PSEG
P.O. Box 236, Hancocks Bridge, NJ 08038-0236

PSEG
Nuclear LLC

10 CFR 50.90

LR-N11-0045
FEB 14 2011

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

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

Subject: **Response to Second Request for Additional Information - License Amendment Request: Emergency Diesel Generators (EDG) A and B Allowed Outage Time (AOT) Extension**

References: (1) Letter from PSEG to NRC, "License Amendment Request: Emergency Diesel Generators (EDG) A and B Allowed Outage Time (AOT) Extension," dated March 29, 2010

(2) Letter from PSEG to NRC, " Response to Request for Additional Information - License Amendment Request: Emergency Diesel Generators (EDG) A and B Allowed Outage Time (AOT) Extension," dated September 30, 2010

In Reference 1, PSEG Nuclear LLC (PSEG) submitted a license amendment request (H10-03) for the Hope Creek Generating Station (HCGS). The proposed change would modify Technical Specification (TS) 3/4.8.1, "AC Sources – Operating"; specifically ACTION b concerning one inoperable Emergency Diesel Generator (EDG). The proposed change would extend the Allowed Outage Time (AOT) for the 'A' and 'B' EDGs from 72 hours to 14 days. The proposed extended AOT is based on application of the Hope Creek Generating Station (HCGS) Probabilistic Risk Assessment (PRA) in support of a risk-informed extension, and on additional considerations and compensatory actions.

In Reference 2, PSEG submitted responses to an NRC Request for Additional Information (RAI) on the license amendment request. Subsequently the NRC has provided PSEG a second Request for Additional Information (RAI2); the response to this second request is provided in Attachment 1 of this submittal. Additional proposed changes to TS are provided in Attachment 2. Revised regulatory commitments are provided in Attachment 3.

PSEG has reviewed the information supporting a finding of no significant hazards consideration that was provided in Reference 1. The additional information provided in this submittal does not affect the bases for concluding that the proposed license amendment does not involve a significant hazards consideration.

If you have any questions or require additional information, please do not hesitate to contact Mr. Jeff Keenan at (856) 339-5429.

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

Executed on FEB 14 2011
(Date)

Sincerely,

John F. Perry

John F. Perry
Site Vice President
Hope Creek Generating Station

Attachments (3)

C:

Regional Administrator - NRC Region I
R. Ennis, Project Manager - USNRC
NRC Senior Resident Inspector - Hope Creek
P. Mulligan, Manager IV, NJBNE
Commitment Coordinator – Hope Creek
PSEG Commitment Coordinator – Corporate

REQUEST FOR ADDITIONAL INFORMATION

REGARDING PROPOSED LICENSE AMENDMENT

EMERGENCY DIESEL GENERATORS A AND B ALLOWED OUTAGE TIME EXTENSION

HOPE CREEK GENERATING STATION

DOCKET NO. 50-354

By application dated March 29, 2010, as supplemented by letters dated May 28, 2010, and September 30, 2010 (Agencywide Documents Access and Management System (ADAMS) Accession Nos. ML100900458, ML101590514, and ML102870101 respectively), PSEG Nuclear LLC (PSEG or the licensee) submitted a license amendment request for the Hope Creek Generating Station (HCGS). The proposed amendment would revise the Technical Specifications (TSs) to extend the allowed outage time (AOT) for the "A" and "B" emergency diesel generators (EDGs) from 72 hours to 14 days.

The Nuclear Regulatory Commission (NRC) staff has reviewed the information the licensee provided that supports the proposed amendment and would like to discuss the following issues to clarify the submittal.

Background

Page 11 of Attachment 1 of the application dated March 29, 2010, states that the Tier 2 evaluation is provided in Attachment 4. Page 3-1 of Attachment 4 refers to Appendix D for the Tier 2 evaluation. Appendix D to Attachment 4, "Risk Significant Configurations (Tier 2)," identifies six "configuration specific actions to be discussed" on pages D-2 and D-3, but there is no further reference made to these actions, and no commitments made. Table D-1 is a listing of basic event importance measures and includes six footnotes on page D-11 which are essentially identical to the six original compensatory measures committed to in Attachment 5 of the application (commitments 1-6 correspond to compensatory measures 1-6, respectively). Based on the above, the NRC staff infers that the six original commitments, in Attachment 5 of the application dated March 29, 2010, represent the Tier 2 restrictions to avoid risk-significant plant configurations, consistent with the three-tiered approach discussed in Regulatory Guide (RG) 1.177. It is further inferred by the staff that the six "configuration specific actions to be discussed" are not considered to be part of the Tier 2 restrictions supporting this license amendment request. Subsequently, in Attachment 4 to the supplement dated September 30, 2010, the licensee revised and renumbered the original commitments (and associated compensatory measures) that were contained in the application. Based on the response to request for additional information (RAI) question 1.a.3, it appears that the five revised commitments, in Attachment 4 of the supplement dated September 30, 2010, represent the RG 1.77 Tier 2 restrictions supporting this risk-informed licensing action.

