CP&L
A Progress Energy Company

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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
REQUEST FOR LICENSE AMENDMENTS
EXTENDED POWER UPRATE

Gentlemen:

In accordance with the Code of Federal Regulations, Title 10, Parts 50.90 and 2.101, Carolina Power & Light (CP&L) Company is requesting a revision to the Operating Licenses (OLs) and the Technical Specifications (TSs) 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. This request also includes supporting TS changes necessary to implement the increased power level.

On November 1, 1996, the NRC issued Amendments 183 and 214 for Units 1 and 2, respectively, which authorized an increase in the maximum power level for each unit from 2436 MWt to 2558 MWt. The proposed EPU represents an increase of approximately 20% above original rated thermal power (RTP) and approximately 15% above the current RTP. Enclosure 1 provides a listing, including a brief discussion of the justification, of the proposed changes to the operating licenses and the TSs.

Enclosure 2 provides a list of planned modifications necessary to support EPU. These modifications will be implemented during the next two refueling outages on each unit (i.e., refueling outages beginning in March 2002 (B114R1) and March 2004 (B115R1) for Unit 1 and March 2003 (B216R1) and March 2005 (B217R1) for Unit 2). Modifications performed during the first refueling outage on each unit will allow for a 5 to 7 percent RTP increase. Modifications performed during the second refueling outage should allow the units to achieve the full uprate to 2923 MWt. CP&L has evaluated the modifications currently planned to support EPU and determined that they do not constitute a material alteration to the plant, as discussed in 10 CFR 50.92. These modifications constitute planned actions on

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the part of CP&L. Further evaluations may identify the need for additional modifications or obviate the need for some modifications currently identified. As such, this is not a formal commitment to implement the modifications exactly as described or per the proposed schedule.

The basis for this request was prepared following the guidelines contained in the NRC-approved, General Electric (GE) Company Licensing Topical Reports (LTRs) for Extended Power Uprate (EPU) Safety Analysis: NEDC-32424P-A (ELTR-1), February 1999, and NEDC-32523P-A (ELTR-2), February 2000, and its Supplement 1, Volumes I and II. Enclosure 3 contains NEDC-33039P, "Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2 Extended Power Uprate," dated August 2001 (i.e., the Power Uprate Safety Analysis Report (PUSAR)). The PUSAR is a summary of the results of the safety analyses performed for the BSEP 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), 2.790(a)(4), and 2.790(d)(1). An affidavit supporting this request is provided in Enclosure 4. The NRC may duplicate this submittal, including the PUSAR, for the purpose of internal review.

PUSAR Sections 2.4, "Stability;" 4.3, "Emergency Core Cooling System Performance;" 9.1, "Reactor Transients" (i.e. Anticipated Operational Occurrences); and 10.7, "Plant Life;" are based, in part, on the guidelines contained in GE's Constant Pressure Power Uprate LTR NEDC-33004P, dated March 2001. NEDC-33004P is currently under review by the NRC. The BSEP PUSAR includes Appendix A, "Constant Pressure Extended Power Uprate Supplement," which contains the justifications contained in those portions of NEDC-33004P relied upon in the BSEP PUSAR. As such, the BSEP PUSAR is a stand alone document and NRC approval of NEDC-33004P is not required to support approval of the BSEP EPU.

Additionally, CP&L is taking exception to one of the large transient tests which requires an automatic scram from high power (i.e., main steam isolation valve (MSIV) closure), specified in Section 5.11.9 and Appendix L, Section L.2 of ELTR-1. Enclosure 6 provides justification for not performing this test.

This request, while not being submitted as a risk informed licensing action, as defined by 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, was evaluated from a risk perspective. As demonstrated in Section 10.5 of the PUSAR, when the guidelines established in Regulatory Guide 1.174 are applied, the calculated results from the Level 1 and 2 Probabilistic Safety Analyses (PSA) represent a very small risk increase in core damage frequency (CDF) and small risk increase in large early release frequency (LERF). The best estimate of the risk increase for at-power internal events due to the EPU is a delta CDF of 4E-7/year (i.e., an increase of 1.6% over the base CDF of 2.55E-5/year). The best estimate for at-power internal events results in a delta LERF of 1.9E-7/year (i.e., an increase of 4.5% over the base LERF of 4.27E-6/year).

Transition to the GE14 fuel design is necessary to achieve the full EPU. As a result, modification to the Standby Liquid Control (SLC) system is required to increase the injection capability. Options to support transition to GE14 fuel that were considered included: (1) raising minimum sodium pentaborate solution volume limits for the SLC tank, (2) increasing the boron atomic enrichment to the amount required to meet EPU with two pump operation, and (3) increasing the boron atomic enrichment to a higher value to achieve single pump/squib valve success criteria. CP&L has elected to upgrade the SLC system by increasing neutron absorber concentration to a level that enables single SLC pump/squib valve success criteria. Enhancements resulting from this modification allow the BSEP PSA success criteria for the SLC system to be revised from the current two pump/squib valve criteria to a single pump/squib valve criteria. When this modification is taken into account, the overall PSA change after the EPU, will be a net 9% reduction in the internal events CDF and a corresponding 28% reduction in LERF.

CP&L has performed an assessment of environmental impacts of the proposed EPU from 2558 MWt to 2923 MWt. This assessment was performed by comparing the environmental impacts of the EPU to those previously identified by the U. S. Atomic Energy Commission in the 1974 Final Environmental Statement (FES) for continued construction and proposed issuance of an operating license for BSEP and the 1997 Environmental Assessment for a 5 percent thermal power uprate. The comparisons show that the conclusions of the FES and Environmental Assessment remain valid for operation at 2923 MWt. Enclosure 5 contains a Supplement to the Brunswick Steam Electric Plant Environmental Report. The intent is to provide sufficient information for the NRC to evaluate the environmental impact of the power uprate in accordance with the requirements of 10 CFR 51.

In addition to the proposed amendment, CP&L is proposing a change to the licensing bases with regard to containment overpressure. BSEP is currently committed to the provisions of Safety Guide 1 (i.e., Regulatory Guide 1.1), "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps." As a result of the proposed EPU, CP&L is revising this commitment. Specifically, credit for containment overpressure will be taken to assure adequate net positive suction head (NPSH) is available for low pressure emergency core cooling system (ECCS) pumps following a design basis accident. This change is consistent with actions taken by other utilities who have sought EPUs. Enclosure 7 provides the justification for the proposed change in commitment.

As a result of the EPU, the peak suppression pool temperature for a postulated station blackout (SBO) event is increasing from the currently calculated 199.2 °F to 201.0 °F. This is well within the suppression chamber design temperature of 220 °F. However, the NRC Safety Evaluation Report (SER) for SBO, dated October 4, 1990, assumes a suppression pool temperature limit of 200 °F. The slightly elevated peak suppression pool temperature does not present a concern. The calculated peak suppression pool temperature of 207.7 °F for a design basis loss-of-coolant accident (LOCA) exceeds this postulated SBO condition. As such, based on the results of the evaluation of the design basis LOCA condition, the increased suppression pool temperature is acceptable with respect to component operability. Section 9.3.2 of the PUSAR addresses the SBO event and Section 4 demonstrates the acceptability of containment and ECCS equipment under EPU design basis LOCA conditions. Additionally, the Reactor Core Isolation Cooling (RCIC) system was evaluated and found to be acceptable under the new SBO conditions.

In support of the BSEP EPU project, CP&L has requested, via separate submittals, two additional license amendment requests. The first of these submittals (i.e., Serial: BSEP 01-0076, dated June 26, 2001) supports modifications being made to revise the BSEP thermal-hydraulic stability long-term solution from the existing Boiling Water Reactor Owners' Group (BWROG) Enhanced Option I-A long-term solution to the BWROG Option III solution. The changes requested in BSEP 01-0076 are based on current RTP (i.e., 2558 MWt). Certain RTP based parameters are affected by EPU; changes to these parameters are discussed in Enclosure 1 and justified in the PUSAR.

The second submittal (BSEP 01-0063, dated August 1, 2001) requests a full scope application of an Alternative Source Term (AST) for BSEP. The BSEP EPU was analyzed and the BSEP PUSAR was prepared accounting for AST.

PUSAR Section 3.3.1, "Reactor Vessel Fracture Toughness," states that the TS pressure versus temperature (P/T) curves for the reactor coolant system (RCS) are being modified to accommodate EPU and that this will be addressed in a separate licensing amendment. The NRC is currently reviewing a change to Technical Specification 3.4.9, "RCS Pressure and Temperature (P/T) Limits," (i.e., BSEP 01-0034, dated May 1, 2001) which revises the existing normal operating and hydrostatic and leak testing P/T curves. Originally, CP&L anticipated that sufficient margin was built into the P/T curves submitted via BSEP 01-0034 to bound fluences expected under EPU conditions for up to 32 effective full power years (EFPY). However, when revised core designs, necessary to support EPU were evaluated, it was determined that the pending revisions do not bound EPU conditions for the entire 32 EFPY. To address this issue, CP&L intends to submit a revision to the pending curves by September 30, 2001.

Enclosures 8 and 9 provide marked-up pages to the operating licenses and TSs, showing the revisions resulting from EPU, for Units 1 and 2, respectively. Due to the number of TS pages affected by both EPU and the thermal-hydraulic stability long-term solution change discussed above, typed operating license and TS pages for EPU will be submitted after issuance of the amendments associated with the change to the BWROG Option III solution. Enclosure 10 provides marked-up TS bases pages for Unit 1. These pages are being submitted for information only and do not require issuance by the NRC.

As previously stated, modifications performed during the first refueling outage on each unit will allow for a 5 to 7 percent uprate. As such, Unit 1 will be in the position to implement the first uprate at the completion of the March 2002 refueling outage. Although, for planning and cost benefit purposes, it was assumed that the requested EPU amendments will be issued in October 2002, CP&L requests that the proposed license amendments be issued by June 1, 2002, to support implementation prior to summer load demands.

CP&L requests that the Unit 1 EPU amendment, once approved, be issued with an effective date of either (1) the completion of the B114R1 refueling outage (i.e., the March 2002 refueling outage), or (2) immediately, if issued after the B114R1 outage is completed. The Unit 2 amendment effective date should be upon completion of the B216R1 refueling outage (i.e., the March 2003 refueling outage). To support implementation of the Technical

Specification changes, CP&L requests an implementation period of 120 days following the license amendments becoming effective.

In accordance with 10 CFR 50.91(b), CP&L is providing a copy of the proposed license amendments to Mr. Mel Fry of the State of North Carolina.

Please refer any questions regarding this submittal to Mr. David C. DiCello, Manager - Regulatory Affairs, at (910) 457-2235.

Sincerely,

John S. Keenan

John S. Keenan

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Enclosures:

1. Proposed Changes to the Operating Licenses and Technical Specifications
2. List of Planned Modifications
3. NEDC-33039P, "Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2 Extended Power Uprate," dated August 2001
4. Affidavit for Withholding NEDC-33039P from Public Disclosure
5. Supplement to the Brunswick Steam Electric Plant Environmental Report
6. Justification for Exception to Large Transient Testing Requirements
7. Revision to Licensing Bases - Containment Overpressure
8. Marked-up Technical Specification Pages - Unit 1
9. Marked-up Technical Specification Pages - Unit 2
10. Marked-up Technical Specification Bases Pages - Unit 1 (For Information Only)

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 (with enclosures except as noted):

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ENCLOSURE 1

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62
REQUEST FOR LICENSE AMENDMENTS
EXTENDED POWER UPRATE

Proposed Changes to the Operating Licenses and Technical Specifications

Background

In accordance with the Code of Federal Regulations, Title 10, Parts 50.90 and 2.101, Carolina Power & Light (CP&L) Company is requesting a revision to the Operating Licenses (OLs) and the Technical Specifications (TSs) 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. This request also includes supporting TS changes necessary to implement the increased power level. The proposed uprate represents an increase of approximately 20% above original RTP and approximately 15% above the current RTP. On November 1, 1996, the NRC issued Amendments 183 and 214 for Units 1 and 2, respectively. These amendments authorized an increase in the maximum power level for each unit from 2436 MWt to 2558 MWt.

The following table presents the current requirement, the proposed change, and a brief discussion of the basis for the change.

Proposed OL and TS Changes		
Current	**Proposed**	**Discussion**
OL Section 2.C.(1) The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of 2558 megawatts thermal.	**OL Section 2.C.(1)** The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of 2923 megawatts thermal.	Revised maximum licensed power level based on General Electric (GE) report NEDC-33039P, "Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2 Extended Power Uprate," dated August 2001 (i.e., PUSAR - contained in Enclosure 3). PUSAR Section 1.2.1
1.1 Definitions - Rated Thermal Power (RTP) RTP shall be a total reactor core heat transfer rate to the reactor coolant of 2558 MWt.	**1.1 Definitions - Rated Thermal Power (RTP)** RTP shall be a total reactor core heat transfer rate to the reactor coolant of 2923 MWt.	Revised maximum licensed power level based on GE report, NEDC-33039P. PUSAR Section 1.2.1

Proposed OL and TS Changes		
Current	**Proposed**	**Discussion**
Safety Limit (SL) 2.1.1.1 With the reactor steam dome pressure < 785 psig or core flow < 10% rated core flow: THERMAL POWER shall be ≤ 25% RTP.	**SL 2.1.1.1** With the reactor steam dome pressure < 785 psig or core flow < 10% rated core flow: THERMAL POWER shall be ≤ 23% RTP.	The existing ≤ 25% RTP limit for the TS Safety Limit was based on generic analyses, evaluated up to approximately 50% of original RTP, for the plant with the highest average bundle power (i.e., BWR 6) for all of the BWR product lines. This generic average bundle power was 4.8 MWt/bundle. The BSEP Extended Power Uprate (EPU) will result in an average bundle power of 5.2 MWt/bundle. To maintain the same margin as provided by the original generic analyses, the BSEP SL percent RTP for EPU conditions is reduced to ≤ 23%. PUSAR Section 9.1
TS 3.1.3, Control Rod Operability ***Condition D*** -----------------NOTE----------------- Not applicable when THERMAL POWER > 10% RTP. -- Two or more inoperable control rods not in compliance with banked position withdrawal sequence (BPWS) and not separated by two or more OPERABLE control rods.	**TS 3.1.3, Control Rod Operability** ***Condition D*** -----------------NOTE----------------- Not applicable when THERMAL POWER > 8.75% RTP. -- Two or more inoperable control rods not in compliance with banked position withdrawal sequence (BPWS) and not separated by two or more OPERABLE control rods.	Out of sequence control rods may increase the potential reactivity worth of a dropped control rod during a control rod drop accident (CRDA). The BPWS is enforced by the Rod Worth Mimimizer (RWM). Condition D (i.e., the percent RTP at which inoperable control rods, not in compliance with BPWS, need to be restored) is revised, consistent with the operability requirements of the RWM. The revised percent of RTP remains constant with the existing percent RTP in terms of absolute thermal power and steam flow. See also discussion for changes to TS 3.3.2.1, below. PUSAR Section 5.3.12

Proposed OL and TS Changes		
Current	**Proposed**	**Discussion**
TS 3.1.6, Rod Pattern Control *Applicability* MODES 1 and 2 with THERMAL POWER ≤ 10% RTP.	**TS 3.1.6, Rod Pattern Control** *Applicability* MODES 1 and 2 with THERMAL POWER ≤ 8.75% RTP.	Control rod patterns during startup conditions are controlled by the operator and the RWM which enforces the BPWS. Therefore, the applicability of TS 3.1.6 is revised, consistent with the operability requirements of the RWM. The revised percent of RTP remains constant with the existing percent RTP in terms of absolute thermal power and steam flow. See also discussion for changes to TS 3.3.2.1, below. PUSAR Section 5.3.12
TS 3.2.1, Average Planar Linear Heat Generation Rate (APLHGR) *Applicability* THERMAL POWER ≥ 25% RTP. *Required Action B.1* Reduce THERMAL POWER to < 25% RTP. *SR 3.2.1.1 Frequency* Once within 12 hours after ≥ 25% RTP <u>AND</u> 24 hours thereafter	**TS 3.2.1, Average Planar Linear Heat Generation Rate (APLHGR)** *Applicability* THERMAL POWER ≥ 23% RTP. *Required Action B.1* Reduce THERMAL POWER to < 23% RTP. *SR 3.2.1.1 Frequency* Once within 12 hours after ≥ 23% RTP <u>AND</u> 24 hours thereafter	The APLHGR is a measure of the average LHGR of all the fuel rods in a fuel assembly at any axial location. Limits on the APLHGR are specified to ensure that the fuel design limits are not exceeded during anticipated operational occurrences and that the peak cladding temperature during a postulated design basis loss-of-coolant accident (LOCA) does not exceed 10 CFR 50.46 limits. This change provides consistency with the revision to SL 2.1.1.1, thereby maintaining an acceptable margin to the APLHGR limits. PUSAR Section 9.1
TS 3.2.2, Minimum Critical Power Ratio (MCPR) *Applicability* THERMAL POWER ≥ 25% RTP. *Required Action B.1* Reduce THERMAL POWER to < 25% RTP. *SR 3.2.2.1 Frequency* Once within 12 hours after ≥ 25% RTP <u>AND</u> 24 hours thereafter	**TS 3.2.2, Minimum Critical Power Ratio (MCPR)** *Applicability* THERMAL POWER ≥ 23% RTP. *Required Action B.1* Reduce THERMAL POWER to < 23% RTP. *SR 3.2.2.1 Frequency* Once within 12 hours after ≥ 23% RTP <u>AND</u> 24 hours thereafter	MCPR is the ratio of the fuel assembly power that would result in the onset of boiling transition to the actual fuel assembly power. The operating limit MCPR is established to ensure that no fuel damage results during anticipated operational occurrences. This change provides consistency with the revision to SL 2.1.1.1, maintaining an acceptable margin to the MCPR limits. PUSAR Section 9.1

Proposed OL and TS Changes		
Current	**Proposed**	**Discussion**
TS 3.3.1.1, Reactor Protection System (RPS) Instrumentation ***Required Action E.1*** Reduce THERMAL POWER to < 30% RTP. ***SR 3.3.1.1.16*** Verify Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions are not bypassed when THERMAL POWER is ≥ 30% RTP. ***Table 3.3.1.1-1 Functions 8 and 9, Applicable Conditions*** Function 8 ≥ 30% RTP Function 9 ≥ 30% RTP	**TS 3.3.1.1, Reactor Protection System (RPS) Instrumentation** ***Required Action E.1*** Reduce THERMAL POWER to < 26% RTP. ***SR 3.3.1.1.16*** Verify Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP. ***Table 3.3.1.1-1 Functions 8 and 9, Applicable Conditions*** Function 8 ≥ 26% RTP Function 9 ≥ 26% RTP	The Turbine Stop Valve (TSV) closure and Turbine Control Valve (TCV) fast closure scram bypass trip allows these scrams to be bypassed when reactor power is sufficiently low, such that the scram function is not needed to mitigate a Turbine/Generator (T/G) trip. This power level is the analytical limit for determining the actual trip setpoint, which comes from the turbine first stage pressure (TFSP). Because the turbine bypass capacity is not being changed by EPU, the corresponding percentage of RTP is being revised to maintain the current absolute thermal power value in MWt, corresponding to the analytical limit. PUSAR Section 5.3.11 and Table 5-1
TS 3.3.1.1, Reactor Protection System (RPS) Instrumentation ***SR 3.3.1.1.3*** -----------------NOTE----------------- Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. --- Adjust the average power range monitor (APRM) channels to conform to the calculated power while operating at ≥ 25% RTP.	**TS 3.3.1.1, Reactor Protection System (RPS) Instrumentation** ***SR 3.3.1.1.3*** -----------------NOTE----------------- Not required to be performed until 12 hours after THERMAL POWER ≥ 23% RTP. --- Adjust the average power range monitor (APRM) channels to conform to the calculated power while operating at ≥ 23% RTP.	To ensure that the APRMs are accurately indicating the true core average power, the APRMs are adjusted to conform to the reactor power calculated from a heat balance. It is difficult to accurately maintain APRM indication of core thermal power consistent with a heat balance when power is too low. At low power levels, a high degree of accuracy is unnecessary because of the large, inherent margin to thermal limits (MCPR and APLHGR). This change provides consistency with the revision to SL 2.1.1.1, TS 3.2.1 and TS 3.2.2. PUSAR Section 9.1

Proposed OL and TS Changes		
Current	**Proposed**	**Discussion**
TS 3.3.1.1, Reactor Protection System (RPS) Instrumentation ***Table 3.3.1.1-1 Function 2b (APRM Simulated Thermal Power – High), Allowable Value*** Function 2b $\leq$ 0.66W + 62.0% RTP[(b)] ***Table 3.3.1.1-1 Note (b)*** (b) $\leq$ [0.66(W - ΔW) + 62.0% RTP] when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating." The value of ΔW is defined in plant procedures.	**TS 3.3.1.1, Reactor Protection System (RPS) Instrumentation** ***Table 3.3.1.1-1 Functions 2b (APRM Simulated Thermal Power – High), Allowable Value*** Function 2b $\leq$ 0.55W + 62.6% RTP[(b)] ***Table 3.3.1.1-1 Note (b)*** (b) $\leq$ [0.55(W - ΔW) + 62.6% RTP] when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating." The value of ΔW is defined in plant procedures.	The APRM flow-biased scram equation was changed to incorporate an increase in the Power/Flow map operating region due to power uprate. This was accomplished by applying the ratio of the original licensed thermal power (OLTP) to the EPU. The margin to scram from the Maximum Extended Load Line Limit Analysis (MELLLA) line has remained essentially unchanged. A new allowable value (AV) was established relative to the new analytical limit (AL). For two recirculation loop operation (TLO), the AL for the flow-biased portion of the APRM Simulated Thermal Power (STP) scram is revised. The fixed portion (i.e., clamp) of the APRM STP scram remains unchanged. For single recirculation loop operation, the AL for the fixed portion (i.e., clamp) of the APRM STP scram is the same as that for TLO and remains the same, in terms of percent of the rated thermal power, for EPU conditions. Therefore, the AV of the APRM STP scram clamp remains unchanged.

Proposed OL and TS Changes		
Current	**Proposed**	**Discussion**
TS 3.3.2.1, Control Rod Block Instrumentation *SR 3.3.2.1.2* ------------------NOTE------------------ Not required to be performed until 1 hour after any control rod is withdrawn at ≤ 10% RTP in MODE 2. -- Perform CHANNEL FUNCTIONAL TEST. *SR 3.3.2.1.3* ------------------NOTE------------------ Not required to be performed until 1 hour after THERMAL POWER is ≤ 10% RTP in MODE 1. -- Perform CHANNEL FUNCTIONAL TEST. *SR 3.3.2.1.5* Verify the RWM is not bypassed when THERMAL POWER is ≤ 10% RTP. *Table 3.3.2.1-1, Note (f)* With THERMAL POWER ≤ 10% RTP.	**TS 3.3.2.1, Control Rod Block Instrumentation** *SR 3.3.2.1.2* ------------------NOTE------------------ Not required to be performed until 1 hour after any control rod is withdrawn at ≤ 8.75% RTP in MODE 2. -- Perform CHANNEL FUNCTIONAL TEST. *SR 3.3.2.1.3* ------------------NOTE------------------ Not required to be performed until 1 hour after THERMAL POWER is ≤ 8.75% RTP in MODE 1. -- Perform CHANNEL FUNCTIONAL TEST. *SR 3.3.2.1.5* Verify the RWM is not bypassed when THERMAL POWER is ≤ 8.75% RTP. *Table 3.3.2.1-1, Note (f)* With THERMAL POWER ≤ 8.75% RTP.	The function of the RWM is to support the operator by enforcing rod patterns until reactor power has increased to the low power setpoint (LPSP). Above the LPSP, sufficient negative reactivity feedback mechanisms exist to limit the severity of a worst-case CRDA. The RWM LPSP is based on total steam flow as a measure of reactor power, and it remains constant in terms of absolute thermal power and steam flow. Therefore, the setpoint in percent rated power is lowered proportional to the power increase. PUSAR Section 5.3.12
TS 3.3.2.2, Feedwater and Main Turbine High Water Level Trip Instrumentation *Applicability* THERMAL POWER ≥ 25% RTP *Required Action C.1* Reduce THERMAL POWER to < 25% RTP.	**TS 3.3.2.2, Feedwater and Main Turbine High Water Level Trip Instrumentation** *Applicability* THERMAL POWER ≥ 23% RTP *Required Action C.1* Reduce THERMAL POWER to < 23% RTP.	The feedwater and main turbine high water level trip instrumentation is required to ensure that fuel limits are not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases for TS 3.2.1 and TS 3.2.2, sufficient margin to these limits exists at low power levels. This change provides consistency with the revision to SL 2.1.1.1, TS 3.2.1 and TS 3.2.2. PUSAR Section 9.1

Proposed OL and TS Changes		
Current	Proposed	Discussion
TS 3.7.6, Main Turbine Bypass System *Applicability* THERMAL POWER ≥ 25% RTP. ***Required Action B.1*** Reduce THERMAL POWER to < 25% RTP.	**TS 3.7.6, Main Turbine Bypass System** *Applicability* THERMAL POWER ≥ 23% RTP. ***Required Action B.1*** Reduce THERMAL POWER to < 23% RTP.	The Main Turbine Bypass system is required to ensure that the fuel limits are not violated during the turbine generator load rejection transient. As discussed in the Bases for TS 3.2.1 and TS 3.2.2, sufficient margin to these limits exists at low power levels. This change provides consistency with the revised percentage of RTP established for the TSV or TCV RPS scram functions (i.e., Table 3.3.1.1-1 Functions 8 and 9) discussed above. PUSAR Section 9.1

ENCLOSURE 2

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62
REQUEST FOR LICENSE AMENDMENTS
EXTENDED POWER UPRATE

List of Planned Modifications

The following is a list of currently planned modifications necessary to support Extended Power Uprate (EPU). Unless otherwise indicated, the modifications will be implemented on both Brunswick Steam Electric Plant (BSEP) Unit 1 and Unit 2. These modifications will be implemented during the next two refueling outages on each unit (i.e., refueling outages beginning in March 2002 (B114R1) and March 2004 (B115R1) for Unit 1 and March 2003 (B216R1) and March 2005 (B217R1) for Unit 2). Modifications performed during the first refueling outage on each unit will allow for a 5 to 7 percent uprate, from Rated Thermal Power (RTP). Modifications performed during the second refueling outage should allow the units to achieve the full uprate to 2923 megawatts thermal (MWt). The following modifications constitute planned actions on the part of Carolina Power & Light (CP&L) Company. Further evaluations may identify the need for additional modifications or, on the contrary, obviate the need for some modifications. As such, this list is not a formal commitment to implement the modifications exactly as described or per the proposed schedule. Additionally, various setpoint changes and changes to indicating ranges on certain control room and in-plant instrumentation, which may be necessary, are not listed.

