CP&L
A Progress Energy Company

John S. Keenan
Vice President
Brunswick Nuclear Plant

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

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING
REQUEST FOR LICENSE AMENDMENTS - EXTENDED POWER UPRATE
(NRC TAC NOS. MB2700 AND MB2701)

Ladies and Gentlemen:

On August 9, 2001 (Serial: BSEP 01-0086), Carolina Power & Light (CP&L) Company requested a revision to the Operating Licenses (OLs) and the Technical Specifications for the Brunswick Steam Electric Plant (BSEP), Units 1 and 2. The proposed license amendments increase the maximum power level authorized by Section 2.C.(1) of OLs DPR-71 and DPR-62 from 2558 megawatts thermal (MWt) to 2923 MWt. Subsequently, on January 17, 2002, the NRC provided an electronic version of a Request for Additional Information (RAI) concerning the impact of the Main Generator Lockout Load Shed Modification on the BSEP probabilistic safety analysis of the planned extended power uprate. The response to this RAI is enclosed.

Please refer any questions regarding this submittal to Mr. Leonard R. Beller, Manager - Regulatory Affairs, at (910) 457-2073.

Sincerely,

John S. Keenan

John S. Keenan

MAT/mat

A001

P.O. Box 10429
Southport, NC 28461

T > 910.457.2496
F > 910.457.2803

Enclosure:
Response to Request for Additional Information (RAI) 13

John S. Keenan, having been first duly sworn, did depose and say that the information contained herein is true and correct to the best of his information, knowledge and belief; and the sources of his information are officers, employees, and agents of Carolina Power & Light Company.

Dean S. Mason
Notary (Seal)

My commission expires: 8/29/04

cc:

U. S. Nuclear Regulatory Commission, Region II
ATTN: Dr. Bruce S. Mallett, Regional Administrator
Sam Nunn Atlanta Federal Center
61 Forsyth Street, SW, Suite 23T85
Atlanta, GA 30303-8931

U. S. Nuclear Regulatory Commission
ATTN: Mr. Theodore A. Easlick, NRC Senior Resident Inspector
8470 River Road
Southport, NC 28461-8869

U. S. Nuclear Regulatory Commission **(Electronic Copy Only)**
ATTN: Mr. Allen G. Hansen (Mail Stop OWFN 8G9)
11555 Rockville Pike
Rockville, MD 20852-2738

U. S. Nuclear Regulatory Commission
ATTN: Mr. Mohammed Shuaibi (Mail Stop OWFN 8H4A)
11555 Rockville Pike
Rockville, MD 20852-2738

Ms. Jo A. Sanford
Chair - North Carolina Utilities Commission
P.O. Box 29510
Raleigh, NC 27626-0510

Mr. Mel Fry
Director - Division of Radiation Protection
North Carolina Department of Environment and Natural Resources
3825 Barrett Drive
Raleigh, NC 27609-7221

ENCLOSURE

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Response to Request for Additional Information (RAI) 13

Background

On August 9, 2001 (Serial: BSEP 01-0086), Carolina Power & Light (CP&L) Company requested a revision to the Operating Licenses (OLs) and the Technical Specifications for the Brunswick Steam Electric Plant (BSEP), Units 1 and 2. The proposed license amendments increase the maximum power level authorized by Section 2.C.(1) of OLs DPR-71 and DPR-62 from 2558 megawatts thermal (MWt) to 2923 MWt.

Subsequently, in a letter dated December 17, 2001 (Serial: BSEP 01-0163), CP&L submitted responses to a RAI concerning, in part, a planned Main Generator Lockout Load Shed Modification supporting extended power uprate (EPU). On January 17, 2002, the NRC provided an electronic version of a RAI concerning the impact of the Main Generator Lockout Load Shed Modification on the BSEP probabilistic safety analysis of EPU. The response to this RAI follows.

