply when the loop not in operation is isolated from the reactor pressure vessel.

4.4.1.1.3 Each pump MG set scoop tube mechanical and electrical stop shall be demonstrated OPERABLE with overspeed setpoints less than or equal to 109% and 107%, respectively, of rated core flow, at least once per 18 months.

REACTOR COOLANT SYSTEM

JET PUMPS

LIMITING CONDITION FOR OPERATION

3.4.1.2 All jet pumps shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2.

ACTION:

With one or more jet pumps inoperable, be in at least HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS*

4.4.1.2 All jet pumps shall be demonstrated OPERABLE as follows:

a. Each of the above required jet pumps shall be demonstrated OPERABLE prior to THERMAL POWER exceeding ~~25%~~ 24% of RATED THERMAL POWER and at least once per 24 hours by determining recirculation loop flow, total core flow and diffuser-to-lower plenum differential pressure for each jet pump and verifying that no two of the following conditions occur when the recirculation pumps are operating in accordance with Specification 3.4.1.3.

   1. The indicated recirculation loop flow differs by more than 10% from the established pump speed-loop flow characteristics.

   2. The indicated total core flow differs by more than 10% from the established total core flow value derived from recirculation loop flow measurements.

   3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from the established patterns by more than 20%.

b. During single recirculation loop operation, each of the above required jet pumps in the operating loop shall be demonstrated OPERABLE at least once per 24 hours by verifying that no two of the following conditions occur:

   1. The indicated recirculation loop flow in the operating loop differs by more than 10% from the established* pump speed-loop flow characteristics.

   2. The indicated total core flow differs by more than 10% from the established* total core flow value derived from single recirculation loop flow measurements.

   3. The indicated diffuser-to-lower plenum differential pressure of any individual jet pump differs from established* single recirculation loop patterns by more than 20%.

c. The provisions of Specification 4.0.4 are not applicable provided that this surveillance is performed within 24 hours after exceeding 24% ~~25%~~ of RATED THERMAL POWER.

*During startup following any refueling outage, baseline data shall be recorded for the parameters listed to provide a basis for establishing the specified relationships. Comparisons of the actual data in accordance with the criteria listed shall commence upon conclusion of the baseline data analysis. Single loop baseline data shall be recorded the first time the unit enters single loop operation during an operating cycle.

PRIMARY CONTAINMENT LEAKAGE

LIMITING CONDITION FOR OPERATION

3.6.1.2 Primary containment leakage rates shall be limited to:

a. An overall integrated leakage rate (Type A test) in accordance with the Primary Containment Leakage Rate Testing Program.

b. A combined leakage rate in accordance with the Primary Containment Leakage Rate Testing Program for all penetrations and all valves listed in Table 3.6.3-1, except for main steam line isolation valves*, valves which form the boundary for the long-term seal of the feedwater lines, and other valves which are hydrostatically tested per Table 3.6.3-1, subject to Type B and C tests.

c. *Less than or equal to 150 scfh per main steam line and less than or equal to 250 scfh combined through all four main steam lines when tested at 5 psig (leakage rate corrected to 1 Pa, ~~48.1~~ 50.6 psig).

d. A combined leakage rate of less than or equal to 10 gpm for all containment isolation valves which form the boundary for the long-term seal of the feedwater lines in Table 3.6.3-1, when tested at 1.10 Pa, ~~52.9~~ 55.7 psig.

e. A combined leakage rate of less than or equal to 10 gpm for all other penetrations and containment isolation valves in hydrostatically tested lines in Table 3.6.3-1 which penetrate the primary containment, when tested at 1.10 Pa, ~~52.9~~ 55.7 psig Δp.

APPLICABILITY: When PRIMARY CONTAINMENT INTEGRITY is required per Specification 3.6.1.1.

ACTION:
With:

a. The measured overall integrated primary containment leakage rate (Type A test) not in accordance with the Primary Containment Leakage Rate Testing Program, or

b. The measured combined leakage rate for all penetrations and all valves listed in Table 3.6.3-1, except for main steam line isolation valves*, valves which form the boundary for the long-term seal of the feedwater lines, and other valves which are hydrostatically tested per Table 3.6.3-1, subject to Type B and C tests not in accordance with the Primary Containment Leakage Rate Testing Program, or

c. The measured leakage rate exceeding 150 scfh per main steam line or exceeding 250 scfh combined through all four main steam lines, or

*Exemption to Appendix "J" of 10 CFR 50.

SURVEILLANCE REQUIREMENTS (Continued)

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d. DELETED.

e. DELETED.

f. Main steam line isolation valves shall be leak tested at least once per 18 months.

g. Containment isolation valves which form the boundry for the long-term seal of the feedwater lines in Table 3.6.3-1 shall be hydrostatically tested at 1.10 P_a, ~~52.9~~ 55.7 psig, at least once per 18 months.

h. All containment isolation valves in hydrostatically tested lines in Table 3.6.3-1 which penetrate the primary containment shall be leak tested at least once per 18 months.

i. DELETED.

j. DELETED.

TABLE 3.6.3-1

PRIMARY CONTAINMENT ISOLATION VALVES

NOTES

NOTATION

1. Main Steam Isolation Valve leakage is not added to 0.60 La allowable leakage.*

2. Containment Isolation Valves are sealed with a water seal from the HPCI and/or RCIC system to form the long-term seal boundary of the feedwater lines. The valves are tested with water at 1.10 Pa, ~~52.9~~ 55.7 psig, to ensure the seal boundary will prevent by-pass leakage. Seal boundary liquid leakage will be limited to 10 gpm.

3. Containment Isolation Valve, Type C gas test at Pa, ~~48.1~~ 50.6 psig. Leakage added to entire system leakage. Allowable leakage for entire system limited to 0.60La.

4. Containment Isolation Valve, Type C water test at 1.10 Pa, ~~52.9~~ 55.7 psig delta P. Leakage added to entire system leakage. Allowable leakage for entire system limited to 10 gpm.

5. Containment boundary is discharge nozzle of relief valve, leakage tested during Type A test.*

6. Drywell and suppression chamber pressure and level instrument root valves and excess flow check valves, leakage tested during Type A.*

7. Explosive shear valves (SE-V021 through SE-V025) not Type C tested.*

8. Surveillances to be performed per Specification 3.6.1.8.

9. All valve I.D. numbers are preceded by a numeral 1 which represents a Unit 1 valve.

10. The reactor vessel head seal leak detection line (penetration J5C) excess flow check valve (BB-XV-3649) is not subject to OPERABILITY testing. This valve will not be exposed to primary system pressure except under the unlikely conditions of a seal failure where it could be partially pressurized to reactor pressure. Any leakage path is restricted at the source; therefore, this valve need not be OPERABILITY tested.

11. Containment Isolation Valve(s) are not Type C tested. Containment by-pass leakage is prevented since the line terminates below the minimum water level in the suppression chamber and the system is a closed system outside Primary Containment. Refer to Specification 4.0.5.

*Exemption to Appendix J of 10 CFR Part 50.

PLANT SYSTEMS

3/4.7.7 MAIN TURBINE BYPASS SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.7 The main turbine bypass system shall be OPERABLE.

APPLICABILITY: OPERATIONAL CONDITION 1 when THERMAL POWER is greater than or equal to 25% 24% of RATED THERMAL POWER.

ACTION: With the main turbine bypass system inoperable, restore the system to OPERABLE status within 2 hours or reduce THERMAL POWER to less than or equal to 25% 24% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.7.7 The main turbine bypass system shall be demonstrated OPERABLE at least once per:

a. 31 days by cycling each turbine bypass valve through at least one complete cycle of full travel, and

b. 18 months by:

1. Performing a system functional test which includes simulated automatic actuation and verifying that each automatic valve actuates to its correct position.

2. Demonstrating TURBINE BYPASS SYSTEM RESPONSE TIME meets the following requirements when measured from the initial movement of the main turbine stop or control valve:

a) 80% of turbine bypass system capacity shall be established in less than or equal to 0.3 second.

b) Bypass valve opening shall start in less than or equal to 0.1 second.

SPECIAL TEST EXCEPTIONS

3/4.10.2 ROD WORTH MINIMIZER

LIMITING CONDITION FOR OPERATION

3.10.2 The sequence constraints imposed on control rod groups by the rod worth minimizer (RWM) per Specification 3.1.4.1 may be suspended for the following tests provided that control rod movement prescribed for this testing is verified by a second licensed operator or other technically qualified member of the unit technical staff present at the reactor console:

a. Shutdown margin demonstrations, Specification 4.1.1.

b. Control rod scram, Specification 4.1.3.2.

c. Control rod friction measurements.

APPLICABILITY: OPERATIONAL CONDITIONS 1 and 2 when THERMAL POWER is less than or equal to ~~10%~~ 8.6% of RATED THERMAL POWER.

ACTION:

With the requirements of the above specification not satisfied, verify that the RWM is OPERABLE per Specifications 3.1.4.1.

SURVEILLANCE REQUIREMENTS

4.10.2 When the sequence constraints imposed by the RWM are bypassed, verify:

a. That movement of the control rods from 75% ROD DENSITY to the RWM low power setpoint is limited to the approved control rod withdrawal sequence during scram and friction tests.

b. That movement of control rods during shutdown margin demonstrations is limited to the prescribed sequence per Specification 3.10.3.

c. Conformance with this specification and test procedures by a second licensed operator or other technically qualified member of the unit technical staff.

6.8.4.f Primary Containment Leakage Rate Testing Program

A program shall be established, implemented, and maintained to comply with the leakage rate testing of the containment as required by 10CFR50.54(o) and 10CFR50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program", dated September 1995, as modified by the following exception:

a. NEI 94-01-1995, Section 9.2.3: The first Type A test performed after April 12, 1994 shall be performed no later than April 12, 2009.

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is ~~48.1~~ 50.6 psig.

The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.5% of primary containment air weight per day.

Leakage Rate Acceptance Criteria are:

a. Primary containment leakage rate acceptance criterion is less than or equal to 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are less than or equal to 0.6 L_a for Type B and Type C tests and less than or equal to 0.75 L_a for Type A tests;

b. Air lock testing acceptance criteria are:

1) Overall air lock leakage rate is less than or equal to 0.05 L_a when tested at greater than or equal to P_a,

2) Door seal leakage rate less than or equal to 5 scf per hour when the gap between the door seals is pressurized to greater than or equal to 10.0 psig.

The provisions of Specification 4.0.2 do not apply to the test frequencies specified in the Primary Containment Leakage Rate Testing Program.

The provisions of Specification 4.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

6.8.4.g. Radioactive Effluent Controls Program

A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to MEMBER(S) OF THE PUBLIC from radioactive effluents as low as reasonably achievable. The program (1) shall be contained in the ODCM, (2) shall be implemented by operating procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

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EXTENDED POWER UPRATE
LIST OF COMPLETED AND PLANNED MODIFICATIONS

The following is a list of completed and currently planned modifications necessary to support Extended Power Uprate (EPU). The planned modifications are to be implemented before restart from Hope Creek refueling outage RF14, currently scheduled for Fall 2007. The planned modifications listed are subject to change based on evaluations performed as part of PSEG's design change process. As such, the list is not a formal commitment to implement the modifications exactly as described. Additionally, various setpoint changes and changes to indicating ranges on certain control room and in-plant instrumentation, which may be necessary, are not listed. Implementation of these modifications will be in accordance with the requirements of 10 CFR 50.59.

Completed Modifications

- Additional 500 kV circuit breaker in Hope Creek switchyard
- Cooling tower fill and flow distribution modifications
- Low Pressure Turbine replacement
- Electrohydraulic Control (EHC) and Turbine Supervisory Instrumentation (TSI) replacement
- Main Transformer replacement
- Main Generator Stator Water Cooling upgrade
- Turbine Moisture Separator upgrade
- Piping Vibration Monitoring
- Average Power Range Monitor (APRM) and Rod Block Monitor (RBM) flow-biased trip reference card replacement
- Isolated Phase Bus Duct Cooling modification
- Steam Jet Air Ejector modification
- Feedwater Heater Dump Valve replacements
- Moisture Separator and 5th Point Feedwater Heater rerating

Planned Modifications

- High Pressure Turbine replacement
- Pipe support modifications (where required)
- Steam dryer modifications (where required)
- Small bore piping modifications for FIV (where required)

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REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
STEAM DRYER EVALUATION

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HCGS STEAM DRYER EVALUATION

Executive Summary

The Hope Creek Generating Station (HCGS) steam dryer is a curved hood design that was further upgraded on-site prior to commercial operation. It has been properly inspected on a recurring basis and has shown no fatigue damage as of the last inspection, spring 2006.

HCGS used the Acoustic Circuit Model (ACM) load transfer methodology to calculate steam dryer loads at 100% Current Licensed Thermal Power (CLTP) using plant measurements from strain gages installed on the main steam lines (MSL). The ACM methodology was benchmarked at Quad Cities 2 using an instrumented steam dryer to compare predicted and actual loads. The HCGS strain gage installation replicated the Quad Cities 2 strain gage locations. The loads calculated by the ACM were inputted into a finite element model (FEM) developed specifically for the HCGS steam dryer. The CLTP FEM analysis shows that the most limiting component on the steam dryer is not overstressed, and has adequate margin to address ACM uncertainties.