Table 3.4-5 in Attachment 4 of the application dated March 29, 2010, provides quantitative results for six cases. The values in the Table 3.4-5 case labeled "Compensatory Measures 3-6" match the values in the table titled "Results of the Risk Evaluation for Hope Creek" in Section 4.5.4 of Attachment 1 of the application (Section 4.5.4 provides the licensee's conclusions regarding the proposed license amendment request). As noted above, in Attachment 4 to the supplement dated September 30, 2010, the licensee revised and renumbered the original commitments (and associated compensatory measures) that were contained in the application. In addition, Table RAI-5c-1 in Attachment 2 of the supplement dated September 30, 2010, provided a revised version of Table 3.4-5 reflecting the renumbering of the compensatory measures and adding two sensitivity cases. The values in the Table RAI-5c-1 case labeled "Compensatory Measures 1-4 (of Attachment 4)" match the values in the table titled "Results of the Risk Evaluation for Hope Creek" in Section 4.5.4 of Attachment 1 of the application dated March 29, 2010. Based on the above, the NRC staff infers that the compensatory measures shown in commitments 1, 2, 3, and 4 in Attachment 4 of the supplement dated September 30, 2010, are credited in the risk analysis which is the proposed licensing basis for the 14-day EDG AOT.

<u>Request for Additional Information</u>

1. *Based on the information provided by the licensee, it appears that the five compensatory measures reflected in commitments 1 through 5 in Attachment 4 of the supplement dated September 30, 2010, represent the RG 1.77 Tier 2 restrictions supporting this risk-informed licensing action. In addition, it appears that the compensatory measures shown in commitments 1, 2, 3, and 4 in Attachment 4 of the supplement dated September 30, 2010, are credited in the risk analysis which would become the licensing basis for the 14-day EDG AOT. Please confirm that:*

    a. *The five compensatory measures reflected in commitments 1 through 5 in Attachment 4 of the supplement dated September 30, 2010, represent the RG 1.77 Tier 2 restrictions supporting this risk-informed licensing action.*

    b. *The compensatory measures shown in commitments 1, 2, 3, and 4 in Attachment 4 of the supplement dated September 30, 2010, are credited in the risk analysis which would become the licensing basis for the 14-day EDG AOT (i.e., values shown in table titled "Results of the Risk Evaluation for Hope Creek" in Section 4.5.4 of Attachment 1 of the application dated March 29, 2010).*

    c. *The compensatory measures shown in commitments 1, 2, 3, and 4 in Attachment 4 of the supplement dated September 30, 2010, are being relied on to meet the acceptance guidelines of RG 1.174.*

    d. *The compensatory measure shown in commitment 5 in Attachment 4 of the supplement dated September 30, 2010, is not credited in the risk analysis.*

<u>**RESPONSE TO 1**</u>

The approach taken in the implementation of RG 1.177 for the subject risk-informed licensing amendment is that the identified compensatory measures are prudent items that will enhance safety margin even if they are difficult to quantify.

Compensatory measures can be considered as two different types:

- Measures that are required in order to demonstrate that the RG 1.177 and RG 1.174 acceptance guidelines are met. These are required to meet the acceptance guidelines for the risk-informed licensing basis.

- Measures that are found to be prudent actions that provide additional margin to the acceptance guideline, but that are not required to meet the acceptance guidelines.

a. The Tier 2 evaluation as stated in RG 1.177 and applied for the HCGS EDG A&B AOT extension request is "to ensure that appropriate restrictions on dominant risk-significant configurations associated with the change are in place".

   Items 1-4 [Ref.2] were derived from this process to provide prudent compensatory measures consistent with the RG 1.177 paragraph 2.3. Item 5 was not derived as a PRA compensatory measure.

   Table 3.4-5 in Attachment 4 of Ref. 1 and Table RAI-5c-1 of Ref. 2 provide the quantitative assessments of the compensatory measures individually and for various combinations.

   Compensatory Measure 1 of Ref. 2 (which is the same as Compensatory Measure 3 of Ref. 1) is the required compensatory measure to meet the RG 1.177 acceptance guidelines. PSEG considers this compensatory measure a Tier 2 restriction.

   The remaining compensatory measures are prudent actions that PSEG has identified to increase safety margin but are not relied upon to meet the acceptance guidelines.

   Compensatory Measure 1 is currently part of the HCGS Technical Specification 3.8.1.1 Action e, as described in RAI Response to 1.c.2 included in Ref. 2. Because Compensatory Measure 1 is sufficient by itself to bring the risk metrics within the RG Acceptance Guidelines, only Compensatory Measure 1 is a Tier 2 restriction.

b. Each of the compensatory measures 1-4 are evaluated quantitatively in the Tier 1 PRA analysis and the results are reported both individually and collectively in the LAR submittals [Refs 1 & 2] (e.g., Table RAI-5c-1 in Ref. 2). As discussed in the response to 1.a above, Compensatory Measures 2, 3 and 4 of Ref. 2 are not relied upon to meet RG 1.177 Acceptance Guidelines, but are retained as prudent actions to manage the risk of an extended EDG AOT. Because Compensatory Measure 1 is currently required by TS and is sufficient by itself to bring the risk metrics within the RG Acceptance Guidelines, only Compensatory Measure 1 is a Tier 2 restriction.