NRC Question 13-1

Please identify the nonsafety-related 4kV motors involved in the modification that allows for these loads to be selectively, manually tripped from the control room.

Response to Question 13-1

The Main Generator Lockout Load Shed Modification will not require Control Room Operators to manually trip loads from the Control Room in response to an event. Key-lock selector switches, located on the subject breakers' cubicle doors, will be used for the load shed, added by this modification. This is consistent with the existing Loss-of-Coolant-Accident (LOCA) Load Shed configuration. Switch manipulation will be controlled via plant operating procedures and will be performed during normal system lineup at the end of an outage or when an affected standby pump is placed in service.

With exception of the Service Air Compressor, the breaker control circuit for each nonsafety-related 4kV motor supplied from 4.16kV Buses 1C(2C) and 1D(2D) will be modified to provide the capability to automatically trip the load on a main generator lockout signal. No manual operator action will be required at the time of the event. The Unit 1 and Unit 2 load shed schemes are independent of one another (e.g., only loads supplied from Unit 1 buses would be tripped on a Unit 1 load shed signal). The following table provides a listing of affected loads and describes when the load shed will be enabled for each motor.

Motor	Source Bus	Comment
Heater Drain Pump 1A(2A) Heater Drain Pump 1B(2B) Heater Drain Pump 1C(2C)	1D(2D) 1C(2C) 1D(2D)	Automatic tripping of two running Heater Drain Pump (HDP) motors on a main generator lockout signal will be enabled whenever the main generator is on-line.
Circulating Water Intake Pump 1A(2A) Circulating Water Intake Pump 1B(2B) Circulating Water Intake Pump 1C(2C) Circulating Water Intake Pump 1D(2D)	1C(2C) 1D(2D) 1C(2C) 1D(2D)	Automatic tripping of one running Circulating Water Intake Pump (CWIP) motor on a LOCA signal will be enabled whenever the main generator is on-line. Automatic tripping of a second running CWIP motor on a main generator lockout signal will be enabled upon System Dispatcher notification.
Condensate Pump 1A(2A) Condensate Pump 1B(2B) Condensate Pump 1C(2C)	1D(2D) 1C(2C) 1D(2D)	Two Condensate Pumps (CPs) normally operate with the third pump in standby operation. Automatic blocking of the starting of the standby CP whenever a LOCA signal or main generator lockout signal is present will be enabled whenever the main generator is on-line. This feature will not block automatic starting of the standby pump during normal plant operations.
Condensate Booster Pump 1A(2A) Condensate Booster Pump 1B(2B) Condensate Booster Pump 1C(2C)	1C(2C) 1D(2D) 1C(2C)	Two Condensate Booster Pumps (CBPs) normally operate with the third pump in standby operation. Automatic blocking of the starting of the standby CBP whenever a LOCA signal or main generator lockout signal is present will be enabled whenever the main generator is on-line. This feature will not block automatic starting of the standby pump during normal plant operations.
Unit 1 Turbine Building Chiller Unit 2 Turbine Building Chiller Spare Turbine Building Chiller	1C 2D 2C	Automatic tripping of this load on a main generator lockout signal will not be enabled at this time. This feature is being installed in anticipation of future grid load growth in the region.
Service Air Compressor 1D Service Air Compressor 2D	1C 2C	The breaker control circuit for this load will not be modified to provide selective tripping.

NRC Question 13-2

Please describe the impact of the operational and procedural changes of the Main Generator Lockout Load Shed Modification on the probabilistic risk assessment (PRA) specific system models, including operator actions and/or success criteria, and potential for creating or increasing the frequency of an initiating event. In addition, please describe the consequences of the operator failing to take the appropriate load shedding actions when required (i.e., following a loss of coolant accident or generator lockout).

Response to Question 13-2

There are two potential impacts of the Main Generator Lockout Load Shed Modification on the BSEP Probabalistic Safety Assessment (PSA) model. First, certain mitigation equipment, currently modeled in the PSA, will not be readily available. Second, mis-alignment of load shed switches during heavy grid load conditions could result in a trip-induced loss-of-offsite power to the AC Emergency Power System.