Modifications Supporting Initial Uprate

1. First Load of GE14 Fuel

   Unit 2 loaded the first batch of GE14 fuel during the Spring 2001 refueling outage.

2. High Pressure Turbine Replacement and Electro-Hydraulic Control Admission Mode Change

3. Main Generator Rewind (Unit 1)

   This modification was completed on Unit 2 during the Spring 2001 refueling outage.

4. Reactor Feedwater Pump Turbine Replacement

5. Isophase Bus Cooling Upgrade (Unit 1)

6. Out-of-Step Relay and Blocking Modification

   This modification addresses grid stability issues under EPU conditions.

7. Feedwater Heater Replacement

   Unit 1 will require replacement of feedwater heaters 5A and 5B to support the initial uprate. Unit 2 does not require replacement of any feedwater heaters to support the initial uprate. However, for convenience, feedwater heater 4B, whose replacement is required to support the full uprate, will be replaced during the Spring 2003 refueling outage.

8. Condensate Cooling Modification

9. Generator Lockout Load Shed Modification

   This modification assures adequate loss-of-coolant accident voltage support following a generator lockout.

10. Nuclear Instrumentation Upgrade

    This modification results in a revision to the BSEP long-term solution to thermal-hydraulic stability from the existing Boiling Water Reactor Owners' Group (BWROG) Enhanced Option I-A long-term solution to the BWROG Option III solution. CP&L has requested, via separate submittal, a license amendment request (Serial: BSEP 01-0076, dated June 26, 2001) which supports this change.

11. Main Steam and Feedwater Vibration Monitoring Instrumentation

12. Potential modifications supporting Alternative Source Term implementation

Modifications Supporting Full Uprate

1. Standby Liquid Control (SLC) Upgrade

   SLC upgrade supports the transition to GE14 fuel design, necessary to achieve the full EPU. This modification is not required until the second reload with GE14 on each unit. As such, the associated license amendments, revising the sodium pentaborate solution concentration requirements contained in Technical Specification 3.1.7, "Standby Liquid Control (SLC) System," will be submitted separate from the EPU submittal. Since Unit 2 has already had one reload using GE14 fuel, issuance of this amendment will be required in Spring 2003, to support initial Unit 2 uprate.

2. Stator Cooling Water Upgrade

3. Power System Stabilizer

   This modification will provide feedback to the voltage regulatory to dampen oscillations following grid disturbances.

4. Isophase Bus Cooling Upgrade (Unit 2)

5. Main Transformer Replacement/Rewind

6. Condensate System Upgrade

7. Feedwater Heater Replacement

   Unit 1 will require replacement of feedwater heaters 3A, 3B, and 4A to support the final uprate. Unit 2 will require replacement of feedwater heater 4B (i.e., to be performed during the Spring 2003, refueling outage) to support the final uprate.

8. Moisture Separator Reheater (MSR) Upgrade

9. Reactor Building Component Cooling Water System Heat Exchanger Retubing (Unit 1)

10. Condensate Filter Demineralizer (CFD) Upgrade

    This modification will install longer filter elements to increase CFD filter element life.

11. MSR Relief Valve Modifications

    This modification will implement higher setpoints and replace a spring in one valve

12. Reactor Feed Pump Upgrade

ENCLOSURE 4

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62
REQUEST FOR LICENSE AMENDMENTS
EXTENDED POWER UPRATE

Affidavit For Withholding NEDC-33039P
From Public Disclosure

General Electric Company

AFFIDAVIT

I, **George B. Stramback,** being duly sworn, depose and state as follows:

(1) I am Project Manager, Regulatory Services, General Electric Company ("GE") and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in the GE proprietary report NEDC-33039P, *Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2 Extended Power Uprate,* Class III (GE Proprietary Information), dated August 2001. This document, taken as a whole, constitutes a proprietary compilation of information, some of it also independently proprietary, prepared by the General Electric Company. The independently proprietary elements are identified by bars marked in the margin adjacent to the specific material.

(3) In making this application for withholding of proprietary information of which it is the owner, GE relies upon the exemption from disclosure set forth in the Freedom of Information Act ("FOIA"), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), 2.790(a)(4), and 2.790(d)(1) for "trade secrets and commercial or financial information obtained from a person and privileged or confidential" (Exemption 4). The material for which exemption from disclosure is here sought is all "confidential commercial information", and some portions also qualify under the narrower definition of "trade secret", within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) Some examples of categories of information which fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by General Electric's competitors without license from General Electric constitutes a competitive economic advantage over other companies;

b. Information which, if used by a competitor, would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product;

c. Information which reveals cost or price information, production capacities, budget levels, or commercial strategies of General Electric, its customers, or its suppliers;

d. Information which reveals aspects of past, present, or future General Electric customer-funded development plans and programs, of potential commercial value to General Electric;

e. Information which discloses patentable subject matter for which it may be desirable to obtain patent protection.

Both the compilation as a whole and the marked independently proprietary elements incorporated in that compilation are considered proprietary for the reason described in items (4)a. and (4)b., above.

(5) The information sought to be withheld is being submitted to NRC in confidence. That information (both the entire body of information in the form compiled in this document, and the marked individual proprietary elements) is of a sort customarily held in confidence by GE, and has, to the best of my knowledge, consistently been held in confidence by GE, has not been publicly disclosed, and is not available in public sources. All disclosures to third parties including any required transmittals to NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary agreements which provide for maintenance of the information in confidence. Its initial designation as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in paragraphs (6) and (7) following.

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge. Access to such documents within GE is limited on a "need to know" basis.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist or other equivalent authority, by the manager of the cognizant marketing function (or his delegate), and by the Legal Operation, for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GE are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary agreements.

(8) The information identified by bars in the margin is classified as proprietary because it contains detailed results and conclusions from these evaluations, utilizing analytical models and methods, including computer codes, which GE has developed, obtained NRC approval of, and applied to perform evaluations of transient and accident events in the GE Boiling Water Reactor ("BWR"). The development and approval of these system, component, and thermal hydraulic models and computer codes was achieved at a significant cost to GE, on the order of several million dollars.

The remainder of the information identified in paragraph (2), above, is classified as proprietary because it constitutes a confidential compilation of information, including detailed results of analytical models, methods, and processes, including computer codes, and conclusions from these applications, which represent, as a whole, an integrated process or approach which GE has developed, obtained NRC approval of, and applied to perform evaluations of the safety-significant changes necessary to demonstrate the regulatory acceptability of a given increase in licensed power output for a GE BWR. The development and approval of this overall approach was achieved at a significant additional cost to GE, in excess of a million dollars, over and above the very large cost of developing the underlying individual proprietary analyses.

To effect a change to the licensing basis of a plant requires a thorough evaluation of the impact of the change on all postulated accident and transient events, and all other regulatory requirements and commitments included in the plant's FSAR. The analytical process to perform and document these evaluations for a proposed power uprate was developed at a substantial investment in GE resources and expertise. The results from these evaluations identify those BWR systems and components, and those postulated events, which are impacted by the changes required to accommodate operation at increased power levels, and, just as importantly, those which are <u>not</u> so impacted, and the technical justification for not considering the latter in changing the licensing basis. The scope thus determined forms the basis for GE's offerings to support utilities in both performing analyses and providing licensing consulting services. Clearly, the scope and magnitude of effort of any attempt by a competitor to effect a similar licensing change can be narrowed considerably based upon these results. Having invested in the initial evaluations and developed the solution strategy and process described in the subject document GE derives an important competitive advantage in selling and performing these services. However, the mere knowledge of the impact on each system and component reveals the process, and provides a guide to the solution strategy.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GE's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GE's comprehensive BWR technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development

of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods, including justifications for not including certain analyses in applications to change the licensing basis.

GE's competitive advantage will be lost if its competitors are able to use the results of the GE experience to avoid fruitless avenues, or to normalize or verify their own process, or to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions. In particular, the specific areas addressed by any document and submittal to support a change in the safety or licensing bases of the plant will clearly reveal those areas where detailed evaluations must be performed and specific analyses revised, and also, by omission, reveal those areas not so affected.

While some of the underlying analyses, and some of the gross structure of the process, may at various times have been publicly revealed, enough of both the analyses and the detailed structural framework of the process have been held in confidence that this information, in this compiled form, continues to have great competitive value to GE. This value would be lost if the information as a whole, in the context and level of detail provided in the subject GE document, were to be disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources, including that required to determine the areas that are not affected by a power uprate and are therefore blind alleys, would unfairly provide competitors with a windfall, and deprive GE of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing its analytical process.

STATE OF CALIFORNIA)
) ss:
COUNTY OF SANTA CLARA)

George B. Stramback, being duly sworn, deposes and says:

That he has read the foregoing affidavit and the matters stated therein are true and correct to the best of his knowledge, information, and belief.

Executed at San Jose, California, this 8th day of August 2001.

George B. Stramback
General Electric Company

Subscribed and sworn before me this 8th day of August 2001.

TERRY J. MORGAN
Commission # 1304914
Notary Public - California
Santa Clara County
My Comm. Expires May 18, 2005

Notary Public, State of California

ENCLOSURE 5

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62
REQUEST FOR LICENSE AMENDMENTS
EXTENDED POWER UPRATE

Supplement to the Brunswick Steam Electric Plant
Environmental Report

Supplemental Environmental Report

Brunswick Steam Electric Plant
Extended Power Uprate

Prepared for:
CP&L
P.O. Box 1551
Raleigh, North Carolina 27602

Prepared by:
Tetra Tech NUS, Inc.
900 Trail Ridge Road
Aiken, South Carolina 29803
June 2001

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1.0 EXECUTIVE SUMMARY

This Supplemental Environmental Report contains CP&L's assessment of environmental impacts of the proposed Brunswick Steam Electric Plant (BSEP) extended power uprate (EPU) from 2,558 megawatts-thermal (MWt) to 2,923 MWt at each unit. The intent is to provide sufficient information for NRC to evaluate the environmental impact of the power uprate in accordance with the requirements of 10 CFR 51.

The environmental impacts of the EPU are described and compared to those previously identified by the U. S. Atomic Energy Commission in the (1974) Final Environmental Statement (FES) for continued construction and proposed issuance of an operating license for BSEP and the (1997) Environmental Assessment for a 5 percent thermal power uprate. The comparisons show that the conclusions of the FES and Environmental Assessment remain valid for operation at 2,923 MWt.

In a few cases, the analysis in the FES (or an underlying assumption) was no longer applicable, because of developments in the basic science underlying the analysis or refinements in scientific methodologies (e.g., dose assessment). In other cases, the FES did not contain sufficient detail for comparing the impact of extended power operation or there had been changes in pertinent regulatory standards (e.g., offsite radiation doses from airborne effluents). In these instances, the analysis was updated or more detail was presented and conclusions based on current regulatory criteria.

The BSEP EPU would be implemented without making extensive changes to plant systems that directly or indirectly interface with the environment. All necessary modifications would be in or on existing buildings at BSEP; none would involve land disturbance or new construction outside of established facility areas. There would be no change in the amount of water withdrawn from the Cape Fear River for condenser cooling, and a relatively small increase in the amount of waste heat discharged to the Atlantic Ocean. Generation of LLRW would increase slightly compared to the current generation rate, but would still be bounded by FES values. There would be no change in the quantity of radioactivity released to the environment through liquid effluents, and only a small increase in airborne emissions of radioactivity. All offsite radiation doses would be small and within applicable regulatory standards.

CP&L concludes that the environmental impacts of operation at 2,923 MWt are either bounded by impacts described in earlier National Environmental Policy Act assessments or constrained by applicable regulatory criteria. As a consequence, CP&L believes that the EPU would not significantly (as defined in 40 CFR 1508.27) affect human health or the environment.

2.0 INTRODUCTION

CP&L, a Progress Energy Company, is committed to operating Brunswick Steam Electric Plant (BSEP) in an environmentally responsible manner. Plant activities including design, construction, maintenance, and operations are conducted in a manner so as to protect the environment and preserve natural resources. BSEP has operated for more than 25 years in compliance with state and federal environmental regulations, while providing safe, reliable, and economical electrical service to its customers in North and South Carolina.

In keeping with this commitment to environmental stewardship and in accordance with regulatory requirements, CP&L has conducted a comprehensive environmental evaluation of the proposed extended power uprate (EPU) of BSEP from 2,558 megawatts-thermal (MWt) to 2,923 MWt for both Unit 1 and Unit 2. This would increase the electrical output of the two nuclear units to 958 megawatts-electric (MWe) Reference Unit Power and 951 MWe Reference Unit Power, respectively. Reference Unit Power is a measurement of electrical output that normalizes the impact of seasonal variation, primarily due to differences in condenser inlet temperature. The proposed uprate will serve the future power requirements of the CP&L customer base, whose peak demand is expected to increase by approximately 40 percent from 2001 to 2015 (CP&L 2000).

This environmental evaluation is provided pursuant to 10 CFR 51.41 ("Requirements to Submit Environmental Information") and is intended to support the U.S. Nuclear Regulatory Commission (NRC) environmental review of the proposed uprate. The uprate would require the issuance of operating license amendments for Units 1 and 2. The regulation (10 CFR 51.41) requires that applications to the NRC be in compliance with Section 102(2) of the National Environmental Policy Act (NEPA) and consistent with the procedural provisions of NEPA (40 CFR 1500-1508). There are no NRC regulatory requirements or guidance documents specific to preparation of environmental reports for EPUs.

In January 1974, the U.S. Atomic Energy Commission (AEC; predecessor agency to the NRC) published the *Final Environmental Statement related to the continued construction and proposed issuance of an operating license for the Brunswick Steam Electric Plant Units 1 and 2* (AEC 1974). The AEC concluded that the issuance of full-term operating licenses for Units 1 and 2, subject to certain conditions related to monitoring and mitigation, was the appropriate course of action under NEPA. This decision was based on the analysis presented in the Final Environmental Statement (FES) and the weight of environmental, economic, and technical information reviewed by the AEC. It also took into consideration the environmental costs and economic benefits of operating BSEP. The AEC subsequently issued operating licenses to BSEP that authorized operation up to a maximum power level of 2,436 MWt per unit.

In 1997, a 5 percent thermal power uprate was carried out and evaluated by the NRC in an Environmental Assessment (EA). This increased the licensed thermal power level of BSEP Units 1 and 2 from 2,436 MWt to 2,558 MWt. The NRC's EA of this uprate concluded that the uprate "...would not have a significant effect on the quality of the human environment" (Federal Register, Vol. 61, No. 209, pp. 55673-55675) and resulted in a Finding of No Significant Impact.

This Supplemental Environmental Report is intended to provide sufficient detail on both the radiological and non-radiological environmental impacts of the proposed EPU to allow NRC to make an informed decision regarding the proposed action. It does not reassess the current environmental licensing basis or justify the environmental impacts of operating at the current licensed power level of 2,558 MWt.

3.0 PROPOSED ACTION AND NEED

BSEP is located in Brunswick County in southeastern North Carolina, approximately 2.5 miles north of the town of Southport. The Plant is situated on approximately 1,250 acres of land that include the powerblock area and support facilities, the nuclear exclusion zone, a buffer zone, a 3-mile-long intake canal that is used to withdraw cooling water from the Cape Fear River, and a 6-mile long discharge canal that conveys heated effluent to the Atlantic Ocean (Figure 3-1).

BSEP's two units both use boiling water reactors and turbine-generators designed and built by General Electric. Construction permits for Units 1 and 2 were issued in February 1970. The U.S. Atomic Energy Commission approved the Unit 2 operating license (DPR-62) in December 1974; commercial operation began on November 3, 1975. The Unit 1 operating license (DPR-71) was approved in September 1976; commercial operation began on March 18, 1977.

3.1. Proposed Action

The proposed action is to increase the licensed core thermal level of BSEP Units 1 and 2 from 2,558 megawatts-thermal (MWt) to 2,923 MWt per unit, which represents an increase of approximately 15 percent from the current licensed core thermal level of 2,558 MWt. This change in core thermal level would require the U.S. Nuclear Regulatory Commission (NRC) to amend the facility's two operating licenses. The operational goal of the EPU is a corresponding (approximately 14 percent) increase in each nuclear unit's electrical output, from 841 to 958 megawatts-electric (MWe) (Unit 1) and from 835 to 951 MWe (Unit 2). This is considered an EPU because it follows a 5 percent uprate in 1997 from the original licensing basis of 2,436 MWt to 2,558 MWt. The 5 percent uprate was implemented during the Spring 1997 refueling outage (Unit 1) and the Fall 1997 refueling outage (Unit 2).

CP&L intends to increase the power level in two phases. Unit 1 would be increased to 111 percent of originally licensed thermal power (OLTP) during the Spring 2002 Refueling Outage and to 120 percent of OLTP during the Spring 2004 Refueling Outage. Unit 2 would be increased to 111 percent of OLTP during the Spring 2003 Refueling Outage and to 120 percent of OLTP during the Spring 2005 Refueling Outage. This Supplemental Environmental Report evaluates environmental impacts of increase to 120 percent of OLTP, which equates to 2,923 MWt per unit.

3.2. Need for Action

CP&L forecasts a 40 percent increase in electrical demand by 2015 within its North Carolina-South Carolina service area. Although current generating capacity is sufficient to meet demand, population growth and industrial development in the region require CP&L to plan for increased generating capacity over the short- and long-term. Large baseload plants are not planned for the foreseeable future. CP&L expects to meet increases in customer demand over the next 15 years by increasing the number of gas-fired combustion turbines in service or by purchasing power from other utility and non-utility generators. The cost of adding the additional generating capacity at BSEP is roughly equivalent to the cost of constructing several small (50-MWe) combustion turbine units. However, nuclear power generation costs (including the costs of fuel, operations, and maintenance) are approximately one-third those of natural gas-powered generation. The proposed EPU would provide increased capacity at a lower production cost than natural gas or other fossil fuel alternatives.

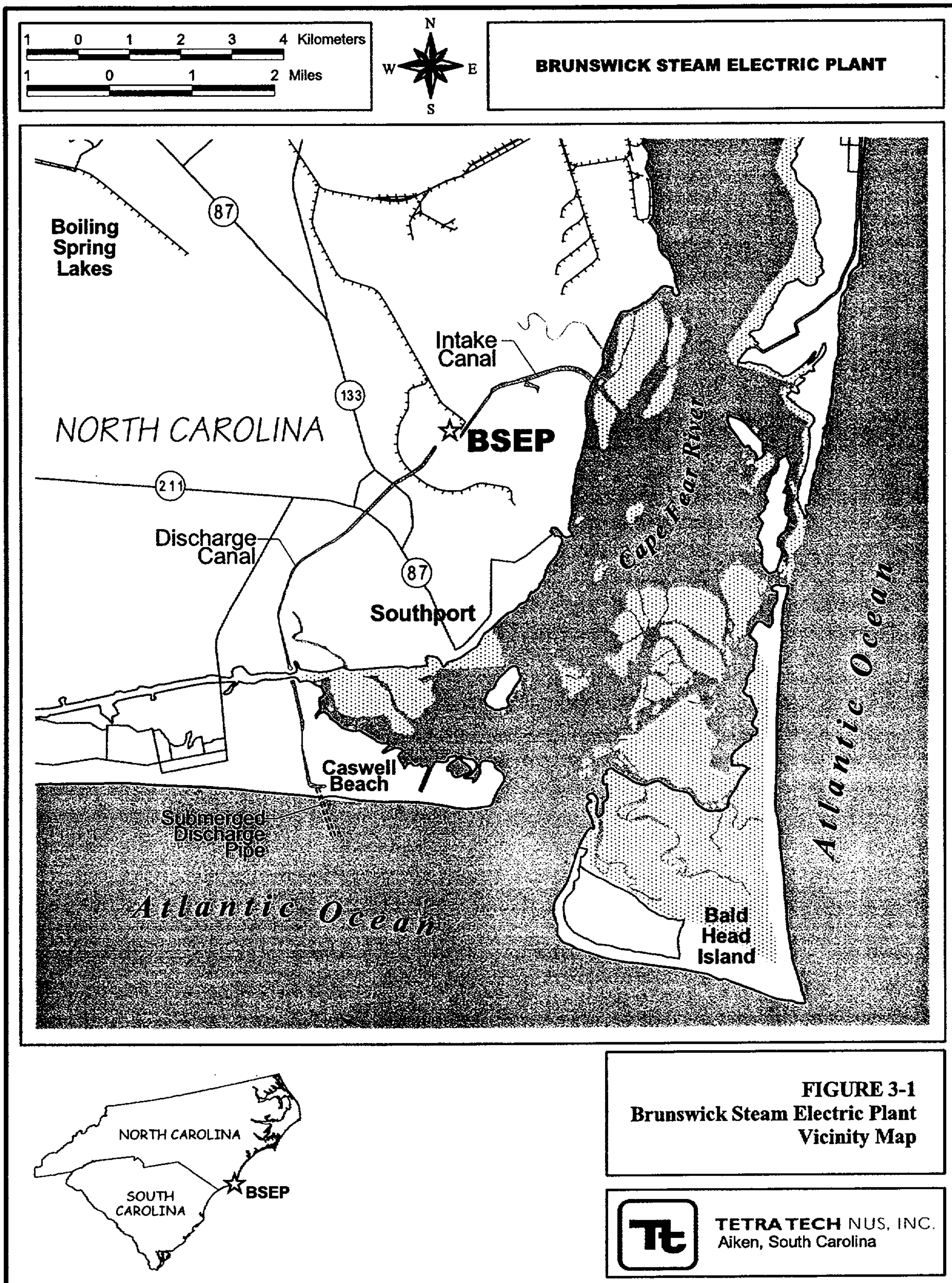

FIGURE 3-1
Brunswick Steam Electric Plant
Vicinity Map

TETRA TECH NUS, INC.
Aiken, South Carolina

4.0 OVERVIEW OF OPERATIONAL AND EQUIPMENT CHANGES

CP&L proposes to uprate the power of BSEP in a phased approach over an approximately four-year period during normal refueling outages. The first phase includes modifications required for the plant to uprate from 105 percent to 111 percent of the originally licensed thermal power. The second phase would raise the thermal power to 120 percent. Table 4-1 depicts the schedule and activities proposed for each unit's uprate.

Table 4-1
Equipment Modifications to Support BSEP Uprates

March 2002 Unit 1 Refueling Outage Uprate to 111%	March 2003 Unit 2 Refueling Outage Uprate to 111%	March 2004 Unit 1 Refueling Outage Uprate to 120%	March 2005 Unit 2 Refueling Outage Uprate to 120%
GE14 fuel	GE14 fuel	GE14 fuel	GE14 fuel
Power Range Nuclear instrumentation modification	Standby Liquid Control modification	Standby Liquid Control modification	Main transformers replacement
Main generator rewind[a,b]	Power Range Nuclear instrumentation modification	Main transformers replacement	Isophase bus cooling modification
Isophase bus cooling modification	High-pressure turbine replacement	Generator cooling modifications	Generator cooling modifications
High-pressure turbine replacement	Reactor feedwater pump turbine replacement	Feedwater heater replacements	Feedwater heater replacements
Reactor feedwater pump turbine replacement	Condensate System upgrade	Moisture Separator Reheater upgrades	Moisture Separator Reheater upgrades
Condensate heat exchangers and cooling tower addition	Condensate heat exchangers and cooling tower addition	Condensate System upgrade	Reactor feed pump upgrade
Electrical grid protection modifications	Electrical grid protection modifications	Reactor feed pump upgrade	
Feedwater heater replacements	Feedwater heater replacements		

a. This activity would have been performed regardless of the uprate.
b. The Unit 2 main generator rewind occurred during a 2001 outage.

The activities needed to produce thermal power increases are a combination of those that directly produce more power and those that must accommodate the effects of the power increase. The primary means of producing more power are a change to a more densely packed fuel bundle, an operational change in reactor thermal-hydraulic parameters, and upgrade of Balance of Plant Capacity by component replacement or modification. Other changes include replacing the high-pressure turbine, replacing selected feedwater heaters that are already operating at capacity, providing additional cooling for some plant systems, various electrical upgrades to accommodate the higher currents and to improve electrical stability, modifications to accommodate greater steam and condensate flow rates, and instrumentation upgrades that include replacing parts, changing setpoints, and modifying software.

5.0 SOCIOECONOMIC CONSIDERATIONS

The proposed EPU at BSEP would provide significant economic benefits to the surrounding communities through tax revenues, local business revenues funded by plant construction and operations, and gainful employment of the local population.

5.1. Current Socioeconomic Status

Currently BSEP employs approximately 750 full-time staff and about 235 contract employees. During outages, approximately 850 contract personnel provide additional support. Through income, sales, and personal property taxes, employees' salaries contribute to the surrounding communities and make evident the fact that current employment levels continue to have a positive influence on the economies of the region. Additionally, property taxes paid by BSEP to Brunswick County are significant. Table 5-1 presents the County's property tax revenues attributable to BSEP for the past five years. For the year 2000, the equalized assessed value of BSEP was 687 million dollars. The Brunswick EPU would increase the plant's equalized assessed value, which would result in increased tax revenues for the County. Communities surrounding BSEP have benefited and will continue to benefit from local taxes paid by CP&L. Public services, including law enforcement, fire protection, public education, and health services, receive a significant amount of economic support through these tax revenues.

Table 5-1
Taxes Paid by CP&L for Brunswick Steam Electric Plant for Tax Years 1996-2000

Tax Year	Property Tax Payment
1996	$5,800,000
1997	$5,700,000
1998	$4,500,000
1999	$4,200,000
2000	$4,200,000

Source: Keith 2001.