   Given this, the table submitted in Section 4.5.4 of Attachment 1 of Ref. 1 should be replaced with the Table 1.b-1 (below) which provides the calculated risk metrics specified in RG 1.177 and 1.174 compared with the acceptance guidelines when only the required Compensatory Measure 1 is included (Table 1.b-1 replicates the data provided in Row 2 of Table 3.4.5 in Attachment 4 of Ref. 1, and also Row 2 of Table RAI-5c-1 of Ref. 2). Table 1.b-1 provides the quantitative risk metric results for the risk-informed licensing basis.

c. None of the compensatory measures are relied upon to meet the RG 1.174 acceptance guidelines, i.e., R.G. 1.174 acceptance guidelines are met without any compensatory measures.

d. It is confirmed that commitment 5 in Attachment 4 of the supplement dated September 30, 2010 is not credited in the risk analysis.

Table 1.b-1

RESULTS OF RISK EVALUATION FOR HOPE CREEK

Risk Metric	Risk Metric Results[(1)]	Risk Significance Guideline	Meets Acceptance Guideline
ΔCDF_{AVE}(/yr)	3.44E-07	<1.0E-06	Yes[(2)]
$\Delta LERF_{AVE}$(/yr)	2.36E-08	<1.0E-07	Yes[(2)]
$ICCDP_{EDG\ A}$	2.34E-07	<5.0E-07	Yes
$ICLERP_{EDG\ A}$	1.27E-09	<5.0E-08	Yes
$ICCDP_{EDG\ B}$	4.26E-07	<5.07E-07	Yes
$ICLERP_{EDG\ B}$	4.41E-08	<5.0E-08	Yes

(1) Incorporates Compensatory Measure 1 to ensure only single EDG is unavailable (Tech Spec 3.8.1.1 Action e) or else reactor shutdown is required.

(2) Region III of RG 1.174 – very small risk changes.

2. *Consistent with the guidance in SECY-98-224, "Staff and Industry Activities Pertaining to the Management of Commitments Made by Power Reactor Licensees to the NRC," dated September 28, 1998 (ADAMS Accession No. ML992870043), and NRR Office Instruction LIC-100, "Control of Licensing Bases for Operating Reactors" (ADAMS Accession No. ML010660227), escalating a licensee commitment into a legally binding requirement should be reserved for matters that warrant: (1) inclusion in the TSs based on the criteria in 10 CFR 50.36; or (2) inclusion in the license (which includes the TSs) based on determination that the issue is of high safety or regulatory significance. The major distinction between obligations and other parts of the licensing bases is that changes generally cannot be made without prior NRC approval.*

As discussed in RG 1.177, the intent of the Tier2 evaluations is to identify risk-significant plant configurations, not considered in the Tier 1 analyses, which should be avoided during a proposed extended AOT. Based on the sensitivity studies provided to the NRC staff in the licensee's submittals, it is not clear that any of compensatory measures shown in Attachment 4 of the supplement dated September 30, 2010, individually or as a group, are risk-significant. However, it appears that the licensee has identified these compensatory measures as necessary Tier 2 restrictions and has credited some of them in the risk analysis in order to meet the acceptance guidelines of RG 1.174.

The commitments, shown in Attachment 4 of the supplement dated September 30, 2010, which are Tier 2 restrictions and are credited in the risk analysis are considered by the NRC staff to be of high regulatory significance (i.e., associated compensatory measures are important with respect to NRC's determination on acceptability of proposed amendment). Consistent with the guidance in SECY-98-224 and NRR Office Instruction LIC-100, these types of commitments warrant inclusion in the TSs or the license to ensure NRC prior approval if the commitments are changed in the future. Please propose suitable TS required actions for such commitments/compensatory measures. As noted above, it appears that commitments 1, 2, 3, and 4 in Attachment 4 of the supplement dated September 30, 2010, are Tier 2 restrictions and are credited in the risk analysis. RAI questions 3 through 6 below provide further concerns regarding the *specific compensatory measures associated with commitments 1, 2, 3, and 4, respectively.*

The NRC staff notes that the licensee may wish to re-evaluate the scope of its Tier 2 restrictions and, if appropriate, provide revised Tier 1 risk analyses which do not credit one or more of these items.

RESPONSE TO 2

The following is a brief summary of the four compensatory actions that were evaluated as part of the AOT assessment:

Compensatory Measure		
No.	Description	Relied Upon to Achieve RG 1.177 Acceptance Guidelines
1	When the A EDG is removed from service for an extended 14 day AOT, the C EDG shall be operable. When the B EDG is removed from service for an extended 14 day AOT, the D EDG shall be operable.	Yes
2	When either A or B EDG is removed from service for an extended 14 day AOT, both HPCI and RCIC shall be operable.	No
3	Any component testing or maintenance that increases the likelihood of a plant transient shall be avoided during the extended 14 day AOT. This encompasses work activities categorized as Production Risk.	No
4	Voluntary entry into this LCO action statement should not be scheduled if adverse weather conditions are expected.	No

Compensatory measures 2, 3, and 4 are similar in nature to those suggested by the NRC in RAI #8, i.e., prudent actions, but not quantitatively required to meet acceptance guidelines.