HCGS is aware of industry concerns with the operation of steam dryers under Extended Power Uprates (EPU) conditions. To reduce risks, HCGS proactively undertook steps to minimize the unknowns associated with relief valve acoustic resonance, which has been identified as the primary loading that caused damage at Quad Cities and Dresden steam dryers. This effort included a 1/8th scale model test (SMT) of the HCGS components to determine the ¼ wave acoustic frequency for the HCGS safety relief valves (SRV) and obtain an estimate of the SRV loading as well as the overall increase between CLTP and EPU. HCGS reran the FEM using the predicted EPU loads that included a conservative estimate of the SRV loads. This is referred to as the interim EPU FEM. These analyses demonstrate that the HCGS maintains a positive margin for EPU operation when considering a very conservative loading and the nominal frequency. A positive margin is also expected with a ±10% frequency shift with some reduction in the conservatism assumed for the EPU loading.

The EPU power ascension test plan will incorporate predetermined hold points above CLTP to allow for review and confirmation that dryer loads remain below acceptable values. HCGS will rely on the strain gage readings to monitor the changes during this initial power ascension to EPU. HCGS will validate during this power ascension that loading, including uncertainties, will not result in unacceptable steam dryer fatigue stresses.

This Attachment summarizes actions completed or currently planned to ensure the integrity of the steam dryer at the EPU condition.

Background

In June 2002, Quad Cities 2 (a BWR 3) was operating at approximately 113% of original licensed thermal power (OLTP) when it experienced a failure of a steam dryer cover plate resulting in the generation of loose parts, which were ingested into a main steam line (MSL). In April 2003, the same plant experienced a second steam dryer failure. This second failure occurred at a weld between the outer hood and an end plate.

In October 2003, a hood failure occurred at Quad Cities 1, a sister unit to the BWR 3 that had experienced the previously noted failures. This unit was also operating at EPU conditions. The observed hood damage was virtually the same as the May 2003 failure described above.

In August 2002, General Electric Company (GE) issued a Services Information Letter (SIL) (reference 1) that recommended monitoring steam moisture content (MC) and other reactor parameters for BWR 3-style steam dryers. Reference 1 also recommended inspection of the cover plates at the next refueling outage for those plants operating at greater than OLTP.

Reference 2 broadened the earlier recommendations for BWR 3-style steam dryer plants and provided additional recommendations for BWR 4 and later steam dryer design plants planning to or already operating at greater than OLTP. Following this revised guidance, inspections were performed on plants operating at OLTP, stretch uprate (5%), and extended power uprate (EPU) conditions. These inspections indicated that steam dryer fatigue cracking could also occur in plants operating at OLTP. Reference 2 described additional significant fatigue cracking that has been observed in steam dryer hoods and provided inspection and monitoring recommendations for all BWR plants.

Significant industry efforts were expended in finding a methodology to measure plant loads since it became apparent that generic loads were not appropriate. This resulted in the development of the Acoustic Circuit Method, which uses either strain gages or pressure sensors on the MSL to measure plant data and then calculate the differential pressure across the steam dryer.

In addition, efforts were expended to determine the source of the significant loading. The remedial actions in the spring of 2006 that installed acoustic side branches at the Quad Cities relief valve standpipes confirmed that the majority of the Quad Cities steam dryer loading was from the relief valve ¼ wave acoustic waves. Prior to installation of the acoustic side branches, Quad Cities had been operating at essentially the peak SRV acoustic resonance condition.

BWR Fleet Operating History

In addition to the instances described for Quad Cities, steam dryer cracking has been observed throughout the BWR fleet operating history. Steam dryer cracking has been observed in the following components at several BWRs: dryer hoods, dryer hood end plates, drain channels, support rings, skirts, tie bars, and lifting rods. These crack experiences have predominately occurred during OLTP conditions, and are described in References 2 and 4. Except for the Quad Cities events, there have not been any loose parts generated.

The operating environment has a significant influence on the susceptibility of the dryer to cracking. Most of the steam dryer is located in the steam space with the lower half of the skirt immersed in reactor water at saturation temperature. These environments are highly oxidizing and increase the susceptibility to inter-granular stress corrosion cracking (IGSCC).

BWROG Recommendations

The BWR Owners Group in September 2004 issued Reference 3. Sections 3.5 and 3.6 of that document address steam dryer loads and inspections/evaluations, respectively. The two recommendations specific to steam dryers are cited below.

- An evaluation of steam dryer loads for EPU conditions should be made prior to implementation of EPU. Modifications of the dryer or bases for not making modifications should be made based on the results of this evaluation.
- Follow the inspection and monitoring recommendations made by the GE SIL (Reference 2) and by the EPRI BWR vessel internal project (VIP) steam dryer inspection guidelines (Reference 4).

HCGS has performed an evaluation of the steam dryer with estimated EPU loads. This evaluation is summarized later. HCGS has performed inspections in RF12 and RF13 following guidance of references 2 and 4. The Power Ascension Test Plan (PATP) addresses post EPU steam dryer inspections.

HCGS Steam Dryer Description

HCGS Steam Dryer History

The HCGS reactor steam dryer went into service with the startup of the plant in 1986. Since start-up, HCGS has concentrated on maintaining good water chemistry in the reactor coolant system, which contributes to reducing the occurrence of IGSCC. IGSCC-type indications have been observed on the HCGS dryer as noted below.

HCGS Steam Dryer Inspections

HCGS has performed the baseline visual inspections of its steam dryer per BWRVIP guidelines (reference 4). The baseline inspection was completed during the latest refueling outage (RF-13 in Spring 2006). The HCGS steam dryer indications observed during inspections performed prior to and through RF-13 are listed below:

1. Support ring, 205°, horizontal crack, found in RF07. Measured every outage since. RF07 through RF10 measured at 2.25 inch. RF11 measured at 2.87 inch. RF12

measured at 2.25 inch. The RF11 measurement was discounted. This indication has been dispositioned as IGSCC due to residual stress from cold forming of the support ring and its proximity to the upper weld Heat Affected Zone (HAZ). No growth observed since discovery.

2. Skirt, 5°, horizontal weld below the dryer support lug, found in RF10. Horizontal crack in the HAZ below the weld. Measured RF10, 11, and 12. All measurements 0.75-inch. This indication has been dispositioned as IGSCC due to residual stress from welding. No growth observed since discovery.
3. Lifting lug, 220°, upper support bracket, found broken on one side in RF11. During RF12 the upper bracket was removed. Left less than one-inch stub. Justification for removal on file.
4. Support ring, 20°, on top, radial 0.625 inch (from edge to hood weld) and down side vertical 0.75 inches. Crack thought to be started on top and side shows depth. Identified during RF12. This indication has been dispositioned as IGSCC due to residual stress from cold forming of the support ring and its proximity to the weld HAZ.
5. Inner curved hood, crack above a repair strip added prior to commercial operation. Identified during RF13. Dispositioned as IGSCC. Insufficient crack opening to result in any steam bypass.
6. Lifting lug, 140°, cracks near the tack welds that prevent rotation of the lifting rod eye on the lift rod. Identified during RF13. Dispositioned as IGSCC.
7. Steam outlet end plate for outer hood, crack at the bottom of the plate, about 1-¼ inches long. Identified during RF13. Dispositioned as IGSCC.
8. Support ring at 230° top surface, approximately 5-inches in length. Identified during RF13. Dispositioned as IGSCC.

None of these indications approach the critical flaw size. They will be reinspected periodically as required by their current flaw evaluations.

A key finding is that no indications have been found indicating FIV damage on any of the HCGS dryer areas. This includes the hoods, cover plates, tie bars, drain channels, and steam outlet end plates. As discussed below, Hope Creek has a curved hood steam dryer, which was reinforced in the areas of greatest FIV concern.

<u>HCGS Steam Dryer Design</u>

The HCGS steam dryer is typical of the late BWR 4/5 curved hood design with some notable exceptions. Per Reference 4, the HCGS steam dryer is essentially the same as Limerick 1&2, LaSalle 1&2, Susquehanna 1&2, Fermi 2, Tokai 2, 1Fukishima 6, Nine Mile Point 2, and Columbia (12 total). Prior to operation, the HCGS steam dryer was modified on-site with the following recommended GE upgrades to improve its structural integrity:

- The 0.125-inch thick outer hoods were replaced with 0.5-inch hoods. In addition, the weld attaching the outer hoods to their internal, vertical hood supports was strengthened.
- The 0.1875-inch thick central steam outlet end plates, on the outlet of the inner hoods, were replaced with 0.5-inch plates.
- The 0.5 by 1-inch tie bars, spanning across the top of the vane assemblies, were replaced with an increased number of 2 by 2-inch tie bars. Seven (7) bars tie the outer vane assembly to its middle vane assembly. Nine (9) bars tie the middle vane assembly to its inner vane assembly. Five (5) bars tie the two inner vane banks to each other.
- 0.187-inch thick reinforcing strips were added at the outer edges of the middle and inner 0.125-inch thick hoods where they are welded to their 0.250-inch end plates. These reinforcing strips extended the full length of the weld.

HCGS Steam Dryer Comparison to Dryers Operating at EPU

Dryer design, steam velocities, and relief valve dead leg acoustic loads have been identified as contributors to dryer failures and the subsequent generation of loose parts.

The HCGS steam dryer curved hood design is an upgrade to the earlier, square hood dryers that failed at Quad Cities. These upgrades include improved flow characteristics and improved structural strength in the upper part of the dryer.

The square hood design has 4-foot high dryer vanes, sharp 90° corners at various flow points, and includes a steam dam (raised plate perpendicular to the top of the dryer). This design inherently causes turbulence as the steam flows through the steam dryer into the reactor steam dome. Furthermore, the square hood design results in turbulence as the steam flows from the steam dome towards the MS nozzles since the steam encounters the outside 90° corners of the outer hoods.

The curved hood design has 6-foot high vanes, eliminates the 90° corners, and eliminates the steam dam, all of which provide a distinct advantage in reducing turbulence. Average steam flow velocities through the dryer vanes at EPU conditions will remain relatively modest (~ 4 feet per second). The average velocity entering the bottom of the hoods and exiting the outlet of the hoods is approximately 15 fps.

The significant structural failures in the Quad Cities dryers were at the outer hood, facing the MS nozzles. The square hood design initially used internal bracing, which provided support to the hoods only at the upper corner of the hood, resulting in a high stress condition. The curved hood dryer uses interior, vertical support plates, which provide continuous support along the entire height of the hood and eliminate the need for external gusset plates. The HCGS outer hoods consist of 0.5-inch thick bent plate welded to 0.375-inch thick end plates and, at the bottom, to a 0.375-inch thick horizontal cover plate.

Another advantage of the curved hood design is that it has a total of four wide drain channels welded to the outside of the dyer skirt. Each drain channel spans approximately 45 degrees along the circumference of the skirt and spans nearly the full height of the skirt (from the bottom of the upper support ring to just above the bottom ring). These four wide drain channels provide added stiffness to the skirt.

The table below summarizes steam dryer design and main steam line (MSL) velocities for several BWR plants that have received extended power uprates, and it provides post EPU steam dryer experience. HCGS information is included for comparison. Section 2.1 of Reference 3 provides a more complete listing of BWR uprates.

Reactor Type	*Station/Plant Dryer Design*	*MSL Velocities fps*	*EPU Operation*	*Comments*
251BWR 3	Dresden 2, 3 Square hood	OLTP 168 EPU 202	117% OLTP	RV ¼ wave acoustic resonance peaked below OLTP. Failure in the outer hood area.
251BWR 3	Quad Cities 1, 2 Square hood	OLTP 168 EPU 202	117% OLTP	RV ¼ wave acoustic resonance peaked at EPU. Failure in the outer hood area.
205BWR3/4	Vermont Yankee Square hood	OLTP 140 EPU 168	120% OLTP	Steam dryer strengthened before EPU. Onset of RV ¼ wave acoustic resonance between OLTP and EPU.
218BWR 4	Brunswick 1, 2 Slanted hood	OLTP 129 EPU 149	120% OLTP	No cover plate/hood fatigue failures.
218BWR 4	Hatch 1 Slanted hood Hatch 2 Curved hood	OLTP 119 EPU 134 OLTP 121 EPU 140	115% OLTP	No cover plate/hood fatigue failures

Reactor Type	*Station/Plant Dryer Design*	*MSL Velocities fps*	*EPU Operation*	*Comments*
251BWR 4	HCGS Curved hood	CLTP 145 EPU 167	115% CLTP requested	CLTP = 101.4% OLTP

The Brunswick 1,2 and Hatch 1 slanted hood design and the Hatch 2 curved hood have not had any failures that are attributable to EPU based on the information presented in Table 2-2 of Reference 4, Steam Dryer Inspection Results. Hatch 2, like HCGS, has 0.125" inner hoods.