5.2. Extended Uprate Impacts to Socioeconomics

Although the proposed EPU is not expected to affect the size of the BSEP workforce and would not have a material effect on the labor force required for future plant outages, there would be positive economic benefits to the local economy. Employee income, sales, and personal property taxes would continue to contribute to the surrounding communities. BSEP's current equalized assessed values would continue to translate into substantial tax revenues to the surrounding jurisdictions. Additionally, it is likely that the assessed value of the BSEP would increase as a result of capital upgrades. Local taxing authorities would experience an increase in the plant's property tax base and significant positive economic benefits would be realized by local, regional, and national businesses contributing goods and services to the proposed EPU. In addition, engineering and consulting firms, equipment suppliers, and service industries would receive payments for EPU activities. The direct revenue associated with EPU installation would not be sustained once modifications are complete. However, the economic benefits associated with the EPU would represent a positive impact on the regional economies, both in terms of the one-time benefit of EPU installation and in the long-term viability of operating BSEP.

5.3. Conclusion

The socioeconomic effects of implementing the EPU at BSEP are, in part, dependent on the ability of CP&L to remain competitive in a market that is being deregulated. Implementation of EPU is not the primary factor affecting the overall competitiveness of CP&L, but it is a factor that must be considered. CP&L has determined that, notwithstanding the uncertainty associated with deregulation, the favorable capital cost of the proposed EPU compared to new generating capacity, and the reduction in incremental operating costs that result from EPU, make the EPU project attractive. In addition, the investment associated with the proposed EPU will result in increased revenues, thus enhancing the value of BSEP as a provider of electricity.

6.0 COST – BENEFIT ANALYSIS

The largest direct benefit resulting from an EPU to CP&L's current capacity is the additional supply of more than 200 megawatts of reliable electrical power for residential and commercial customers. A national comparison of power-producing alternatives indicates that nuclear power generation production costs are approximately 25 percent of purchased power (Progress Energy 2000), 88 percent of coal-fired power (Nuclear Energy Institute 2001), 58 percent of oil-fired power (Nuclear Energy Institute 2001), and 32 percent of natural gas power production (Tetra Tech NUS 2001a). Power production costs represent a combination of fuel, operations, and maintenance costs.

A quantitative study of environmental costs of alternatives would not be necessary to recognize that significant environmental benefits may be derived from an EPU when compared to other options regarding additional capacity. As demonstrated herein, an EPU would not result in significant environmental costs. Unlike fossil fuel plants, BSEP does not routinely emit sulfur dioxide, nitrogen oxides, carbon dioxide, or other atmospheric pollutants during normal operations. Routine operation of BSEP at extended power uprate conditions would not contribute to greenhouse gases or acid rain. The radiological effects of the uranium fuel cycle are described in 10 CFR 51.51 and 51.52 and are classified as small. The tables in 10 CFR 51.52 encompass the EPU level. While the project would produce additional spent nuclear fuel, the added amount would not be appreciable and would be accommodated by CP&L's spent fuel pools.

Based upon the discussion above, it is reasonable to conclude the BSEP EPU provides an economic advantage over other alternatives for additional generation. EPU involves a cost-effective utilization of an existing asset, with relatively little environmental impact, making it the preferred means of securing additional generating capacity.

7.0 NON-RADIOLOGICAL ENVIRONMENTAL IMPACTS

7.1. Terrestrial Effects

7.1.1. Land Use

The proposed EPU for BSEP would not affect land use at the 1,250-acre BSEP site or in adjoining areas of Brunswick County. No new construction is planned outside of existing facilities and no expansion of buildings, roads, parking lots, equipment storage areas, or transmission facilities would be required to support the EPU. EPU is not expected to require substantial additional volumes of industrial chemicals, fuels, or lubricants and, as a result, would not require additional space for above- or below-ground storage tanks. Three small mechanical-draft cooling towers, each approximately 24 feet by 24 feet, would be erected on the roof of the Radwaste Building (64-foot elevation) to service the new condensate cooling system. Small volumes of water treatment chemicals would be used in the new condensate cooling system, but ample storage space is available to accomodate the quantity of water treatment chemicals that would be on-site at any given time.

As discussed in Section 5.2, the EPU would not affect the size of the workforce at BSEP. Because no land disturbance would be required and because there would be no expansion of the existing workforce, impacts to aesthetic resources and historic/archeological resources would be negligible. The conclusions of the FES with respect to land use, aesthetics, and historic/archeological resources remain valid for the EPU.

7.1.2. Transmission Facilities

<u>Transmission Lines</u>

The EPU would not require any new transmission lines and would not require changes in the maintenance and operation of existing transmission lines, switchyards, or sub-stations. Right-of-way maintenance practices (including vegetation management) would not be affected by the EPU. The only change to transmission facilities from the EPU would be increased current. Voltage would be unchanged.

<u>Shock Hazards</u>

Power uprate does not increase the probability of shock from primary or secondary currents. Transmission lines are designed in accordance with the applicable shock prevention provisions of the National Electric Safety Code®.

<u>Electromagnetic Fields (EMF)</u>

The increased electrical power output would cause a corresponding current rise on the transmission system and this would result in an increased magnetic field. CP&L adopts by reference the NRC conclusion that chronic effects of EMF on humans are not quantified at this time and no significant impacts to terrestrial biota have been identified (NRC 1996).

7.1.3. Miscellaneous Wastes

CP&L reviewed a number of plant systems and associated (non-radiological) discharges for potential effects from the proposed extended power uprate. Discharge limits for systems such as roof drains, yard drains, low volume waste, metal cleaning waste, and the sewage treatment plant are set in the BSEP National Pollutant Discharge Elimination System (NPDES) permit. Discharges from these systems are not expected to change under EPU conditions; therefore, the impact on the environment will not change. Nonradiological parameters affected by the EPU will remain within the bounding conditions established in the NPDES permit, and as a consequence no significant impacts will result from the operation of BSEP under EPU conditions.

7.1.4. Noise

The FES for continued construction and operation of BSEP (AEC 1974) evaluated potential noise impacts of operation of the Caswell Beach (see Figure 3-1) pumping station, which is the only noise source associated with Plant operation that has the potential for offsite impacts. Estimated noise levels at 250 and 500 feet from the pumping station were higher (55.7 and 49.7 dBA, respectively) than background levels (AEC 1974), but below those known to disturb wildlife or the beach-going public (Golden et al. 1980). CP&L has received no complaints from the public to date about noise levels at the pumping station, and no mitigative measures have been necessary.

The EPU would not produce measurable changes in the character, sources, or intensity of noises generated at BSEP or the Caswell Beach pumping station. The new equipment necessary to implement power uprate would be installed within or upon existing buildings at BSEP. No significant increase in ambient noise levels is expected inside or outside of the Plant. The FES conclusions for noise levels remain valid for EPU conditions.

7.1.5. Terrestrial Biota

The area that encompasses the BSEP site includes a variety of natural communities that are defined by differences in soils, topography (surface elevation), hydrologic regime, and proximity to the salt waters of the Atlantic Ocean. Moving from upland to lowland, these include xeric pine-hardwood forests, longleaf pine-wiregrass communities, pine savannahs and pocosins, and dune-strand communities. Most upland portions of the 1,250-acre BSEP site are comprised of planted (loblolly) pines and scrub oaks, however. The FES (AEC 1974) contains detailed descriptions of these plant communities and the animals that are typically associated with them. Because the proposed action would not involve any land disturbance, any increase in noise levels outside the plant, or any increase in the size of the workforce (which would imply a general increase in activity on the site and increased vehicular traffic), there would be no impacts to terrestrial biota beyond those previously described in the FES.

In 1998, CP&L conducted a self-assessment that evaluated more than 90 sensitive plant and animal species that could occur in the vicinity of BSEP (based on lists published by Pacific Northwest National Laboratory, the U.S. Fish and Wildlife Service, and the North Carolina Heritage Program) and evaluated potential threats to these species from activities at BSEP (CP&L 1998).

The self-assessment showed that three federally listed terrestrial species (Table 7-1) could potentially be affected by BSEP operations, future facility expansion, or other activities: the red-cockaded woodpecker (*Picoides borealis*), rough-leaved loosestrife (*Lysimachia asperulaefolia*), and Cooley's meadowrue (*Thalictrum cooleyi*). Red-cockaded woodpeckers, federally listed as endangered, are found in eastern North Carolina in mature pine forests (generally longleaf pine) with sparse understory vegetation. Suitable nesting habitat for this species is not found at BSEP, but birds may forage in the area. Rough-leaved loosestrife, a federally endangered species, is a perennial herb that occurs in pocosins in eastern North Carolina (Radford et al. 1973). Cooley's meadowrue, a federally endangered species, is a perennial herb that occurs in pine savannahs in eastern North Carolina (Radford et al. 1973). The Biological Assessment Unit of CP&L's Environmental Services Section, which conducted the self-assessment, noted that in every case, there were mechanisms in place to protect or mitigate impacts to BSEP populations (if present). Table 7-1 shows protective measures enacted by CP&L to protect these populations.

Table 7-1
Federally listed terrestrial species found in the vicinity of BSEP

Species	Federal status	Reason for concern at BSEP	Protective measures taken by CP&L
Rough-leaved loosestrife	Endangered	A population occurs on a BSEP right-of-way (offsite).	The population is protected and managed by CP&L by agreement with NC Natural Heritage Program.
Cooley's meadowrue	Endangered	A population occurs on a BSEP right-of-way (offsite).	The population is protected and managed by CP&L by agreement with NC Natural Heritage Program.
Red-cockaded woodpecker	Endangered	Known to occur in mature pine forests in Brunswick County and regularly observed in Southport-Oak Island area.	Any facility expansion involving removal of mature longleaf pine would require surveys for this species to ensure that no red-cockaded woodpeckers or trees with their nest-cavities are harmed.

Source: CP&L 1998.

Because the EPU would not involve any land disturbance, any increase in noise levels outside the Plant, any increase in the size of the BSEP workforce or any changes in the right-of-way maintenance practices, there would be no significant impacts to terrestrial biota, including threatened or endangered species.

7.2. *Hydrology*

7.2.1 BSEP Cooling Water System

BSEP is equipped with a once-through heat dissipation system that is designed to remove 11.7×10^9 (winter) to 12.0×10^9 (summer) BTUs per hour (BTU/hr) of waste heat from the condensers (two single-pass condenser sections per nuclear unit) when both reactors are operating at full power.

Under full power operation, as much as 1.05 million gallons per minute (2,335 cubic feet per second) of water are withdrawn from the Cape Fear River via a 3-mile-long intake canal for condenser cooling. After passing through the Plant's condensers, the heated water travels through a 6-mile-long discharge canal to Caswell Beach before being pumped 2,000 feet offshore through a pair of (13-foot diameter) underwater pipes that extend into the Atlantic Ocean along the bottom (Figure 3-1). Although some of the waste heat is radiated to the atmosphere from the surface of the discharge canal, the bulk of the heat is dissipated by mixing with cooler Atlantic Ocean water.

The ocean floor in the vicinity of the discharge pipes is sandy with no natural features that would attract invertebrate life or fish. The bottom is also devoid of vegetation. Tidal flow is the dominant hydrologic influence in this area with the net flow to the west, away from the mouth of the Cape Fear River.

Cooling water flow (withdrawal) rates and heat rejection rates (defined by water temperatures in the area of the ocean discharge) are limited by the provisions of NPDES permit number NC0007064, issued to CP&L on September 19, 2000 by the North Carolina Department of Environment and Natural Resources, Division of Water Quality. The permit was effective October 1, 2000 and expires on November 30, 2001.

The NPDES permit for BSEP also contains a requirement for semi-annual monitoring of water temperatures at the ocean discharge. Temperature monitoring is to be conducted once a year during the months of April – November and once a year during the months of December – March.

7.2.2 Discharges

Surface water and wastewater discharges at BSEP are regulated by the state of North Carolina. The National Pollutant Discharge Elimination System (NPDES) permit is periodically reviewed and re-issued by the North Carolina Department of Environment and Natural Resources Division of Water Quality.

As discussed in Section 7.1.1, CP&L plans to build three small mechanical-draft cooling towers to service the new condensate cooling system (non-regenerative heat exchangers). One cooling tower will be dedicated to each BSEP unit, with a "swing" tower available to accommodate either unit. Two approved water treatment chemicals, ChemTreat CL-216® (a biocide) and ChemTreat CL-4800® (a dispersant) would be used in the cooling towers according to manufacturer's recommendations for safe use. Make-up water for the new condensate cooling system will be obtained from the Brunswick County water system. Blowdown from the cooling towers will be piped to the existing storm drain system, which flows to a storm drain basin north of the plant and is pumped to a stabilization pond. Discharges from the stabilization pond flow into the BSEP intake canal. Blowdown will be automatically controlled, based on basin water conductivity. Because blowdown from the system will be relatively small (maximum blowdown rate of 130 gallons per minute) relative to the volume of the storm drain basin, and the biocide would be applied at rates only high enough to control biofouling organisms in the condensate cooling system, impacts to aquatic organisms in receiving waters (where concentrations would be much lower, by virtue of dilution) would be small. BSEP uses chlorine to control biofouling in condenser cooling water, but the NPDES permit requires monitoring at the Caswell Beach pumping station to ensure that no total residual chlorine is discharged at the ocean outfall.

Note that Special Condition 2 of the BSEP NPDES permit requires CP&L to "...obtain authorization from the Division of Water Quality prior to utilizing any new biocide in cooling waters to be discharged. The permittee shall notify the Director in writing not later than ninety (90) days prior to instituting use of any additional biocide...in cooling systems which may be toxic to aquatic life (other than those previously reported to the Division)."

7.2.3 Entrainment and Impingement

The BSEP NPDES permit currently allows the withdrawal from the Cape Fear River of 922 cubic feet of water per second (cfs), per unit, from December through March; 1,105 cfs, per unit, from April through November; and 1,230 cfs through one unit only from July through September. No changes to the flow rate of intake circulating water will occur as a result of the proposed uprated power levels; therefore, there will be no associated increase in the entrainment of planktonic organisms or in the impingement of fish or shellfish.

7.2.4 Thermal Discharge Effects

At extended power uprate conditions, the heat rejected at the main condensers would increase, resulting in higher discharge temperatures and increased heat loads at the ocean outfall. CP&L commissioned a study in 2001 to analyze the effect of the proposed uprate on water temperatures and temperature distribution in the Atlantic Ocean in the area of the discharge outfall. This study was intended to define area-temperature relationships in order to determine the effect of increased heat loads associated with the EPU (Tetra Tech NUS 2001b). Area-temperature relationships (isotherm areas) were then compared to established NPDES thermal criteria (mixing zone areas), which are defined in the BSEP NPDES permit.

Using historical data (intake temperatures, discharge temperatures, plant operating conditions, and meteorological conditions), thermal distribution was mapped (isotherms) using statistical software. Post-uprate thermal distributions were calculated using historical data and heat rejection rates (BTUs/hour) associated with uprated power levels. This yielded discharge temperatures (Tetra Tech NUS 2001b, Table 6) and thermal plume (isotherm) areas (Tetra Tech NUS 2001b, Tables 9 and 10) that would be expected under EPU conditions.

Based on the thermal study, maximum temperatures in the area of the ocean outfall could increase by 3 to 5 degrees depending on plant operating conditions (plant power level, circulating water flows).

Similarly, the area of thermal influence (defined by temperatures above ambient) would be somewhat larger under uprate conditions, but restricted to a relatively small area around the terminus of the discharge pipes. For example, the area of the surface isotherm defined by a delta-t of 1.44°F (1.44 degrees above ambient) would be less than 1,000 acres in late summer (Tetra Tech NUS 2001b, Table 9). The area of the surface isotherm defined by a delta-t of 3.96°F would be approximately 20 to 150 acres. Existing thermal criteria were scaled to account for the increased heat rejection rates associated with uprated power levels (Tetra Tech NUS 2001b), resulting in new mixing zone limits (areas) which could be applied to these uprate conditions.

In May 2001, CP&L submitted an application for renewal of the BSEP NPDES permit to the North Carolina Department of Environment and Natural Resources Division of Water Quality. Based on the thermal analysis conducted in support of the EPU, CP&L has requested that the Temperature condition of Part I A(1) of the permit be modified as follows:

(1) the temperature increase above ambient water temperature shall not exceed 7 degrees outside an area of 120 acres (the criterion was 60 acres in previous permits) included within the plume extending from the point of discharge.

(2) the temperature increase above ambient water temperature shall not exceed 0.8°C (1.44°F) increase above ambient water temperature during the months of June – August; 2.2°C (3.96°F) increase above ambient water temperature during the months of September – May. In no case should the temperature increase exceed 32°C (89.6°F) outside an area of 2,000 acres (was 1,000 acres in previous permits)

(3) the temperature increase above ambient water temperature at the bottom (defined as one foot above the ocean floor) shall not exceed 7°F for more than 1,000 feet (was 500 feet in previous permits) from the point of discharge, nor for an area of more than four acres (was two acres in previous permits).

7.2.5 Aquatic Biota

Results of thermal studies conducted in the vicinity of the ocean discharge since 1973 have indicated that there has been no adverse environmental impact on the populations of fish and shellfish passing through the area as a result of thermal inputs from the ocean discharge (CP&L 1979). Further, the proposed extended power uprate will have no significant adverse impact on these fish and shellfish populations. This conclusion can be reached based upon results of twenty-seven years of thermal and environmental monitoring plus results of the BSEP Uprate Thermal Discharge Analysis completed during May 2001 (Tetra Tech NUS 2001b). Evaluation of these results lead to several key indicators supporting this conclusion:

- There is no critical habitat in the vicinity of the ocean discharge. The ocean floor is flat and sandy with no natural features such as rocky outcrops or vegetative cover that would attract fish and invertebrates.

- The area of thermal input is insignificant compared to the area along the entire Brunswick County coastline.

- Historical studies have been conducted on the thermal tolerances of the more abundant organisms typically collected in the vicinity of the ocean discharge. Copeland (1976) concluded that brown shrimp, white shrimp, and croaker would experience loss of equilibrium only if temperatures exceeded 86°F. The temperature at which spot experienced loss of equilibrium was found to be 95°F (Hodson et al. 1979). Predicted areal coverage based upon results from the BSEP Uprate Thermal Discharge Analysis show that, in general, thermal tolerances for these species would not be exceeded.

- The most abundant organisms are demersal and would therefore remain near the bottom underneath the 86°F isotherm. Further, these organisms are fully capable of swimming away from the small area with higher temperature and would do so.

- The potential problems associated with elevated temperatures is further reduced by the fact that during the late summer when the most elevated temperatures would occur, most fish have seasonally vacated the near-shore coastal waters for deeper, offshore waters (Schwartz et al 1979).

- Potential thermal effects on the larvae entering the estuary will be minimal due to the net westward drift of the near-shore coastal waters in the vicinity of the ocean discharge. Copeland et al. (1979) demonstrated that larvae enter the estuary from offshore waters to the east along Frying Pan shoals and the ship's channel. Thus, most larvae would not be exposed to the small area of the thermal plume to the west.

7.2.6 Sensitive Aquatic Species

As discussed Section 7.1.5, CP&L conducted a self-assessment in 1998 that evaluated potential threats from activities at BSEP to more than 90 sensitive plant and animal species that could occur in the vicinity of the plant (CP&L 1998).

The self-assessment showed that three federally listed aquatic species (Table 7-2) could potentially be affected by BSEP operations, future facility expansion, or other activities: the loggerhead sea turtle (*Caretta caretta*), the green sea turtle (*Chelonias mydas*), and the Kemp's Ridley sea turtle (*Lepidochelys kempi*). The loggerhead sea turtle, the sea turtle most commonly observed along the south Atlantic coast, nests as far north as Ocracoke Inlet, North Carolina in late spring and early summer (Martof et al. 1980). The green sea turtle migrates along the North Carolina coast and occasionally comes ashore to bask, but does not normally nest in the Carolinas (Martof et al. 1980). The Kemp's Ridley sea turtle is an uncommon visitor to the Carolinas (immature and sub-adult individuals), but nests almost exclusively along the northern Gulf Coast of Mexico and on Padre Island, Texas (Martof et al. 1980, Ogren 1992). Table 7-2 also includes mitigative measures taken by CP&L to protect these sensitive species.

Table 7-2
Federally listed aquatic species found in the vicinity of BSEP

Species	Federal status	Reason for Concern at BSEP	Protective Measures Taken by CP&L
Loggerhead sea turtle	Threatened	Has been collected in the BSEP intake canal.	Blocker panels installed in diversion structure; blocker panel maintenance; intake canal patrols and removal of turtles.
Green sea turtle	Threatened	Has been infrequently collected in the intake canal.	Blocker panels installed in diversion structure; blocker panel maintenance; intake canal patrols and removal of turtles
Kemp's Ridley sea turtle	Endangered	Has been infrequently collected in the intake canal.	Blocker panels installed in diversion structure; blocker panel maintenance; intake canal patrols and removal of turtles

Source: CP&L 1998.

In compliance with the provisions of the Endangered Species Act that require Federal agencies to consult with the National Marine Fisheries Service (NMFS) when actions potentially jeopardize listed species, NRC in 1998 initiated a formal Section 7 consultation with the NMFS. The NMFS reviewed data on incidental takes of sea turtles at BSEP and the operation of the cooling water intake system and issued a final Biological Opinion (with an incidental take statement) in January 2000 that concluded:

> "...operation of the water intake system of the Brunwick Steam Electric Plant...is not likely to jeopardize the continued existence of the loggerhead, leatherback, green, hawksbill, or Kemp's ridley sea turtles. No critical habitat has been designated for these species in the action area; therefore, none will be affected. This conclusion is based on the proposed action's {operation of the cooling water intake system} anticipated effects on each of these species being limited to the incidental take, through death or injury, on a small number of immature sea turtles per year over the next 20 years."

Because the EPU would not involve any increase in cooling water withdrawal rates, approach velocities at the diversion structure and the cooling water intake structure would be unchanged. There would be no increase in debris loading or fouling of screen panels at the diversion structure, and no increased likelihood that screen damage would occur. As a result, there would be no increase in the incidence of sea turtles or other large marine animals moving into the intake canal through breaches in the diversion structure.

As noted previously, the proposed EPU is expected to result in a small increase (3-5 degrees F) in maximum water temperatures at the ocean outfall (Tetra Tech NUS 2001b, Table 6). In addition, the area of thermal influence (defined by temperatures above ambient) would be somewhat larger, but restricted to a relatively small area around the terminus of the discharge pipes. This isolated area of heated water would have no effect on sea turtles in fall and winter months, when these species are largely absent, and would have little or no effect on these species in spring and summer beyond creating a small (relative to the expanse of open ocean that lies off Oak Island) area that might be avoided, if temperatures are greater than those preferred by the species in question.

Because the discharge area is 2,000 feet offshore and approximately 2 miles from the mouth of the Cape Fear River, there is virtually no potential for blocking or restricting the inshore (from open ocean to shallows) or longshore (along the beach) movement of fish or turtles or movement in and out of the Cape Fear River. Another factor mitigating potential thermal impacts to fish and sea turtles is the tendency of heated water to move to the surface. Because buoyant force moves hotter, less-dense water to the surface, deeper waters are less affected by the thermal discharge. Animals (e.g., sea turtles, fish, and other nektonic organisms) moving through the thermal discharge area are, in effect, presented with two means of avoiding the thermally impacted area: they may swim around or under the warmer water.

8.0 RADIOLOGICAL ENVIRONMENTAL IMPACTS

8.1. Radioactive Waste Streams

The radioactive waste systems at BSEP are designed to collect, process, and dispose of radioactive wastes in a controlled and safe manner. The design bases for these systems during normal operation are to limit discharges in accordance with 10 CFR 20, to limit exposures to the requirements of 40 CFR 190, and to satisfy the design objectives of 10 CFR 50 Appendix I. Adherence to these limits and objectives would continue under the proposed EPU.

Operation at EPU conditions would not result in any physical changes to the solid waste, liquid waste, or gaseous waste systems. The safety and reliability of these systems would be unaffected by the proposed EPU. Also, EPU would not affect the environmental monitoring of any of these waste streams or the radiological monitoring requirements of the BSEP Technical Requirements Manual. Under normal operating conditions, EPU would not introduce any new or different radiological release pathways and would not increase the probability of an operator error or equipment malfunction that would result in an uncontrolled radioactive release from the radioactive waste streams. The specific effects of the proposed EPU on each of the radioactive waste systems are evaluated in the following sections.

8.1.1. Solid Waste

Solid radioactive wastes include solids recovered from the reactor process system, solids in contact with reactor process system liquids or gases, and solids used in the reactor process system operation. The largest volume of solid radioactive waste at BSEP is low-level radioactive waste (LLRW). Sources of LLRW at BSEP include resins and charcoal, sludges and filters from water processing, dry active waste (DAW) from outages and routine maintenance, and oil from plant systems. DAW includes paper, plastic, wood, rubber, glass, floor sweepings, cloth, metal, and other types of waste routinely generated during site maintenance and outages. Table 8.1 presents the annual volume of LLRW generated at BSEP for the most recent five-year period.

Table 8-1
Low-Level Radioactive Waste Generated at BSEP, 1996 – 2000

Year	Volume generated (ft^3)
1996	60,655
1997	26,444
1998	25,636
1999	19,722
2000	13,877

Source: Kitchen 2001a.

It is estimated that the EPU would result in an increase in the generation of resins, sludges, and used filters that is linear with the EPU (Kitchen 2001a). The basis for this estimate is the projected increase in the flow through plant systems that is expected due to the EPU project. Even if all LLRW, including DAW were to increase by 15 percent over the year 2000 values, this rate (15,958 cubic feet [ft^3]) would be bounded by the

Final Environmental Statement (FES), which predicted an annual generation rate of 1,357,620 ft^3 (AEC 1974, pg. III-21, first paragraph states there would be 1,650 55-gallon drums generated per unit. The total of 3,300 55-gallon drums × 7.48 ft^3/gallon = 1,357,620 ft^3). This conclusion is also true for the 5-year average LLRW generation rate (29,266 ft^3 per year) which, if increased by 15 percent (to 33,656 ft^3), would still be bounded by the FES values.

In addition to LLRW, the EPU would result in an increase in removal of control rod blades. Ten control rod blades would be replaced in each unit during the next refueling outage. For the subsequent 5 outages on each unit, 25 control rod blades would be removed (Kitchen 2001a). These wastes would be managed in a similar fashion to the existing core components. The only current option for storage of these wastes (as with other irradiated reactor components) is storage in the BSEP spent fuel pools. Frequent processing and disposal campaigns would be needed to manage the volume on a regular basis. The frequency of these processing and disposal campaigns is expected to increase linearly with the EPU.