The required restriction associated with the requested EDG A&B AOT extension is that the A&C or B&D EDGs are not removed from service coincidentally.

Because Compensatory Measure #1 is currently required by Technical Specifications and is sufficient by itself to bring all of the risk metrics within the Regulatory acceptance guidelines, only Compensatory Measure 1 is considered a Tier 2 restriction. Compensatory Measure 1 is currently part of the HCGS Technical Specification 3.8.1.1 Action e, as described in RAI Response to 1.c.2 included in Ref. 2.

Therefore, there are no other required restrictions to support the EDG A&B AOT extensions. Nevertheless, PSEG believes it to be prudent to include additional procedural restrictions (similar to those suggested by the NRC in RAI #8). These additional Compensatory Measures 2, 3, and 4 of the September 30, 2010 RAI response [Ref.2] are prudent safety enhancements that PSEG has included to provide additional margin to the acceptance guidelines.

3. *A plain language reading of commitment 1 in Attachment 4 of the supplement dated September 30, 2010, implies that simultaneous outages of the A and C EDGs, or of the B and D EDGs, will be prohibited. In response to RAI 1.c.2 (page 6 of Attachment 1 of the*

supplement dated September 30, 2010), the licensee stated that the commitment only applies to verification of operability prior to removing the EDG from service, and that the existing 2-hour completion time (CT) applicable when two EDGs are inoperable would then apply for any emergent EDG failure. Since the 14-day CT cannot apply to the condition of two EDGs inoperable per the existing TSs, this commitment appears to simply state that the licensee will not deliberately violate the TSs. The licensee needs to clarify how this commitment implements any action more restrictive than the existing TSs, or provide revised risk analyses which do not credit the commitment and delete it from the Tier 2 restrictions.

RESPONSE TO 3

Commitment 1 has been eliminated as it is redundant to existing TS restrictions, as discussed below.

As previously discussed in the response to RAI 1.c.2 [Ref.2]), this commitment would require PSEG to verify the second EDG in the same mechanical division to be OPERABLE prior to removing the EDG from service for the extended AOT. The operability of the second EDG in the same mechanical division is a compensatory measure based on the PRA analysis provided for the extended AOT. However, once any EDG is removed from service, if a second EDG were to become INOPERABLE, TS 3.8.1.1 Action e would be invoked with the required 2 hour completion time as is currently required for the 72 hour AOT. Consequently, as noted in the NRC question, this commitment does not effectively implement any action that is more restrictive than the existing TS (i.e., the commitment would be redundant). The PRA assessment for the A or B EDG extended AOT crediting the existing Technical Specification requirement remains the same as that attributed to commitment/compensatory measure #1. Therefore; it is not necessary to establish a separate commitment; the compensatory measure is subsumed within the existing TS.

4. *A plain language reading of commitment 2 in Attachment 4 of the supplement dated September 30, 2010, implies that high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) will be operable while the 14-day CT is in effect for any EDG. In response to RAI 1.a.2 (page 2 of Attachment 1 of the supplement dated September 30, 2010), the licensee indicated that this commitment would apply to both planned inoperability and emergent failure of EDGs. In response to RAI 1.a.5 (page 4 of Attachment 1 of the supplement dated September 30, 2010), the licensee indicated that inoperabilities of HPCI or RCIC occurring during the EDG 14-day CT would be addressed by the TS required actions associated with HPCI or RCIC. Further, the licensee stated that with an EDG also inoperable, an additional assessment must be made on the effect to systems supplied by the out-of-service EDG (cascading effect) and could procedurally require further TS actions, including entry into TS 3.0.3, as applicable.*

   It is not clear to the staff that an emergent EDG failure occurring while either HPCI or RCIC (or both) are inoperable would be precluded from using the 14-day CT for the EDG. Specifically, the emergent nature of the failure would preclude an a priori restoration of HPCI/RCIC. Cascading of the impact of the EDG inoperability would appear not to impact HPCI and RCIC, since these systems operate independently of AC power. Since the existing CTs for HPCI and RCIC are also 14 days, plant operation with an EDG and one or both HPCI and RCIC inoperable would not be limited by the TSs or by this commitment. This contradicts the risk analysis basis which assumes concurrent unavailability of the EDG with these systems does not occur. The licensee should revise the commitment to more accurately describe what action is required and propose *suitable TS required actions for those actions (see RAI 2 above), or provide revised risk analyses which do not credit this commitment and delete it from the Tier 2 restrictions.*

RESPONSE TO 4

RCIC LCO Action Statement 3.7.4 states: 'With the RCIC system inoperable, operation may continue provided the HPCI system is OPERABLE..." Based on this action statement, if HPCI and RCIC were inoperable simultaneously, the station would be required to enter Technical Specification 3.0.3 which would require action to place the plant in an OPERATIONAL CONDITION in which the specification does not apply. In this case, the station would have to shutdown and lower reactor pressure to less than 200 psig. The station would have a maximum of 13 hours to complete the shutdown and cooldown.