The curved hood design at HCGS was the next stage of steam dryer design. It was used in later BWR 4 units and in BWR 5s and 6s. Similarities with the slanted hood design include 6-foot high dryer vanes, internal, vertical support plates, and elimination of the upper dam. The primary difference is that the curved hood uses a single bent plate rather than four straight plates in forming the hood.

One design drawback of the earlier curved hood design, which applies to the HCGS steam dryer, is that the inner hoods are 0.125-inch thick, whereas the inner hoods on the previous square and slanted hood designs were 0.5-inch thick. This has led to two types of curved hood failures described below.

Per Reference 2, weld joint cracking was found in the weld between the 0.125-inch middle hood and its 0.250-inch end plate at five plants. Cracks at four plants occurred early in plant life, within the first three or four cycles of operation. The weld joints were subsequently reinforced, either by adding reinforcing strips or by adding an additional weld on the inside of the joint inside the hood. The fifth occurrence occurred after about 16 years of operation, the last 9 years at 5% stretch power. This dryer had been reinforced in that weld joint with additional, inside welding except at the upper part of the weld. The cracking occurred in the upper part of the hood where the joint was not reinforced. As stated earlier, this area was reinforced at HCGS on the middle and inner hoods prior to the start of commercial operation by adding the external strips along the entire length of the weld. No failures have occurred at HCGS, and this detail received careful modeling during the HCGS finite element model (FEM) preparation described later.

Per Reference 4, weld joint cracking has also been reported on the curved hood steam outlet end plates. These plates serve as a steam dam that bridges the gap between the vane bank outlet end plate and the next hood. They ensure that the steam exiting the vane banks flows upward into the steam dome rather than laterally. On one side, they overlap the vane bank end plates and are attached to it by a fillet weld. At the other side, they are fillet welded to the outside of the adjacent hood. Since these plates are on the steam outlet, weld cracking would not result in steam bypassing the vane bank. No failures have occurred at HCGS.

HCGS Main Steam Line and Safety Relief Valve Description

HCGS has four 26-inch nominal diameter steam lines in containment. The lines increase to a nominal 28-inch diameter in the Main Steam tunnel outside of the containment.

HCGS has a total of fourteen (14) relief valves on the MSLs. Two MS lines have 4 valves each; two MS lines have 3 valves each. As opposed to earlier plants, the HCGS design has only one type of relief valve. This is the Target Rock 7567F design, which combines the function of a safety relief valve (SRV) to prevent overpressurization and a power operated relief valve to provide controlled depressurization and cooldown. HCGS has collected the required information for detailed analytical modeling of the SRV branch line. The relief valve branch line and relief valve configuration, including heights, are identical at all 14 locations. The configuration is a 26-inch to 8-inch sweepolet fitting, an 8-inch nominal diameter schedule 160 pipe stub, and a flange that bolts up the bottom of the relief valve. The flange serves a second function. The inside diameter (ID) of the reducing flange is tapered to transition from the 6.8-inch to 5.2-inch at the entrance of the SRV. The ID on the inlet of the relief valve is 6.0-inches. The uppermost portion of the SRV chamber is rounded.

HCGS Steam Dryer Evaluation Methodology

Determining Steam Dryer Loading

Previous analysis of main steam line pressure data at other BWRs shows the presence of pressure pulsations at discrete frequencies, which suggests that deterministic mechanisms are active in the MS system. As stated in an ASME Journal of Pressure Vessel Technology article (Reference 5):

> "High velocity flow past a cavity such as the stub of a closed SRV creates vortices which, under the right conditions, can couple with the acoustic resonance of the stub. Thus relatively small vortex pulsations can be amplified...."

In a fluid system with many junctions and branch lines of various lengths and diameters, a strictly analytical approach cannot be relied on to determine if the vortexing across the various branch lines will create acoustic resonance at that branch line, and furthermore, if the acoustic resonance in a branch line is amplified or attenuated by the piping system.

The method used to determine the loading across the HCGS steam dryer due to phenomena in the main steam lines (MSL) is called the Acoustic Circuit Model developed by Continuum Dynamics Incorporated (CDI). This methodology requires sensors mounted on the MSLs to detect and measure plant specific, pressure pulsation loads. The ACM uses a mathematical model of the HCGS main steam system including the steam dome, steam dryer in the reactor pressure vessel, and the MSLs including the sensor locations to calculate steam dryer loads from the measured MSL pressure pulsations. Specifically, the ACM model provides a high-resolution load over a grid mesh of three inch spacing across all surfaces of the steam dryer. The ACM methodology was validated through benchmarking the CDI results against an instrumented steam dryer at Quad Cities 2. Since the ACM uses plant measurements, the dryer loading reflects all sources and does not rely on an analytical approach to determine what the sources are.

The specific ACM load transfer used for HCGS is the "Bounding Pressure" method described in Reference 6. This method is the same that was used for Vermont Yankee during its EPU power ascension testing. All CDI ACM efforts were done under CDI's QA program, which conforms to 10CFR50 Appendix B requirements. HCGS reviewed piping configuration, as modeled in the CDI design record for HCGS. HCGS verified that the appropriate drawings were used and that the correct piping information piping dimensions were obtained from those drawings.

Uncertainty/Bias Evaluation for Steam Dryer Loading:

The uncertainty/bias evaluation for the steam dryer loading considers the uncertainty/bias of the strain gage data inputted into ACM. This is broken down into two items.

a) The strain gage conversion of micro-strain reading to dP:
This was obtained from Reference 7. Note that it conservatively neglects any pipe bending that is not balanced out by the other strain gages.

b) The strain gage location with respect to the benchmarked QC2 location:
Reference 6 section 7.2 provides the formula to calculate the error. This is small for HCGS since the strain gage locations are very similar to QC2.

It also considers the uncertainty/bias of the ACM itself. This is broken down into three items.

c) QC2 steam dryer pressure data measurements:
Reference 8 Table 10 provides the values for the QC2 steam dryer pressure data measurements bias and uncertainty. Note that the reference states a minus 3 to minus 8% range for the bias. The minimal bias is assumed herein for conservatism.

d) ACM bias due to low frequency limitations (0-20Hz):
Reference 8 Table 10 provides the values for the ACM bias due to low frequency limitations (0-20Hz).

e) ACM bias and uncertainty on predicted versus measured QC2 data:
Reference 9 compares the QC2 measured root mean square (RMS) pressure against the QC2 predicted root mean square (RMS) pressure for the 15 pressure measurements on the QC2 outer hoods. It determines the bias as well as the standard deviation (one sigma). This comparison used the range

of frequencies predicted for HCGS, 120Hz and less. The higher frequencies were not used since these are not predicted at HCGS. Also, the evaluation used the P_{RMS} value for comparison since it provides the energy for the signal (i.e., the area under the peak).

The above uncertainties are summarized in the table below. As used herein, a minus bias over predicts the loads and a positive bias under predicts the loads. The individual uncertainties are combined by SRSS. Individual biases are algebraically added.

Term	Item	Bias	Uncertainty
Strain Gage Conversion	a		+/- 7.2%
Strain Gage Location	b		+/- 4.2%
QC2 dryer pressure measurement	c	-3%	+/- 2.9%
ACM low frequency limitation	d	3%	
ACM accuracy	e	-10.8%	+/- 25.7%
Subtotal	a-e	-10.8%	+/- 27.2%

For conservatism, HCGS will not credit the 10.8% bias under prediction, which results in a +/- 27.2% loading uncertainty.

<u>Determining Steam Dryer Stresses (Finite Element Model)</u>

In order to determine the steam dryer stresses due to the pressure pulsations calculated by the ACM, a HCGS plant specific finite element model (FEM) was developed. The HCGS FEM development benefited significantly from the availability on-site of the abandoned steam dryer (intended for HCGS Unit 2). HCGS verified that the abandoned dryer was identical in design and fabrication to the one in use with the exception of the field modifications which were made only to the Unit 1 steam dryer.

Detailed measurements were made of the abandoned HCGS Unit 2 steam dryer supplemented by the available, detailed information on the field modifications. The entire steam dryer was modeled including the skirt and the water at the lower portion of the skirt. HCGS engineers, knowledgeable on the steam dryer, supported the CDI effort by determining the applicable drawings and the steam dryer field modification instructions that were applicable to the HCGS steam dryer.

The FEM was developed by CDI using the ANSYS 10.0 program. All CDI FEM activities were done under CDI's QA program, which conforms to 10CFR50 Appendix B requirements. This includes field measurements made on the Unit 2 abandoned dryer.

The HCGS steam dryer modeling is discussed in References 10 and 14. They discuss the modeling refinements and studies undertaken to optimize the modeling to obtain accurate results while maintaining a reasonable model size. The FEM model received third party review by MPR Associates. The FEMs differ slightly in that Reference 14, the interim EPU FEM, incorporated additional modeling refinements; however, it was judged that the changes were not that significant to warrant rerunning the CLTP FEM from plant data.

Uncertainties on the FEM

The calculated stress values are compared against an allowable alternating stress limit of 13,600 psi, which is the lowest value for stainless steel (Reference 12).

To conservatively estimate the stresses resulting from the inputted loads, the calculated weld stresses were increased by a factor of 1.8 to account for weld uncertainty. In addition, a Raleigh damping ratio of 1% was used for the frequency range between 10 and 150 Hz. This is considered the minimum damping for a welded structure and it results in predicting higher fatigue stresses. For example, assuming only 1% damping results in alternating stresses that are approximately 1.4 times ($\sqrt{2}/\sqrt{1}$) those that would be produced with a credible 2% damping.

The uncertainty on the finite element frequency modeling of the steam dryer components is addressed by varying the measured frequency of the steam dryer loads by up to plus and minus 10% at 2.5% intervals. This also captures any ACM frequency uncertainty. This is done solely for EPU FEMs. It was not done for the CLTP baseline case since satisfactory operation at CLTP has been demonstrated by plant operation and inspections.

Steam Dryer Evaluation Results

Baseline Conditions (100% CLTP)

During RF13 (spring 2006), the HCGS MSLs were instrumented with strain gages at eight locations on vertical runs in the drywell approximating the benchmarked Quad Cities 2 locations. This consists of two locations per MSL approximately 36 feet apart. Each location consisted of four strain gages located at 90° intervals. The 0° and 180° strain gages were wired together and the 90° and 270° strain gages were wired together to obtain an average signal for that location.

The ACM loads for the baseline condition (100% CLTP power) were taken in Spring 2006 and are reported in Reference 11. Prior to the strain gage data being taken, the strain gages on the lower location for the "C" and "D" lines failed. The loading inputted into the HCGS steam dryer is reported in reference 11. It explains how the data taken for the "A" and "B" lines, which are essentially mirror images of the "D" and "A" lines respectively, were used for the failed lines. The report also explains how the phasing between the individual MSL was accounted for.

The CLTP FEM loading assumed the worst case phasing for the "C" and "D" MSL inputs. Reference 11 used data from Susquehanna. Susquehanna and HCGS have the same steam dryer, same steam dome diameter, same MSL diameter, no SRV acoustic resonance, and within 1%, the same steam flow. The primary difference is that Susquehanna has the relief valves on its MSL "A" and "D" mounted of dead legs. CDI determined in section 4.2 of reference 11 that the worst case phasing results in a pressure difference 1.33 times the pressure difference using actual phase data. Reference 16 used the HCGS SMT data. It showed that the worst case phasing adjustment varies with power, but that the average factor is 1.41. The lowest value at 112% CLTP is 1.29. This closely agrees with the Susquehanna data. Note that this bias was not eliminated when the loads were inputted into the CLTP FEM. Therefore the reported dryer stress ratios for the CLTP FEM include this over prediction of ~ 1.30.

The predicted loads from the ACM using plant data at CLTP included a significant load spike at 80 Hz. CDI reviewed their model and determined that the ACM with the HCGS parameters would generate a significant 80 Hz load even when the only input to the HCGS ACM was white noise. PSEG and CDI compared the upper and lower strain gage data and determined that the 80 Hz signal is uncorrelated. PSEG confirmed with Quad Cities that they had similarly had an 80 Hz prediction that they confirmed was not present using plant measurements, including the steam dryer instrumentation. Accordingly, the 80 Hz spike load was eliminated.

Reference 10 is the CLTP FEM analysis using the spring 2006 strain gage data. The table below tabulates the limiting components (stress ratio less than 2.5), as reported in Table 6.3 of Reference 10. The FEM report includes figures that clarify the locations.

Components (all are welds)	Peak stress ratio	Alternating stress ratio
Drain trough vertical plate to drain trough bottom plate	1.54	>2.5
Inner hood to steam outlet end plate	1.60	>2.5
Inner hood to center support (stiffener), junction at bottom	1.79	2.26
Outer hood to its end plates	2.33	>2.5

The stress ratio is obtained by dividing the allowable value by the calculated stress value. The reported stress values include a 1.1 factor to account for differences in the Young's modulus of elasticity, and for welds, it includes a 1.8 multiplier to account for stress intensification in the weld. These stress ratios do not include the 27.2% loading uncertainties (strain gage and ACM), but do include the ~30% over prediction bias due to worst case phasing. Note that the dryer has operated over 20 years, including approximately 3 years at CLTP, with no indication of any fatigue failure.