The first impact of the modification is due to tripping of equipment credited in the model. On a main generator lockout, the modification will automatically:

- Block the start of the standby condensate and condensate booster pump, and
- Trip the previously selected running circulating water pump once the dispatcher has notified the control room of high loading of the grid.

The second impact on the PSA is a new potential failure mode of the offsite power sources to the AC Emergency Power System. If the selector switches are improperly aligned prior to a LOCA and/or unit trip event, the voltage at the 4.16kV Emergency Buses may be insufficient to reset the Degraded Grid Voltage Relays and result in the tripping of the incoming line breakers to the 4.16kV Emergency Buses. Failure to shed one or more of the selected loads would result in greater voltage drop through the unit's startup auxiliary transformer (SAT) than presently credited in the voltage analysis. This condition could only occur when the grid and the unit's auxiliary electrical distribution system are heavily loaded. Since it is hard to predict the condition of the grid, this evaluation assumes that power to the SAT and the unit auxiliary transformer (UAT) is not available.

This modification does not impact the current success criteria in the PSA model. For example, only one condensate pump and one condensate booster pump are necessary for success of the condensate function; this does not change as a result of the modification.

The frequency of any initiating event is not expected to increase as a result of this modification. The load shedding actions occur after a unit trip, or a LOCA, and do not impact the likelihood of either of these initiators.

As discussed in Response to NRC Question 13-1, the operators are not required to take any manual load shedding actions.

NRC Question 13-3

Please provide the quantitative impact of these changes, in terms of the change in core damage frequency (CDF) and large early release frequency (LERF). This impact needs to address both aspects of the change (i.e., potential impact on existing modeled capabilities and also the potential impact of failing to perform the required actions for the EPU plant). If these changes were not modeled in the EPU risk evaluation and quantitative impacts cannot be estimated, then a sensitivity study may be acceptable that removes the credit for using the affected systems and that also increases the likelihood of a post-trip induced loss of site power and any other consequence of not performing the load shed properly.

Response to Question 13-3

The PSA model was altered, as necessary, to allow an appropriate sensitivity analysis of the potential plant conditions with and without the load shed modification. The primary assumptions used in this analysis were as follows:

- An operator error (i.e., failure to align any one of six Load Shed switches to ENABLE) results in failure of power from the SAT and UAT during a unit trip event given heavy grid load conditions.
- A conservative limited exposure time for operation of the transmission grid at maximum analyzed load limits, corresponding to an eight-hour period each day for one month.
- Since the switchyards are electrically separated, no impact is assumed to the SAT and UAT of the second, unaffected unit during the heavy grid load conditions.

The first two assumptions are conservative with respect to risk. The first assumes definite failure of the SAT and UAT even if only one switch is misaligned, irrespective of the condition of the grid. The second is a bounding estimate of the amount of time that the load on the grid might be at its maximum analyzed load limits. It should be noted that the transmission grid load has never reached the maximum analyzed load limit.

Case 1

A sensitivity analysis was performed assuming the load shed alignment was properly established by the operating staff followed by the tripping of two running circulating water pumps and the automatic blocking of the starting of the standby condensate and condensate booster pumps. No credit was given for the operator re-aligning the switch and manually starting any pump that was impacted by the load shed switches (i.e. assigned a human error probability (HEP) of 1.0 to failure to restart the pumps). CDF was calculated, and the events associated with this case did not appear above truncation, indicating a very small impact on risk. Since impact on CDF was negligible, change in LERF was deemed to be very small and was not calculated.

Case 2

A sensitivity analysis was performed assuming the load shed alignment was not properly established. A limiting grid condition was assumed for a bounding period of time. For this case, the impact on CDF was also negligible. Since impact on CDF was negligible, change in LERF was deemed to be very small and was not calculated.