With the HPCI system inoperable, and no other ECCS systems or EDG inoperable, a 14 day action times applies. With either the A or B EDG inoperable and no other ECCS or HPCI inoperable, a 72 hour action time currently applies. However, if any EDG and HPCI are or become, inoperable simultaneously, guidance is provided in Operations Procedure OP-HC-108-115-1001. This guidance ensures compliance with Generic Letter 91-18. The guidance provides for 'cascading' of the effect of the EDG operability to the systems supplied by the EDG. This would require the station to consider the affected RHR pump inoperable for the LPCI function. It would also require the station to consider the affected Core Spray Loop inoperable. In this case, a separate HPCI LCO Action Statement (TS 3.5.1, Action c.2) would apply and the station would have 12 hours to be in Hot Shutdown and a subsequent 24 hours to lower reactor steam dome pressure to ≤200 psig.

Based on these facts, an emergent EDG failure occurring while HPCI is inoperable would drive the station into a 72 hour Action Statement which would exclude the use of the 14 day CT.

As discussed in RAI 2 above, PSEG will retain this compensatory measure/commitment; however, PSEG does not believe it warrants inclusion in TS since it is not relied upon to meet the RG 1.177 and RG 1.174 acceptance guidelines.

5. *Commitment 3 in Attachment 4 of the supplement dated September 30, 2010, has been credited in the risk analysis as a 10% reduction in the turbine trip frequency. No quantitative basis for this reduction, implemented by the procedural restrictions on "production risk," has been provided. The licensee should provide the quantitative basis for the 10% reduction in turbine trip frequency and propose suitable TS required actions for the compensatory measures in this commitment (see RAI 2 above), or provide revised risk analyses which do not credit this commitment and delete it from the Tier 2 restrictions.*

RESPONSE TO 5

The 10% reduction[1] in Turbine Trip Frequency has a small impact on the calculated risk metrics. As can be seen from Table RAI-5c-1 of the RAI response [Ref.2], this compensatory measure has a very small effect on the risk metrics. It is not relied upon to meet the RG 1.174 or RG 1.177 Acceptance Guidelines; therefore PSEG does not believe it warrants inclusion in TS.

1 The 10% is far less than the year to year variation seen in the BWR population as reported in NUREG/CR6928 [Industry-average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants]

There are at least two safety benefits that can be attributed to this commitment:

- Reduction in spurious reactor trips associated with testing or maintenance
- Reduction in spurious LOOP events due to testing or maintenance in the switchyard

The quantification of this safety benefit focused only on the reduction in spurious reactor trips. The reduction in spurious LOOP events is not quantified because of a lack of data.

In addition, it is a conservative representation of the effect of the "no testing" compensatory measure, i.e., underestimates the benefit of the risk reduction.

The basis for the 10% reduction in turbine trip frequency is BWR operating experience. The BWR operating experience of turbine trip events is reviewed for the frequency of:

- Spurious turbine trips during plant testing (includes spurious MSIV closure)
- Other spurious causes related to testing

Data from NUREG/CR-5750 [Rates of Initiating Events at U.S. Nuclear Power Plants: 1987 – 1995] are evaluated to assess the potential for spurious initiated transients. The results are as follows:

Transient Initiators	Scrams	Estimated Spurious Initiators Due to Testing
Spurious Closure of all MSIVs	16	16
High Pressure (RPS Trip)	9	
Reactivity Control Balance	6	
Core Power Excursion	39	
Turbine Trip	173	
Other Reactor Trip (Valid RPS Trip)	16	
Spurious Reactor Trip	63	63
Spurious Engineered Safety Feature Actuation	14	
Total	336	79

Ratio of Spurious Initiators to Total Initiators = 79/336 = 0.23 = 23%

Of these 23% spurious events due to testing or related manipulations, it was conservatively assumed that the fraction of these spurious events that could be prevented by the proposed compensatory measure is 0.5.

Therefore, approximately a 10% reduction in turbine trip events is expected based on data and this is then incorporated into the model tied to the Compensatory Measure.

Again, as can be seen from Table RAI-5c-1 of the RAI responses [Ref.2], this compensatory measure has a very small effect on the risk metrics, i.e., it is not relied upon to calculate risk metrics within the RG acceptance guidelines. Nevertheless, PSEG judges this to be appropriate and prudent to include in the compensatory actions desired during a plant configuration with an EDG in an extended AOT. Therefore, the procedural guidance that reduces the likelihood of a plant transient will be provided for the A&B EDG AOT extension similar to its use in conjunction with the existing extended AOT for the C&D EDG.

