CP&L
A Progress Energy Company

John S. Keenan
Vice President
Brunswick Nuclear Plant

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

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

Ladies and Gentlemen:

On August 9, 2001 (Serial: BSEP 01-0086), Carolina Power & Light (CP&L) Company requested a revision to the Operating Licenses (OLs) and the Technical Specifications for the Brunswick Steam Electric Plant (BSEP), Units 1 and 2. The proposed license amendments increase the maximum power level authorized by Section 2.C.(1) of OLs DPR-71 and DPR-62 from 2558 megawatts thermal (MWt) to 2923 MWt. Subsequently, on November 7, 2001, the NRC provided an electronic version of a Request For Additional Information (RAI) concerning the probabilistic safety assessment (PSA) evaluation performed in support of the BSEP extended power uprate. Enclosure 1 provides the response to this RAI. Enclosure 2 contains the PSA evaluation.

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

MAT/mat

P.O. Box 10429
Southport, NC 28461

T > 910.457.2496
F > 910.457.2803

A001

Enclosures:

1. Response to Request For Additional Information (RAI) 6
2. Identification of Risk Implications Due to Extended Power Uprate at Brunswick

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.

Kenneth M. Nicely
Notary (Seal)

My commission expires: MAY 18, 2003

cc:

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

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

U. S. Nuclear Regulatory Commission
ATTN: Mr. Donnie J. Ashley (Mail Stop OWFN 8G9)
11555 Rockville Pike
Rockville, MD 20852-2738

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

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

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

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

ENCLOSURE 1

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

Response to Request For Additional Information (RAI) 6

Background

On August 9, 2001 (Serial: BSEP 01-0086), Carolina Power & Light (CP&L) Company requested a revision to the Operating Licenses (OLs) and the Technical Specifications for the Brunswick Steam Electric Plant (BSEP), Units 1 and 2. The proposed license amendments increase the maximum power level authorized by Section 2.C.(1) of OLs DPR-71 and DPR-62 from 2558 megawatts thermal (MWt) to 2923 MWt. Subsequently, on November 7, 2001, the NRC provided an electronic version of a Request For Additional Information (RAI) concerning the probabilistic safety assessment (PSA) evaluation performed in support of the BSEP extended power uprate (EPU). The responses to this RAI follow.

Enclosure 2 contains the PSA study (i.e., "Identification of Risk Implications Due to Extended Power Uprate at Brunswick") which was performed to determine the net impact of EPU on the BSEP risk profile. The results in the study were generated with the pre-uprate Level 1 and Level 2 / large early release frequency (LERF) PSA models comprising the BSEP model-of-record (i.e., designated by CP&L as "MOR 98"). ERIN, who completed the study, and CP&L subsequently performed additional sensitivities to demonstrate that the risk insights obtained during the EPU review were not significantly altered by changes that were being considered for incorporation into the models.

NRC Question 6-1

The licensee has evaluated the impacts of the extended power uprate (EPU) using their current, pre-uprate probabilistic risk assessment (PRA) model and a revised model to reflect the EPU plant conditions. The licensee needs to demonstrate that the PRA models are acceptable for this license amendment and address any weaknesses that have been identified through peer reviews of the PRA that might affect the results associated with this license amendment. Specifically, the licensee needs to describe how they assure that the current PRA model reflects the as-built, as-operated (or to be operated) plant. This description should include if the current PRA has been through an industry peer review certification process and if so (or if only an independent review was performed), provide the overall findings of the review (by element) and discuss any

elements rated low (e.g., less than a 3 on a scale of 1 to 4) or any findings/observations that potentially affect the sequences impacted by the licensee's proposed EPU.

Response to Question 6-1

The pre-uprate BSEP PSA model was used as the starting point for a study of the risk implications of EPU at BSEP. Although the request for a license amendment to operate the BSEP units at higher power levels is not a risk-informed submittal, a risk study was prepared using the guidance in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated July 1998.

Appendix C of Enclosure 2 documents, in detail, the acceptability of the BSEP PSA model for estimating the risk implications of EPU. It includes information on how the model has been kept up-to-date to reflect the as-built, as-operated plant. As stated in Appendix C, the BSEP PSA model and documentation has been maintained living and is routinely updated to reflect the current plant configuration following refueling outages and to reflect the accumulation of additional plant operating history and component failure data. The Level 1 and Level 2 BSEP PSA analyses were originally developed and submitted to the NRC in August 1992, as the Brunswick Individual Plant Examination (IPE). The BSEP Level 1 PSA models supporting the IPE were subsequently updated in 1993 and 1996. A full upgrade of the Level 1 PSA models began in 1998 and was completed in 2000. The Level 2 analysis was fully upgraded in 2001 and the Level 2 documentation is currently being finalized.