8.1.2. Liquid Waste

Liquid radioactive wastes include liquids from the reactor process systems and liquids that have become contaminated with process system liquids. Table 8.2 presents liquid releases from BSEP for the most recent five-year period. The BSEP liquid effluent reduction program has implemented a strategy to maintain liquid releases to as low as reasonably achievable (ALARA). This philosophy is based on processing and returning all radioactive waste inputs that would not impact reactor vessel chemistry to the plant. This program, along with the initiatives provided by the BSEP Radwaste Improvement Team, led to 2000 being the lowest year in BSEP history for release volume and radioactivity releases. As noted in Table 8.2, 244,773 gallons and 2.36 millicuries of fission and activation products were released in the year 2000. These values are assumed to be valid for future normal operations, because of CP&L's decisions to continue the release of salt water intrusions, detergent drains, and fuel cask processing. Liquid effluent release volumes are not expected to increase significantly as a result of EPU (Kitchen 2001b). These values would remain bounded by the FES (AEC 1974), which estimated liquid effluent releases of about 50 curies per year (combined for both units). The offsite radiation dose consequences of these effluent releases are described in Section 8.2.

Table 8-2
Liquid Effluent Releases From the BSEP, 1996 – 2000

Year	Gallons Released	Activity Released (mCi)
1996	2,960,000	37.6
1997	886,000	19.4
1998	1,250,000	75
1999	855,000	19
2000	244,773	2.36

Source: Kitchen 2001b.

8.1.3. Gaseous Waste

Gaseous radioactive wastes principally include activation gases and fission product radioactive noble gases vented from process equipment and, under certain conditions, building ventilation exhaust air. Table 8.3 presents gaseous releases from BSEP for the most recent five-year period. Radioactive releases would increase linearly to the 15 percent EPU (Kitchen 2001b). If the year 2000 release values are assumed to be a valid representation of future normal operations, this would result in releases of approximately 100 curies of noble gases and 2.5×10^{-3} curies of particulates and iodines per year after the EPU. These values would remain bounded by the FES (AEC 1974), which estimated gaseous effluent releases of about 22,000 curies per year for noble gases and 0.83 curies per year for iodines (combined for both units). The offsite radiation dose consequences of these effluent releases are described in Section 8.2.

Table 8-3
Gaseous Effluent Releases From the BSEP, 1996 – 2000

Year	Noble Gases (Ci)	Particulates and Iodines (Ci)
1996	713	2.59×10^{-2}
1997	947	4.49×10^{-2}
1998	2,436	1.51×10^{-1}
1999	1,552	6.20×10^{-2}
2000	696	1.76×10^{-2}

Source: Kitchen 2001b.

8.2. Radiation Levels and Offsite Dose

8.2.1. Operating and Shutdown In-Plant Levels

In-plant radiation levels and associated doses are controlled by the ALARA program, as required by 10 CFR 20. CP&L has a policy of maintaining occupational dose equivalents to the individual and the sum of dose equivalents received by all exposed workers to ALARA levels. This ALARA philosophy is implemented in a manner consistent with BSEP operating, maintenance, and modification requirements and accounts for the state of technology, the economics of improvements relative to the state of technology, the economics of improvements relative to public health and safety benefits, the public interest relative to utilization of nuclear energy and licensed materials, and other societal and socioeconomic considerations. Table 8.4 presents the collective BSEP occupational radiation doses for the most recent five-year period.

Table 8-4
Collective Occupational Radiation Dose at BSEP, 1996 – 2000

Year	Collective dose (person-rem)
1996	716.2
1997	411.3
1998	395.5
1999	418.4
2000	321.8

Source: Kitchen 2001a.

The BSEP ALARA program manages exposure by:

- Minimizing the time personnel spend in radiation areas,
- Maximizing the distance between personnel and radiation areas, and
- Maximizing shielding to minimize radiation levels in routinely occupied plant areas and in the vicinity of plant equipment requiring attention.

Shielding is used throughout the Plant to protect personnel against radiation emanating from the reactors and their auxiliary systems, and to limit radiation damage to operating equipment. CP&L has determined that the current shielding designs are adequate for any dose increase that may occur after the EPU.

For EPU, normal operation radiation levels would increase by no more than the percentage increase of EPU. For conservatism, many aspects of the Plant were originally designed for higher-than-expected radiation sources. Thus, the increase in radiation levels would not affect radiation zoning or shielding in the various areas of the Plant because it is offset by conservatism in the original design, source terms used, and analytical techniques. Therefore, no new dose reduction programs are planned and the ALARA program would continue in its current form.

8.2.2. Offsite Doses at Power Uprate Conditions

Offsite doses from radioactive effluents and direct radiation is monitored at BSEP using two types of monitoring stations: direct radiation monitors and air sampling monitors. Direct radiation monitoring consists of two thermoluminescent dosimeters provided at each location to monitor the integrated radiation exposure. Air sampling monitors consist of particulate and iodine air samplers. Monitoring is performed at onsite and offsite locations, as described in the Offsite Dose Calculation Manual.

Offsite doses from liquid effluents are summarized and averaged for 1996 through 2000 (Table 8-5), according to 10 CFR 50, Appendix I. For the five-year period, average annual whole body dose was 2.99×10^{-4} millirem (mrem), and average annual dose to the critical organ was 4.06×10^{-4} mrem. As discussed in Section 8.1, no significant change in the volume or activity of water treated and released is expected as a result of EPU. Therefore, all offsite doses from liquid effluent releases would remain well below the regulatory standards contained in 10 CFR 50, Appendix I. These doses would also be bounded by the FES (AEC 1974), which predicted an offsite whole body dose of 3.9×10^{-3} mrem/year and a maximum organ dose (thyroid) of 0.019 mrem/year.

Table 8-5
Radiation Dose from Liquid Effluent Pathways, 1996-2000

	1996	1997	1998	1999	2000	Average 1996-2000 (limit)
Maximum Individual Dose						
Organ (mrem)[a]	7.49×10^{-4}	2.64×10^{-4}	7.10×10^{-4}	2.72×10^{-4}	3.66×10^{-5}	4.06×10^{-4} (20)
Whole Body (mrem)[a]	6.05×10^{-4}	2.02×10^{-4}	4.51×10^{-4}	2.08×10^{-4}	3.04×10^{-5}	2.99×10^{-4} (6)
Total Integrated and Recreation Population Dose						
Whole Body (person-rem)	5.01×10^{-4}	4.82×10^{-3}	9.31×10^{-3}	6.16×10^{-3}	3.26×10^{-3}	4.81×10^{-3}

Source: Kitchen 2001a.

a. mrem = millirem.

Note: Regulatory limits specify a generic organ dose limit; nuclide-specific critical organ limits may be lower, depending on effluent composition.

Doses to individuals from gaseous releases are summarized and averaged for 1996 through 2000 (Table 8-6) according to 10 CFR 50 Appendix I categories. For the five-year period, average annual whole body dose at the site boundary from releases of iodines, tritium, and particulate radionuclides was 7.09 mrem and average annual dose to the critical organ from these releases was 8.68×10^{-2} mrem. As discussed in Section 8.1, gaseous effluents would increase linearly with the planned percentage change in the EPU program. The offsite doses for the previous five years of operation were well below the 10 CFR 50 Appendix I standards, with the highest percentage of the regulatory standard being 22.7 percent for the average annual whole body dose at the site boundary fromreleases of iodines, tritium, and particulate radionuclides. Therefore, after the EPU, offsite doses from gaseous effluent releases would remain well below the regulatory standards contained in 10 CFR 50 Appendix I.

Table 8-6
Radiation Dose from Gaseous Effluent Pathways, 1996-2000.

	1996	1997	1998	1999	2000	Average 1996-2000 (limit)
Noble gas air dose at site boundary						
Gamma Air Dose (mrad)[a]	1.18×10^{-2}	1.26×10^{-2}	3.55×10^{-2}	2.90×10^{-2}	1.74×10^{-2}	2.13×10^{-2} (20)
Beta Air Dose (mrad)[a]	1.61×10^{-2}	1.54×10^{-2}	4.63×10^{-2}	3.57×10^{-2}	2.17×10^{-2}	2.70×10^{-2} (40)
Iodine-131, iodine-133, tritium, and particulate dose to an offsite individual						
Maximum dose at site boundary for all pathways (mrem)[b]	3.27	5.22	19.7	5.24	2.04	7.09 (30)
Maximum dose at 4.75 miles for cow-milk pathway (mrem)[b]	1.21×10^{-1}	2.07×10^{-1}	7.66×10^{-1}	2.65×10^{-1}	7.58×10^{-2}	2.87×10^{-1} (30)
Organ dose to maximally exposed individual (mrem)[b]	3.03×10^{-2}	5.06×10^{-2}	1.66×10^{-1}	9.55×10^{-2}	9.18×10^{-2}	8.68×10^{-2} (30)
Total 50-mile integrated population dose						
Thyroid (person-rem)	6.31×10^{-2}	6.83×10^{-2}	2.04×10^{-1}	9.52×10^{-2}	7.15×10^{-2}	1.00×10^{-1}
Whole Body (person-rem)	2.85×10^{-2}	1.71×10^{-2}	4.55×10^{-2}	3.79×10^{-2}	5.61×10^{-2}	3.70×10^{-2}

Source: Kitchen 2001a.

a. mrad = millirad.

b. mrem = millirem.

Note: Regulatory limits specify a generic organ dose limit, nuclide specific critical organ limits may be lower depending on effluent composition.

8.3. Radiological Consequences of Accidents

Section VI.A of the FES (AEC 1974) identified nine categories of accidents, the severity of their consequences ranging from trivial (Class 1 – small leaks into containment) to very serious (Class 9 – severe accidents). The consequence analysis presented in the FES was based on representative accidents provided in the BSEP Environmental Report (ER) prepared by CP&L (1971) as part of the original license application. Some categories of accidents were treated in detail in the subsequent Final Safety Analysis Report (FSAR) as part of the analysis of potential refueling accidents (Class 6) and design basis accidents (Class 8). The consequences of these accidents have been reassessed as part of periodic updates to the FSAR (UFSARs). Prior to the proposed EPU, NRC prepared an Environmental Assessment to address the impacts from a 105 percent uprate in the licensed power level (61 FR 55673, October 28, 1996). The Environmental Assessment determined that there would be no significant increase in radiological impacts from accidents, leading NRC to issue a finding of no significant impact (61 FR 55675, October 28, 1996). This section addresses potential radiological consequences of accidents from a proposed uprate to 120 percent of the originally licensed thermal power.

The ER estimated the collective dose from accidents to the population within 50 miles of the reactor (in rem to the thyroid and person-rem to the whole body). There are no criteria or limits on the collective dose to members of the public that can be used for comparison. In addition to estimating the collective whole body dose to the public, the FES also estimated the fraction of the 10 CFR 20 limit that could be incurred by an individual located at the site boundary at the time of an accident.

At the time the FES was prepared, this dose limit was 500 mrem per year. Since the FES was issued, the dose limit for a member to the public in 10 CFR 20 has been reduced to 25 mrem per year. In addition, the dose calculation methodology was changed substantially at the same time the 10 CFR 20 limit was reduced. Organ and whole body doses were replaced with the total effective dose equivalent (TEDE), a methodology which incorporates organ doses from radionuclide intakes as well as whole body doses from external radiation. In addition, the revised dose methodology results in internal dose conversion factors that tend to be at least a factor of two times lower for most radionuclides when compared to the old methodology.

While a comparison with dose limits in 10 CFR 20 may be appropriate for routine emissions, it is not strictly applicable to accidents with low probabilities of occurrence. The dose criteria in 10 CFR 100 apply more appropriately to such accidents. The limiting criteria are 300 rem to the thyroid from radioiodine releases and 25 rem to the whole body of an individual at the exclusion zone received over two hours from all radionuclides released in an accident. These criteria have not changed since the time of the original license application, and have been used in the UFSARs issued prior to 2001 in the evaluation of consequences from refueling accidents and other design basis accidents.

The differences in applicability of dose acceptance criteria (i.e., 10 CFR 20 vs. 10 CFR 100), as well as the changes in the criteria and calculational methodology over time (i.e., revisions to 10 CFR 20 and 10 CFR 50), make the direct comparison of impacts between the original licensed power and the proposed power uprate more challenging. In addition, the methodology used to estimate the radiological source term (i.e., the amount of radionuclides released to the environment, as well as the timing of the release) directly affects the estimation of doses to members of the public. The source term methodology used in the past for severe accident analyses was based on releases from a severely damaged core, as published in 1962 by the U.S. Atomic Energy Commission (AEC 1962) in Technical Information Document (TID) 14844, "Calculation of Distance Factors for Power and Test Reactors." Since this document was published, there have been significant advances in establishing the timing, magnitude, and chemical forms of the fission product release from severe reactor accidents. This extensive research and experience culminated in the development of a new or revised source term described in NUREG-1465, "Accident Source Terms for Light-Water Nuclear Power Plants," and published by NRC in 1995 (NRC 1995).

CP&L (2001) used the alternative radiological source term (AST) methodology established in NRC Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors" (NRC 2000), to reassess the consequences of refueling and design basis accidents. Regulatory Guide 1.183 implements the findings in NUREG-1465, and includes the revised 10 CFR 50.67 criteria. In addition, the guidance requires consideration of the dose at the site boundary over the worst two-hour interval after the accident.

In the previous guidance, only the first two hours after an accident were considered, because the bulk of the radionuclides were assumed to be released immediately following an accident.

The comparison of older analyses contained in the ER and FES with more current analyses reported in CP&L (2001) is complicated by a number of factors. As indicated earlier, the FES reports doses at the site boundary in terms of fractions of the 10 CFR 20 limit that was applicable at the time (500 mrem, whole body), as well as collective doses to the public; only collective doses are reported in the ER. The NRC's dose acceptance criteria, analysis assumptions, and acceptable source term methodologies for low- probability/ high-consequence accidents have changed significantly since the FES and ER were published. Depending on the accident, the current dose acceptance criteria contained in Regulatory Guidance 1.183 are:

- Loss of Coolant Accident (LOCA), 25 rem TEDE (30 days for containment, Emergency Core Cooling System, and Main Steam Isolation Valve leakage)
- BWR Main Steam Line Break (Instantaneous puff)
  - Fuel damage or Pre-incident Spike, 25 rem TEDE
  - Equilibrium Iodine Activity 2.5 rem TEDE
- BWR Rod Drop Accident, 6.3 rem TEDE, 24 hours
- Fuel Handling Accident, 6.3 rem TEDE, 2 hours

While the older analyses are presented for comparison, direct comparisons are difficult due to different assumptions. Where applicable, accident consequences should be evaluated against the current acceptance criteria.

8.3.1. Class 1 – Trivial Incidents - Small Leaks Inside Containment

Class 1 accidents were not considered in either the BSEP ER or the FES, consistent with the AEC guidance for environmental reports at the time. The magnitude of these leaks is bounded by those analyzed under Class 8.1 (LOCA Inside or Outside Primary Containment), because small leaks and spills are defined here as being below the Technical Specification limits. The FES concluded that the dose to an offsite individual from small leaks inside the containment building would be bounded by the design objectives for routine liquid and gaseous effluents (i.e., 5 mrem/yr). Plant improvements since the period of initial operations have led to significantly lower concentrations of radionuclides in reactor coolant than those predicted by the FES. These improvements more than offset any potential increases in activity concentrations attributable to the EPU. Therefore, any impacts from small leaks remain bounded by the criteria for routine effluents.

8.3.2. Class 2 – Miscellaneous Small Leaks Outside Containment

The BSEP ER identified small gaseous or liquid releases anywhere in the Turbine Building as being representative of this class of accidents. The bounding accident in this class was defined as a steam leak equivalent to 7 gallons per minute of saturated liquid released to the environment through the Turbine Building roof vent.

The assumed noble gas offgas activity associated with this release is 25,000 μCi/sec concentration 30 minutes downstream of the reactor. The iodine-131 release rate was assumed to be 0.013 μCi/sec, a factor of at least three times higher than the highest measured release rates from the building ventilation systems of operating BWRs. Based on these releases, the cumulative thyroid dose was estimated to be 1.5 rem to the public within 50 miles of the Plant. Cumulative whole body doses were estimated to be 0.18 person-rem.

Under EPU conditions, the activity is expected to increase linearly in proportion to the power. Therefore, a 20 percent increase in activity would be anticipated relative to the originally license thermal power output. As indicated above, actual operations result in significantly lower activity concentrations than postulated above. In addition, application of the revised dose factor methodology would further reduce the estimated dose from such a release. Therefore, the radiological consequences of this accident would not exceed those calculated in the ER.

The FES did not estimate the radiological consequences of a Class 2 accident. The rationale for dismissing this class of accidents was the same as the one used to dismiss the Class 1 accidents.

8.3.3. Class 3 – Radwaste System Failures

This class of accidents was addressed in Table VI-2 of the FES and consists of three postulated events:

- Equipment leakage or malfunction (Class 3.1)
- Release from the Offgas System (Class 3.2)
- Release of liquid waste storage (Class 3.3)

8.3.3.1. Class 3.1 – Equipment Leakage or Malfunction

Radwaste system failures were assumed to be due to either a single equipment failure or a single operator error. The ER selected two accidents, a liquid radwaste discharge and a gaseous radwaste discharge, as being representative of Class 3 accidents. These were classified as Class 3.1 events in the FES. The Class 3.2 and 3.3 accidents evaluated in the FES were analyzed as Class 8 accidents in the ER, but will be addressed here to maintain consistency with the treatment in the FES.

The discharge of liquid radwastes to the discharge canal had been postulated because at the time routine discharges were anticipated. However, current operational policies make this event extremely unlikely for both current power and EPU operating conditions. In addition, the ER postulated that a high-activity batch discharge due to operator error would be highly unlikely due to control by redundant valves. Excessive concentrations would be detected by the radiation monitor on the discharge line and result in the automatic closure of the second discharge valve. If the second valve failed to close automatically, the control room operator would have sufficient time to respond to the alarm and close the valve manually. Therefore, the consequences of such an improbable event were not considered in the ER.

The discharge of gaseous radwaste is described in the ER as the result of a loss of the drain line water seal, followed by release of 0.2 percent of a 2-minute-old gaseous diffusion mixture. The resulting release rate was estimated to be 286 μCi/sec of fission product gases, in addition to larger activities of short-lived activated nitrogen and oxygen. Collective population exposures to the whole body were estimated to be 0.043 person-rem, with negligible thyroid doses. The ER concludes that such releases are negligible compared to exposure from normal stack effluents.

As described in Section 8.3.2, operational concentration levels were expected to be at least three times lower than the releases postulated here. Therefore, a 20 percent increase in concentrations due to the EPU is not affected by this large margin of safety and would not change the conclusions in the ER.

The FES estimated that doses from equipment leakage and malfunction would be 6 percent of the 10 CFR 20 limit at the site boundary (equivalent to 30 mrem) and would result in a collective dose of 2.8 person-rem. The assumptions for these dose estimates were not provided in the FES. Depending on the assumed exposure pathways and dominant radionuclides, it is likely that impacts calculated using revised dose factors alone would be reduced by more than enough to offset the 20 percent increase in releases from such an accident following the EPU.

The probability of these postulated accidents would not be affected by the EPU, and are lower in the case of accidental discharges of liquid radwaste because liquid discharges are no longer routine events.

8.3.3.2. Class 3.2 – Release from the Offgas System

An offgas system accident was treated in the ER as a Class 8 accident resulting from the ignition of radiolytic hydrogen and oxygen in the offgas holdup pipe, with an instantaneous release of the gas contained in the holdup volume. The gas was assumed to contain the same activity concentration as indicated in Section 8.3.3.1. The estimated collective population impacts from this accident (0.048 person-rem) are slightly higher than those resulting from an offgas leak postulated in the previous section, due primarily to differences in the release height (30 meters vs. ground level).

As indicated before, the normal operating concentrations would be at least a factor of three times lower, which would more than offset an increase of 20 percent in the estimated offgas activity concentrations under EPU.

The FES estimated that doses due to release from the Offgas system would be 24 percent of the 10 CFR 20 limit at the site boundary (equivalent to 120 mrem) and would result in a collective dose of 11 person-rem. If the impacts estimated in the FES were recalculated using current dose factors and normal operating concentrations, they would not be higher even with a 20 percent increase in activity released as a result of the EPU.

The probability of this accident would not be affected by the EPU. Therefore, the conclusions in the ER and FES remain bounding.

8.3.3.3. Class 3.3 – Release of Liquid Waste Storage

A liquid radwaste tank accident was treated in the ER as a Class 8 accident resulting from the failure of a tank and the release of tank contents to the containment basin. Because the latter are sized to hold twice as much liquid as the former, the probability of a uncontrolled catastrophic release to the environment is classified as extremely low. Therefore, the impacts from such an event were not quantified in the ER.

The impacts due to release from liquid waste storage were estimated in the FES to be very low (less than 0.5 mrem for an individual and less than 0.1 person-rem for the population). These impacts would not increase because the EPU conditions would not have significant impacts on the effectiveness of the liquid waste treatment system or on the amount and concentration of the waste liquid generated from this processing. The already extremely low probability of this accident would not be affected by the EPU. Therefore, the conclusions in the ER and FES remain bounding.

8.3.4. Class 4 – Events That Release Radioactivity into Primary System

No events that release large amounts of radioactivity into the primary system were identified in the BSEP ER. The ER classified random fuel cladding defects or perforations that result from defects in manufacture under the category of Normal Reactor Faulty Operation. Releases due to cladding defects were also considered in the FES to be within the design objectives for routine effluents.

However, releases resulting from off-design transients that induce fuel failures above those expected were analyzed in the FES. The doses from the release of fission products to the primary system were estimated to be 0.3 percent of the 10 CFR 20 limit at the site boundary (equivalent to 1.5 mrem) and to result in a collective dose of 0.29 person-rem. The assumptions for these dose estimates are not provided in the FES.

As part of the EPU, the number of fuel rods in each fuel assembly would increase from the original 7×7 configuration considered in the FES to the 10×10 configuration in GE14 fuel assemblies. However, the total number of fuel assemblies in the reactor core would not change as a result of the EPU. It therefore follows that, on average, each new fuel assembly must be capable of generating proportionally more power and would thus be expected to have a larger inventory of fission products per fuel assembly than the older fuel assemblies. However, the fission product inventory of an individual fuel rod in a 10×10 fuel assembly would actually be lower than an individual fuel rod in a 7×7 fuel assembly. Because cladding defects due to non-transient events affect individual fuel rods rather than entire assemblies, it is likely that any releases to the primary system from fuel failures would be lower than the 20 percent increase in thermal power output. In addition, improvements in fuel fabrication have resulted in significant reductions in the incidence and extent of fuel cladding defects, thus reducing the probability of individual fuel rod failures. Finally, the operational limits established at BSEP involve significant margins to prevent transient-induced fuel failures. These operational limits would still apply under power uprate conditions.

As indicated in previous sections, if the impacts estimated in the FES were recalculated using revised dose factors, even the highly unlikely event of a 20 percent increase in released activity is bounded by the original calculation.

8.3.5. Class 5 – Events That Release Radioactivity into Secondary Containment

Severe accidents that release radioactivity in to secondary containment systems apply primarily to PWRs. Because BWRs do not have a true secondary system, the impacts of events in this class were not analyzed in the BSEP ER or the FES. The BSEP ER interprets the secondary system to mean the secondary side (shells) of heat exchangers containing primary system coolant. The only possibility for a release that was identified in the ER was a small, low-activity leak into the service water side of one of the RHR heat exchangers. However, in the event of a large leak, the redundant capacity of the two heat exchangers allows the faulty heat exchanger to be valved off, using only the second heat exchanger. EPU does not change these conclusions.

8.3.6. Class 6 – Refueling Accidents Inside Containment

Only one refueling accident was considered in the ER: dropping a heavy object onto the fuel in the reactor core. The heavy object selected in the ER for analysis is actually a fuel assembly being handled over the core, as this is the only heavy object that is routinely suspended over the core. The FES considers two distinct accidents: one is a fuel assembly drop into the core and the other is a heavy object dropped onto the fuel in the reactor core. The nature of this heavy object is not specified in the FES, nor is the number of perforated fuel rods indicated, but the impacts of the fuel assembly drop are bounded by the dose resulting from the heavy object drop. The collective whole-body dose reported in the ER is 0.35 person-rem, with a negligible thyroid dose, because the release is assumed to occur under water. The bounding heavy-object drop in the FES resulted in a negligible dose at the site boundary and a collective population dose of 0.14 person-rem.

In the ER analysis, all 49 fuel rods in a 7×7 assembly were assumed to be perforated. If similar assumptions were used for a 10×10 assembly, the calculated dose would increase only in proportion to the power uprate, since the total number of fuel assemblies in the reactor core is the same.

The most current analysis (CP&L 2001) assumes that a 10×10 spent fuel assembly is dropped into the core and causes secondary damage, resulting in the failure of a total of 172 fuel rods. In addition the analysis was performed using the AST methodology and the extremely conservative assumption that no secondary containment is present to mitigate the release. The impacts at the site boundary from a fuel assembly drop are estimated to be 5.51 rem TEDE over two hours (CP&L 2001). Even without taking credit for secondary containment, this calculated dose is still below the acceptance criterion for a fuel handling accident (6.3 rem TEDE over two hours) in Regulatory Guide 1.183 (NRC 2000).

8.3.7. Class 7 – Accidents to Spent Fuel Outside Containment

Three subclasses of accidents involving spent fuel handling are reported in the FES. The first two involve dropping either a fuel assembly or another heavy object onto the fuel rack in the spent fuel storage pool. Both accidents are similar to those described in Section 8.3.6, but involve the spent fuel storage pool rather than the reactor core. The doses for these accidents are bounded by the impacts reported in the FES for Class 6 accidents, due to the lower fission product inventories in the stored spent fuel assemblies. As indicated in Section 8.3.6, no credit was taken for secondary containment in the most current analysis performed by CP&L (2001) involving a spent fuel handling accident inside containment. Therefore, that analysis would also bound the impacts of a similar accident that occurs outside containment.