Interim Analyses for EPU Conditions

The term "interim" is used to designate the evaluations done to predict the EPU loads and stresses based on the SMT results. This differentiates these analyses from the "final" EPU analyses, which will be based on the measured plant loads following power ascension.

HCGS aim was to gain, to the extent reasonably possible, as much information about the potential EPU loading prior to EPU power ascension to minimize the risk and uncertainty during EPU power ascension. The following items were considered:

- Based on Exelon experience at Quad Cities and Dresden, HCGS concluded that the principal risk to the HCGS steam dryer at EPU conditions is from high frequency acoustic loading from the relief valve branch lines. Dresden experienced the peak of this phenomenon below CLTP, and Quad Cites experienced the peak at EPU. HCGS reviewed the discrete frequencies for the CLTP loads and determined that relief valve acoustic response is not present at or below 100% CLTP. This included a review of the strain gage readings at 95.9%, 97.5%, and 100% CLTP power. There is no appreciable change in the overall magnitude and no indication of SRV ¼ wave acoustic resonance[1]. The MSL accelerometers likewise did not detect any discrete frequencies other than those corresponding to the 5x recirculation pump speed. However, available literature indicated that based on the Strouhal number calculated at EPU, SRV ¼ wave acoustic resonance could be anticipated. In addition, the available literature indicates that the loading at the onset conditions is much lower than at peak conditions and that it is dependent on a number of other factors.
- The experience gained on FEM analyses demonstrated that the resulting stresses are dependent not only on the magnitude of the loading, but also on the frequency.

Thus, in order to provide a more meaningful EPU steam dryer analysis prior to EPU power ascension, HCGS undertook a 1/8th scale test with the objectives of (1) determining the HCGS relief valve branch line acoustic frequency and (2) estimating if the onset would be expected at EPU, and if so, the loading at EPU conditions. The small scale test (SMT) was performed by CDI. The CDI SMT was successfully used to test the Quad Cities relief valve mitigation plan.

The HCGS SMT modeled the reactor pressure vessel, steam dryer, four MSLs to the turbine, SRVs (including the spare, blanked location) equalizing rings, and the 10-inches and 12-inches drain pots. The SMT results are provided in Reference 13.

The SMT testing range was 80% CLTP to 145% CLTP. One result was that the onset of the resonance was observed in the SMT below 90% CLTP, which demonstrates that the SMT conservatively bounds actual conditions since plant data shows that it is not

[1] The strain gages can detect the recirculation vane passing frequency (5x motor speed). Some of the strain gages will show a ~ 118 Hz signal when the recirculation pumps are at ~1416 rpm. It was confirmed that this was not SRV acoustic resonance by noting that with a recirculation pump speed change, the suspect indication followed the 5x motor speed.

occurring at 100% CLTP. A second result is that the measured SRV ¼ wave acoustic frequency is 118 Hz. A third result, discussed in Reference 11, is that the peak dryer differential pressures at EPU is 1.57 the CLTP value, and the EPU root mean square (RMS) differential pressure is 1.37 the CLTP value.

Although SRV acoustic resonance is predicted at EPU, the overall loading predicted EPU loading remains relatively small. A comparison of the 115% CLTP HCGS loading predicted by the SMT against the measured Quad Cities 2 loading at 930 MWe (prior to the mitigation effort done spring 2006) determined that the HCGS EPU loading is less than 1/8th of the Quad Cities 2 loading (Reference 15). This comparison is conservative since it did not consider that (a) the HCGS SMT predicts a clear SRV ¼ wave acoustic resonance signal at 90% CLTP, whereas the plant data shows no detectable acoustic resonance at 100% CLTP and (b) based on Reference 11, the SMT predicted loads are significantly higher than measured plant loads, as explained in the following paragraph.

The SMT included MSL pressure transducers to replicate the HCGS strain gage locations. In order to benchmark the SMT results, Reference 11 made a comparison of the ACM low resolution loads at the same power, 100% CLTP, between (a) SMT data and (b) plant data. This showed that the SMT load is significantly higher than the plant data load. The explanation for the difference is that the SMT uses compressed air below 200 psig in the steam delivery system, as opposed to 1020 psia steam, which lowers the damping. In addition, there is no water in the SMT reactor vessel. Section 4.3 of Reference 11 states that the peak differential pressure predicted by the SMT at CLTP is over 4 times higher than the peak pressure at CLTP from plant data, even considering the ~1.30 bias resulting from worst case phasing. The interim EPU FEM load used is the SMT output without any reduction except for eliminating the 80 Hz peak, discussed below. Therefore, the loads used for the interim EPU FEM are considerably higher than the best estimate for EPU.

The loads from the ACM using scale model test results predicted a significant load at 80 Hz. To supplement the earlier discussion on why this is not a valid plant load, the test data for the single pressure transducer on each SMT outer hood, near the MS nozzle connection, was reviewed. It confirmed that there was no 80 Hz load in the SMT steam dome. Accordingly, the 80 Hz spike was eliminated.

The table below tabulates the components with less than a 1.5 stress ratio. The information is extracted from Reference 14 Table 7b. This information is for the nominal (best estimate) frequency case. As with the discussion for the CLTP FEM, the reported stress values include the 1.1 factor to account for differences in the Young's modulus of elasticity, and for welds, it includes a 1.8 multiplier to account for stress intensification in the weld.

Components (all are welds)	Peak Stress ratio	Alternating stress ratio
Drain channel to skirt (at bottom)	1.99	1.09
Outer hood to cover plate	1.41	1.13
Middle hood to steam outlet end plate	> 2.0	1.36
Skirt to upper support ring	1.41	> 2.0
Inner hood to steam outlet end plate	1.42	1.81
Drain trough vertical plate to perforated plate	> 2.0	1.46

Although the margins for the nominal frequency analysis are in some cases not significantly above 1.0, it should be noted that the load inputted into the interim EPU FEM is considerably higher than the best estimate. Therefore, additional margins above 1.00 are not considered necessary.

Reference 14 also discusses the sensitivity run for frequency variation. The sensitivity study covered +/- 10% at 2.5% intervals. The maximum impact occurs at the +10% and at –10%. The impact is due to the frequency shift of the largest single load, the SRV ¼ wave acoustic resonance. At a –10% shift, the major impact is to the welds at the top of the steam outlet end plates; the stress ratio at the limiting location (middle hood to steam outlet end plate) drops to 0.984. Also, the weld at the bottom of the drain channel to skirt drops to a stress ratio of 0.99. At a +10% shift, the major impact is to the weld between the middle hood and its end plates; its stress ratio drops to 0.832. All other reported stress ratios are above 1.00. Additional reviews will be performed to confirm that the conservatisms in the loads are sufficient to ensure that the actual stress ratios remain above 1.00.

<u>EPU Power Ascension</u>

The HCGS interim EPU FEM analysis is not intended to replace monitoring and verification during power ascension. HCGS will record strain gage data during EPU power ascension and review the data against acceptance criteria. This effort will be done at discrete power intervals as described in the PAP.

Prior to EPU power ascension HCGS will repair the failed strain gages.

<u>Additional, CFD Evaluation</u>

HCGS performed an additional analysis using computational fluid dynamics (CFD) model. This is a mathematical model that includes the flow from the outlet of the steam separators, thru the steam dryer and reactor dome, and into the MS nozzles. This methodology relies upon first principles and very fine computational detail to generate a model of the fluid flow within the reactor steam dome.

HCGS reviewed the results from the CFD analyses for CLTP and EPU to determine if there are any significant changes in the flow patterns due to operation at the higher power. The results are that the CLTP model predicts that there is vortexing at the inlet of the MS nozzles that increases in strength, as expected, at EPU. No new flow phenomenon was indicated. As discussed earlier, the HCGS steam dryer design is a curved hood that minimizes turbulence as compared to the square hood. Also, the curved hood design does not have any external gussets or square edges that would create added turbulence at the locations of peak velocity in the steam dome, the entrance of the MS nozzles.

The CFD evaluation is considered by HCGS qualitative only since it has not been benchmarked nor is it considered practical to do so. In addition, it was not performed by a vendor with a QA program that conformed to 10CFR50 Appendix B.

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15. CDI Technical Memo 06-23P (Proprietary), "Comparison of The Hope Creek and Quad Cities Steam Dryer Loads at EPU Conditions," Revision 0, dated September 2006.

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HOPE CREEK GENERATING STATION
FACILITY OPERATING LICENSE NPF-57
DOCKET NO. 50-354

REQUEST FOR LICENSE AMENDMENT
EXTENDED POWER UPRATE
FLOW INDUCED VIBRATION

1 Introduction:

Section 2.0 of this attachment summarizes in the susceptibility review to determine systems and components susceptible to flow induced vibration (FIV) increases at Extended Power Uprate (EPU) conditions. Section 3.0 summarizes the remote monitoring program that measured the actual vibration levels on key systems at the current licensed thermal power (CLTP) and that will be used to monitor vibration at the uprated power and compare them against acceptance criteria. Section 4.0 reports the results for each system or subsystem that will see a significant increase of flow at the uprated power. Section 4.0 includes actions completed or currently planned.

2 Susceptibility Review:

The susceptibility review leverages a number of inputs including engineering judgment, operating experience (OE) reports, and earlier EPU reports/submittal to identify susceptible components in the susceptible systems.

2.1 Susceptible Systems:

The systems that will see a significant increase in flow at EPU, and accordingly, may be susceptible for higher FIV are:

- Main Steam (MS)
- Feed Water (FW)
- Extraction Steam
- Moisture Separator and Feed Water Heater (FWH) drain lines
- Condensate

Recirculation flow will not be significantly increased during EPU operation, which requires only a small increase in recirculation flow rates. Consequently FIV levels of the recirculation system components are expected to remain essentially the same.

Other systems will see either no increase or a negligible increase in flow.

2.2 Susceptible Components:

The following types of components on affected systems were considered susceptible:

- Small bore branch lines connections/fittings to main headers. In the case of the MS line, this includes EHC system lines connected to the turbine stop and control valves.

- Main header cantilevered components, e.g., relief valves.

- Rigid connections between a vibrating component and its electrical or pneumatic service (e.g., air-lines to Air Operated Valves (AOVs), electrical conduits to Solenoid Operated Valves (SOVs)).

- Valves/components mounted on vibrating lines.

- In-line components that will see increased vibration as a result of flow past or through that component (e.g., heat exchanger tubing, sample probes, expansion joints, thermowells).

- Condensate and FW pumps if operating further from their optimal design point.

2.3 Susceptibility Review Methodology:

The three key sources HCGS used to select the components potentially susceptible to damage due to higher vibration levels at EPU are discussed below.

2.3.1 Industry Reports:

To determine the more susceptible components in affected systems a review of industry OEs and BWR OG lessons learned for FIV failures was performed. HCGS continuously screens OEs for FIV issues. OEs issued as of first quarter 2006 have been screened. In addition, the project reviewed NEDO-33159 Reference 1, which is the BWR Owners Group review of OEs and evaluations from BWR plants that have previously implemented EPU. The project also reviewed detailed EPU FIV evaluations for Quad Cities and Dresden. The results are tabulated on Table 1 and discussed below.

The most significant grouping resulted from steam dryer and MS line vibration problems. All significant MS line and steam dryer EPU FIV OEs originated from the Quad Cities and Dresden plants. These plants have high vibration pre-EPU. The MS line vibration levels were drastically reduced and generally trended with ρV^2 following the modification done at Quad Cities 2 in April 2006 that essentially eliminated relief valve acoustic resonance. The results clearly demonstrate that the cause of the high MS line vibration was due to relief valve standpipe acoustic resonance.

Another significant source of EPU FIV OEs were turbine EHC lines attached to the MS lines. The units reporting problems were not limited to those with the abnormal MS line vibrations.

Several units reported a failure of the sockolet fitting attaching a small bore line to the main header. The fix is typically to change the taper of the weld to reduce the stress in the socket weld.

The fourth significant grouping involved FWH problems. However, these were assorted problems due to higher flow (rather than FIV). Nevertheless, the OEs identified the need to carefully scrutinize FWHs for EPU flow impact.

2.3.2 HCGS Interviews:

Interviews were completed to identify flow problems, including FIV that may be causing hanger problems following the 2004 moisture separator (M/S) dump line failure,.

Additional interviews with plant operators were completed in May 2006 that targeted FIV problems in the MS, FW, extraction steam, FWH and M/S level control, and condensate systems to identify any existing FIV degradation or problems at CLTP. The objective was to identify existing vulnerabilities that may be exacerbated by higher flows at EPU. The BWR OG evaluation noted that many of the problems following EPU were already present at CLTP.

2.3.3 HCGS Walkdowns and Reviews:

Experienced pipe stress engineering personnel performed walkdowns during the RF13 outage and drawing reviews of impacted systems to look for vulnerable configurations. The walkdowns included the drywell, steam tunnel, FWH rooms, turbine area, and RFP rooms. In addition, the information from the extensive hanger walkdowns done in late 2004 was reviewed.