The BSEP PSA model was subjected to the industry peer review certification review during the week of September 10, 2001. The final report has not yet been received. The draft report has been received, and provided the following summary level observations:

Overall Assessment: Based on the PSA Peer Review Team review, the PSA can be effectively used to support applications involving absolute risk determination when combined with deterministic insights.

Areas Recommended for Enhancement: The principal areas recommended for enhancement include the following:

- Use of plant specific calculation or support of success criteria on individual systems,
- Elimination of some apparent conservatisms in assumed equipment performance and quantitative characterization,
- Development of model/software to achieve a lower truncation limit than currently used, and
- Performance of a search for plant unique uncertainties and the associated sensitivity studies to support the uncertainty ranges.

Additional Areas Recommended for Enhancement: The certification team identified 65 Level B "Facts and Observations" (F&O's). The Level B F&O's are considered important and necessary to address, but disposition may be deferred until the next PSA update. These F&O's are still draft and under review by CP&L. There were no Level A F&O's. There were six strengths identified.

The following table, extracted from the draft report, provides the element grades assigned to the BSEP PSA.

SUMMARY OF GRADE ASSIGNMENTS BY PSA ELEMENT:
DISTRIBUTION BY GRADE FOR SUB-ELEMENTS

PSA Certification Areas Reviewed	Total Reviewed	Summary Grade	Average Grade	Number of Individual Sub-elements by Grade			
				1	2	3	4
Initiating Events	21	3	2.95	0	2	18	1
Accident Sequences Evaluation	24	3	2.88	0	3	21	0
Thermal Hydraulic Analysis	9	2	2.44	0	5	4	0
Systems Analysis	26	3	3.15	0	3	16	7
Data Analysis	20	3	3.00	0	3	14	3
Human Reliability Analysis	28	3	3.04	0	2	23	3
Dependency Analysis	14	3	3.14	0	1	10	3
Structural Response	11	3	2.91	0	2	8	1
Quantification and Results Interpretation	28	3	3.03	0	3	21	4
Containment Performance Analysis	27	3	3.19	0	0	22	5
Maintenance and Update Process	15	3	3.13	0	2	9	4
TOTAL	223	---	---	0	26	166	31
PERCENT	100%	---	---	0%	11.7%	74.4%	14%

The only element that received a summary grade lower than "3" from the certification team was "Thermal Hydraulic Analysis." This was an area in which the team believed that attention was merited to reduce identified conservatism in the existing success criteria and data of the BSEP PSA models. This was also a recognized area for improvement by CP&L and measures were already being taken to generate more Level 1 and Level 2 supporting thermal-hydraulic analyses for BSEP and to link these results into the risk models. The risk study performed for the BSEP EPU was based upon some of the thermal hydraulic analyses being generated with the MAAP code as described in Appendix A of Enclosure 2.

NRC Question 6-2

Please provide a breakdown, by initiating event, of the current (pre-uprate) and post-uprate core damage frequency (CDF) and large early release frequency (LERF) contribution.

Response to Question 6-2

The risk study that was performed was very broad in scope and addressed the proposed EPU using the best-available information on planned plant modifications and operating conditions. Sensitivity analyses were performed to ensure that the risk estimate conclusions would not change within a range of expected final plant configurations. The BSEP PSA models have not yet been updated to reflect the EPU; the update will take place on a schedule commensurate with modification implementation for each Brunswick unit's power uprate and the expected usage of the PSA models.

Table 1 compares the pre-uprate initiating event contribution to CDF and LERF to the contributions in the base case of the EPU risk study.

NRC Question 6-3

Are there any plant modifications being implemented as part of, or in parallel with, the EPU modifications that are associated with equipment actuation or plant scram logic or equipment setpoints that could impact the frequency of reactor scrams? If so, please identify these modifications/impacts and describe how these potential impacts have been considered in determining the change in risk associated with the licensee's proposed EPU.

Response to Question 6-3

Refer to Table 3.4-1 of Enclosure 2 for a discussion of modifications evaluated as part of the EPU PSA review. There are no additional modifications, to be performed in parallel with EPU, which have not been appropriately addressed in the EPU PSA review.

NRC Question 6-4

During plant normal or expected conditions (e.g., following a turbine trip) for the EPU plant configuration is there any equipment being operated beyond its name plate specifications (e.g., main transformer), operating ranges, or limits? If so, please identify the equipment that may be operated beyond its design limits, etc. and describe how these potential impacts have been considered in determining the change in risk associated with the licensee's proposed EPU.