In summary, the net increase in CDF for EPU, including the conservative load shed sensitivity, was not impacted by this modification and remains very small (i.e., Region III, as defined in Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated July 1998).

NRC Question 13-4

If these changes impact any of the previously identified risk results, including the prior sensitivity calculations, please provide the revised results.

Response to Question 13-4

Based on the evaluation discussed in Response to NRC Question 13-3, the implementation of the load shed modification will have only a negligible impact on the previously identified risk results, including the prior sensitivity calculations.

NRC Question 13-5

Please describe in detail the required operator actions, including the information needed to initiate the action, the time available for, and description of, each manipulation, the information needed to know that the action was successful, and the changes required to the operating procedures.

Response to Question 13-5

As previously discussed, key-lock selector switches, located on the subject breakers' cubicle doors, will be used for the Unit Trip Load Shed, added by this modification. This is consistent with the existing LOCA Load Shed configuration. Switch manipulation will be controlled via plant operating procedures and will be performed during normal system lineup at the end of an outage or when an affected standby pump is placed in service. Since switches will be enabled prior to the LOCA and/or unit trip event, no manual operator action is required.

Normal load shed switch alignment will be configured as described in the response to item 1. In the event that a main generator lockout occurs, two running HDP motors will automatically trip and the standby CP and standby CBP motors will be automatically blocked from starting. In the event a Unit Trip with LOCA occurs, one running CWIP motor will also trip.

During periods of abnormally high grid load conditions, "part-time" tripping of a second running CWIP motor on a main generator lockout signal will be enabled. Section DTRM-GP-24 of the "Dispatcher's Technical Reference Manual (DTRM)" requires the System Dispatcher to inform the affected BSEP unit's Control Room Operator when the Eastern Transmission Area load is approaching the point where the required post-unit trip minimum switchyard voltage can no longer be sustained. When it has been determined that the Eastern Transmission Area can no longer support the required LOCA and/or post-unit trip minimum switchyard voltage, a second notification will be made. The time between notifications is expected to be several hours. Prior to the second notification, Operators will refer to plant procedure 1(2)-OP-50, "Unit Trip Load Shedding of Selected Loads." This procedure will provide guidance to enable the main generator lockout load shed feature for the second running CWIP on a "part-time" basis. In the event that a main generator lockout occurs, this pump will automatically trip without any manual operator action. Upon System Dispatcher notification that the grid has returned to normal load conditions, the main generator lockout load shed switch for this load will be procedurally returned to the disable position.

The following procedures will be modified to implement the load shed scheme.

- The operating procedures for the CPs and the CBPs will be revised to enable Unit Trip Load Shed and LOCA Load Shed feature on standby pumps to prevent starting during these events.

- The operating procedure for the CWIPs will be revised to enable the LOCA Load Shed feature on one running pump.

- The operating procedure for the HDPs will be revised to enable the Unit Trip Load Shed feature on the two running pumps.

- The operating procedure for the Electrical Distribution System will be revised to enable "part-time" Unit Trip Load Shed feature on a second running Circulating Water Intake Pump when notified by System Dispatcher of abnormal grid load conditions.

- The operating procedure for Turbine Building Chillers will be revised to acknowledge existence of Unit Trip Load Shed feature and to show normal switch position as disabled.

- The annunciator procedures for the affected pump motors will be revised to reflect tripping of the pump motors on a unit trip event.

- Emergency Operating Procedure 0EOP-01-LEP-01, "Alternate Coolant Injection," will be revised to provide instructions for disabling the load shed feature on a Heater Drain Pump, if the pump is required for alternate coolant injection.

- Abnormal Operating Procedures 0AOP-37.0, "Low Condenser Vacuum," and 0AOP-37.1 "Intake Structure Blockages," will be revised to reflect selector switch position for one running CWIP on low condenser vacuum and intake structure blockage, respectively.