3 Remote Monitoring Program for Piping:

The MS, FW, and recirculation piping inside the drywell and the MS and FW piping inside the steam tunnel are inaccessible during normal plant operation. Therefore, remote vibration monitoring was installed to monitor the steady state vibration levels of these piping systems. Instruments, which are hardwired to remote, stand-alone digital data acquisition systems (DAS), are mounted on the outside of the piping, located outside the drywell. Accelerometers were selected to monitor the steady state vibration levels due to their ease of installation. This program conforms to the guidance of ASME OM-S/G-1994 Reference 2, part 3, for vibration monitoring group (VMG) 1 piping. The installation of the instrumentation and monitoring system occurred during the 12th refueling outage (RF12, October 2004).

3.1 Sensor Locations:

The accelerometer locations on this piping were selected based on detailed analyses of the piping, which identifies the resonance frequencies for the piping, correlates vibration levels to FIV stress levels, and establishes the maximum allowed vibration (i.e., acceptance criteria). To determine the accelerometer locations, models of the piping were created, using PIPESTRESS which represents the dynamic characteristics of each monitored line. To provide the maximum number of natural frequencies with the minimum number of instruments, modal analyses of the piping systems were performed. Minimizing the number of instruments minimizes ALARA exposure to radiation associated with instrument installation and electrical cable routing inside containment.

Table 2 lists the remotely monitored locations. Each sensor measures the acceleration in one direction. The directions and locations are selected based on the results of the modal analysis. The lower modes of a piping system typically govern the response. To measure the vibration response of the piping system to increased flow, the directions and locations should correspond to locations that are expected to see the maximum response of the piping system. The directions were selected to coincide with locations of high response and the maximum modal displacement (e.g., where the mode shape normalizes to one, based on the maximum modal displacement). In the unexpected event that one accelerometer fails, the data from the other accelerometers can still be used to determine the response of the piping system.

3.2 Acceptance Criteria:

Acceptance criteria were developed for each of the measurement locations for the MS, FW, and extraction steam piping systems. This is the maximum allowed, measured vibration level at that location. The acceptance criterion is based on the guidance of ASME OM S/G Part 3 (Reference 2), which states that the calculated stress shall not exceed S_{el}/α. The equation from OM Part 3 for the stress criteria is given below:

$$S_{alt} = \frac{C_2 K_2}{Z} M \leq S_{el} / \alpha$$

Where

S_{alt}	=	Alternating stress as defined in ASME Code (NB-3600)
C_2	=	Secondary stress index as defined in ASME Code
K_2	=	Local stress index as defined in ASME Code
M	=	Maximum zero to peak dynamic moment loading due to vibration only
Z	=	Section modulus of the pipe
S_{el}	=	$0.8S_A$, where S_A is the alternating stress at 10^6 cycles from Figure I-9.1 of Section III of the ASME Code (Reference 3) for carbon steel
α	=	Allowable stress reduction factor, 1.3 for carbon steel

For carbon steel pipe, S_A = 12,500 psi, thus, the maximum allowed stress due to steady state vibration is 0.8*12,500 psi /1.3 = 7692 psi.

Since the forcing function can occur over a range of frequencies, a broad band amplified response spectra (ARS) was inputted into the PIPESTRESS model developed for each of the piping systems. The displacements, accelerations, and stresses due to the broad band ARS in each of the three orthogonal directions were calculated at each node of the piping system. The total response was obtained by combining the results from each of the three directions by the SRSS method. The acceptance criteria for the measured accelerations was determined by multiplying the calculated acceleration at each sensor location in a unit load analysis by the ratio of the allowable steady state stress to the maximum calculated stress in the piping system. This ensures that the maximum steady state stress for each piping system does not exceed the OM Part 3.

3.3 Data Acquisition

Dynamic data was acquired via Structural Integrity Associates' Vibration Data Acquisition System (VDAS). This system was comprised of Endevco Signal Conditioners, National Instruments SCXI components, a personal computer, and SI's VDAS software (coded using National Instruments LabView software).

Digital signals were acquired at 1024 samples-per-second (sps) per channel for each power level during the February 2005 power ascension. The data acquisition time was 120 seconds for each power level. This acquisition duration and sample rate is deemed adequate for collecting steady state vibration data.

3.4 Data Reduction Methodology

Data reduction tasks were accomplished using a custom data processing program written in MatLab. The data reduction analysis consisted of creating filtered acceleration time histories, generation of frequency spectra and the calculation of acceleration, velocity and displacement time history characteristics; such as overall root-mean-squared (RMS) and maxima/minima for each power level. Additionally, during power ascension, a data trend analysis was performed that assessed overall RMS acceleration and strain trends versus power level.

The first step in the data reduction procedure was filtering each vibration time history. Each time signal was filtered using a 2-200 Hz Chebyshev bandpass filter, which allowed frequencies between 2-200 Hz to pass. A 5^{th} order Chebyshev filter was used because of its high roll-off characteristics outside the frequency range. Second, each time signal was evaluated for time history characteristics, such as overall minima, maxima and RMS values at each power level. Then, the time histories were converted from the time domain to the frequency domain using a Fast Fourier Transform (FFT) algorithm.

Data reduction and evaluation of the steady state vibration data was performed for data collected during the power ascension immediately following completion of RF12. The numerical results are discussed in section 4.0 under the applicable systems.

4 Discussion of Results for Susceptible Systems

4.1 Main Steam (MS) System:

4.1.1 MS Piping Vibration at CLTP

The MS piping merits the highest level of monitoring since it has a significant increase in flow, has four attachments to the reactor pressure vessel, and has a significant length of the high energy piping. The monitoring program for the MS drywell and steam tunnel piping follows Reference 2, part 3, VMG 1 requirements.

Due to the similar piping routing of the four MS lines, only the "A" and "B" lines were instrumented. The "C" and "D" lines inside the drywell (DW) are a mirror image of "B" and "A", respectively. The routing of all four MS lines outside containment is similar. The RCIC steam supply line inside the DW and MS Safety Relief Valves (SRV) "P" & "J" discharge piping were chosen to be monitored, representative of MS branch line connections. The MS DW scope monitors eight locations using 18 accelerometers. The MS steam tunnel scope monitors four locations using 10 accelerometers.

For the purposes of this discussion, the potential sources of MS piping vibration are: (1) vibration due to steam flow turbulence in the MS lines that trends with the dynamic flow parameter, ρv^2, (2) vibration transmitted by common supports or structures from the reactor recirculation system to the MS piping, and (3) vibration from pressure pulsations within the MS lines that are due to acoustic resonance from relatively short dead legs such as for the HCGS safety relief valves (SRV).

In the spring of 2005, HCGS recorded the 100% CLTP baseline vibration data. Tables 3 and 4 provide the recorded vibration acceleration levels in g- root mean square (rms) for the MS piping with the recirculation pumps at nominal and maximum speed, respectively. All recorded MS vibration levels are well below 0.1 g-rms. Tables 3 and 4 also provide the measured vibrations as a percentage of the allowable vibration.

The most limiting MS DW value (Node 22J, Z) with recirculation pumps at nominal speed is 18.8% of allowable. Many locations show a nominal increase in vibration level when the recirculation pumps go from nominal speed to maximum speed. Only one MS DW location (Node 460, Z) sees a significant increase. It goes from 11.7% to 21.9% of allowable. Figure 1 shows the frequency spectrum plot for node number 460Z. A review of this spectrum shows that the only discrete frequency responses occur at harmonics of the recirculation pump speeds. This is attributed to the fact that the pipe supports for both the MS and reactor recirculation piping systems are connected to the same secondary steel, thus, the recirculation pump vane passing frequency is being transmitted through the structure and is seen as a response in the MS piping accelerometers. Two discrete frequencies are visible at 100% power, corresponding to the 5th harmonic (5X) of the recirculation pumps. Recirculation loops A and B pumps were operating at 1480 and 1510 rpm, respectively. Other discrete frequencies with far lower peak values were also observed corresponding to multiples of pump speed or hardware resonances within the system.

Review of the 100% CLTP plant vibration data shows that none of the MS piping has any indication of a frequency spike due to dead leg acoustic resonance. This is also supported by the 100% CLTP MS strain gage data.

The most limiting MS steam tunnel value is 27.0% of the fatigue allowable, node Z018, Y. Figure 3 shows the frequency spectrum plot for node Z018. A review of this spectrum does not show any recirculation pump harmonics. A review of the other MS steam tunnel data shows that the recirculation pump speed has little to no impact on the MS steam tunnel piping vibration levels.

These CLTP baseline values demonstrate significant margin to accommodate EPU increases.

4.1.2 MS Piping Vibration at EPU

Since the EPU velocity will be 1.164 times the value at CLTP, the EPU piping vibration due to the dynamic flow parameter, ρv^2, would be expected to equal 1.36 of the CLTP value. Since the portion due to recirculation pump vibration is not expected to increase at EPU, Table 5 provides the estimated vibration for the DW piping at CLTP due to ρv^2 alone. It was calculated by filtering out the known recirculation pump frequency spikes from the recorded data. The average ρv^2 value at CLTP for the 26" MS DW piping is 0.035 g-rms, which would increase to 0.048 g-rms at EPU, resulting in a 0.013 g-rms increase.

Due to the possibility of dead leg acoustic resonance, a flow phenomenon that could increase with power much higher than ρv^2, HCGS performed scale model testing (SMT) to identify the potential for dead leg acoustic resonance between CLTP and EPU conditions to reduce the uncertainty during power ascension. This testing is detailed in Reference 4. Briefly, the conclusion of the testing is that SRV acoustic resonance is anticipated at EPU conditions at a frequency of 118 Hz. Although the testing was designed to determine the impact on steam dryer loading and not on the MSL vibration, it provided data that the pressure pulsations in the MSL would only go up by 37% between CLTP and EPU, suggesting that the SRV resonance will not have a significant impact.

Overall, it is judged that the EPU vibration would be less than twice the CLTP vibration. Table 4, CLTP vibration with the recirculation pumps at maximum speed, shows that the DW MS piping can accept over a four-fold increase in vibration and remain within the acceptance criteria. The steam tunnel MS piping can accept just under a four-fold increase.

4.1.3 MS System Component Review

Due to the critical nature of the SRVs, the original qualification report, which includes the testing for operating vibration levels, was reviewed by MPR, reference 5. MPR was selected based on their experience with the Quad Cities electromatic relief valves (ERVs). The MPR review factored in the measured CLTP vibration levels and the results of the CDI small-scale test for EPU conditions. The results are that the overall vibration levels at CLTP are low and are expected to remain acceptable for the valve body. It also identified that the HCGS actuators were well constructed compared to the actuators that failed at Quad Cities. However, the MPR review identified that the original GE testing identified three lowly damped modes in the pilot valve assembly at 103, 110, and 128 Hz. . While these frequencies do not match the SRV ¼ wave acoustic resonance frequency, 118 Hz, predicted by the SMT, low damped modes could result in high amplification factors if the valves were excited at that frequency. Therefore, HCGS will instrument SRV pilot valve assemblies to verify no significant vibration at EPU conditions.

The walkdowns and review of the original SRV qualification report confirmed that the as-installed configuration matches the as-tested configuration, with the clarification that the vibration testing did not include the discharge piping. To minimize vibration concerns the HCGS SRVs air-lines to the air-operated pilot valves use flexible hoses and the electrical power to the solenoid operated valves uses flexible conduits. This is in conformance with the original testing for these valves.

HCGS small bore MS lines were reviewed by experienced piping design engineers during RF13 since small bore lines attached to the main headers may experience higher vibration than the main headers. These engineers reviewed how the main header piping was supported to determine the areas of greater susceptibility to vibration, reviewed the small bore drawings, and performed walkdowns. It should be noted that HCGS has detailed small bore drawings for all MS connections. The engineering effort included consideration of the connection (e.g., sockolet) for the small diameter branch lines that the operating experience (OE) reports indicated to be a weak link. This effort determined that MS piping in the vicinity of the Turbine Stop Valve (TSV) and Turbine Control Valve (TCV) is designed to be flexible, so as to accommodate valve closure transients. Accordingly hydraulic snubbers are used to limit movement rather than more rigid supports. Consequently, the MS small bore lines in the vicinity of the TSVs and TCVs are considered the most vulnerable to higher vibration. Additional engineering effort will determine if these small bore lines are acceptable as-is, require added support (e.g., tie-backs), or require sockolet weld re-enforcement. None of the small bore piping in the drywell was judged susceptible to higher FIV.

For the same reasons, the turbine EHC system connections to the TSVs and TCVs were screened as a FIV concern. The review of the OE reports likewise indicated that EHC connections could be a FIV problem. Additional engineering effort will determine if the EHC connections are acceptable as-is or should be replaced with flexible hoses.