Response to Question 6-4

It is not currently expected that any safety-related equipment will be operated beyond the nameplate specifications, operating ranges, or limits as a result of EPU. Modifications will be installed on certain equipment (e.g. High Pressure turbine replacement, main transformer

replacement, generator rewind, etc.) to extend the ratings of certain equipment to bound EPU conditions. A listing of the anticipated modifications was provided in Enclosure 2 to the BSEP EPU license amendment request (Serial: BSEP 01-0086, dated August 9, 2001). As part of the EPU evaluation, it was determined that parameters for some non-safety, balance-of-plant (BOP) equipment may exceed original design values, as detailed below.

1. The pressure and/or temperature in some BOP piping (e.g. heater drain piping) could slightly exceed the conservative design pressures/temperatures from the original specification. An initial code evaluation of these components has confirmed their acceptability, and there is no impact on plant risk.

2. The flow velocities in the 3rd, 4th, and 5th point feedwater heaters, which are not replaced as part of EPU, may marginally exceed original design values and Heat Exchanger Institute (HEI) recommendations. Although these slightly higher velocities have the potential to increase tube vibration, there is no expected increase in plant risk. The material condition of these feedwater heaters is monitored periodically by the thermal performance program and eddy current testing.

3. The motors for condensate and condensate booster pumps were shown, by analysis, to encroach on the nameplate ratings under full EPU conditions. These pump motors will be monitored during the initial uprate cycle to trend available margin. Appropriate equipment modifications and/or evaluations will be completed based on this trending to ensure component reliability. BSEP is maintaining a Condensate System configuration which includes a standby condensate and condensate booster pump, with auto-start logic, under full EPU conditions. No increase in plant risk is anticipated.

The performance of other power sensitive plant systems/equipment will be monitored as part of the EPU testing program to ensure acceptable performance and reliability.

NRC Question 6-5

Appendix A of Regulatory Guide (RG) 1.174 refers to the need for the use of importance measures (e.g., Fussell-Vesely (F-V)) to be a function of the base case CDF and LERF rather than being a fixed value for all plants and states further that the licensee should demonstrate how the chosen criteria are related to, and conform with, the acceptance guidelines described in this document [RG 1.174]. The licensee's submittal indicates that important operator actions are defined as those that have a F-V importance measure greater than 5E-3. How does this value relate to the acceptance guidelines of RG 1.174? Are there any operator actions that have not been evaluated in the licensee's submittal, that if assumed failed, would increase the CDF by more than 1E-6/year or LERF by more than 1E-7/year? If so, please identify and address these additional operator actions.

Response to Question 6-5

A detailed discussion of the operator actions assessed in the BSEP EPU risk study is found in Tables 4.1-8 and 5.1-1 of Enclosure 2. Table 4.1-8 summarizes the assessment of the operator actions explicitly reviewed in support of this analysis. The operator actions identified for explicit review were selected based on the following criteria:

1. F-V importance greater than 5E-3, as assessed by the BSEP PSA, or
2. Time critical (i.e., less than 30 minutes available) action

Twenty-six operator actions of highest importance in the PSA (i.e., F-V importance greater than 5E-3) were identified; and an additional 16 time critical Human Error Probabilities (HEPs) (i.e., less than 30 minutes available for operator action) were identified.

The F-V importance of operator actions was considered an appropriate measure for deciding which operator actions required further review for impact from EPU. A F-V importance of 5E-3 is the value used to identify high-safety significant equipment in the Maintenance Rule; that value was recommended in the NUMARC 93-01 guidance document and endorsed in RG 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 1, dated January 1995. A F-V importance of 5E-3 was judged appropriate for this study.

Risk Achievement Worth (RAW) is not considered an applicable measure in this case since there are no operator actions currently credited in the model that would be precluded as a result of the EPU. The assumption that an operator action completely fails as a measure of that action's importance would be overly conservative. For example, a RAW importance measure of 2.0 is frequently used in Maintenance Rule as a screening criterion. However, for a plant with a nominal CDF of 5E-5, a RAW of only 1.02 would result in exactly a 1E-6 change in risk. Thus, the suggested approach is not the appropriate screen for assessing operator action importances in this case.

NRC Question 6-6

The individual plant examination (IPE) safety evaluation report (SER) identifies a number of important operator actions, many, but not all, of which the licensee has identified in this submittal. Specifically, not addressed are: failure to recover offsite power, failure to initiate suppression pool cooling, and failure to vent or control venting. Please also address how the EPU potentially impacts each of these important operator actions, the time available for performing these actions, and their associated human error probability (HEP).