The third subclass of accidents considered in the FES was a fuel cask drop resulting in a release of fission products. The doses from this event were estimated to be 8.9 percent of the 10 CFR 20 limit at the facility boundary (45 mrem) and 4.2 person-rem to the public within 50 miles of the reactor. The assumptions regarding this release were not described in the FES. If all fuel rods were assumed to fail, it is possible that an accident involving the same number of fuel assemblies irradiated under extended fuel uprate operations may result in a 20 percent increase in the source term.

This accident was described in the ER, but the fuel cask was assumed to maintain its integrity without a release of radionuclides to the environment outside the cask. Therefore, the dose impacts were stated as being negligible.

The EPU does not modify any equipment used to handle spent fuel casks and would not have an impact on the probability of such an accident.

8.3.8. Class 8 – Accident Initiation Events Considered in the Design Basis Evaluation in the Safety Analysis Report

Three subclasses of design basis accidents are analyzed in the FES. These include a LOCA inside containment, a control rod drop accident, and a main steamline break accident. These accidents were also analyzed in the BSEP ER and most recently in CP&L (2001) using the AST methodology. Two additional accidents were classified in the ER as being Class 8, the offgas system accident and the liquid radwaste tank accident. In this report, they have been treated as Class 3 accidents, for consistency with their treatment in the FES, and are described in Sections 8.3.3.2 and 8.3.3.3, respectively.

8.3.8.1. Loss of Coolant Accident Inside Containment

The FES estimated that doses from a large break in the coolant recirculation line would result in a dose at the boundary equivalent to 0.1 percent (0.5 mrem) of the 10 CFR 20 limits applicable at the time; the collective population dose from this accident was estimated to be 1.9 person-rem. The dose from a small-break LOCA is bounded by the dose from a large-break LOCA. In addition, a break in an instrument line inside the reactor building was considered under the Class 8.1 accidents. The dose from this accident is also bounded by the dose from a large break LOCA.

The ER calculated collective impacts to the population from a large-break LOCA. The collective whole-body and thyroid doses were estimated to be 0.014 person-rem and 0.01 thyroid-rem, respectively.

EPU would not result in an increase in these doses by more than 20 percent, if recalculated using the same methodology. Using the AST methodology, CP&L (2001) estimated the doses to persons at the site boundary and in the low population zone (LPZ) to be 0.61 and 1.34 rem TEDE, respectively, over 30 days. These doses are well below the dose acceptance criteria of 25 rem TEDE in Regulatory Guide 1.183 (NRC 2000).

8.3.8.2. Rod Drop Accident

The FES estimated that doses from a control rod drop accident (CRDA) would result in a dose at the site boundary equivalent to 0.3 percent (1.5 mrem) of the 10 CFR 20 limits applicable at the time; the collective population dose from this accident was estimated to be 0.34 person-rem.

The ER also calculated collective impacts to the population from a CRDA. The whole-body and thyroid doses were both estimated to be negligible.

EPU would not result in an increase in these doses by more than an additional 20 percent, if recalculated using the same methodology that was used in the ER and FES. Use of the AST methodology results in an estimated dose of 0.27 rem TEDE at the site boundary over 2 hours, and a dose of 0.22 rem TEDE in the LPZ over 30 days (CP&L 2001). These doses are well below the acceptance criterion of 6.3 rem TEDE in Regulatory Guide 1.183 (NRC 2000).

8.3.8.3. Main Steam Line Break

The FES estimated that doses from a main steam line break (MSLB) accident would result in a dose at the site boundary equivalent to 0.3 percent (1.5 mrem) of the 10 CFR 20 limits applicable at the time. The collective population dose from this accident was estimated to be 0.34 person-rem.

The ER also calculated collective impacts to the population from an MSLB. As was the case for the CRDA, the whole-body dose was estimated to be negligible. An integrated thyroid dose of 0.04 thyroid-rem was reported for this accident.

Using the AST methodology, CP&L (2001) re-analyzed the MSLB accident using a different basis than the original analysis.. Two conditions were analyzed. The first condition assumes the maximum equilibrium concentration of iodine in the water permitted by the Technical Specifications (0.2 μCi/g), while the second condition assumes that the iodine concentration would be at the maximum short-term concentrations (a pre-existing iodine spike of 4 μCi/g permitted by the Technical Specifications). The impacts from the first condition are estimated to be 0.127 rem TEDE at the site boundary and 0.045 rem TEDE in the LPZ. The impacts from the second condition are estimated to be 2.52 rem TEDE at the site boundary and 0.89 rem TEDE in the LPZ. The dose acceptance criteria in Regulatory Guide 1.183 (NRC 2000) are 2.5 rem and 25 rem TEDE for the first and second condition, respectively. For either condition, the estimated doses are at least one order of magnitude below the acceptance criteria.

Doses resulting from the historical analyses vary over several orders of magnitude, due to different methodologies that have been used over time. However, the current methodology indicates that EPU would not result in substantial change in the calculated dose from an MSLB, since the iodine concentration in the reactor coolant is defined by Technical Specification, not power level.

8.3.9. Class 9 – Severe Accidents

The impacts of any severe accidents outside the design basis provided by the engineered safety system were not evaluated in the FES or the ER. The possible sequence of events that might lead to beyond design basis accidents are of very low probability when considering the design conservatism, multiple barriers, quality assurance, and testing that are now in place. The environmental risk of Class 9 accidents is extremely low, and the EPU would not involve any changes that would alter the validity of this conclusion.

8.4. Other Potential Environmental Accidents

Other potential environmental accidents could involve chemicals, industrial gases, oil, oil products, or other hazardous substances. The EPU would not significantly alter their inventory, storage, usage, or control requirements, and no new hazardous substances would be used or introduced. The risk from oil or chemical spills, releases of industrial gases, or other events involving non-radioactive hazardous material would not increase significantly as a result of the EPU.

9.0 ENVIRONMENTAL EFFECTS OF URANIUM FUEL CYCLE ACTIVITIES AND FUEL AND RADIOACTIVE WASTE TRANSPORT

NRC regulations 10 CFR 51.51 (Table S-3) provide the basis for evaluating the contribution of the environmental effects of the uranium fuel cycle to the environmental impacts of licensing a nuclear power plant. NRC regulations 10 CFR 51.52 (Table S-4) describe the environmental impacts of transporting nuclear fuel and radioactive wastes. The tables were developed in the 1970s. Since that time, most plants have increased both their uranium-235 enrichment and the fuel's burnup limits.

In 1988, NRC generically evaluated the impacts of extended burnup fuel and increased enrichment on the uranium fuel cycle, including transportation of nuclear fuel and wastes, to determine whether higher burnup and enrichment could result in environmental impacts greater than those described in Tables S-3 and S-4. The environmental assessment and finding of no significant impact (53 FR 6040; February 29, 1988) concluded that burnup limits of up to 50,000 MWd/MTU or higher (as long as the maximum rod average burnup level of any fuel rod is no greater than 60,000 MWd/MTU) and uranium-235 enrichment up to 5 weight percent would have no significant adverse environmental effects on the uranium fuel cycle or the transport of nuclear fuel and wastes, and would not change the impacts presented in Tables S-3 and S-4.

In 1999, in connection with the generic environmental impact statement for license renewal of nuclear power plants, NRC looked at transporting higher enrichment and higher burnup fuel to a geologic repository (NRC 1999). The conclusion of that evaluation was that the environmental impacts would be consistent with the values presented in Table S-4 and that the impacts in Table S-4 are bounding.

For the proposed action, design studies project that the BSEP fuel enrichment will increase to about 4.4 weight percent and burnup will remain at approximately 45,000 MWd/MTU. Reload design goals exist at 50,000 MWd/MTU and five weight percent so that the BSEP fuel cycles will remain well within the limits bounded by the impacts in Tables S-3 and S-4. Therefore, CP&L concludes that impacts to the uranium cycle and transport of nuclear fuel from the proposed action would be insignificant and not require mitigation.

As described in Section 8.1, the proposed action would generate about 15 percent more volume of low-level radioactive wastes, with a less than 15 percent increase in activity. Because BSEP is steadily reducing the amount of low-level waste generated annually (the volume in 2000 was 23 percent of the volume generated in 1996), the increased waste volume and activity is not expected to affect the transportation of low-level wastes.

10.0 EFFECTS OF DECOMMISSIONING

The FES for BSEP Units 1 and 2 did not evaluate the environmental effects of decommissioning. In 1988, NRC published the Final Generic Environmental Impact Statement on decommissioning of nuclear facilities (NUREG-0586) that discusses decommissioning of nuclear power reactors. Procedures for decommissioning a nuclear power plant are found in NRC regulations at 10 CFR 50.75, 50.82, 51.53, and 51.95. In addition, NRC is considering new rulemaking to address certain aspects of decommissioning.

Prior to any decommissioning activity at BSEP, CP&L would submit a post-shutdown decommissioning activities report to describe planned decommissioning activities, any environmental impacts of those activities, a schedule, and estimated costs. Implementation of an extended power uprate does not affect the ability of CP&L to maintain sufficient financial reserves for decommissioning.

The potential environmental impacts on decommissioning associated with an extended power uprate are due to increases in the feedwater flow rate and increased neutron fluence. These increases could increase the amount of activated corrosion products and, consequently, post-shutdown radiation levels. Increases in radiation levels are expected to be insignificant, and would be addressed in the post-shutdown decommissioning activities report.

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ENCLOSURE 6

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62
REQUEST FOR LICENSE AMENDMENTS
EXTENDED POWER UPRATE

Justification for Exception to Large Transient Testing Requirements

Background

The basis for the Extended Power Uprate (EPU) request was prepared following the guidelines contained in the NRC-approved, General Electric (GE) Company Licensing Topical Reports for Extended Power Uprate (EPU) Safety Analysis: NEDC-32424P-A (ELTR-1), February 1999, and NEDC-32523P-A (ELTR-2), February 2000, and its Supplement 1, Volumes I and II. However, Carolina Power & Light (CP&L) Company is taking exception to one of the large transient tests, which requires an automatic scram from high power (i.e., main steam isolation valve (MSIV) closure), specified in Section 5.11.9 and Appendix L, Section L.2 of ELTR-1.

ELTR-1 was written in 1996, prior to industry experience with EPUs. ELTR-1 discussed the potential for performing an EPU without increasing reactor pressure. Maintaining a constant pressure simplifies the analyses and plant changes required to achieve uprated conditions. Five units have since implemented EPUs at constant pressure as noted below.

- Hatch Units 1 and 2 (105% to 113% of Original Licensed Thermal Power (OLTP))
- Monticello (106% OLTP)
- Muehleberg (i.e., KKM) (105% to 116% OLTP)
- Leibstadt (i.e., KKL) (105% to 117% OLTP)

Data collected from testing and responses to unplanned transients for these plants has shown that plant response has consistently been within expected parameters.

CP&L believes that the MSIV closure test, specified in ELTR-1, is not necessary. If performed, the MSIV closure test would not confirm any significant aspect of performance that is not routinely demonstrated by component level testing. Plant modeling, data collection, and analyses capabilities support elimination of large transient testing. This is further supported by industry experience which has demonstrated plant performance, as predicted, under EPU conditions. In addition, the risk posed by intentionally initiating a MSIV closure transient, although small, should not be incurred unnecessarily.

ELTR-1 requirements for performance of a generator load rejection test have been met at BSEP. If an MSIV closure event occurs following implementation of EPU, it will be analyzed in accordance with BSEP event response procedures.

Discussion

BSEP Generator Load Rejection Event

Section L.2.4 (2) of ELTR-1 (NEDC-32424-P-A) specifies, "When the power uprate is within 10% and 15% power of previously recorded data, for MSIV closure and Generator Load Rejection events, respectively, no uprate specific tests are necessary. Previously recorded data may include unplanned as well as planned transients." Additionally, the response to a request for additional information, included in the NRC approved copy of ELTR-1, also indicates the acceptability of data available as a result of inadvertent events in lieu of data obtained from a special test in fulfilling the large transient testing requirements.

BSEP Unit 2 experienced an unplanned Generator Load Rejection from approximately 2558 megawatts thermal (MWt) that provides the data necessary to fulfill the requirements of Section L.2.4 of ELTR-1 up to and including power levels of 2923 MWt for the Generator Load Rejection test. The BSEP Generator Load Rejection event occurred on September 22, 2000, and was reported to the NRC in Licensee Event Report (LER) 2-00-002, dated October 20, 2000. No anomalies were seen in the plant's response to this event. This event satisfies the ELTR-1 requirement for previously recorded Generator Load Rejection transient data within 15% of the BSEP EPU licensed power level of 2923 MWt.

MSIV Closure Event

The MSIV closure is an Anticipated Operational Occurrence (i.e., AOO or transient) as described in Chapter 15 of the BSEP Updated Final Safety Analysis Report (UFSAR). Without a concurrent failure of the MSIV position switches this transient is not considered significant enough to warrant routine re-evaluation. The MSIV closure transient, assuming the backup flux scram versus the valve position scram, is more significant. The UFSAR has been regularly updated for this case and it has been re-evaluated for EPU. The UFSAR indicates that the most significant aspect of this case is overpressure protection.

ELTR-1 indicates that large transient tests would be done similar to the original startup tests. The original MSIV closure test allowed the scram to be initiated by the MSIV position switches. As such, if the original MSIV closure test were re-performed, the results would be much less significant than the MSIV closure analysis performed by GE for EPU. The original MSIV closure test was intended to demonstrate the following.

1. Increase in heat flux shall be minimal (i.e., 0% desired, up to 2% with evaluation). No thermal limits are to be exceeded.

2. Reactor pressure rise shall be close to prediction (i.e., 120 psi desired, up to 145 psi with evaluation).

3. MSIV closure time must be between 3 and 5 seconds.

4. The Safety Relief Valves (SRVs) must close properly without leakage.

5. Feedwater controls must automatically prevent flooding of the main steam lines.

6. The Reactor Core Isolation Cooling (RCIC) system should start automatically and operate without isolating.

The intent of Item 1, above, was to monitor fuel thermal performance. For this event, the closure of the MSIVs causes a vessel pressure increase and an increase in reactivity. The negative reactivity of the scram from MSIV position switches should offset the positive reactivity of the pressure increase such that there is a minimal increase in heat flux. Therefore, the thermal performance during the proposed MSIV closure test is much less limiting than any of the transients routinely re-evaluated. EPU will have minimal impact on the components important to achieving the desired thermal performance. Reactor Protection system (RPS) logic is unaffected and with no steam dome pressure increase, overall control rod insertion times will not be significantly affected. MSIV closure speed is controlled by adjustments to the actuator and is considered very reliable as indicted below.

Due to the minimal nature of the flux transient, the expected reactor pressure rise, Item 2 above, is largely dependent on SRV setpoint performance. There has been an industry issue with SRV setpoint performance. However, BSEP has implemented design changes and maintenance improvements that have greatly reduced concerns about SRV setpoint upward drift. Since these improvements were implemented, no surveillance results have had more than two SRVs out of specification high and the last two sets of tests results had no SRVs out of specification high. Note that this is bounded by the BSEP design analysis for peak vessel pressure which assumes two of the eleven SRVs do not open at all. Given the improved performance of the BSEP SRVs along with the design margins, performance of an actual MSIV closure test would provide little benefit for demonstrating vessel overpressure protection that is not already accomplished by the component level testing that is routinely performed, in accordance with the BSEP Technical Specifications (TSs).

Because steam flow assists MSIV closure, the focus of Item 3 was to verify that the steam flow from the reactor was not shut off faster than assumed, 3 seconds. MSIV actuators are adjusted to control closure speed and BSEP test performance has been good. MSIV closure speed verification is also a key parameter that is checked during actual events. Industry experience, including BSEP, has shown that there are no significant generic problems with this design. Confidence is very high that steam line closure would not be less than assumed by the analysis.

Since rated vessel steam dome pressure is not being increased and SRV setpoints are not being changed, there is no increase in the probability of leakage after an SRV lift. Because SRV leakage performance is considered acceptable at the current conditions, which match EPU conditions with respect to steam dome pressure and SRV setpoints, SRV leakage performance will continue to be acceptable at EPU conditions. An MSIV closure test would provide no significant additional confirmation of the Item 4 performance criteria than the routine component testing performed every cycle, in accordance with the BSEP TSs.

Performance of an MSIV closure test is not required to ensure that the performance criteria of Items 4 and 5 are met. Overfill of the vessel after a trip would only occur if level exceeded 260 inches. Since the Feedwater turbines, the High Pressure Coolant Injection (HPCI) turbine, and the RCIC turbine all receive trip signals prior to level reaching 208 inches, a substantial margin exists. BSEP operating history has demonstrated that this margin greatly exceeds vessel level overshoot during transient events. EPU will result in only a minor change in expected overshoot. As long as the above turbine trips work as designed, there is adequate confidence that the vessel level will remain well below the main steam lines under EPU conditions. These trip functions are routinely verified as required by TSs and are considered very reliable.

Lastly, a MSIV closure test is not needed to demonstrate the performance criteria of Item 6. RCIC has been successfully used for vessel level control on several occasions at BSEP. The most recent examples were a brief injection during a September 20, 1995 Unit 1 scram, numerous injections during a July 13, 1995 Unit 1 scram and an injection during the July 27, 1996 planned Unit 2 maintenance shutdown. Reactor steam dome pressure and SRV setpoints were increased as part of the 105% uprate. Since that time, RCIC has been routinely tested to assure that it can deliver rated flow and pressure. The above items are adequate to show that RCIC can reliably deliver rated flow. The original testing did not take any action to prevent HPCI operation. Since HPCI starts at the same vessel level as RCIC, the test would result in operation of both systems unless operators were to intervene. Therefore, verification that RCIC alone would maintain level was not part of the test scope.

Industry Boiling Water Reactor (BWR) Power Uprate Experience

Southern Nuclear Operating Company's (SNOC) application for EPU of Hatch Units 1 and 2 was granted without requirements to perform large transient testing. BSEP Units 1 and 2 are similar in design, size and vintage as Hatch. Hatch is a BWR/4 with a Mark I containment of essentially the same design as BSEP, including the key balance of plant area of turbine-generator control logic (i.e., Electro-Hydraulic Control system). Consequently, the BSEP plant response to transients would be very similar to Hatch. Although Hatch was not required to perform large transient testing, Hatch Unit 2 experienced an unplanned event that resulted in a generator load reject from 98% of uprated power in the summer of 1999. As noted in SNOC's LER 1999-005, no anomalies were seen in the plant's response to this event. In addition, Hatch Unit 1 has experienced one turbine trip and one generator load reject event subsequent to its uprate (i.e., LERs 2000-004 and 2001-002). Again, the behavior of the primary safety systems was as expected. No new plant behaviors were observed that would indicate that the analytical models being used are not capable of modeling plant behavior at EPU conditions.

The KKL power uprate implementation program was performed during the period from 1995 to 2000. Power was raised in steps from its previous operating power level of 3138 MWt (i.e., 104.2% of OLTP) to 3515 MWt (i.e., 116.7% OLTP). Uprate testing was performed at 3327 MWt (i.e., 110.5% OLTP) in 1998, 3420 MWt (i.e., 113.5% OLTP) in 1999 and 3515 MWt in 2000.

KKL testing for major transients involved turbine trips at 110.5% OLTP and 113.5% OLTP and a generator load rejection test at 104.2% OLTP. The KKL turbine and generator trip testing demonstrated the performance of equipment that was modified in preparation for the higher power levels. Equipment that was not modified performed as before. The reactor vessel pressure was controlled at the same operating point for all of the uprated power conditions. No unexpected performance was observed except in the fine-tuning of the turbine bypass opening that was done as the series of tests progressed. These large transient tests at KKL demonstrated the response of the equipment and the reactor response. The close matches observed with predicted response provide additional confidence that the uprate licensing analyses consistently reflected the behavior of the plant.

Plant Modeling, Data Collection and Analyses

From the power uprate experience discussed above, it can be concluded that large transients, either planned or unplanned, have not provided any significant new information about transient modeling or actual plant response. Since the BSEP uprate does not involve reactor pressure changes, this experience is applicable. Based on industry experience, GE has submitted a licensing topical report for NRC review that applies to EPUs accomplished without reactor pressure increases. This topical report does not include large transient testing as a requirement.

The safety analyses performed for BSEP used the NRC-approved ODYN transient modeling code. The NRC accepts this code for GE BWRs with a range of power levels and power densities that bound the requested power uprate for BSEP. The ODYN code has been benchmarked against BWR test data and has incorporated industry experience gained from previous transient modeling codes. ODYN uses plant specific inputs and models all the essential physical phenomena for predicting integrated plant response to the analyzed transients. Thus, the ODYN code will accurately and/or conservatively predict the integrated plant response to these transients at EPU power levels and no new information about transient modeling is expected to be gained from performing these large transient tests. This is especially true for the MSIV closure test where the lack of MSIV position switch failures, as modeled in the transient analysis, would affect all aspects of the response and prevent realistic comparisons.

Risk Insights Relative to Large Transient Testing

The risk imposed by intentionally initiating large transient testing should not be incurred unnecessarily. The risk of a single event is given by its conditional core damage probability (CCDP). The CCDP value for the MSIV closure is 5.26E-6 for EPU.

<u>Conclusion</u>

CP&L believes that (1) the BSEP generator load rejection event which occurred on September 22, 2000, satisfies the ELTR-1 requirement for previously recorded Generator Load Rejection transient data within 15% of the BSEP EPU licensed power level of 2923 MWt and (2) sufficient justification has been provided to demonstrate that an MSIV transient test is not necessary or prudent. As such, CP&L does not plan to perform additional large transient testing following the BSEP EPU.

ENCLOSURE 7

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62
REQUEST FOR LICENSE AMENDMENTS
EXTENDED POWER UPRATE

Revision to Licensing Bases - Containment Overpressure

Background

The Brunswick Steam Electric Plant (BSEP) is currently committed to the provisions of Safety Guide 1 (i.e., Regulatory Guide 1.1), "Net Positive Suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps." As a result, no credit is currently taken for containment (i.e., suppression chamber) pressure when performing Emergency Core Cooling Systems (ECCS) net positive suction head (NPSH) calculations. Due to the proposed Extended Power Uprate (EPU), Carolina Power & Light (CP&L) Company is revising this commitment. Specifically, credit for containment overpressure will be taken to assure adequate NPSH is available for low pressure ECCS pumps (i.e., Residual Heat Removal (RHR) and Core Spray (CS)) following a design basis loss-of-coolant accident (LOCA). Post-LOCA NPSH concerns are not applicable to the High Pressure Coolant Injection (HPCI) system.

Discussion

EPU operation increases the reactor decay heat, which increases the heat addition to the suppression pool following a design basis LOCA. This increased heat input could potentially increase the peak suppression pool water temperature and containment pressure during the post-LOCA RHR and CS pump operation.

Short-Term NPSH Requirements

For short-term (i.e., 0 to 600 seconds), post-LOCA operation, no operator action is credited and, as a result, the RHR and CS pumps are assumed to be at runout conditions. For RHR, runout flow is 10,500 gpm per pump and 21,000 gpm per loop. For CS, runout flow is 6,700 gpm per pump. The reactor is assumed to be at 0 psig. As discussed in Section 4.2.5 of NEDC-33039P, "Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2 Extended Power Uprate," dated August 2001 (i.e., the Power Uprate Safety Analysis Report (PUSAR)), the peak suppression pool temperature prior to assumed operator action (i.e., short-term) was calculated to be 169.1 °F.

Based on the above assumptions, NPSH available (NPSHa) was calculated using the following equation.

$$NPSHa = \frac{(P_1 - P_{SAT})(144)}{\rho} + Z - (h_{Lpiping}) - (h_{Lstrainer})$$

where:

P_1 = atmospheric pressure, psia
P_{SAT} = saturation pressure at suppression pool temperature, psia
ρ = density of suppression pool water, lb/ft^3
Z = static head, ft
$h_{Lpiping}$ = piping friction losses, ft
$h_{Lstrainer}$ = strainer friction losses, ft

The NPSH margin equals NPSHa minus NPSH required (NPSHr). The RHR and CS pumps have NPSH margins of + 4.1 ft and + 6.4 ft at the worst-case short-term temperature of 169.1 °F.

Long-Term NPSH Requirements

For long-term (i.e., greater than 600 seconds) post-LOCA operation, operator action to throttle the RHR and CS pumps is assumed. As such, the assumed pump flows are 5,775 gpm per RHR pump (i.e., 11,550 gpm loop flow) and 4,725 gpm for each CS pump. For EPU, a re-analysis of the primary containment response to pipe breaks was performed. Section 4.1.1 of the PUSAR documents the results of this re-analysis. Accounting for single failure requirements, the re-analysis assumed a minimum post-LOCA pump configuration of two RHR pumps and two RHR Service Water pumps. The re-analysis was also performed both with and without crediting containment spray. The case that did not credit containment spray produced the peak temperature response of 207.7 °F with a corresponding pressure of 25.5 psig. However, the case that credited containment spray produced a slightly lower temperature profile (i.e., 206.8 °F peak) and a much lower pressure profile (i.e., a 11.3 psig peak). For conservatism, the NPSH calculations were performed based on the containment spray case, with the containment spray temperature profile increased by 0.9 °F such that the peak temperature equaled that of the no spray case.

Using the conservative profile discussed above and the preceding equation, the NPSH parameters were determined for bounding conditions. The results are summarized in Tables 7-1 and 7-2 below. This re-analysis demonstrates that, with credit for containment overpressure, NPSH for the ECCS pumps will be available to meet the long-term worst-case scenario. For the period of interest, the maximum required overpressure needed to ensure NPSH is 3.1 psig, with 11.3 psig containment overpressure available. In all cases, the available containment overpressure is in excess of three times the amount required to ensure adequate NPSH. Therefore, CP&L has concluded that adequate NPSH margin exists for the ECCS pumps.

Conclusion

To ensure sufficient margin exists to address potential future issues, CP&L requests that containment overpressure of up to 5.0 psig be credited for calculating ECCS pump NPSH margins. This re-analysis will become the new licensing basis for the primary containment response to pipe breaks and Section 6.2.1.1.3 of the BSEP Updated Final Safety Analysis Report will be revised accordingly.