Based on OE reports for sample probes, in-line probes that have a significant protrusion into the flow stream were reviewed for FIV. HCGS has one pair of fluid sample probes in the "C" MS line at opposite sides of the piping, a thermowell (1004A-D) in each MS line, and an additional thermowell (N040) in the "A" line. These are located in the 28" piping downstream of the MS Stop Valve, which will have steam velocities ~ 147 fps at EPU. The thermowells and sample probes have a similar design. They are fabricated of forged bar material with a tapered OD. Specifically:

- The two identical sample probes (AB-SE-1025A,B) are inserted 9" into the flow stream The OD along the length protruding into the flow stream is tapered from 1.95" down to 0.950".

- The 1004A-D thermowells are inserted 7.5" into the flow stream. The OD along the length protruding into the flow stream is tapered from 1.50" down to 1.00".

- The single N040 thermowell is inserted 4.7" into the flow stream. The OD is tapered from 1.0 to 0.5 inches

Although the tapered design provides greater vibration resistance than a straight probe, the initial screening for the MS sample probe and thermowells was judged inconclusive. Detailed analyses are in progress. If the detailed analyses are not conclusive that these probes are satisfactory, they will be modified prior to EPU operation.

The following MS system work that supports the EPU effort is planned and will be complete to support EPU power ascension:

- MS small bore connections in the vicinity of the TSV and TCVs will receive further evaluations to justify as-is, or alternatively, they will be modified to improve vibration resistance. Modifications may include strengthening of the sockolet welds or improvements in the supports. This includes the EHC connections.

- The MS thermowells and sample probe detailed analyses will be completed. If necessary, the components will be modified. If modification is required, shortening the penetration length is the most likely solution since significant moisture or temperature stratification is not likely in the MS lines.

- Instrument SRV pilot valve assembly (or assemblies, as required) and monitor during EPU power ascension to verify no significant vibration at EPU conditions.

4.2 Feedwater (FW) System:

4.2.1 FW Piping Vibration at CLTP

The monitoring program for the FW system in the drywell and the steam tunnel follows Reference 2, part 3, VMG 1 requirements since the system has a significant increase in flow, has six attachments to the reactor pressure vessel, and has a significant amount of the high energy piping.

Due to the similar piping routing of the two FW lines, only one of the two is monitored. The drywell scope monitors five FW locations using 12 accelerometers. The steam tunnel scope monitors two locations using 4 accelerometers (see Table 2 for locations).

For the purposes of this discussion, the potential sources of FW piping vibration are: (1) vibration due to water flow turbulence in the FW lines, which trends with the dynamic flow parameter, ρv^2, (2) vibration transmitted by common supports or structures from the reactor recirculation system and potentially from the MS system due to SRV acoustic resonance.

In the spring of 2005, HCGS recorded the 100% CLTP baseline vibration data. Tables 3 and 4 provide the vibration levels for the FW piping at 100% CLTP with the recirculation pumps at nominal and maximum speed, respectively. Although some values in Table 4 are close to 0.1 g-rms, all recorded FW vibration levels are below 0.1 g-rms. In addition, Tables 3 and 4 also provide the measured vibration as a percentage of the allowable vibration.

The most limiting FW DW value (Node 280, Z) with the recirculation pumps at nominal speed is 23.4%. When the recirculation pumps go from nominal speed to maximum speed, the vibration at a number of locations increases. The location most affected (Node Z002, Z) goes from 14.2% to 30.6%. Figure 2 shows the frequency spectrum plot for FW node number Z002Z. A review of this spectrum shows that the only response occurs at harmonics of the recirculation pump speeds. This is attributed to the fact that the pipe supports for both the FW and reactor recirculation piping systems are connected to the same secondary steel, thus, the recirculation pump vane passing frequency is being transmitted through the structure and is seen as a response in the FW piping accelerometers. Two discrete frequencies are visible at 100% power, corresponding to the 5th harmonic (5X) of the recirculation pumps. Recirculation loops A and B pumps were operating at 1480 and 1510 rpm, respectively. Other discrete frequencies with far lower peak values were also observed corresponding to multiples of pump speed or hardware resonances within the system. The limiting locations are on the 12" headers. The FW valves inside containment are on the 24" headers, which experience lower vibration levels.

The most limiting value (Node 731, X) for the FW piping in the steam tunnel is only 3.2%. This is with the recirculation pumps at maximum speed, but the recirculation pump speed impact is very small.

The CLTP baseline values demonstrate significant margin to accommodate EPU increases.

4.2.2 FW Piping Vibration at EPU

The FW will see a nominal 16.4% flow increase at EPU. The EPU vibration due to the ρv^2 is estimated to equal 1.36 of the CLTP value. However, as can be seen from Table 5, the CLTP ρv^2 component for the DW FW piping is small, less than 0.04 g-rms. Thus the expected increase is not large.

The portion due to recirculation pump vibration is not expected to increase at EPU.

Overall, it is judged that the FW EPU vibration, at the limiting location, would be marginally above the CLTP vibration. Table 4, CLTP vibration with the recirculation pumps at maximum speed, shows that the DW FW piping can accept over a three-fold increase in vibration and remain within the acceptance criteria.

The steam tunnel FW piping has nearly a 16-fold margin.

4.2.3 FW Component Susceptibility

Small bore lines attached to the FW headers were reviewed by experienced piping design engineers during RF13 (spring 2006). These engineers reviewed how the piping was supported to determine the more susceptible areas, reviewed the small bore drawings, and performed walkdowns. It should be noted that HCGS has detailed small bore drawings for all these FW connections. None of the FW small bore branch lines were considered susceptible to higher EPU vibration.

The FW system piping connected to the reactor feed pump (RFP) can be affected by changes in the RFP vibration. The review for RFP vibration is included with the condensate system review for condensate pump vibrations.

HCGS has only one FW sample probe, located on the common 30" header downstream of the 6th point FWHs. The probe is fabricated from 1.5" diameter solid bar forged steel. The OD along the 8.7" length protruding into the flow stream is tapered down from 1.5" to 1.0". The ID of the sample probe is 0.406". Based on a review of existing calculations, the frequency ratio (excitation frequency/natural frequency) at a flow velocity of 22 fps (115% CLTP) remains well below the original design criteria of $\leq$ 0.80. This is the only balance of plant (BOP) sample probe that, if broken, would have the potential to damage the reactor vessel FW sparger.

With the exception of thermowells N041A-D, the protrusion length for the FW thermowells in the large bore piping is 2.5-inches, and the protrusion length is tapered from 1.5-inches to 1.0 inch. Due to their short protrusion, they are not considered susceptible. The N041A-D thermowells are on the FW flow nozzles and have a 4.2" protrusion; detailed analysis is in progress to determine if any modification is required.

The HCGS design consists of the 1st through 5th point FWHs upstream of the RFP and the 6th point FWH downstream of the RFP. Each FWH point has three parallel FWH trains. The original FWH design criterion was to allow full OLTP operation with only 2 of the 3 FWH trains in service. The original equipment manufacturer (OEM) evaluated the FWHs for EPU conditions, including a review of the tubing vibration susceptibility. The OEM evaluation concluded that EPU flows would not cause tube vibrations. However, this analysis was based on all 3 FWH trains in operation. Additional effort will be undertaken to define the power limits with a FWH out of service.

The FWH isolation and bypass valves are motor operated valves (MOVs). The walkdowns performed during RF13 confirmed that the electrical power to the motors uses flexible conduit at the valve connection, which is typical of the HCGS MOVs.

4.3 Extraction Steam System:

4.3.1 Extraction Steam Piping

The extraction steam to the 6th point FWH is instrumented in conformance to Reference 2, part 3, VMG 1 requirements since it has a relatively high steam pressure. The configuration of the extraction steam system is not symmetric so additional locations were selected to be able to capture the dynamic response of the piping system. A total of four locations were monitored with 10 accelerometers. In the spring of 2005, HCGS obtained the baseline vibration data (see Tables 3 and 4). The measured acceleration was between 0.017 and 0.026 g-rms. The average vibration levels at 100% CLTP was 0.021 g-rms. Although the average vibration level is low, the extraction steam piping is not safety related and not supported to resist dynamic motions (e.g., seismic). Accordingly the piping itself is less resistant to FIV. The limiting location was at 46% of allowable. A review of this extraction steam spectrum confirms that, as expected, no acoustic phenomenon or recirculation pump vibrations exist in this piping system. Refer to Figure 5 for a typical extraction steam spectra plot.

The remaining extraction steam lines will follow the guidance of Reference 2, part 3, for VMG 3 piping. The 1st to 5th point extraction steam lines, although important to power generation, do not have a safety significance in case of failure, have not had FIV concerns at CLTP, and are low pressure.

4.3.2 Extraction Steam Components

A FIV evaluation was performed on the extraction steam expansion joints using Expansion Joint Manufacturers Association standards. The expansion joints on the 1st and 2nd point FWHs were judged inadequate for EPU conditions. They were replaced as part of the LP turbine replacement (Fall 2004).

4.4 Moisture Separator (M/S) and FWH Drain Lines

The M/S and FWH level control lines will follow the guidance of Reference 2, part 3, for VMG 3 piping. These lines although important to power generation, do not have a safety significance in case of failure, have not had FIV concerns at CLTP except as noted below, and are low pressure.

HCGS had a pipe break in October 2004 of the "A" M/S dump valve line to the condenser. A precursor to this event was vibration that caused a hanger rod to unthread from its eye nut. Following this event, an "Extent of Condition" evaluation was performed. This included a walkdown on all BOP steam and high energy piping systems by inservice inspection (ISI) personnel, and a hand-over-hand validation by design engineers for the following systems:

- FW Heater Vents and Drains
- Moisture Separator Vent and Drains
- Extraction Steam

The result of this evaluation at HCGS was that there were no pervasive hanger deficiencies and no other indication of FIV damage to hangers in these systems.

Based on reviews, FWH level control lines have not experienced any significant vibration at CLTP except for the 6A FWH flow to the 5A FWH line, which has been a recent problem. Examination in RF13 confirmed that failure of the 5A FWH level control valve was the cause; the disc had separated from the stem causing flow pulsations and, consequently, line vibration. It was replaced with an improved design in RF13. The same valve upgrade is planned for 6B FWH to 5B FWH and 6C to 5C in RF14.

4.5 Condensate:

The condensate piping will follow the guidance of Reference 2, part 3, for VMG 3 piping. The condensate system, although important to power generation, does not have a safety significance in case of failure, has not had FIV concerns at CLTP, and is low pressure. The FIV levels must consider both the increase in piping FIV and the impact on the operating point of the condensate pumps.

The plants that reported condensate system (including RFP suction piping) vibration concerns following EPU had a condensate and reactor FW pump configuration that resulted in these pumps operating further below their Best Efficiency Point (BEP) at EPU. The design of these plants maintained at OLTP one of each type of pumps off-line, whereas at EPU all condensate and RFPs were placed in operation. In contrast HCGS already operates with all 3 RFPs, 3 Secondary Condensate Pumps (SCP), and 3 Primary Condensate Pumps (PCP) in-service. The pumps' BEP versus power are summarized below. The information accounts for current, benchmarked pump performance as opposed to new pump performance.

	CLTP	115% CLTP	ANSI/HI 9.6.3-1997 Guidelines
PCP	78%	92%	80 to 115%
SCP	90%	107%	70 to 120%
RFP	77%	94%	70 to 120%

The PCP and RFP will be significantly closer to their BEP. The SCP will go from 10% below to 7% above its BEP. All pumps will operate well within the ANSI/HI 9.6.3-1997 guidelines at EPU flows.

The pump minimum flow recirculation lines and valves for the condensate and reactor feed pumps are not impacted by EPU. The same flow setpoints, measured in gpm, are maintained. Thus, the pumps' recirculation flow conditions are not changed by the power uprate.

HCGS has the condensate system sample probes listed below. All probes were fabricated from 1.5" diameter solid bar material. The OD along the length protruding into the flow stream is tapered from 1.5" down to 1.0". The ID is 0.406". Based on a review of existing calculations, the frequency ratio (excitation frequency/natural frequency) at 115% CLTP remains well below the original design criteria of ≤ 0.80.

Quantity	Pipe nominal diameter & location	Insertion depth (ins)	Velocity (fps)
One	38" Condensate Pre-Filter influent hdr	12.9	10.6
One	32" Condensate Pre-Filter Outlet hdr	11.6	15.3
One	36" Condensate Demin Inlet hdr	12.9	11.9
Seven	16" Condensate Demin Vessel Outlet line	5.9	10.2
One	38" Condensate Demin Discharge hdr	12.9	10.6
Three	16" 3rd Point FWH to 2nd Point FWH line	5.9	11.2

The protrusion length for the condensate thermowells is 2.5-inches, and it is tapered from 1.5-inches to 1.0 inch. Due to their short protrusion, they are not considered susceptible.