6. *A plain language reading of commitment 4 in Attachment 4 of the supplement dated September 30, 2010, implies that the EDG 14-day CT will not be voluntarily entered if adverse weather conditions are expected. In response to RAI 1.g (page 7 of Attachment 1 of the supplement dated September 30, 2010), the licensee clarified that "adverse weather" only includes hurricanes, tropical storms, and coastal floods, and that the "expectation" of these conditions would be based on a 10-day weather forecast indicating warnings for hurricanes, tropical storms, or coastal floods. The licensee response also stated that "[t]his commitment requires PSEG to return EDGs to an operable status if Hurricane, Tropical Storm or Coastal flood WARNINGS are issued for the area." However, the commitment does not contain this requirement (only discusses voluntary entry into the 14-day CT).*

   The NRC staff's understanding is that National Weather Service "warnings" are based on the expectation of conditions within a short time period (e.g., 36 hours in advance for hurricane or tropical storm) and would never be in effect 10 days in advance for such events. It is not clear to the staff why this subset of severe weather events is sufficient, given that many loss-of-offsite-power (LOOP) events are caused by lightning during severe storms, tornadoes, high winds not related to tropical storms, icing events, etc. The staff is also not clear as to the licensee's statement that the commitment "requires PSEG to return EDGs to operable status," when the plain wording of the commitment refers to considerations taken prior to voluntary entry into the 14-day CT. Further, it is not clear to the staff why weather-related LOOP should be reduced by 75% based on a 10-day forecast for this subset of events.

   The licensee needs to clarify its basis for selecting these three types of events and neglecting other weather-related causes of LOOP, justify its 75% reduction in weather-related LOOP frequency, confirm that warnings are in fact issued 10 days in advance of these types of events, and propose suitable TS required actions for the compensatory measures in this commitment (see RAI 2 above), or provide revised risk analyses which do not credit this commitment and delete it from the Tier 2 restrictions.

RESPONSE TO 6

The Compensatory Measure #4 (Voluntary entry into this LCO action statement should not be scheduled if adverse weather conditions are expected) is not required to meet the acceptance guidelines of RG 1.174 or RG 1.177. Nevertheless, the effect of limiting the EDG entry into an extended AOT based on best available information on impending hurricanes or other adverse weather conditions is considered a prudent action and one that can be correlated to real physical events. This is a prudent safety enhancement. PSEG does not believe it warrants inclusion in TS since it is not relied upon to meet the RG 1.177 and RG 1.174 acceptance guidelines.

As background, it is noted that the latest available data from NUREG/CR-6890 [Analysis of Loss of Offsite Power Events: 1986-2004] regarding offsite AC power outage durations are used to characterize the following causal events which are included in the PRA:

- Plant Centered LOOP
- Grid Centered LOOP
- Switchyard Centered LOOP
- Weather Related LOOP

However, only the weather contribution is the subject of this Compensatory Measure. The long duration LOOP outages for the other causes are still embedded in the risk calculation, i.e., are not affected by this compensatory measure.

Current PSEG procedures address the following weather related conditions: In HC.OP-AB.MISC-0001, ACTS OF NATURE, there are two weather related conditions that refer to the EDGs. When: Condition 1: Hurricane, Tropical Storms or Coastal flood WARNINGS are issued for the area or Condition 2: A Severe Thunderstorm, High Winds or Tornado Warning has been issued for the area the required action is to terminate surveillance testing, EDG maintenance, and restore systems at the discretion of the Shift Manager. In HC.OP-AB.BOP-0004, GRID DISTURBANCE, which may be entered as a result of weather conditions not in the immediate area, there is also the requirement to CONSIDER deferral of any in progress or proposed EDG maintenance.

The basis for the 75% reduction in severe weather induced LOOP is an assessment of the historical data. The events of interest are those that could lead to an extended LOOP event where HPCI and RCIC may not be able to survive (e.g., due to battery depletion).

The data are examined from several different viewpoints, and the result of the data assessment is that a range of conclusions are possible depending on the assumptions regarding applicability of the data to the HCGS site. From 71% to 80% of the applicable data could be eliminated if adequate pre-planning was included.

Because the data are sparse and widely scattered, PSEG presented a sensitivity study to demonstrate credit for elimination of 75% of weather related events, 50%, and 0% during the extended EDG AOT. The benefit is judged to be real and lies within the range of the sensitivity study but it is not required to meet the acceptance guidelines. These results were presented in RAI Response 5c from September 2010. Table RAI-5c-1 of the RAI response [Ref. 2] provides the sensitivity to demonstrate the marginal impact if this credit is reduced from 75% to 50% or to 0%. If the benefit associated with this compensatory measure is reduced, the acceptance guidelines would still be met because Compensatory Measure 1 is still effective.

A review of the extended LOOP (LOOP > 4 hours) data from NUREG/CR-6890 indicates the following weather related events for coastal plants that may apply[2] to Hope Creek are:

Data
4 Hurricane Events
1 Snow Event

Results
4/5 are hurricane (80%)

75% was chosen as a conservative estimate of the events that could be avoided.

As can be seen from Table RAI-5c-1 of the RAI response [Ref. 2], this compensatory measure has a very small effect on the limiting ICLERP risk metrics, i.e., it is not relied upon to calculate acceptable risk metrics. The change in a limiting risk metric (ICLERP with EDG B OOS) is 5E-10 compared with the acceptance guideline of 5E-08.

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2 It is noted that the salt spray events and the midwest tornado and high wind events causing loss of off-site power are judged not to be applicable to the Hope Creek site.