Response to Question 6-6

Important operator actions, the time available for performing key actions, and whether HEP recalculation is necessary are assessed in Section 4.1.6 and associated Table 4.1-8 of

Enclosure 2. The specific actions for failure to recover offsite power, failure to initiate suppression pool cooling, and failure to vent or control venting are addressed.

NRC Question 6-7

The submittal addresses SLC initiation at 4 minutes, which is typically identified in other boiling water reactor (BWR) PRAs as early initiation, but does not address a late SLC initiation (e.g., at about 15 minutes to 20 minutes). Does the licensee's PRA model differentiate between early and late initiation of the standby liquid control (SLC) system? If so, please address how the late SLC initiation is affected by the EPU conditions, the time available for performing this late action, and the associated HEP.

Response to Question 6-7

The BSEP PSA does not differentiate between early and late SLC System initiation. A single four minute time frame SLC HEP event is modeled. This is consistent with the Emergency Operating Procedures and is conservative in that the additional opportunity to ensure SLC injection success is not credited.

NRC Question 6-8

The submittal addresses some operator actions by stating that the EPU action timing is bounded by the timing used in the current, pre-uprate PRA. However, the HEP values are not presented for these actions. Please provide the HEPs for the following identified core cooling for loss of injection transients, early SLC injection, and inhibiting the Automatic Depressurization System (ADS). Also, please provide the times available and associated HEPs for performing the RPV depressurization action after the following events: an anticipated transient without scram (ATWS), small loss of coolant accident (LOCA), and medium LOCA.

Response to Question 6-8

Section 4.1.6, Table 4.1-8, and Appendix E of Enclosure 2 provide information and describe the analyses used to determine available action times and HEPs. The report also provides MAAP studies in Appendix A that were used to support the human reliability analysis. The following table provides a summary of the requested HEPs.

Summary of HEP Values Associated with Injection and Depressurization Events

Operator Action	Description	HEP Base	HEP EPU
OPER-DILUTE (XOP-DILUTE)	Operator Fails To Preclude Boron Washout During Low Pressure Injection	4.3E-2	4.3E-2

Summary of HEP Values Associated with Injection and Depressurization Events			
Operator Action	**Description**	**HEP Base**	**HEP EPU**
OPER-DEPRESS (XOP-DEPRESS)	Operator Fails To Manually Initiate And Align Low-Pressure Systems	6.9E-3	6.9E-3
OPER-FPS1 (XOP-FPS1)	Operator Fails To Align Firewater For Coolant Injection Flow (One Unit)	9.6E-2	9.6E-2
OPER-LLEVEL1 (XOP-LLEVEL1)	Operator Fails To Control Lowered Water Level With High Pressure Coolant Injection (HPCI) During ATWS	1.3E-2	3.1E-2
OPER-LLEVEL2 (XOP-LLEVEL2)	Operator Fails To Control Lowered Water Level With Reactor Core Isolation Cooling (RCIC) During ATWS	9.1E-3	1.9E-2
XOP-COM2-15	Operator Fails To Control Lowered Water Level With RCIC During ATWS And Fails To Preclude Boron Washout During Low Pressure Injection	4.8E-3	1.0E-2
OPER-INHIBITADS (XOP-INHIBITADS)	Operator Fails To Inhibit ADS During ATWS	3.5E-3	3.5E-3
OPER-SPCATWS (XOP-SPCATWS)	Operator Fails To Initiate Suppression Pool Cooling During An ATWS	5.0E-2	5.0E-2
OPER-WVDHR (XOP-WVDHR)	Operator Fails To Initiate Wetwell Venting For Decay Heat Removal	1.5E-3	1.5E-3
OPER-FWS-INJ (XOP-FWS-INJ)	Operator Fails To Properly Control Condensate Injection Flow Rate	1.7E-2	1.7E-2
XOP-COM2-09	Operator Fails To Align Firewater For Coolant Injection Flow (One Unit) And Fails To Properly Control Condensate Injection Flow Rate	9.4E-3	9.4E-3
OPER-SLCS (XOP-SLCS)	Operator Fails To Initiate SLC System	1.5E-3	1.5E-3
XOP-COM2-12	Operator Fails To Initiate Suppression Pool Cooling During An ATWS And Fail To Preclude Boron Washout During Low Pressure Injection	9.1E-3	9.1E-3
XOP-COM2-13	Operator Fails To Inhibit ADS During ATWS And Fails To Preclude Boron Washout During Low Pressure Injection	1.8E-3	1.8E-3