Table 7-1							
Long-Term RHR NPSH - 2 Pumps Operating At 5,775 gpm Each (11,550 gpm Loop Flow)							
Time (hr)	Temperature (°F)	NPSHa (feet)	NPSHr (feet)	NPSH Margin (feet)	Containment Pressure (feet)	NPSH Margin (psi)	Containment Pressure (psig)
0.0	95.9	36.3	14.1	22.2	0.0	9.6	0.0
0.2	170.5	24.5	14.4	10.1	15.8	4.3	6.7
1.0	187.6	17.9	14.4	3.5	18.8	1.5	7.9
1.8	196.0	13.9	14.5	-0.6	22.2	-0.3	9.3
2.7	200.9	11.2	14.5	-3.3	24.2	-1.4	10.1
3.6	204.0	9.4	14.5	-5.1	25.7	-2.1	10.7
4.9	206.6	7.8	14.6	-6.7	26.7	-2.8	11.1
6.2	207.5	7.2	14.6	-7.3	26.9	-3.0	11.2
7.3	207.7	7.1	14.6	-7.4	27.1	-3.1	11.3
8.4	207.5	7.2	14.6	-7.3	26.7	-3.0	11.1
10.2	206.5	7.9	14.6	-6.7	26.0	-2.8	10.8
11.8	205.1	8.7	14.5	-5.8	24.9	-2.4	10.4
13.5	203.5	9.7	14.5	-4.8	24.1	-2.0	10.0
16.1	200.6	11.4	14.5	-3.1	22.5	-1.3	9.4
18.7	197.6	13.0	14.5	-1.5	20.9	-0.6	8.7
21.4	194.8	14.5	14.5	0.0	19.5	0.0	8.1
24.0	192.0	15.9	14.5	1.4	18.2	0.6	7.6
27.5	188.5	17.5	14.4	3.1	16.5	1.3	6.9
31.9	184.7	19.2	14.4	4.8	14.8	2.0	6.2
35.8	182.2	20.2	14.4	5.8	13.9	2.4	5.8
41.6	179.7	21.2	14.4	6.8	13.0	2.9	5.5
48.0	176.7	22.3	14.4	7.9	12.0	3.3	5.0

Table 7-2							
Long-Term Core Spray NPSH - 1 Pump Operating at 4725 gpm							
Time (hr)	Temperature (°F)	NPSHa (feet)	NPSHr (feet)	NPSH Margin (feet)	Containment Pressure (feet)	NPSH Margin (psi)	Containment Pressure (psig)
0.0	95.9	36.4	13.1	23.4	0.0	10.1	0.0
0.2	170.5	24.6	13.3	11.3	15.8	4.8	6.7
1.0	187.6	18.1	13.4	4.7	18.8	2.0	7.9
1.8	196.0	14.0	13.5	0.6	22.2	0.2	9.3
2.7	200.9	11.4	13.5	-2.1	24.2	-0.9	10.1
3.6	204.0	9.5	13.5	-3.9	25.7	-1.6	10.7
4.9	206.6	8.0	13.5	-5.6	26.7	-2.3	11.1
6.2	207.5	7.4	13.5	-6.1	26.9	-2.6	11.2
7.3	207.7	7.3	13.5	-6.3	27.1	-2.6	11.3
8.4	207.5	7.4	13.5	-6.1	26.7	-2.6	11.1
10.2	206.5	8.0	13.5	-5.5	26.0	-2.3	10.8
11.8	205.1	8.9	13.5	-4.6	24.9	-1.9	10.4
13.5	203.5	9.8	13.5	-3.7	24.1	-1.5	10.0
16.1	200.6	11.5	13.5	-2.0	22.5	-0.8	9.4
18.7	197.6	13.2	13.5	-0.3	20.9	-0.1	8.7
21.4	194.8	14.6	13.4	1.2	19.5	0.5	8.1
24.0	192.0	16.0	13.4	2.6	18.2	1.1	7.6
27.5	188.5	17.7	13.4	4.3	16.5	1.8	6.9
31.9	184.7	19.3	13.4	5.9	14.8	2.5	6.2
35.8	182.2	20.4	13.4	7.0	13.9	2.9	5.8
41.6	179.7	21.4	13.4	8.0	13.0	3.4	5.5
48.0	176.7	22.5	13.4	9.1	12.0	3.8	5.0

ENCLOSURE 8

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62
REQUEST FOR LICENSE AMENDMENTS
EXTENDED POWER UPRATE

Marked-Up Technical Specification Pages - Unit 1

(5) Pursuant to the Act and 10 CFR Parts 30 and 70 to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of Brunswick Steam Electric Plant, Unit Nos. 1 and 2, and H. B. Robinson Steam Electric Plant, Unit No. 2.

(6) Carolina Power and Light Company shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report for the facility and as approved in the Safety Evaluation Report, dated November 22, 1977, as supplemented April 1979, June 11, 1980, December 30, 1986, December 6, 1989, July 28, 1993, and February 10, 1994, respectively, subject to the following provision:

> The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

C. This license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; 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) <u>Maximum Power Level</u>

The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of ~~2558~~ 2923 megawatts thermal.

(2) <u>Technical Specifications</u>

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 213, are hereby incorporated in the license. Carolina Power & Light Company shall operate the facility in accordance with the Technical Specifications.

1.1 Definitions (continued)

OPERABLE—OPERABILITY	A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of ~~2558~~ MWt. 2923
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.
SHUTDOWN MARGIN (SDM)	SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming that: a. The reactor is xenon free; b. The moderator temperature is 68°F; and c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.

(continued)

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

2.1.1.1 With the reactor steam dome pressure < 785 psig or core flow $< 10\%$ rated core flow:

THERMAL POWER shall be $\leq$ ~~25%~~ RTP. 23%

2.1.1.2 With the reactor steam dome pressure ≥ 785 psig and core flow $\geq 10\%$ rated core flow:

MCPR shall be ≥ 1.10 for two recirculation loop operation or ≥ 1.11 for single recirculation loop operation.

2.1.1.3 Reactor vessel water level shall be greater than the top of active irradiated fuel.

2.1.2 Reactor Coolant System Pressure SL

Reactor steam dome pressure shall be ≤ 1325 psig.

2.2 SL Violations

With any SL violation, the following actions shall be completed within 2 hours:

2.2.1 Restore compliance with all SLs; and

2.2.2 Insert all insertable control rods.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2 Disarm the associated CRD.	4 hours
D. ---------NOTE--------- Not applicable when THERMAL POWER > ~~10%~~ RTP. 8.75% --------------------- Two or more inoperable control rods not in compliance with banked position withdrawal sequence (BPWS) and not separated by two or more OPERABLE control rods.	D.1 Restore compliance with BPWS. OR D.2 Restore control rod to OPERABLE status.	4 hours 4 hours
E. Required Action and associated Completion Time of Condition A, C, or D not met. OR Nine or more control rods inoperable.	E.1 Be in MODE 3.	12 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.6 Rod Pattern Control

LCO 3.1.6 OPERABLE control rods shall comply with the requirements of the banked position withdrawal sequence (BPWS).

APPLICABILITY: MODES 1 and 2 with THERMAL POWER ≤ ~~10%~~ RTP. 8.75%

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more OPERABLE control rods not in compliance with BPWS.	A.1 --------NOTE--------- Control rod may be bypassed in the rod worth minimizer (RWM) or RWM may be bypassed as allowed by LCO 3.3.2.1, "Control Rod Block Instrumentation." --------------------- Move associated control rod(s) to correct position.	8 hours
	OR	
	A.2 Declare associated control rod(s) inoperable.	8 hours

(continued)

3.2 POWER DISTRIBUTION LIMITS

3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

LCO 3.2.1 All APLHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ ~~25%~~ RTP.
23%

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any APLHGR not within limits.	A.1 Restore APLHGR(s) to within limits.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < ~~25%~~ RTP. 23%	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.1.1 Verify all APLHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ ~~25%~~ RTP 23% AND 24 hours thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

LCO 3.2.2 All MCPRs shall be greater than or equal to the MCPR operating limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ ~~25%~~ RTP.

23%

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any MCPR not within limits.	A.1 Restore MCPR(s) to within limits.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < ~~25%~~ RTP. 23%	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.2.1 Verify all MCPRs are greater than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ ~~25%~~ RTP 23% **AND** 24 hours thereafter

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more Functions with RPS trip capability not maintained.	C.1	Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < ~~30%~~ 26% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.3	------------------NOTE------------------ Not required to be performed until 12 hours after THERMAL POWER ≥ ~~25%~~ 23% RTP. -- Adjust the average power range monitor (APRM) channels to conform to the calculated power while operating at ≥ ~~25%~~ 23% RTP.	7 days
SR 3.3.1.1.4	------------------NOTE------------------ Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. -- Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.5	Perform a functional test of each automatic scram contactor.	7 days
SR 3.3.1.1.6	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to withdrawing SRMs from the fully inserted position
SR 3.3.1.1.7	------------------NOTE------------------ Only required to be met during entry into MODE 2 from MODE 1. -- Verify the IRM and APRM channels overlap.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.13	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. --- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.1.14	Verify the APRM Flow Biased Simulated Thermal Power—High time constant is ≤ 7 seconds.	24 months
SR 3.3.1.1.15	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.16	Verify Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ ~~30%~~ 26% RTP.	24 months

(continued)

This page was submitted for NRC review in BSEP 01-0076, "Request for License Amendments Thermal-Hydraulic Stability Option III," dated June 26, 2001. The revision bars indicate the areas changed by BSEP 01-0076.

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux —High	2	3	G	SR 3.3.1.1.2 SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 120/125 divisions of full scale
	5(a)	3	H	SR 3.3.1.1.2 SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 120/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.15	NA
	5(a)	3	H	SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.2.2.15	NA
2. Average Power Range Monitors					
a. Neutron Flux —High (Setdown)	2	3(c)	G	SR 3.3.1.1.2 SR 3.3.1.1.5 SR 3.3.1.1.7 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ 22.7% RTP
b. Simulated Thermal Power —High	1	3(c)	F	SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.5 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13 SR 3.3.1.1.18	~~≤ 0.66W + 62.0%~~ ≤ 0.55W + 62.6% RTP(b) and ≤ 117.1% RTP

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) ~~≤ [0.66(W − ΔW) + 62.0% RTP]~~ when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating." The value of ΔW is defined in plant procedures.

(c) Each APRM channel provides inputs to both trip systems.

≤ [0.55(W − ΔW) + 62.6% RTP]

Table 3.3.1.1-1 (page 3 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. Scram Discharge Volume Water Level —High	1,2	2	G	SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 108 gallons
	5(a)	2	H	SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 108 gallons
8. Turbine Stop Valve —Closure	≥ ~~30%~~ 26% RTP	4	E	SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ 10% closed
9. Turbine Control Valve Fast Closure, Control Oil Pressure —Low	≥ ~~30%~~ 26% RTP	2	E	SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≥ 500 psig
10. Reactor Mode Switch — Shutdown Position	1,2	1	G	SR 3.3.1.1.12 SR 3.3.1.1.15	NA
	5(a)	1	H	SR 3.3.1.1.12 SR 3.3.1.1.15	NA
11. Manual Scram	1,2	1	G	SR 3.3.1.1.9 SR 3.3.1.1.15	NA
	5(a)	1	H	SR 3.3.1.1.9 SR 3.3.1.1.15	NA

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.2.1.2 8.75%	------------------NOTE------------------ Not required to be performed until 1 hour after any control rod is withdrawn at ≤ ~~10%~~ RTP in MODE 2. -- Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.2.1.3	------------------NOTE------------------ Not required to be performed until 1 hour after THERMAL POWER is ≤ ~~10%~~ RTP in MODE 1. -- Perform CHANNEL FUNCTIONAL TEST.	8.75% 92 days
SR 3.3.2.1.4	------------------NOTE------------------ Neutron detectors are excluded. -- Verify the RBM: a. Low Power Range—Upscale Function is not bypassed when THERMAL POWER is ≥ 29% RTP and ≤ Intermediate Power Range Setpoint specified in the COLR. b. Intermediate Power Range—Upscale Function is not bypassed when THERMAL POWER is > Intermediate Power Range Setpoint specified in the COLR and ≤ High Power Range Setpoint specified in the COLR. c. High Power Range—Upscale Function is not bypassed when THERMAL POWER is > High Power Range Setpoint specified in the COLR.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.5	Verify the RWM is not bypassed when THERMAL POWER is ≤ ~~10%~~ 8.75% RTP.	24 months
SR 3.3.2.1.6	------------------NOTE------------------- Not required to be performed until 1 hour after reactor mode switch is in the shutdown position. --- Perform CHANNEL FUNCTIONAL TEST.	24 months
SR 3.3.2.1.7	------------------NOTE------------------- Neutron detectors are excluded. --- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.2.1.8	Verify control rod sequences input to the RWM are in conformance with BPWS.	Prior to declaring RWM OPERABLE following loading of sequence into RWM

Table 3.3.2.1-1 (page 1 of 1)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Rod Block Monitor				
a. Low Power Range —Upscale	(a)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.7	(h)
b. Intermediate Power Range —Upscale	(b)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.7	(h)
c. High Power Range —Upscale	(c),(d)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.7	(h)
d. Inop	(d),(e)	2	SR 3.3.2.1.1	NA
e. Downscale	(d),(e)	2	SR 3.3.2.1.1 SR 3.3.2.1.7	NA
2. Rod Worth Minimizer	1(f),2(f)	1	SR 3.3.2.1.2 SR 3.3.2.1.3 SR 3.3.2.1.5 SR 3.3.2.1.8	NA
3. Reactor Mode Switch —Shutdown Position	(g)	2	SR 3.3.2.1.6	NA

(a) THERMAL POWER ≥ 29% RTP and ≤ Intermediate Power Range Setpoint specified in the COLR and MCPR < 1.70.

(b) THERMAL POWER > Intermediate Power Range Setpoint specified in the COLR and ≤ High Power Range Setpoint specified in the COLR and MCPR < 1.70.

(c) THERMAL POWER > High Power Range Setpoint specified in the COLR and < 90% RTP and MCPR < 1.70.

(d) THERMAL POWER ≥ 90% RTP and MCPR < 1.40.

(e) THERMAL POWER ≥ 29% and < 90% RTP and MCPR < 1.70.

(f) With THERMAL POWER ≤ ~~10%~~ RTP. 8.75%

(g) Reactor mode switch in the shutdown position.

(h) Allowable Value specified in the COLR.

3.3 INSTRUMENTATION

3.3.2.2 Feedwater and Main Turbine High Water Level Trip Instrumentation

LCO 3.3.2.2 Three channels of feedwater and main turbine high water level trip instrumentation shall be OPERABLE.

23%

APPLICABILITY: THERMAL POWER ≥ ~~25%~~ RTP.

ACTIONS

-----------------------------------NOTE-----------------------------------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One feedwater and main turbine high water level trip channel inoperable.	A.1 Place channel in trip.	7 days
B. Two or more feedwater and main turbine high water level trip channels inoperable.	B.1 Restore feedwater and main turbine high water level trip capability.	4 hours
C. Required Action and associated Completion Time not met.	C.1 Reduce THERMAL POWER to < ~~25%~~ RTP.	4 hours

23%

3.7 PLANT SYSTEMS

3.7.6 The Main Turbine Bypass System

LCO 3.7.6 The Main Turbine Bypass System shall be OPERABLE.

OR

The following limits are made applicable:

a. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR; and

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ ~~25%~~ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Satisfy the requirements of the LCO.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < ~~25%~~ 23% RTP.	4 hours

ENCLOSURE 9

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62
REQUEST FOR LICENSE AMENDMENTS
EXTENDED POWER UPRATE

Marked-Up Technical Specification Pages - Unit 2

(5) Pursuant to the Act and 10 CFR Parts 30 and 70 to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of Brunswick Steam Electric Plant, Unit Nos. 1 and 2, and H. B. Robinson Steam Electric Plant, Unit No. 2.

(6) Carolina Power and Light Company shall implement and maintain in effect all provision of the approved fire protection program as described in the Final Safety Analysis Report for the facility and as approved in the Safety Evaluation Report dated November 22, 1977, as supplemented April 1979, June 11, 1980, December 30, 1986, December 6, 1989, July 28, 1993, and February 10, 1994 respectively, subject to the following provision:

> The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

C. This license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; 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

2923

The licensee is authorized to operate the facility at steady state reactor core power levels not in excess of ~~2558~~ megawatts (thermal).

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 240, are hereby incorporated in the license. Carolina Power & Light Company shall operate the facility in accordance with the Technical Specifications.

> For Surveillance Requirements (SRs) that are new in Amendment 233 to Facility Operating License DPR-62, the first performance is due at the end of the first surveillance interval that begins at implementation of

1.1 Definitions (continued)

OPERABLE-OPERABILITY

A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).

RATED THERMAL POWER (RTP)

RTP shall be a total reactor core heat transfer rate to the reactor coolant of ~~2558~~ 2923 MWt.

REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME

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

SHUTDOWN MARGIN (SDM)

SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming that:

a. The reactor is xenon free;

b. The moderator temperature is 68°F; and

c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn.

With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.

(continued)

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 <u>Reactor Core SLs</u>

2.1.1.1 With the reactor steam dome pressure < 785 psig or core flow < 10% rated core flow:

THERMAL POWER shall be ≤ ~~25%~~ RTP. 23%

2.1.1.2 With the reactor steam dome pressure ≥ 785 psig and core flow ≥ 10% rated core flow:

MCPR shall be ≥ 1.09 for two recirculation loop operation or ≥ 1.10 for single recirculation loop operation.

2.1.1.3 Reactor vessel water level shall be greater than the top of active irradiated fuel.

2.1.2 <u>Reactor Coolant System Pressure SL</u>

Reactor steam dome pressure shall be ≤ 1325 psig.

2.2 SL Violations

With any SL violation, the following actions shall be completed within 2 hours:

2.2.1 Restore compliance with all SLs; and

2.2.2 Insert all insertable control rods.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2 Disarm the associated CRD.	4 hours
D. ---------NOTE--------- Not applicable when THERMAL POWER > ~~10%~~ 8.75% RTP. --------------------- Two or more inoperable control rods not in compliance with banked position withdrawal sequence (BPWS) and not separated by two or more OPERABLE control rods.	D.1 Restore compliance with BPWS. OR D.2 Restore control rod to OPERABLE status.	4 hours 4 hours
E. Required Action and associated Completion Time of Condition A, C, or D not met. OR Nine or more control rods inoperable.	E.1 Be in MODE 3.	12 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.6 Rod Pattern Control

LCO 3.1.6 OPERABLE control rods shall comply with the requirements of the banked position withdrawal sequence (BPWS).

APPLICABILITY: MODES 1 and 2 with THERMAL POWER ≤ ~~10%~~ RTP. 8.75%

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more OPERABLE control rods not in compliance with BPWS.	A.1	--------NOTE--------- Control rod may be bypassed in the rod worth minimizer (RWM) or RWM may be bypassed as allowed by LCO 3.3.2.1, "Control Rod Block Instrumentation." ---------------------	
		Move associated control rod(s) to correct position.	8 hours
	OR		
	A.2	Declare associated control rod(s) inoperable.	8 hours

(continued)

3.2 POWER DISTRIBUTION LIMITS

3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

LCO 3.2.1 All APLHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ ~~25%~~ RTP. 23%

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any APLHGR not within limits.	A.1 Restore APLHGR(s) to within limits.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < ~~25%~~ RTP. 23%	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.1.1	Verify all APLHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ ~~25%~~ RTP 23% <u>AND</u> 24 hours thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

LCO 3.2.2 All MCPRs shall be greater than or equal to the MCPR operating limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ ~~25%~~ RTP. 23%

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any MCPR not within limits.	A.1 Restore MCPR(s) to within limits.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < ~~25%~~ RTP. 23%	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.2.1 Verify all MCPRs are greater than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ ~~25%~~ RTP 23% __AND__ 24 hours thereafter

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more Functions with RPS trip capability not maintained.	C.1	Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < ~~30%~~ 26% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.3	-------------------NOTE------------------- Not required to be performed until 12 hours after THERMAL POWER ≥ ~~25%~~ 23% RTP. -- Adjust the average power range monitor (APRM) channels to conform to the calculated power while operating at ≥ ~~25%~~ RTP.	7 days
SR 3.3.1.1.4	-------------------NOTE------------------- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. -- Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.5	Perform a functional test of each automatic scram contactor.	7 days
SR 3.3.1.1.6	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to withdrawing SRMs from the fully inserted position
SR 3.3.1.1.7	-------------------NOTE------------------- Only required to be met during entry into MODE 2 from MODE 1. -- Verify the IRM and APRM channels overlap.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.13	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. --- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.1.14	Verify the APRM Flow Biased Simulated Thermal Power—High time constant is ≤ 7 seconds.	24 months
SR 3.3.1.1.15	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.16	Verify Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ ~~30%~~ RTP. 26%	24 months

(continued)

This page was submitted for NRC review in BSEP 01-0076,
"Request for License Amendments Thermal-Hydraulic Stability Option III,"
dated June 26, 2001. The revision bars indicate the areas changed by BSEP 01-0076.

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux —High	2	3	G	SR 3.3.1.1.2 SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 120/125 divisions of full scale
	5(a)	3	H	SR 3.3.1.1.2 SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 120/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.15	NA
	5(a)	3	H	SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.2.2.15	NA
2. Average Power Range Monitors					
a. Neutron Flux —High (Setdown)	2	3(c)	G	SR 3.3.1.1.2 SR 3.3.1.1.5 SR 3.3.1.1.7 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ 22.7% RTP
b. Simulated Thermal Power —High	1	3(c)	F	SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.5 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13 SR 3.3.1.1.18	~~≤ 0.66W + 62.0%~~ ≤0.55W + 62.6% RTP(b) and ≤ 117.1% RTP

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) ~~≤ [0.66(W − ΔW) + 62.0% RTP]~~ ≤ [0.55(W−ΔW)+62.6% RTP] when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating." The value of ΔW is defined in plant procedures.

(c) Each APRM channel provides inputs to both trip systems.

Table 3.3.1.1-1 (page 3 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. Scram Discharge Volume Water Level —High	1,2	2	G	SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 108 gallons
	5(a)	2	H	SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 108 gallons
8. Turbine Stop Valve —Closure	≥ ~~30%~~ RTP 26%	4	E	SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ 10% closed
9. Turbine Control Valve Fast Closure, Control Oil Pressure —Low	≥ ~~30%~~ RTP	2	E	SR 3.3.1.1.5 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≥ 500 psig
10. Reactor Mode Switch — Shutdown Position	1,2	1	G	SR 3.3.1.1.12 SR 3.3.1.1.15	NA
	5(a)	1	H	SR 3.3.1.1.12 SR 3.3.1.1.15	NA
11. Manual Scram	1,2	1	G	SR 3.3.1.1.9 SR 3.3.1.1.15	NA
	5(a)	1	H	SR 3.3.1.1.9 SR 3.3.1.1.15	NA

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.2.1.2	-------------------NOTE------------------- Not required to be performed until 1 hour after any control rod is withdrawn at ≤ ~~10%~~ 8.75% RTP in MODE 2. -- Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.2.1.3	-------------------NOTE------------------- Not required to be performed until 1 hour after THERMAL POWER is ≤ ~~10%~~ 8.75% RTP in MODE 1. -- Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.2.1.4	-------------------NOTE------------------- Neutron detectors are excluded. -- Verify the RBM: a. Low Power Range—Upscale Function is not bypassed when THERMAL POWER is ≥ 29% RTP and ≤ Intermediate Power Range Setpoint specified in the COLR. b. Intermediate Power Range—Upscale Function is not bypassed when THERMAL POWER is > Intermediate Power Range Setpoint specified in the COLR and ≤ High Power Range Setpoint specified in the COLR. c. High Power Range—Upscale Function is not bypassed when THERMAL POWER is > High Power Range Setpoint specified in the COLR.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.2.1.5	Verify the RWM is not bypassed when THERMAL POWER is ≤ ~~10%~~ 3.75% RTP.	24 months
SR 3.3.2.1.6	-----------------NOTE------------------ Not required to be performed until 1 hour after reactor mode switch is in the shutdown position. --------------------------------------- Perform CHANNEL FUNCTIONAL TEST.	24 months
SR 3.3.2.1.7	-----------------NOTE------------------ Neutron detectors are excluded. --------------------------------------- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.2.1.8	Verify control rod sequences input to the RWM are in conformance with BPWS.	Prior to declaring RWM OPERABLE following loading of sequence into RWM

Table 3.3.2.1-1 (page 1 of 1)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Rod Block Monitor				
a. Low Power Range —Upscale	(a)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.7	(h)
b. Intermediate Power Range —Upscale	(b)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.7	(h)
c. High Power Range —Upscale	(c),(d)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.7	(h)
d. Inop	(d),(e)	2	SR 3.3.2.1.1	NA
e. Downscale	(d),(e)	2	SR 3.3.2.1.1 SR 3.3.2.1.7	NA
2. Rod Worth Minimizer	$1^{(f)}, 2^{(f)}$	1	SR 3.3.2.1.2 SR 3.3.2.1.3 SR 3.3.2.1.5 SR 3.3.2.1.8	NA
3. Reactor Mode Switch —Shutdown Position	(g)	2	SR 3.3.2.1.6	NA

(a) THERMAL POWER ≥ 29% RTP and ≤ Intermediate Power Range Setpoint specified in the COLR and MCPR < 1.70.

(b) THERMAL POWER > Intermediate Power Range Setpoint specified in the COLR and ≤ High Power Range Setpoint specified in the COLR and MCPR < 1.70.

(c) THERMAL POWER > High Power Range Setpoint specified in the COLR and < 90% RTP and MCPR < 1.70.

(d) THERMAL POWER ≥ 90% RTP and MCPR < 1.40.

(e) THERMAL POWER ≥ 29% and < 90% RTP and MCPR < 1.70.

(f) With THERMAL POWER ≤ ~~10%~~ RTP. 8.75%

(g) Reactor mode switch in the shutdown position.

(h) Allowable Value specified in the COLR.

3.3 INSTRUMENTATION

3.3.2.2 Feedwater and Main Turbine High Water Level Trip Instrumentation

LCO 3.3.2.2 Three channels of feedwater and main turbine high water level trip instrumentation shall be OPERABLE.