7. *As discussed on page 2 of Attachment 1 of the supplement dated May 28, 2010, and on page 29 of Attachment 2 of the supplement dated September 30, 2010), the licensee plans to credit the existing onsite Gas Turbine Generator (GTG) (designated as Salem Unit 3) as an alternate alternating current (AAC) source in the event of a LOOP concurrent with failure of the EDGs (i.e., for station blackout (SBO) conditions). The licensee has indicated that the AAC is not needed to meet the requirements for SBO, however, the AAC is being credited for defense-in-depth.*

   Commitment 5 in Attachment 4 of the supplement dated September 30, 2010, requires that the availability of the GTG be checked before entering into any "A" or "B" EDG extended 14-day CT. The licensee has proposed to incorporate this commitment into the TS Bases.

   a. *The licensee should clarify the actions that will be taken if the GTG becomes unavailable during the extended EDG outage and revise commitment 5 accordingly. In addition, the commitment should be revised to require that the availability of the GTG be verified at least once every 12 hours.*

   b. *Several studies have been performed (e.g., NUREG-1784 and NUREG/CR-6890) which concluded that the average duration of LOOP events has increased from the durations assumed at the time of issuance of the SBO rule. As such, from a deterministic perspective, the NRC staff considers that the compensatory measures associated with ensuring that the GTG is available before entering and during the extended 14-day CT is of high regulatory significance (i.e., associated compensatory measures are important with respect to NRC's determination on acceptability of proposed amendment). Consistent with the guidance in SECY-98-224 and NRR Office Instruction LIC-100, this type of commitment warrants inclusion in the TSs or the license to ensure NRC prior approval if the commitment is changed in the future. Please propose suitable TS required actions for the compensatory measures in commitment 5 (as revised based on RAI 7.a).*

RESPONSE TO 7

a. The actions that will be taken if the GTG becomes unavailable will be included in TS; PSEG proposes to place this defense-in-depth measure in TS 3.8.1.1 (see response to 7.b below). Since this measure will now be in TS, it will no longer be needed as a commitment.

b. PSEG proposes the following change to TS 3.8.1, ACTION b, to address the Salem Unit 3 GTG defense in depth measure:

   b. *With one diesel generator of the above required A.C. electrical power sources inoperable,*

   1. *Demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 separately for each diesel generator within 24 hours**

unless the absence of any potential common mode failure for the remaining diesel generators is demonstrated.

2. *For the inoperable A or B diesel generator, if continued operation is permitted by LCO 3.7.1.3:*

   a) *Restore the inoperable diesel generator to OPERABLE status within 72 hours, or*

   b) *Verify the Salem Unit 3 gas turbine generator (GTG) is available within 72 hours and once per 12 hours thereafter#, and restore the inoperable diesel generator to OPERABLE status within 14 days.*

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

3. *For the inoperable C or D diesel generator, if continued operation is permitted by LCO 3.7.1.3, restore the inoperable diesel generator to OPERABLE status within 14 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.*

 # After the initial verification period, the GTG may be unavailable for a single period of up to 24-hours and the once-per 12-hour requirement to verify that the GTG is available may be suspended during this period.

The marked up TS change is provided in Attachment 2.

8. *The NRC staff requests that the licensee revise the list of commitments to add the following compensatory measures:*

   a. *The system dispatcher will be contacted once per day and informed of the EDG outage status during the 14-day EDG CT.*

   b. *Operating crews will be briefed on the EDG work plan and procedural actions regarding LOOP and SBO, prior to entering the 14-day EDG CT.*

   The above compensatory measures should be incorporated into the appropriate plant procedures and the procedure number(s) should be listed in the respective commitment.

<u>RESPONSE TO 8</u>

a. PSEG understands that the purpose of the compensatory measure of contacting the system dispatcher once per day is to establish communication between the station and the dispatcher to ensure there are no grid conditions that could result in a LOOP, and to ensure that if there is a LOOP, offsite power would be expeditiously restored. Based on current procedural requirements it does not appear that any additional measure is needed as discussed below.

   Hope Creek is connected to the PSE&G transmission system and the transmission system is controlled by the PSE&G Electrical Systems Operations Center (ESOC). The PSE&G transmission system is part of a Regional Transmission Operations system called the Pennsylvania-New Jersey-Maryland (PJM) Interconnection which is operated and controlled by the PJM.

Hope Creek, as a nuclear generator on the PJM transmission system, has been classified as a Priority 1 Critical Load per PJM Manual M-36, "System Restoration". Per the PJM requirements for Priority 1 Critical loads, continuity of normal power as well as restoration of power during blackout conditions is given the highest priority. Power restoration plans, per Manual M-36, have been fully developed by the Transmission Owner (PSE&G) for restoration to Hope Creek in an expeditious manner. These restoration plans are validated on a bi-annual basis via mandatory PJM/Transmission Owner restoration drills. A drill objective is that power is restored to Nuclear Generators within a period of 4 hours.