Table 1
Summary of FIV and Flow Issues from OEs

Unit	RV Acoustic Phenomena reported?	Dryer Failure reported?	FIV failures reported:	Other EPU flow concern reported:
Hatch 1 & 2	No	No	None	FWH level problem due to instrument sensing line depth
KKL	No	No	None	None
KKM	No	No	None	None
Clinton	No	No (but an existing crack propagated)	None	Condensate demin shortcomings (dP and flow); Power limitations with a FWH OOS not evaluated.
Brunswick 1 & 2	No	No	EHC Accumulator seals & EHC TCV drain line fitting failures.	
Duane Arnold	No	No	Increased frequency of EHC accumulator losing charge.	Increased wastage rate on two FWHs at extraction steam inlet
Dresden 2 & 3	Yes, but already peaked before 100% OLTP, magnitude decreased at EPU. MSL FIV decreased at EPU.	Yes (cracks)	RFP relief valve failure at pipe connection. Four condensate or FW sample probes failed.	Dresden and Quad Cities: EPU required all RFPs and condensate pumps to operate (eliminating standby pumps). This caused the pumps to operate further below their BEP increasing vibration levels. Minimum flow lines adversely impacted by operation with added pumps.
Quad Cities 1 & 2	Yes, increased between OLTP and EPU. QC2 mitigated April 2006.	Yes (loose parts). Steam dryers replaced.	MSL ERV, ML drain line, TCV EHC accumulator leaks, TBCCW line to condensate booster pump failed.	
Monticello	No	No	None	None
Fitzpatrick (Stretch power)	No	No	Sockolet failure on zinc injection line to FW; FWH level control valve high vibration (broken air-lines, valve yokes, valve internal welds)	
Limerick (Stretch power)	No	No	None	Broken FWH extraction steam inlet plate due to fabrication defects
LaSalle (Stretch power)	No	No	Multiple FWH tube leaks due to vibration	
Vermont Yankee	N/A: Info based on EPU susceptibility review.		Will proactively 2/1 taper MSL drain sockolet and add flex lines to FWH AOVs	

Table 2
Accelerometer Locations

1. **MS inside the Drywell**
   a. M/S line A, between inboard MSIV and drywell penetration (node 081); Accelerometers in x and y

   b. M/S line A, on vertical run after first elbow outside of RPV (node 014); Accelerometers in x and z

   c. 4" RCIC outlet line near 26" M/S line A (node 430) - MS Branch connection; Accelerometers in y and z

   d. M/S line A, on SRV "J" line (node 022j); Accelerometers in x and z

   e. M/S line B, on vertical run before last elbow before inboard MSIV (node 534); Accelerometers in x and y

   f. M/S line B, between SRVs "K" and "B" (node 490); Accelerometers in y and z

   g. M/S line B, on vertical run after first elbow outside of RPV (node 460); Accelerometers in x, y and z

   h. M/S line B, on SRV "P" line (node 040p); Accelerometers in x, y and z

2. **FW inside the Drywell**
   a. 12" FW line B, N4C branch just past the reducer after the N4B branch (node 160) Accelerometers in x and y

   b. 12" FW line B, N4C branch just past the elbow after the N4B branch (node z002) Accelerometers in x, y and z

   c. 12" FW line B, N4B branch 27 inches past the reducer after the N4A branch (node 280); Accelerometers in x and z

   d. 12" FW line B, N4A branch on the upward sloping section (node 220); Accelerometers in x and y

   e. 24" FW line B, prior to N4A branch (node 50); Accelerometers in x, y and z

3. **MS inside the Turbine Building Steam Tunnel**
   a. 28" M/S "A" between outboard MSIV and equalizing header (node z013); Accelerometers in x and y

   b. 28" M/S "A" between equalizing header and turbine stop valves (node z018); Accelerometers in x, y and z

c. 28" M/S "B" between outboard MSIV and equalizing header (node z003); Accelerometers in x and y

d. 28" M/S "B" between equalizing header and turbine stop valves (node z008); Accelerometers in x, y and z

4. FW inside the Turbine Building Steam Tunnel

a. 24" FW "A"3.3 feet downstream from hanger AE-013-H62 (node 817); Accelerometers in y and z

b. 24" FW "A" 24 feet upstream from header (node 731); Accelerometers in x and y

5. Extraction Steam inside the Turbine Building

a. 14" extraction steam line on the horizontal run prior to elbow and riser to FWH 6C (node z008); Accelerometers in x, y and z

b. 14" extraction steam line on the horizontal run prior to 2nd elbow and riser to FWH 6A (node 046); Accelerometers in x and y

c. 14" extraction steam line on the horizontal run just past 3rd elbow prior to riser to FWH 6B (node 230g); Accelerometers in x and y

d. 14" extraction steam line on the horizontal run 35 feet prior to 3rd elbow prior to riser to FWH 6B (node z010); Accelerometers in x, y and z

Table 3 CLTP Recorded Values
At Normal Recirculation Pump Speed

		Acceptance Criteria g-rms			Actual values at **normal** recirc pump speed g-rms*			Actual values divided by acceptance criteria %		
Inside Drywell	Node	Xg	Yg		Xg	Yg	Zg	X%	Y%	Z%
MS A 26" vert riser, 154'	14	0.584	-----	0.490	NS	-----	0.038			7.8%
MS B, 26" vert riser 140'	490	-----	0.296	0.234	-----	0.038	0.022		12.8%	9.4%
MS B, 26" horiz run by SRVs	460	0.474	0.265	0.383	0.052	0.032	0.045	11.0%	12.1%	11.7%
MS B, 26" by venturi	534	0.323	0.343	-----	NS	0.034	-----		9.9%	
MS A 26" by MSIV, 107'	81	0.438	0.635	-----	NS	0.055	-----		8.7%	
average value					0.040					
MS A, SRV "J" disch	22J	0.518	-----	0.298	0.035	-----	0.056	6.8%		18.8%
MS B, SRV "P" disch	40P	1.013	0.121	0.633	0.056	0.016	NS	5.5%	13.2%	
average values					0.041					
MS A, RCIC line	430	-----	1.342	0.969	-----	0.058	0.068		4.3%	7.0%
average value					0.063					
FW DW, 24" by valve	50	0.420	0.555	0.525	0.024	0.023	0.042	5.7%	4.1%	8.0%
FW DW, 24/12 reducer to "C"	160	0.828	0.893	-----	0.053	0.041	-----	6.4%	4.6%	
average value for 24" header					0.037					
FW DW, 12" "A"	220	0.557	1.248	-----	0.071	0.053	-----	12.7%	4.2%	
FW DW, 12" "B"	280	0.438	-----	0.145	0.031	-----	0.034	7.1%		23.4%
FW DW, 12" "C"	Z002	0.468	1.559	0.352	0.025	0.048	0.05	5.3%	3.1%	14.2%
average value for 12" risers					0.045					
Outside Drywell										
MS A, TB, nearer pen	Z013	0.212	0.244	-----	0.045	0.038	-----	21.2%	15.6%	
MS B, TB, nearer pen	Z003	0.225	0.224	-----	0.043	0.002	-----	19.1%	0.9%	
MS A, TB, after first elbow	Z018	0.199	0.163	0.237	0.023	0.044	0.051	11.6%	27.0%	21.5%
MS B, TB, after first elbow	Z008	0.216	0.248	0.328	0.027	0.03	0.054	12.5%	12.1%	16.5%
average value					0.037					
FW Stm Tunnel, downstream	731	0.344	0.334	-----	0.011	NS	-----	3.2%		
FW Stm Tunnel, upstream	817	-----	0.261	0.340	-----	NS	0.008			2.4%
average value					0.010					
Extrac Steam, by 6A FWH	49	0.148	0.406	-----	0.024	0.023	-----	16.2%	5.7%	
Extrac Steam, by 6B FWH	Z010	0.080	0.266	0.325	0.024	0.019	0.017	30.0%	7.1%	5.2%
Extrac Steam, by 6B FWH	230	0.040	0.345	-----	0.018	0.026	-----	45.0%	7.5%	
Extrac Steam, by 6C FWH	Z008	0.056	0.328	0.132	0.024	0.025	0.019	42.9%	7.6%	14.4%
average value					0.022					

* values reported for drywell did not filter out 60 hz, 120 hz, and 180 Hz electrical noise. Values for outside drywell filtered out 60 hz, 120 hz, and 180 Hz electrical noise.

---- indicates not monitored. NS means "no signal" due to failed instrument

Table 4 CLTP Recorded Values At Maximum Recirculation Pump Speed

		Acceptance Criteria g-rms			Actual values at **max** recirc pump speed g-rms*			Actual values divided by acceptance criteria %		
Inside Drywell	Node	Xg	Yg		Xg	Yg	Zg	X%	Y%	Z%
MS A 26" vert riser, 154'	14	0.584	-----	0.490	NS	-----	0.039		-----	8.0%
MS B, 26" vert riser 140'	490	-----	0.296	0.234	-----	0.041	0.023	-----	13.9%	9.7%
MS B, 26" horiz run by SRVs	460	0.474	0.265	0.383	0.054	0.033	0.084	11.4%	12.3%	21.9%
MS B, 26" by venturi	534	0.323	0.343	-----	NS	0.036	-----		10.5%	-----
MS A 26" by MSIV, 107'	81	0.438	0.635	-----	NS	0.055	-----		8.7%	-----
average value					0.046					
MS A, SRV "J" disch	22J	0.518	-----	0.298	0.032	-----	0.053	6.3%	-----	17.8%
MS B, SRV "P" disch	40P	1.013	0.121	0.633	0.048	0.016	NS	4.8%	13.6%	
average values					0.038					
MS A, RCIC line	430	-----	1.342	0.969	-----	0.061	0.076	-----	4.6%	7.9%
average value					0.069					
FW DW, 24" by valve	50	0.420	0.555	0.525	0.026	0.021	0.043	6.1%	3.9%	8.2%
FW DW, 24/12 reducer to "C"	160	0.828	0.893	-----	0.093	0.054	-----	11.2%	6.0%	-----
average value for 24" header					0.047					
FW DW, 12" "A"	220	0.557	1.248	-----	0.097	0.096	-----	17.5%	7.7%	-----
FW DW, 12" "B"	280	0.438	-----	0.145	0.037	-----	0.030	8.3%	-----	20.5%
FW DW, 12" "C"	Z002	0.468	1.559	0.352	0.026	0.044	0.108	5.6%	2.8%	30.6%
average value for 12" risers					0.062					
Outside Drywell										
MS A, TB, nearer pen	Z013	0.212	0.244	-----	0.044	0.036	-----	20.7%	14.8%	-----
MS B, TB, nearer pen	Z003	0.225	0.224	-----	0.043	0.002	-----	19.1%	0.9%	-----
MS A, TB, after first elbow	Z018	0.199	0.163	0.237	0.023	0.042	0.049	11.6%	25.8%	20.7%
MS B, TB, after first elbow	Z008	0.216	0.248	0.328	0.026	0.028	0.053	12.0%	11.3%	16.2%
average value					0.036					
FW Stm Tunnel, downstream	731	0.344	0.334	-----	0.011	NS	-----	3.2%		-----
FW Stm Tunnel, upstream	817	-----	0.261	0.340	-----	NS	0.009	-----		2.6%
average value					0.010					
Extrac Steam, by 6A FWH	49	0.148	0.406	-----	0.022	0.021	-----	14.9%	5.2%	-----
Extrac Steam, by 6B FWH	Z010	0.080	0.266	0.325	0.023	0.017	0.017	28.9%	6.4%	5.2%
Extrac Steam, by 6B FWH	230	0.040	0.345	-----	0.019	0.024	-----	46.3%	6.8%	-----
Extrac Steam, by 6C FWH	Z008	0.056	0.328	0.132	0.023	0.025	0.020	41.1%	7.6%	15.2%
average value					0.021					

*values reported for drywell did not filter out 60 hz, 120 hz, and 180 Hz electrical noise. Values for outside drywell filtered out 60 hz, 120 hz, and 180 Hz electrical noise.