APPLICABILITY: THERMAL POWER ≥ ~~25%~~ RTP.
23%

ACTIONS

-----------------------------------NOTE-----------------------------------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One feedwater and main turbine high water level trip channel inoperable.	A.1	Place channel in trip.	7 days
B. Two or more feedwater and main turbine high water level trip channels inoperable.	B.1	Restore feedwater and main turbine high water level trip capability.	4 hours
C. Required Action and associated Completion Time not met.	C.1	Reduce THERMAL POWER to < ~~25%~~ RTP.	4 hours

23%

3.7 PLANT SYSTEMS

3.7.6 The Main Turbine Bypass System

LCO 3.7.6 The Main Turbine Bypass System shall be OPERABLE.

<u>OR</u>

The following limits are made applicable:

a. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR; and

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ ~~25%~~ RTP.
23%

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Satisfy the requirements of the LCO.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < ~~25%~~ RTP. 23%	4 hours

ENCLOSURE 10

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
DOCKET NOS. 50-325 AND 50-324/LICENSE NOS. DPR-71 AND DPR-62
REQUEST FOR LICENSE AMENDMENTS
EXTENDED POWER UPRATE

Marked-Up Technical Specification Bases Pages - Unit 1

(For Information Only)

BASES

APPLICABLE SAFETY ANALYSES

2.1.1.1 Fuel Cladding Integrity (continued)

3.5 psi. Thus, the bundle flow with a 4.5 psi driving head will be > 28 x 10^3 lb/hr. Full scale ATLAS test data taken at pressures from 14.7 psia (0 psig) to 800 psia (785 psig) indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER > ~~50 %~~ RTP. Thus, a THERMAL POWER limit of 25% RTP for reactor pressure < 785 psig is conservative.

23%

46%

2.1.1.2 MCPR

The fuel cladding integrity SL is set such that no fuel damage is calculated to occur if the limit is not violated. Since the parameters that result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions that result in the onset of transition boiling have been used to mark the beginning of the region in which fuel damage could occur. Although it is recognized that the onset of transition boiling would not result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. However, the uncertainties in monitoring the core operating state and in the procedures used to calculate the critical power result in an uncertainty in the value of the critical power. Therefore, the fuel cladding integrity SL is defined as the critical power ratio in the limiting fuel assembly for which more than 99.9% of the fuel rods in the core are expected to avoid boiling transition, considering the power distribution within the core and all uncertainties.

The MCPR SL is determined using a statistical model that combines all the uncertainties in operating parameters and the procedures used to calculate critical power. The probability of the occurrence of boiling transition is determined using the approved General Electric Critical Power correlations. Details of the fuel cladding integrity SL calculation are given in Reference 1. Reference 1 also includes, by reference, a tabulation of the uncertainties used in the determination of the MCPR SL and of the nominal values of the parameters used in the MCPR SL statistical analysis.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected and allows coupling attempts to be initiated for an uncoupled control rod when greater than the low power setpoint of the RWM. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. The control rods can be electrically disarmed by disconnecting power from all four directional control valve solenoids. Required Action C.1 is modified by a Note, which allows the inoperable control rods to be bypassed in the RWM or the RWM to be bypassed, if required, to allow insertion of the inoperable control rods and continued operation. LCO 3.3.2.1 provides additional requirements when one or more control rods are bypassed in the RWM or when the RWM is bypassed to ensure compliance with the BPWS analysis (Ref. 6).

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

D.1 and D.2

Out of sequence control rods may increase the potential reactivity worth of a dropped control rod during a CRDA. At ≤ ~~10%~~ 8.75% RTP, the generic BPWS analysis (Ref. 6) requires inserted control rods not in compliance with BPWS to be separated by at least two OPERABLE control rods in all directions, including the diagonal. Therefore, if two or more inoperable control rods are not in compliance with BPWS and not separated by at least two OPERABLE control rods, action must be taken to restore compliance with BPWS or restore the control rods to OPERABLE status. Condition D is modified by a Note indicating that the Condition is not applicable when THERMAL POWER is > ~~10%~~ 8.75% RTP, since the BPWS is not required to be followed under these conditions, as described in the Bases for LCO 3.1.6. The allowed Completion Time of 4 hours is acceptable, considering the low probability of a CRDA occurring.

(continued)

BASES

ACTIONS (continued)

E.1

If any Required Action and associated Completion Time of Condition A, C, or D are not met, or there are nine or more inoperable control rods, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. This ensures all insertable control rods are inserted and places the reactor in a condition that does not require the active function (i.e., scram) of the control rods. The number of control rods permitted to be inoperable when operating above ~~10%~~ RTP (e.g., no CRDA considerations) could be more than the value specified, but the occurrence of a large number of inoperable control rods could be indicative of a generic problem, and investigation and resolution of the potential problem should be undertaken. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

8.75%

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

The position of each control rod must be determined to ensure adequate information on control rod position is available to the operator for determining control rod OPERABILITY and controlling rod patterns. Control rod position may be determined by the use of OPERABLE reed switch position indicators (including "full-in" or "full-out" indication), by moving control rods to a position with an OPERABLE reed switch indicator, or by the use of other appropriate methods. The 24 hour Frequency of this SR is based on operating experience related to expected changes in control rod position and the availability of control rod position indications in the control room.

SR 3.1.3.2 and SR 3.1.3.3

Control rod insertion capability is demonstrated by inserting each partially or fully withdrawn control rod at least one notch and observing that the control rod moves. The control rod may then be returned to its original position. This ensures the control rod is not stuck and is free to insert on a scram signal. As noted, SR 3.1.3.2 and SR 3.1.3.3 are not required to be performed until 7 days and 31 days, respectively, after the control rod is withdrawn

(continued)

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Rod Pattern Control

BASES

BACKGROUND

Control rod patterns during startup conditions are controlled by the operator and the rod worth minimizer (RWM) (LCO 3.3.2.1, "Control Rod Block Instrumentation"), so that only specified control rod sequences and relative positions are allowed over the operating range of all control rods inserted to ~~10%~~ 8.75% RTP. The sequences limit the potential amount of reactivity addition that could occur in the event of a Control Rod Drop Accident (CRDA).

This Specification assures that the control rod patterns are consistent with the assumptions of the CRDA analyses of References 1, 2 and 3.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the CRDA are summarized in References 2 and 3. CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analysis. The RWM (LCO 3.3.2.1) provides backup to operator control of the withdrawal sequences to ensure that the initial conditions of the CRDA analysis are not violated.

Prevention or mitigation of positive reactivity insertion events is necessary to limit the energy deposition in the fuel, thereby preventing significant fuel damage which could result in the undue release of radioactivity. Since the failure consequences for UO_2 have shown that sudden fuel pin rupture requires a fuel energy deposition of approximately 425 cal/gm (Ref. 4), the fuel damage limit of 280 cal/gm provides a margin of safety from significant core damage which would result in release of radioactivity (Ref. 5). Generic evaluations (Refs. 2 and 6) of a design basis CRDA (i.e., a CRDA resulting in a peak fuel energy deposition of 280 cal/gm) have shown that if the peak fuel enthalpy remains below 280 cal/gm, then the maximum reactor pressure will be less than the required ASME Code limits (Ref. 7) and the calculated offsite doses will be well within the required limits (Ref. 8).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Control rod patterns analyzed in Reference 2 follow the banked position withdrawal sequence (BPWS). The BPWS is applicable from the condition of all control rods fully inserted to ~~10%~~ 8.75% RTP (Ref. 3). For the BPWS, the control rods are required to be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions (e.g., between notches 08 and 12). The banked positions are established to minimize the maximum incremental control rod worth without being overly restrictive during normal plant operation. Generic analysis of the BPWS has demonstrated that the 280 cal/gm fuel damage limit will not be violated during a CRDA while following the BPWS during a plant startup or shutdown. The generic BPWS analysis (Ref. 9) also evaluates the effect of fully inserted, inoperable control rods not in compliance with the sequence, to allow a limited number (i.e., eight) and a required distribution of fully inserted, inoperable control rods.

Rod pattern control satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 10).

LCO

Compliance with the prescribed control rod sequences minimizes the potential consequences of a CRDA by limiting the initial conditions to those consistent with the BPWS. This LCO only applies to OPERABLE control rods. For inoperable control rods required to be inserted, separate requirements are specified in LCO 3.1.3, "Control Rod OPERABILITY," consistent with the allowances for inoperable control rods in the BPWS.

APPLICABILITY

In MODES 1 and 2, when THERMAL POWER is ≤ ~~10%~~ 8.75% RTP, the CRDA is a Design Basis Accident and, therefore, compliance with the assumptions of the safety analysis is required. When THERMAL POWER is > ~~10%~~ 8.75% RTP, there is no credible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel damage limit during a CRDA (Ref. 3). In MODES 3, 4, and 5, since the reactor is shut down and interlocks allow only a single control rod to be withdrawn from a core cell containing fuel assemblies in MODE 5, adequate SDM ensures that the consequences of a CRDA are acceptable. This is due to the fact that the reactor will remain subcritical with a single control rod withdrawn.

(continued)

BASES (continued)

ACTIONS

A.1 and A.2

With one or more OPERABLE control rods not in compliance with the prescribed control rod sequence, actions may be taken to either correct the control rod pattern or declare the associated control rods inoperable within 8 hours. Noncompliance with the prescribed sequence may be the result of "double notching;" drifting as a result of a control rod drive cooling water transient or leaking scram valves; or a power reduction to ≤ ~~10%~~ RTP before establishing the correct control rod pattern. The number of OPERABLE control rods not in compliance with the prescribed sequence is limited to eight, to prevent the operator from attempting to correct a control rod pattern that significantly deviates from the prescribed sequence. When the control rod pattern is not in compliance with the prescribed sequence, all control rod movement should be stopped except for moves needed to correct the rod pattern, or scram if warranted.

8.75%

Required Action A.1 is modified by a Note which allows an individual control rod to be bypassed in the RWM or the entire RWM to be bypassed to allow the affected control rods to be returned to their correct position. LCO 3.3.2.1 requires verification of control rod movement by a second licensed operator or other qualified member of the technical staff. This ensures that the control rods will be moved to the correct BPWS position. A control rod not in compliance with the prescribed sequence is not considered inoperable except as required by Required Action A.2. OPERABILITY of control rods is determined by compliance with LCO 3.1.3, "Control Rod OPERABILITY," LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators." The allowed Completion Time of 8 hours is reasonable, considering the restrictions on the number of allowed out of sequence control rods and the low probability of a CRDA occurring during the time the control rods are out of sequence.

B.1 and B.2

If nine or more OPERABLE control rods are out of sequence, the control rod pattern significantly deviates from the prescribed sequence. Control rod withdrawal should be suspended immediately to prevent the potential for further

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

deviation from the prescribed sequence. Control rod insertion to correct the position of control rods withdrawn beyond their allowed position is allowed since, in general, insertion of control rods has less impact on control rod worth than withdrawals have. Required Action B.1 is modified by a Note which allows an individual control rod to be bypassed in the RWM or the entire RWM to be bypassed to allow the affected control rods to be returned to their correct position. LCO 3.3.2.1 requires verification of control rod movement by a second licensed operator or other qualified member of the technical staff.

When nine or more OPERABLE control rods are not in compliance with BPWS, the reactor must be manually scrammed within 1 hour. This ensures the reactor is shut down and, as such, does not meet the applicability requirements of this LCO. The allowed Completion Time of 1 hour is reasonable to allow insertion of control rods to restore compliance, and is appropriate relative to the low probability of a CRDA occurring with the control rods out of sequence.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

The control rod pattern is verified to be in compliance with the BPWS at a 24 hour Frequency to ensure the assumptions of the CRDA analyses are met. The 24 hour Frequency was developed considering that the primary check on compliance with the BPWS is performed by the RWM (LCO 3.3.2.1), which provides control rod blocks to enforce the required sequence and is required to be OPERABLE when operating at ≤ ~~10%~~ 8.75% RTP.

REFERENCES

1. UFSAR, Section 15.4.

2. NEDE-24011-P-A-11-US, General Electric Standard Application for Reactor Fuel, Supplement for United States, Section 2.2.3.1, November 1995.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

23%

generated. Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which turbine stop valve closure and turbine control valve fast closure scram trips are bypassed, both high and low core flow $MAPFAC_p$ limits are provided for operation at power levels between ~~25%~~ RTP and the previously mentioned bypass power level. The exposure dependent APLHGR limits are reduced by $MAPFAC_p$ and $MAPFAC_f$ at various operating conditions to ensure that all fuel design criteria are met for normal operation and AOOs. A complete discussion of the analysis code is provided in Reference 8.

LOCA analyses are then performed to ensure that the above determined APLHGR limits are adequate to meet the PCT and maximum oxidation limits of 10 CFR 50.46. The analysis is performed using calculational models that are consistent with the requirements of 10 CFR 50, Appendix K. A complete discussion of the analysis code is provided in Reference 9. The PCT following a postulated LOCA is a function of the average heat generation rate of all the rods of a fuel assembly at any axial location and is not strongly influenced by the rod to rod power distribution within an assembly. The APLHGR limits specified are equivalent to the LHGR of the highest powered fuel rod assumed in the LOCA analysis divided by its local peaking factor. A conservative multiplier is applied to the LHGR assumed in the LOCA analysis to account for the uncertainty associated with the measurement of the APLHGR.

For single recirculation loop operation, Reference 5 shows that no APLHGR reduction is required.

The APLHGR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 10).

LCO

The APLHGR limits for each type of fuel as a function of axial location and average planar exposure specified by reference in the COLR are the result of the fuel design, DBA, and transient analyses. For two recirculation loops operating, the limit is determined by multiplying the smaller of the $MAPFAC_p$ and $MAPFAC_f$ factors times the exposure dependent APLHGR limits. The APLHGR limits have been approved for the respective fuel and lattice type and determined by the approved methodology described in Reference 1. When hand calculations are required, the APLHGR for each type of fuel as a function of average planar

(continued)

BASES

LCO (continued)

exposure shall not exceed the limiting value, adjusted for core flow and core power, for the most limiting lattice (excluding natural uranium) for each type of fuel shown in the applicable figures of the COLR. Limits have been provided in the COLR for two recirculation loop operation and single recirculation loop operation. The limits on single recirculation loop operation are provided to allow operation in this condition in conformance with the requirements of LCO 3.4.1, "Recirculation Loops Operating."

APPLICABILITY

The APLHGR limits are primarily derived from fuel design evaluations and LOCA and transient analyses that are assumed to occur at high power levels. Studies and operating experience have shown that as power is reduced, the margin to the required APLHGR limits increases. This trend continues down to the power range of 5% to 15% RTP when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor scram function provides prompt scram initiation during any significant transient, thereby effectively removing any APLHGR limit compliance concern in MODE 2. ~~Therefore,~~ At THERMAL POWER levels ≤ ~~25%~~ 23% RTP, the reactor is operating with substantial margin to the APLHGR limits~~, thus, this LCO is not required~~.

For consistency with the 2.1.1.1 SL, this power level was selected for LCO applicability.

ACTIONS

A.1

If any APLHGR exceeds the required limits, an assumption regarding an initial condition of the DBA and transient analyses may not be met. Therefore, prompt action should be taken and continued to restore the APLHGR(s) to within the required limits such that the plant operates within analyzed conditions and within design limits of the fuel rods. The 4 hour Completion Time is sufficient to restore the APLHGR(s) to within its limits and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the APLHGR out of specification.

B.1

If the APLHGR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which

(continued)

BASES

ACTIONS

B.1 (continued)

the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < ~~25%~~ 23% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < ~~25%~~ 23% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

APLHGRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ ~~25%~~ 23% RTP and then every 24 hours thereafter. They are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation. The 12 hour allowance after THERMAL POWER ≥ ~~25%~~ 23% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

REFERENCES

1. NEDO-24011-P-A "General Electric Standard Application for Reactor Fuel" (latest approved version).

2. UFSAR, Chapter 4.

3. UFSAR, Chapter 6.

4. UFSAR, Chapter 15.

5. NEDC-31776P, Brunswick Steam Electric Plant Units 1 and 2 Single-Loop Operation, December 1989.

6. NEDC-31654P, Maximum Extended Operating Domain Analysis for Brunswick Steam Electric Plant, February 1989.

7. NEDO-20953-A, Three-Dimensional BWR Core Simulator, October 1978.

8. NEDO-24154, Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors, October 1978.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

state ($MCPR_f$ and $MCPR_p$, respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency (Ref. 7).

Flow dependent MCPR limits are determined using the methodology described in Reference 2 to analyze slow flow runout transients. The operating limit is dependent on the maximum core flow limiter setting in the Recirculation Flow Control System.

Power dependent MCPR limits ($MCPR_p$) are determined using the methodology described in Reference 2. Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scrams are bypassed, high and low flow $MCPR_p$ operating limits are provided for operating between ~~25%~~ 23% RTP and the previously mentioned bypass power level.

The MCPR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 8).

LCO

The MCPR operating limits, as a function of core flow, core power, and cycle exposure, specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the $MCPR_f$ and $MCPR_p$ limits.

APPLICABILITY

The MCPR operating limits are primarily derived from transient analyses that are assumed to occur at high power levels. Below ~~25%~~ 23% RTP, the reactor is operating at a minimum recirculation pump speed and the moderator void ratio is small. Surveillance of thermal limits below ~~25%~~ 23% RTP is unnecessary due to the large inherent margin that ensures that the MCPR SL is not exceeded even if a limiting transient occurs. Statistical analyses indicate that the nominal value of the initial MCPR expected at ~~25%~~ 23% RTP is > 3.5. Studies of the variation of limiting transient behavior have been performed over the range of power and flow conditions. These studies encompass the range of key actual plant parameter values important to typically limiting transients. The results of these studies demonstrate that a margin is expected between performance and the MCPR requirements, and that margins increase as

(continued)

BASES

APPLICABILITY (continued)

power is reduced to ~~25%~~ 23% RTP. This trend is expected to continue to the 5% to 15% power range when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor provides rapid scram initiation for any significant power increase transient, which effectively eliminates any MCPR compliance concern. Therefore, at THERMAL POWER levels < ~~25%~~ 23% RTP, the reactor is operating with substantial margin to the MCPR limits and this LCO is not required.

ACTIONS

A.1

If any MCPR is outside the required limits, an assumption regarding an initial condition of the design basis transient analyses may not be met. Therefore, prompt action should be taken to restore the MCPR(s) to within the required limits such that the plant remains operating within analyzed conditions. The 4 hour Completion Time is normally sufficient to restore the MCPR(s) to within its limits and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the MCPR out of specification.

B.1

If the MCPR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < ~~25%~~ 23% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < ~~25%~~ 23% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The MCPR is required to be initially calculated within 12 hours after THERMAL POWER is ≥ ~~25%~~ 23% RTP and then every 24 hours thereafter. It is compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1 (continued)

recognition of the slowness of changes in power distribution during normal operation. The 12 hour allowance after THERMAL POWER ≥ ~~25%~~ 23% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

SR 3.2.2.2

Because the transient analysis takes credit for conservatism in the scram speed performance, it must be demonstrated that the specific scram speed distribution is consistent with that used in the transient analysis. SR 3.2.2.2 determines the value of τ, which is a measure of the actual scram speed distribution compared with the assumed distribution. The MCPR operating limit is then determined based on an interpolation between the applicable limits for ODYN Option A (scram times of LCO 3.1.4, "Control Rod Scram Times") and ODYN Option B (realistic scram times) analyses. The MCPR operating limits for the ODYN Option A and ODYN Option B analyses are specified in the COLR. The parameter τ must be determined once within 72 hours after each set of scram time tests required by SR 3.1.4.1, SR 3.1.4.2, and SR 3.1.4.4 because the effective scram speed distribution may change during the cycle. The 72 hour Completion Time is acceptable due to the relatively minor changes in τ expected during the fuel cycle.

REFERENCES

1. UFSAR Section 4.4.2.1.
2. NEDO-24011-P-A, General Electric Standard Application for Reactor Fuel (latest approved version).
3. UFSAR, Chapter 4.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. NEDC-31776P, Brunswick Steam Electric Plant Units 1 and 2 Single-Loop Operation, December 1989.

(continued)

This bases page reflects changes submitted for NRC review in BSEP 01-0076, "Request for License Amendments Thermal-Hydraulic Stability Option III," dated June 26, 2001. The revision bars indicate the areas changed as a result of BSEP 01-0076. Markups reflect EPU related changes

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Average Power Range Monitor (APRM)

channel is assigned to one, two or four OPRM "cells," forming a total of 24 separate OPRM cells per APRM channel, each with either three or four detectors. LPRMs near the edge of the core are assigned to either one or two OPRM cells. A minimum of 18 OPRM cells in an APRM channel must have at least two OPERABLE LPRMs for the OPRM Upscale Function 2.f to be OPERABLE (Ref. 22).

2.a. Average Power Range Monitor Neutron Flux—High (Setdown)

For operation at low power (i.e., MODE 2), the Average Power Range Monitor Neutron Flux—High, (Setdown) Function is capable of generating a trip signal that prevents fuel damage resulting from abnormal operating transients in this power range. For most operation at low power levels, the Average Power Range Monitor Neutron Flux—High, (Setdown) Function will provide a secondary scram to the Intermediate Range Monitor Neutron Flux—High Function because of the relative setpoints. With the IRMs at Range 9 or 10, it is possible that the Average Power Range Monitor Neutron Flux—High, (Setdown) Function will provide the primary trip signal for a core-wide increase in power.

No specific safety analyses take direct credit for the Average Power Range Monitor Neutron Flux—High, (Setup) Function. However, this Function is credited in calculations used to eliminate the need to perform the spatial analysis required for the Intermediate Range Monitor Neutron Flux—High Function (Ref. 6). In addition, the Average Power Range Monitor Neutron Flux—High, (Setup) Function indirectly ensures that before the reactor mode switch is placed in the run position, reactor power does not exceed ~~25%~~ RTP (SL 2.1.1.1) when operating at low reactor pressure and low core flow. Therefore, it indirectly prevents fuel damage during significant reactivity increases with THERMAL POWER < ~~25%~~ RTP.

23%

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is < ~~25%~~ RTP.

The Average Power Range Monitor Neutron Flux—High (Setdown) Function must be OPERABLE during MODE 2 when control rods may be withdrawn since the potential for criticality exists.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.a. Average Power Range Monitor Neutron Flux—High (Setdown) (continued)

In MODE 1, the Average Power Range Monitor Simulated Thermal Power—High and Neutron Flux—High Functions provide protection against reactivity transients and the RWM and Rod Block Monitor protect against control rod withdrawal error events.

2.b. Average Power Range Monitor Simulated Thermal Power—High

The Average Power Range Monitor Simulated Thermal Power—High Function monitors neutron flux to approximate the THERMAL POWER being transferred to the reactor coolant. The APRM neutron flux is electronically filtered with a time constant, nominally 6 seconds, representative of the fuel heat transfer dynamics to generate a signal proportional to the THERMAL POWER in the reactor. The trip level is varied as a function of rated recirculation drive flow (W) in percent and is clamped at an upper limit that is always lower than the Average Power Range Monitor Neutron Flux—High Function Allowable Value. The Average Power Range Monitor Simulated Thermal Power—High Function provides a general definition of the licensed core power/core flow operating domain.

A note is included, applicable when the plant is in single recirculation loop operation per LCO 3.4.1, which requires reducing by ΔW the flow value used in the Allowable Value equation. The value of ΔW, is defined in plant procedures. The value of ΔW is established to ~~conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow (i.e., reverse flow) in the jet pumps associated with the inactive recirculation loop. Inaccuracy of the core flow/drive flow correlation results when in single loop operation a higher drive flow is required to produce a specified core flow in comparison to two loop operation. This difference exists because the single loop drive flow must compensate for back flow through the inactive jet pumps, which does not occur in two loop operation. The correlation factor ΔW was implemented to maintain the flow biased trips at the same position, relative to the power/flow map, for single loop operation as they are for two loop operation. This adjusted Allowable Value thus maintains thermal margins essentially unchanged from those for two loop operation.~~

adjust the SLO limit down in power approximately 8.5% RTP to reflect the difference between the analyzed limits for two-recirculation loop operation (TLO) and SLO. The adjustment maintains the SLO limits at approximately the same absolute thermal power level as was established prior to extended power uprate. The 8.5% RTP has been converted to an equivalent "ΔW" value for convenience of representation and to reflect the way the adjustment is actually made in the APRM equipment. In addition to this adjustment, the actual ΔW value entered into the equipment includes an allowance for additional flow measurement uncertainties that may occur in SLO.

The allowable value

(continued)

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Simulated Thermal Power—High (continued)

equation for single loop operation is only valid for flows down to W = ΔW. ~~No correction is required for single loop operation for drive flows less than ΔW (the value of ΔW will always be less than about 15%). Back flow in the inactive recirculation loop does not occur at core flows less than approximately 30 to 40% rated core flow, which corresponds to approximately 30 to 40% drive flow~~.

, at which point the allowable value is equal to the TLD "offset" value, the minimum value required.

The Average Power Range Monitor Simulated Thermal Power—High Function is not associated with an LSSS. Operating limits established for the licensed operating domain are used to develop the Average Power Range Monitor Simulated Thermal Power—High Function Allowable Values, including the clamp value, to provide pre-emptive reactor scram and prevent gross violation of the licensed operating domain. Operation outside the licensed operating domain may result in anticipated operational occurrences and postulated accidents being initiated from conditions beyond those assumed in the safety analysis.

Each APRM channel uses one total recirculation drive flow signal representative of total core flow. The total drive flow signal is generated by the flow processing logic, part of the APRM channel, by summing the flow calculated from two flow transmitter signal inputs, one from each of the two recirculation loops. The flow processing logic OPERABILITY is part of the APRM channel OPERABILITY requirements for this Function.

The Average Power Range Monitor Simulated Thermal Power—High Function uses a trip level generated based on recirculation loop drive flow. Changes in the core flow to drive flow functional relationship may vary over the core flow operating range. These changes can result from gradual changes in the Recirculation System and core components over the reactor life time as well as specific maintenance performed on these components (e.g., jet pump cleaning). The proper representation of drive flow as a representation of core flow is ensured through drive flow alignment, accomplished by SR 3.3.1.1.18.