Existing PJM procedure PJM Manual M-39, "Nuclear Plant Interface Coordination," requires the system dispatcher to notify the station of grid conditions that could potentially result in a LOOP. In addition, PSEG procedures HC.OP-AB.BOP-0004, "Grid Disturbance" and HC.OP-AB.MISC-0001, "Acts of Nature," require HCGS to inform the dispatcher of station activities or observable conditions that could affect grid conditions. If there is a loss of off-site power to Artificial Island, the existing ESOC procedure, "Operating Instruction Emergency Operations 1-6 - PSE&G Restoration Procedure and Philosophy," provides the actions to be taken to restore one source of off-site power within 4 hours (SBO coping time), to comply with the requirements of PJM Manual 36. These procedures and requirements exist without regard to current EDG capability.

Based on the high priority given to maintaining and restoring power to Nuclear Generating Units, adding an additional requirement to notify the dispatcher daily on the status of the EDG outage would not enhance the controls already in place to expeditiously restore power to the station in the event of a LOOP.

Further details on communications between the dispatcher and the station are discussed in PSEG response to GL 2006-02 (PSEG letters dated April 3, 2006 (ADAMS ML061010699) and January 26, 2007 (ADAMS ML070370181.)

b. PSEG will add this compensatory measure/commitment to OP-HC-108-115-1001, OPERABILITY ASSESSMENT AND EQUIPMENT CONTROL PROGRAM. This procedure currently contains the guidance for the extended AOTs for the C and D EDGs. PSEG does not believe the procedure number needs to be in the commitment consistent with similar commitments; the PSEG Commitment Management process (per NEI 99-04) appropriately controls commitment implementation in procedures.

Based on the preceding responses, a revised list of Commitments is included in Attachment 3 of this submittal.

REFERENCES

[1] Letter from PSEG to USNRC, License Amendment Request: Emergency Diesel Generators (EDG) A and B Allowed Outage Time (AOT) Extension, LR-N10-0097, LAR H10-03, dated March 29, 2010.

[2] Letter from PSEG to USNRC, Response to Request for Additional Information – License Amendment Request: Emergency Diesel Generators (EDG) A and B Allowed Outage Time (AOT) Extension), LR-N10-0294, dated September 30, 2010.

TECHNICAL SPECIFICATION PAGES WITH PROPOSED CHANGES

Facility Operating License NPF-57

Technical Specification	**Page**
3/4.8.1	3/4 8-1

INSERT A:

1. Demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 separately for each diesel generator within 24 hours* unless the absence of any potential common mode failure for the remaining diesel generators is demonstrated.

2. For the inoperable A or B diesel generator, if continued operation is permitted by LCO 3.7.1.3:

   a) Restore the inoperable diesel generator to OPERABLE status within 72 hours, or

   b) Verify the Salem Unit 3 gas turbine generator (GTG) is available within 72 hours and once per 12 hours thereafter#, and restore the inoperable diesel generator to OPERABLE status within 14 days.

   Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

3. For the inoperable C or D diesel generator, if continued operation is permitted by LCO 3.7.1.3, restore the inoperable diesel generator to OPERABLE status within 14 days, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

INSERT B:

After the initial verification period, the GTG may be unavailable for a single period of up to 24-hours and the once-per 12-hour requirement to verify that the GTG is available may be suspended during this period.

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

A.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Four separate and independent diesel generators, each with:

   1. A separate fuel oil day tank containing a minimum of 360 gallons of fuel,
   2. A separate fuel storage system consisting of two storage tanks containing a minimum of 44,800 gallons of fuel, and
   3. A separate fuel transfer pump for each storage tank.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

Note: LCO 3.0.4b is not applicable to DGs

a. With one offsite circuit of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the inoperable offsite circuit to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one diesel generator of the above required A.C. electrical power sources inoperable,~~ demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining diesel generators by performing Surveillance Requirement 4.8.1.1.2.a.4 separately for each diesel generator within 24 hours* unless the absence of any potential common mode failure for the remaining diesel generators is demonstrated. If continued operation is permitted by LCO 3.7.1.3:, restore the inoperable diesel generator to OPERABLE status within 72 hours for diesel generators A or B, or within 14 days for diesel generators C or D, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.~~

INSERT A →

* This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABILITY.

INSERT B →

LIST OF REGULATORY COMMITMENTS

The following table identifies those actions committed to by PSEG in this document. Any other statements in this submittal are provided for information only purposes and are not considered to be regulatory commitments.

Regulatory Commitment (The following compensatory actions, which will be included in the TS Bases, will be applicable during the extended AOT for EDG A&B)	**Committed Date**	**Commitment Type**	
		One-Time Action (Yes/No)	**Programmatic (Yes/No)**
1. When either the A or B EDG is removed from service for an extended 14 day AOT, both HPCI and RCIC shall be operable.	1	No	Yes
2. Any component testing or maintenance that increases the likelihood of a plant transient shall be avoided during the extended 14 day AOT. This encompasses work activities categorized as Production Risk.	1	No	Yes
3. Voluntary entry into this extended 14 day AOT should not be scheduled if adverse weather conditions are expected.	1	No	Yes
4. Operating crews will be briefed on the EDG work plan and procedural actions regarding LOOP and SBO, prior to entering the extended 14 day EDG AOT.	1	No	Yes

1. Concurrent with approval and subsequent implementation of this proposed license amendment