---- indicates not monitored. NS means "no signal" due to failed instrument

Table 5 CLTP Drywell Piping Vibration Levels
Recirculation Pump Spikes Subtracted Out
Inside Drywell Piping Only

		Acceptance Criteria g-rms			Estimated values speed g-rms			Estimated values divided by acceptance criteria %		
	Node	Xg	Yg		X	Y	Z	X%	Y%	Z%
MS A 26" vert riser, 154'	14	0.584	-----	0.490	NS	-----	0.038		-----	7.7%
MS B, 26" vert riser 140'	490	-----	0.296	0.234	-----	0.033	0.021	-----	11.1%	8.8%
MS B, 26" horiz run by SRVs	460	0.474	0.265	0.383	0.046	0.028	0.033	9.7%	10.5%	8.5%
MS B, 26" by venturi	534	0.323	0.343	-----	NS	0.028	-----		8.3%	-----
MS A 26" by MSIV, 107'	81	0.438	0.635	-----	NS	0.054	-----		8.5%	-----
average value					0.035					
MS A, SRV "J" disch	22J	0.518	-----	0.298	0.024	-----	0.039	4.5%	-----	13.2%
MS B, SRV "P" disch	40P	1.013	0.121	0.633	0.031	0.015	NS	3.1%	12.4%	
average values					0.030					
MS A, RCIC line	430	-----	1.342	0.969	-----	0.061	0.067	-----	4.6%	6.9%
average value					0.064					
FW DW, 24" by valve	50	0.420	0.555	0.525	0.019	0.015	0.043	4.4%	2.6%	8.1%
FW DW, 24/12 reducer to "C"	160	0.828	0.893	-----	0.029	0.036	-----	3.5%	4.1%	-----
average value for 24" header					0.028					
FW DW, 12" "A"	220	0.557	1.248	-----	0.028	0.034	-----	5.1%	2.7%	-----
FW DW, 12" "B"	280	0.438	-----	0.145	0.027	-----	0.027	6.2%	-----	18.6%
FW DW, 12" "C"	Z002	0.468	1.559	0.352	0.022	0.038	0.039	4.6%	2.5%	11.1%
average value for 12" risers					0.031					

---- indicates not monitored. NS means "no signal" due to failed instrument
Steam Tunnel piping has little or no recirculation pump spikes; therefore, not included

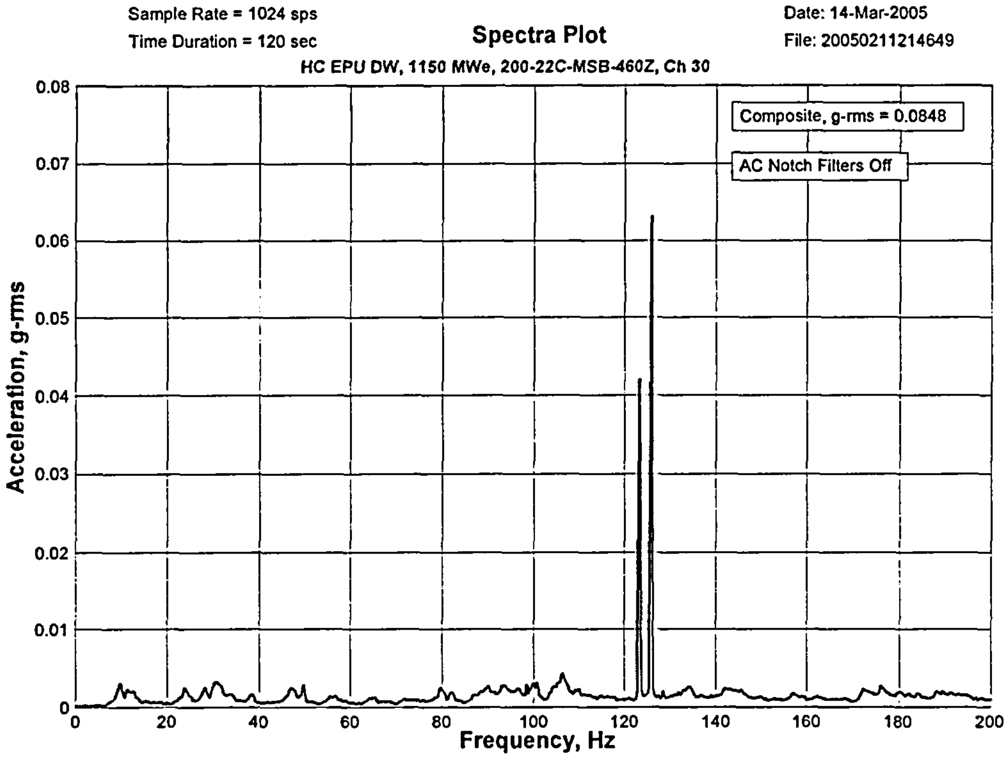

Figure 1. Frequency Spectrum Plot – DW MS Line B Node 460Z,

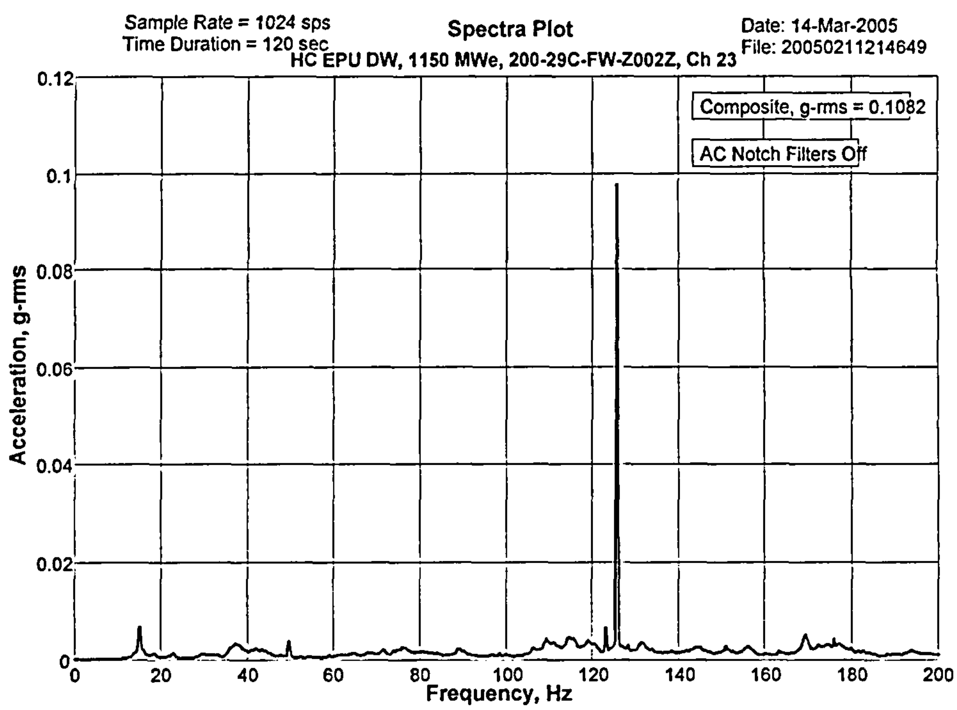

Figure 2. Frequency Spectrum Plot – DW FW Node Z002Z

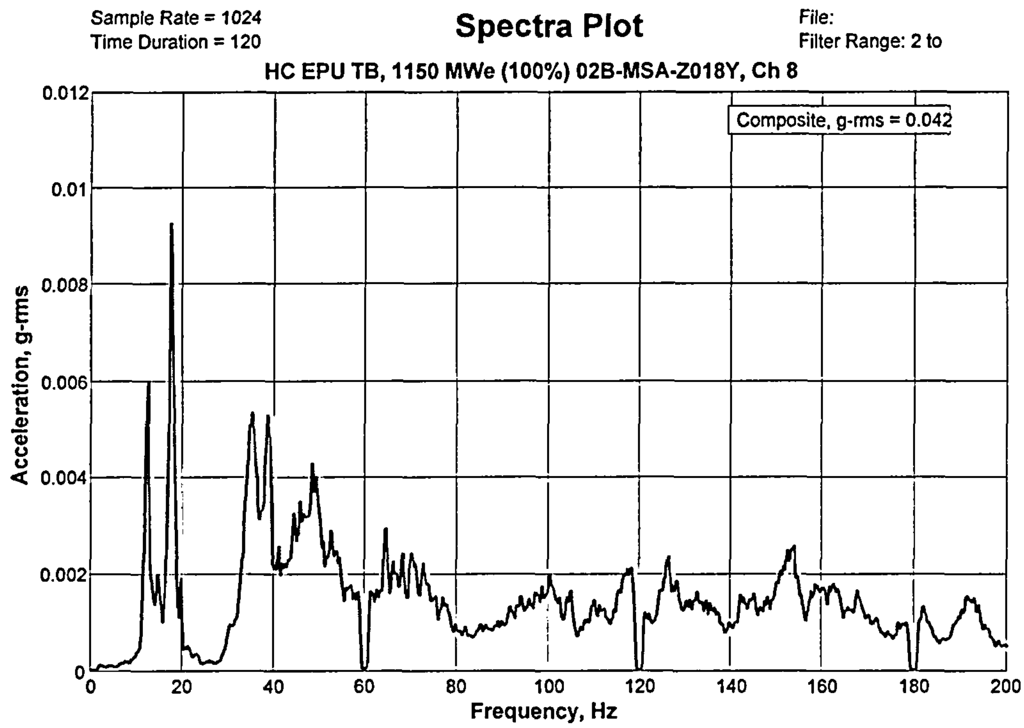

Figure 3. Frequency Spectrum – MS Line A Node Z018Y (Steam Tunnel)

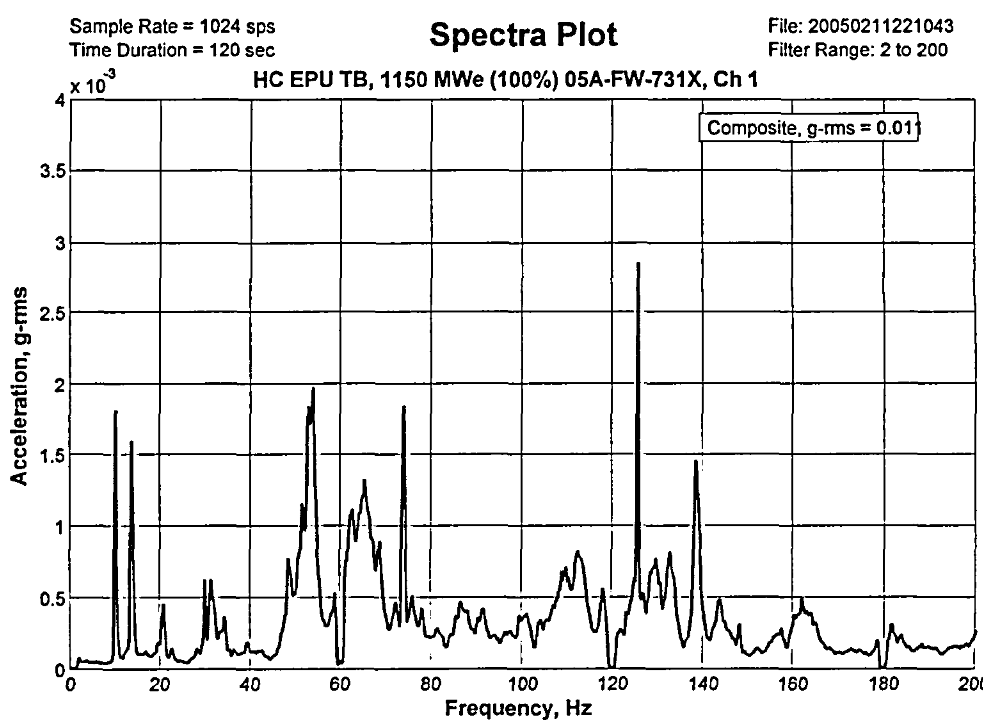

Figure 4. Frequency Spectrum – FW Node 731X (Steam Tunnel)

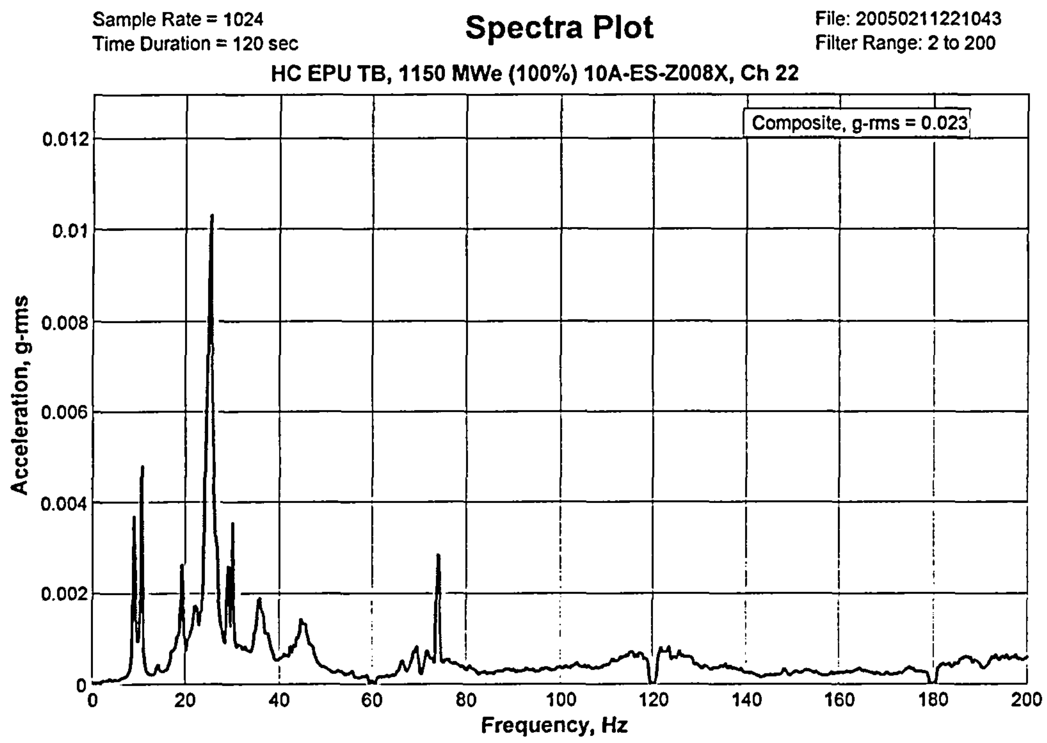

Figure 5. Frequency Spectrum – Extraction Steam Node Z008X (Turbine Building)

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