The Average Power Range Monitor Simulated Thermal Power—High Function is required to be OPERABLE in MODE 1 when there is the possibility of generating excessive

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8. Turbine Stop Valve—Closure (continued)

Turbine Stop Valve—Closure signals are initiated from position switches located on each of the four TSVs. Two independent position switches are associated with each stop valve. One of the two switches provides input to RPS trip system A; the other, to RPS trip system B. Thus, each RPS trip system receives an input from four Turbine Stop Valve—Closure channels, each consisting of one position switch. The logic for the Turbine Stop Valve—Closure Function is such that three or more TSVs must be closed to produce a scram. In addition, certain combinations of two valves closed will result in a half-scram. This Function must be enabled at THERMAL POWER ≥ ~~30%~~ 26% RTP. This is accomplished automatically by pressure switches sensing turbine first stage pressure; therefore, opening of the turbine bypass valves may affect this Function.

The Turbine Stop Valve—Closure Allowable Value is selected to be high enough to detect imminent TSV closure, thereby reducing the severity of the subsequent pressure transient.

Eight channels of Turbine Stop Valve—Closure Function, with four channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function if any three TSVs should close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is ≥ ~~30%~~ 26% RTP. This Function is not required when THERMAL POWER is < ~~30%~~ 26% RTP since the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor Fixed Neutron Flux—High Functions are adequate to maintain the necessary safety margins.

9. Turbine Control Valve Fast Closure, Control Oil Pressure—Low

Fast closure of the TCVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated on TCV fast closure in anticipation of the transients that would result from the closure of these valves. The Turbine Control Valve Fast Closure, Control Oil Pressure—Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 2. For

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

9. Turbine Control Valve Fast Closure, Control Oil Pressure—Low (continued)

this event, the reactor scram reduces the amount of energy required to be absorbed and ensures that the MCPR SL is not exceeded.

26%

Turbine Control Valve Fast Closure, Control Oil Pressure—Low signals are initiated by the electrohydraulic control (EHC) fluid pressure at each control valve. One pressure switch is associated with each control valve, and the signal from each switch is assigned to a separate RPS logic channel. This Function must be enabled at THERMAL POWER ≥ ~~30%~~ RTP. This is accomplished automatically by pressure switches sensing turbine first stage pressure; therefore, opening of the turbine bypass valves may affect this Function.

The Turbine Control Valve Fast Closure, Control Oil Pressure—Low Allowable Value is selected high enough to detect imminent TCV fast closure.

Four channels of Turbine Control Valve Fast Closure, Control Oil Pressure—Low Function with two channels in each trip system arranged in a one-out-of-two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This Function is required, consistent with the analysis assumptions, whenever THERMAL POWER is ≥ ~~30%~~ RTP. This Function is not required when THERMAL POWER is < ~~30%~~ RTP, since the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor Fixed Neutron Flux—High Functions are adequate to maintain the necessary safety margins. 26%

10. Reactor Mode Switch—Shutdown Position

The Reactor Mode Switch—Shutdown Position Function provides signals, via the manual scram logic channels, to two RPS logic channels, which are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.1 and SR 3.3.1.1.2 (continued)

The Frequencies are based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.1.3

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are adjusted to conform to the reactor power calculated from a heat balance. The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.8. 23%

A restriction to satisfying this SR when < ~~25%~~ RTP is provided that requires the SR to be met only at ≥ ~~25%~~ RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < ~~25%~~ RTP. At low power levels, a high degree of accuracy is unnecessary because of the large, inherent 23% margin to thermal limits (MCPR and APLHGR). At ≥ ~~25%~~ RTP, the Surveillance is required to have been satisfactorily performed within the last 7 days, in accordance with 23% SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above ~~25%~~ if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding ~~25%~~ RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

SR 3.3.1.1.4

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, SR 3.3.1.1.4 is not required to be performed when entering MODE 2 from MODE 1, since testing of the MODE 2 required IRM and APRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.14

The Average Power Range Monitor Flow Biased Simulated Thermal Power—High Function uses an electronic filter circuit to generate a signal proportional to the core THERMAL POWER from the APRM neutron flux signal. This filter circuit is representative of the fuel heat transfer dynamics that produce the relationship between the neutron flux and the core THERMAL POWER. The filter time constant must be verified to be ≤ 7 seconds to ensure that the channel is accurately reflecting the desired parameter.

The Frequency of 24 months is based on engineering judgment considering the reliability of the components.

SR 3.3.1.1.15

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic and simulated automatic operation for a specific channel. The functional testing of control rods (LCO 3.1.3), and SDV vent and drain valves (LCO 3.1.8), overlaps this Surveillance to provide complete testing of the assumed safety function.

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has demonstrated that these components will usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.1.1.16

This SR ensures that scrams initiated from the Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Control Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ ~~30%~~ 26% RTP. This is satisfied by calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the Allowable Value and the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.16 (continued)

valves must remain closed during an in-service calibration at THERMAL POWER ≥ ~~30%~~ RTP to ensure that the calibration is valid.

26%

If any bypass channel setpoint is nonconservative (i.e., the Functions are bypassed at ≥ ~~30%~~ RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Control Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (non-bypass). If placed in the non-bypass condition, this SR is met and the channel is considered OPERABLE.

The Frequency of 24 months is based on engineering judgment and reliability of the components.

SR 3.3.1.1.17

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. This test may be performed in one measurement or in overlapping segments, with verification that all components are tested. The RPS RESPONSE TIME acceptance criteria are included in Reference 13.

As noted (Note 1), neutron detectors for Function 2 are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time. In addition, Note 2 states the response time of the sensors for Functions 3 and 4 may be assumed in the RPS RESPONSE TIME test to be the design sensor response time. This is allowed since the sensor response time is a small part of the overall RPS RESPONSE TIME (Ref. 14).

RPS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. Note 3 requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV Closure Function. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal.

(continued)

BASES

BACKGROUND (continued)

occur if the RBM channel signal decreases below the downscale trip setpoint after the RBM channel has been normalized. The inoperable trip will occur during the nulling (normalization) sequence, if the RBM channel fails to null, too few LPRM inputs are available, if a module is not plugged in, or the function switch is moved to any position other than "Operate."

The purpose of the RWM is to control rod patterns during startup and shutdown, such that only specified control rod sequences and relative positions are allowed over the operating range from all control rods inserted to ~~10%~~ 8.75% RTP. The sequences effectively limit the potential amount and rate of reactivity increase during a CRDA. Prescribed control rod sequences are stored in the RWM, which will initiate control rod withdrawal and insert blocks when the actual sequence deviates beyond allowances from the stored sequence. The RWM determines the actual sequence based position indication for each control rod. The RWM also uses steam flow signals to determine when the reactor power is above the preset power level at which the RWM is automatically bypassed. The RWM is a single channel system that provides input into the RMCS rod withdraw permissive circuit.

With the reactor mode switch in the shutdown position, a control rod withdrawal block is applied to all control rods to ensure that the shutdown condition is maintained. This Function prevents inadvertent criticality as the result of a control rod withdrawal during MODE 3 or 4, or during MODE 5 when the reactor mode switch is required to be in the shutdown position. The reactor mode switch has two channels, each inputting into a separate RMCS rod block circuit. A rod block in either RMCS circuit will provide a control rod block to all control rods.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Rod Block Monitor

The RBM is designed to prevent violation of the MCPR SL and the cladding 1% plastic strain fuel design limit that may result from a single control rod withdrawal error (RWE) event. The analytical methods and assumptions used in evaluating the RWE event are summarized in Reference 2. A statistical analysis of RWE events was performed to determine the RBM response for both channels for each event.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. Rod Worth Minimizer (continued) 8.75%

Compliance with the BPWS, and therefore OPERABILITY of the RWM, is required in MODES 1 and 2 when THERMAL POWER is ≤ ~~10%~~ RTP. When THERMAL POWER is > ~~10%~~ RTP, there is no possible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel damage limit during a CRDA (Refs. 5 and 6). In MODES 3 and 4, all control rods are required to be inserted into the core; therefore, a CRDA cannot occur. In MODE 5, since only a single control rod can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will be subcritical.

8.75%

3. Reactor Mode Switch—Shutdown Position

During MODES 3 and 4, and during MODE 5 when the reactor mode switch is required to be in the shutdown position, the core is assumed to be subcritical; therefore, no positive reactivity insertion events are analyzed. The Reactor Mode Switch—Shutdown Position control rod withdrawal block ensures that the reactor remains subcritical by blocking control rod withdrawal, thereby preserving the assumptions of the safety analysis.

The Reactor Mode Switch—Shutdown Position Function satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 3).

Two channels are required to be OPERABLE to ensure that no single channel failure will preclude a rod block when required. There is no Allowable Value for this Function since the channels are mechanically actuated based solely on reactor mode switch position.

During shutdown conditions (MODE 3, 4, or 5), no positive reactivity insertion events are analyzed because assumptions are that control rod withdrawal blocks are provided to prevent criticality. Therefore, when the reactor mode switch is in the shutdown position, the control rod withdrawal block is required to be OPERABLE. During MODE 5 with the reactor mode switch in the refueling position, the refuel position one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") provides the required control rod withdrawal blocks.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.1 (continued)

input. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on reliability analyses (Ref. 8).

SR 3.3.2.1.2 and SR 3.3.2.1.3

A CHANNEL FUNCTIONAL TEST is performed for the RWM to ensure that the system will perform the intended function. The CHANNEL FUNCTIONAL TEST for the RWM is performed by selecting a control rod not in compliance with the prescribed sequence and verifying proper annunciation of the selection error, and by attempting to withdraw a control rod not in compliance with the prescribed sequence and verifying a control rod block occurs. As noted in the SRs, SR 3.3.2.1.2 is not required to be performed until 1 hour after any control rod is withdrawn in MODE 2. As noted, SR 3.3.2.1.3 is not required to be performed until 1 hour

8.75%

after THERMAL POWER is ≤ ~~10%~~ RTP in MODE 1. This allows entry into MODE 2 for SR 3.3.2.1.2, and entry into MODE 1 when THERMAL POWER is ≤ ~~10%~~ RTP for SR 3.3.2.1.3, to perform the required Surveillance if the 92 day Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs. Operating experience has demonstrated these components will usually pass the Surveillances when performed at the 92 day Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.3.2.1.4

The RBM setpoints are automatically varied as a function of power. Three Allowable Values are specified in Table 3.3.2.1-1, each within a specific power range. The power at which the control rod block Allowable Values automatically change are based on the APRM signal's input to each RBM channel. Below the minimum power range setpoint, the RBM is automatically bypassed. These power range setpoints (low power range setpoint, intermediate power range setpoint, and high power range setpoint) must be

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.4 (continued)

verified periodically to be less than or equal to the specified Allowable Values in the COLR. If any power range setpoint is nonconservative, then the affected RBM channel is considered inoperable. Alternatively, the RBM power range channel can be placed in the conservative condition (i.e., enabling the proper RBM setpoint). If placed in this condition, the SR is met and the RBM channel is not considered inoperable. As noted, neutron detectors are excluded from the Surveillance because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.3 and SR 3.3.1.1.8. The 24 month Frequency is based on the actual trip setpoint methodology utilized for these channels.

SR 3.3.2.1.5

The RWM is automatically bypassed when power is above a specified value. The power level is determined from steam flow signals. The automatic bypass setpoint must be verified periodically to be > ~~10%~~ 8.75% RTP. If the RWM low power setpoint is nonconservative, then the RWM is considered inoperable. Alternately, the low power setpoint channel can be placed in the conservative condition (nonbypass). If placed in the nonbypassed condition, the SR is met and the RWM is not considered inoperable. The Frequency is based on the trip setpoint methodology utilized for the low power setpoint channel.

SR 3.3.2.1.6

A CHANNEL FUNCTIONAL TEST is performed for the Reactor Mode Switch—Shutdown Position Function to ensure that the channel will perform the intended function. The CHANNEL FUNCTIONAL TEST for the Reactor Mode Switch—Shutdown Position Function is performed by attempting to withdraw any control rod with the reactor mode switch in the shutdown position and verifying a control rod block occurs.

As noted in the SR, the Surveillance is not required to be performed until 1 hour after the reactor mode switch is in the shutdown position, since testing of this interlock with the reactor mode switch in any other position cannot be

(continued)

BASES

26%

APPLICABLE SAFETY ANALYSES (continued)

The high water level trip indirectly initiates a reactor scram from the main turbine trip (above ~~30%~~ RTP) and trips the feedwater pumps, thereby terminating the event. The reactor scram mitigates the reduction in MCPR.

Feedwater and main turbine high water level trip instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 2).

LCO

The LCO requires three channels of the reactor vessel high water level instrumentation to be OPERABLE to ensure that the feedwater pump turbines and main turbine trip on a valid high water level signal. Two of the three channels are needed to provide trip signals in order for the feedwater and main turbine trips to occur. Each channel must have its setpoint set within the specified Allowable Value of SR 3.3.2.2.2. The Allowable Value is set to ensure that the thermal limits are not exceeded during the event. The actual setpoint is calibrated to be consistent with the applicable setpoint methodology assumptions. Trip setpoints are specified in the setpoint calculations. The setpoints are selected to ensure that the trip settings do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setting less conservative than the trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setting is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The trip setpoints are determined from the analytic limits corrected for defined process, calibration, and instrument errors. The Allowable Values are then determined, based on the trip setpoint values, by accounting for calibration based errors. These calibration based instrument errors are limited to instrument drift, errors associated with measurement and test equipment, and calibration tolerance of loop components. The trip setpoints and Allowable Values determined in this manner provide adequate protection

(continued)

BASES

LCO (continued)

because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for and appropriately applied for the instrumentation.

APPLICABILITY

The feedwater and main turbine high water level trip instrumentation is required to be OPERABLE at ≥ ~~25%~~ 23% RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases for LCO 3.2.1, "Average Planar Linear Heat Generation Rate (APLHGR)," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," sufficient margin to these limits exists below ~~25%~~ 23% RTP; therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A Note has been provided to modify the ACTIONS related to feedwater and main turbine high water level trip instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable feedwater and main turbine high water level trip instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable feedwater and main turbine high water level trip instrumentation channel.

<u>A.1</u>

With one channel inoperable, the remaining two OPERABLE channels can provide the required trip signal. However, overall instrumentation reliability is reduced because a single failure in one of the remaining channels concurrent

(continued)

BASES

ACTIONS

B.1 (continued)

during this period. It is also consistent with the 4 hour Completion Time provided in LCO 3.2.2 for Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

C.1

23%

With the required channels not restored to OPERABLE status or placed in trip, THERMAL POWER must be reduced to < 25% RTP within 4 hours. As discussed in the Applicability section of the Bases, operation below 25% RTP results in sufficient margin to the required limits, and the feedwater and main turbine high water level trip instrumentation is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The allowed Completion Time of 4 hours is based on operating experience to reduce THERMAL POWER to < 25% RTP from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains feedwater and main turbine high water level trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 3) assumption that 6 hours is the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the feedwater pump turbines and main turbine will trip when necessary.

SR 3.3.2.2.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

A plant specific LOCA analysis has been performed assuming only one operating recirculation loop. This analysis has demonstrated that, in the event of a LOCA caused by a pipe break in the operating recirculation loop, the Emergency Core Cooling System response will provide adequate core cooling, without the requirement to modify the APLHGR requirements (Ref. 3). However, the COLR may require APLHGR limits to restrict the peak clad temperature for a LOCA with a single recirculation loop operating below the corresponding temperature for both loops operating.

The transient analyses of Chapter 15 of the UFSAR have also been performed for single recirculation loop operation (Ref. 3) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed without the requirement to modify the MCPR requirements. During single recirculation loop operation, modification to the Reactor Protection System (RPS) average power range monitor (APRM) Simulated Thermal Power—High Allowable Value is required to account for the different ~~relationships between recirculation drive flow and reactor core flow~~. The APRM channel subtracts the ΔW value from the measured recirculation drive flow and uses the adjusted recirculation drive flow value to determine the APRM Simulated Thermal Power—High Function trip setpoint.

analyzed limits between two-recirculation drive flow loop operation and operation with only one loop.

to effectively shift the limits

Recirculation loops operating satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii) (Ref. 4).

LCO

Two recirculation loops are normally required to be in operation with their recirculation pump speeds matched within the limits specified in SR 3.4.1.1 to ensure that during a LOCA caused by a break of the piping of one recirculation loop the assumptions of the LOCA analysis are satisfied. Alternately, with only one recirculation loop in operation, modifications to the required APLHGR limits (LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), and APRM Simulated Thermal Power—High

(continued)

BASES

BACKGROUND (continued)

are in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3), as modified by exceptions listed in Specification 5.5.12, "Primary Containment Leakage Rate Testing Program."

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1, 2, and 4. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

46.4

The maximum allowable leakage rate for the primary containment (L_a) is 0.5% by weight of the containment air per 24 hours at the maximum peak containment pressure (P_a) of 49 psig. The value of P_a (49 psig) is conservative with respect to the current calculated peak drywell pressure of ~~40.9~~ psig (Ref. 4).

Primary containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).

LCO

Primary containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required Primary Containment Leakage Rate Testing Program leakage test. At this time, the applicable leakage limits must be met. In addition, the leakage from the drywell to the suppression chamber must be limited to ensure the pressure suppression function is accomplished and the suppression chamber pressure does not exceed design

(continued)

BASES

REFERENCES (continued)

4. ~~NEDO-32466, Power Uprate Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2 (Supplement 1), March 1996.~~

NEDC-33039P, Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2, Extended Power Uprate, August 2001.

5. 10 CFR 50.36(c)(2)(ii).

6. NRC Regulatory Guide 1.163, Performance-Based Containment Leak-Rate Testing Program, September 1995.

7. Nuclear Energy Institute (NEI) 94-01, Industry Guideline for Implementing Performance-Based Option of 10 CFR 50 Appendix J, July 26, 1995.

8. ANSI/ANS 56.8-1994.

9. NRC SER; Issuance of Amendment No. 181 to Facility Operating License No. DPR-71 and Amendment No. 213 to Facility Operating License No. DPR-62 Regarding 10 CFR 50 Appendix J, Option B - Brunswick Steam Electric Plant, Units 1 and 2 (BSEP 95-0316) (TAC Nos. M93679 and M93680); dated February 1, 1996.

10. Bechtel Topical Report BN-TOP-1, Revision 1, November 1, 1972.

11. NRC SER, Exemption from the Requirements of Appendix J for Brunswick Steam Electric Plant, Units 1 and 2, dated February 17, 1988.

12. NRC SER, Technical Exemption from the Requirements of Appendix J, dated May 12, 1987.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.4.1 (continued)

The following locations are monitored to obtain the drywell average temperature:

a. Below 5 ft elevation;

b. Between 10 ft and 23 ft elevation;

c. Between 28 ft and 45 ft elevation;

d. Between 70 ft and 80 ft elevation; and

e. Above 90 ft elevation.

The 24 hour Frequency of the SR is based on operating experience related to drywell average air temperature variations and temperature instrument drift during the applicable MODES and the low probability of a DBA occurring between surveillances. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to an abnormal drywell air temperature condition.

REFERENCES

1. UFSAR, Section 6.2.

2. ~~GE-NE-T23-00735-01, Brunswick Steam Electric Plant Units 1 and 2 High Drywell Bulk Average Temperature Analysis, October 1996~~.

3. UFSAR, Section 6.2.1.1.1.

4. 10 CFR 50.36(c)(2)(ii).

GE-NE-A22-00113-22-01, Brunswick Nuclear Plant Units 1 and 2, Extended Power Uprate - Task T0400 - Containment System Response, May 2001.

BASES

ACTIONS (continued)

E.1 and E.2

If suppression pool average temperature cannot be maintained at ≤ 120°F, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor pressure must be reduced to < 200 psig within 12 hours, and the plant must be brought to at least MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Continued addition of heat to the suppression pool with suppression pool temperature > 120°F could result in exceeding the design basis maximum allowable values for primary containment temperature or pressure. Furthermore, if a blowdown were to occur when the temperature was > 120°F, the maximum allowable bulk and local temperatures could be exceeded very quickly.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. The average temperature is determined using an algorithm with inputs from OPERABLE suppression pool water temperature channels. The 24 hour Frequency has been shown, based on operating experience, to be acceptable. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently. The 5 minute Frequency during testing is justified by the rates at which tests will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequencies are further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

REFERENCES

1. ~~NEDC-32466P, Power Uprate Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2, September 1995.~~

NEDC-33039P, Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2, Extended Power Uprate, August 2001.

2. NUREG-0783.

3. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS (continued)

B.1 and B.2

If suppression pool water level cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.2.1

Verification of the suppression pool water level is to ensure that the required limits are satisfied. The 24 hour Frequency of this SR has been shown to be acceptable based on operating experience. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool water level condition.

REFERENCES

1. UFSAR, Section 6.2.1.1.3.2.
2. ~~NEDC-32466P, Power Uprate Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2, September 1995.~~ NEDC-33039P, Safety Analysis Report for Brunswick Steam Electric Plant Units 1 and 2, Extended Power Uprate, August 2001.
3. 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS (continued)

B.1

If Required Action A.1 cannot be met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 8 hours. The allowed Completion Time of 8 hours is reasonable, based on operating experience, to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1

Verifying that there is ≥ 4350 gal of liquid nitrogen supply in the CAD System will ensure at least ~~30~~ 29 days of post-LOCA CAD operation. This minimum volume of liquid nitrogen allows sufficient time after an accident to replenish the nitrogen supply for long term inerting. This is verified every 31 days to ensure that the system is capable of performing its intended function when required. The 31 day Frequency is based on operating experience, which has shown 31 days to be an acceptable period to verify the liquid nitrogen supply and on the availability of other hydrogen mitigating systems.

SR 3.6.3.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in each of the CAD subsystem flow paths provides assurance that the proper flow paths exist for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing.

A valve is also allowed to be in the nonaccident position provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable because the CAD System is manually initiated. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Turbine Bypass System

BASES

BACKGROUND

20.6%

The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is ~~25%~~ of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Main Turbine Bypass System consists of four valves connected to the main steam lines between the main steam isolation valves and the turbine stop valves. The bypass valves are controlled by the pressure regulation function of the Turbine Electro Hydraulic Control System, as discussed in the UFSAR, Section 7.7.1.4 (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves that direct all steam flow to the turbine. If the Speed Control System or load limit restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves. When the bypass valves open, the steam flows through connecting piping and bypass valve pressure reducers to the condenser.

APPLICABLE SAFETY ANALYSES

The Main Turbine Bypass System is assumed to function during the generator load rejection transient, the turbine trip transient, and the feedwater controller failure maximum demand transient, as described in the UFSAR, Section 15.2.1 (Ref. 2), Section 15.2.2 (Ref. 3), and Section 15.1.2 (Ref. 4). Opening the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event. An inoperable Main Turbine Bypass System may result in APLHGR and MCPR penalties.

The Main Turbine Bypass System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) (Ref. 5).

(continued)

BASES (continued)

LCO

The Main Turbine Bypass System is required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, so that the Safety Limit MCPR is not exceeded. With the Main Turbine Bypass System inoperable, modifications to the APLHGR limits (LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)") and the MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") may be applied to allow this LCO to be met. The APLHGR and MCPR limits for the inoperable Main Turbine Bypass System are specified in the COLR. An OPERABLE Main Turbine Bypass System requires the minimum number of bypass valves, specified in the COLR, to open in response to increasing main steam line pressure. This response is within the assumptions of the applicable analysis (Refs. 2, 3, and 4).

APPLICABILITY

23%

The Main Turbine Bypass System is required to be OPERABLE at ≥ ~~25%~~ RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the turbine generator load rejection transient. As discussed in the Bases for LCO 3.2.1 and LCO 3.2.2, sufficient margin to these limits exists at < ~~25%~~ RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If the Main Turbine Bypass System is inoperable (one or more bypass valves as specified in the COLR inoperable), and the APLHGR and MCPR limits for an inoperable Main Turbine Bypass System, as specified in the COLR, are not applied, the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status or adjust the APLHGR and MCPR limits accordingly. The 4 hour Completion Time is reasonable, based on the time to complete the Required Action and the low probability of an event occurring during this period requiring the Main Turbine Bypass System.

(continued)

BASES

ACTIONS (continued)

B.1

23%

If the Main Turbine Bypass System cannot be restored to OPERABLE status and the APLHGR and MCPR limits for an inoperable Main Turbine Bypass System are not applied, THERMAL POWER must be reduced to < ~~25%~~ RTP. As discussed in the Applicability section, operation at < ~~25%~~ RTP results in sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the applicable safety analyses transients. The 4 hour Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

Cycling each main turbine bypass valve through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. The 31 day Frequency is based on manufacturer's recommendations (Ref. 6), is consistent with the procedural controls governing valve operation, and ensures correct valve positions. Operating experience has shown that these components usually pass the SR when performed at the 31 day Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.6.2

The Main Turbine Bypass System is required to actuate automatically to perform its design function. This SR demonstrates that, with the required system initiation signals, the valves will actuate to their required position. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) (Ref. 2) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Control rod testing may be performed in compliance with the prescribed sequences of LCO 3.1.6, and during these tests, no exceptions to the requirements of LCO 3.1.6 are necessary. For testing performed with a sequence not in compliance with LCO 3.1.6, the requirements of LCO 3.1.6 may be suspended, provided additional administrative controls are placed on the test to ensure that the assumptions of the special safety analysis for the test sequence are satisfied. Assurances that the test sequence is followed can be provided by either programming the test sequence into the RWM, with conformance verified as specified in SR 3.3.2.1.8 and allowing the RWM to monitor control rod withdrawal and provide appropriate control rod blocks if necessary, or by verifying conformance to the approved test sequence by a second licensed operator or other qualified member of the technical staff. These controls are consistent with those normally applied to operation in the startup range as defined in the SRs and ACTIONS of LCO 3.3.2.1, "Control Rod Block Instrumentation."

APPLICABILITY

Control rod testing, while in MODES 1 and 2, with THERMAL POWER greater than ~~10%~~ 8.75% RTP, is adequately controlled by the existing LCOs on power distribution limits and control rod block instrumentation. Control rod movement during these conditions is not restricted to prescribed sequences and can be performed within the constraints of LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and LCO 3.3.2.1. With THERMAL POWER less than or equal to ~~10%~~ 8.75% RTP, the provisions of this Special Operations LCO are necessary to perform special tests that are not in conformance with the prescribed sequences of LCO 3.1.6.

(continued)