Summary of HEP Values Associated with Injection and Depressurization Events			
Operator Action	**Description**	**HEP Base**	**HEP EPU**
XOP-COM2-14	Operator Fails To Control Lowered Water Level With HPCI During ATWS And Fails To Preclude Boron Washout During Low Pressure Injection	7.0E-3	1.6E-2
OPER-SWRHR-C (XOR-SWRHR-C)	Operator Fails To Locally Close The Service Water (SW) Valves For Feedwater (FW) Injection	0.01	0.01
OPER-SWRHR-O (XOR-SWRHR-O)	Operator Fails To Locally Open The Discharge Valves For Residual Heat Removal (RHR) Injection	0.01	0.01
OPER-CSTSWAP	Operator Fails To Manually Swap RCIC Suction Source Given Loss Of Condensate Storage Tank (CST) Suction	0.3	0.3
OPER-FPS2	Operator Fails To Align Firewater For Coolant Injection Flow (Both Units)	0.3	0.3
OPER-MANECCS	Operator Fails To Manually Initiate And Align Emergency Core Cooling System (ECCS)	0.3	0.3

NRC Question 6-9

Based on other BWR PRAs, the timing for level control actions during an ATWS is typically between 10 minutes and 20 minutes, but the licensee's submittal indicates a time of approximately 30 minutes for this action under the most severe ATWS scenarios. Further, Table 10-3 (pages 10-21 and 10-22) identifies these operator actions as those that were changed for the EPU PRA model, but does not identify the specific times involved. For each operator action, please include the change in time available from the current, pre-uprate condition to the EPU conditions and describe why the time available for performing these actions would exceed 20 minutes.

Response to Question 6-9

The timing for level control actions depends on many conditions, including the severity of the initial transient, the time at which the turbine was tripped, etc. During PSA model development, it was judged that a reasonable estimate of the operator time to establish appropriate flow conditions for level control would be approximately 30 minutes for ATWS scenarios. This timing was specifically evaluated during the EPU risk study, and MAAP analyses were performed which confirmed the variability of the level control timing during ATWS scenarios. Section 4.1.6 and associated Table 4.1-8 of Enclosure 2 provide the information requested regarding pre-uprate and post-uprate operator action times for level control actions during an

ATWS (i.e., refer specifically to the discussion of OPER-LLEVEL1, OPER-LLEVEL2, XOP-COM2-15, and XOP-COM2-14). This information also includes, in Table 4.1-8, a discussion of the basis for these action time changes as supported by MAAP analyses. The applicable MAAP results are provided in Appendix A of Enclosure 2.

NRC Question 6-10

Section 10.5.3.4 (page 10-14) refers to the use of the MAAP computer code to perform thermal hydraulic calculations associated with operator actions. Was the MAAP code, or any other code, used to re-evaluate the system success criteria at EPU conditions? Please describe the thermal hydraulic analysis performed to support the re-evaluation of system success criteria at EPU conditions.

Response to Question 6-10

Selected system success criteria were evaluated for EPU conditions as described in Section 4.1.2 of Enclosure 2. The thermal hydraulic analysis covered the more important aspects of EPU conditions as related the success criteria including the impact on timing of core boil-off, Reactor Pressure Vessel (RPV) inventory makeup, heat load to the suppression pool, blowdown loads, RPV overpressure margin, Safety Relief Valve (SRV) actuations, and RPV depressurization. Additional information regarding the impact of EPU on the minimum success criteria during transient and accident conditions for specific plant system safety functions is provided in Tables 4.1-2 through 4.1-7 of Enclosure 2. The MAAP code was used in the evaluation of the system success criteria at EPU conditions. The applicable MAAP results are provided in Appendix A of Enclosure 2.

NRC Question 6-11

Section 10.5.3.3 (page 10-13) refers to reactor pressure vessel (RPV) injection systems, including the control rod drive (CRD) system, that were considered marginal in the pre-uprate configuration as an independent RPV makeup source and also marginal post-uprate and not adequate in the post-uprate configuration. Were any of these RPV injection systems credited in the current, pre-uprate PRA and if so, were they also credited in the post-uprate PRA model? Please identify any of these systems that are credited in the pre-uprate PRA and address how they were considered in the post-uprate PRA.

Response to Question 6-11

Section 4.1 of the Enclosure 2 discusses the impact of EPU on the pre-EPU PSA success criteria for the credited RPV injection systems. In Section 4.1.2.2, the success criteria for RPV makeup are concluded to remain the same for the post-uprate configuration. Both high pressure (i.e., including FW, HPCI, and RCIC) and low pressure (i.e., including Low Pressure Coolant Injection (LPCI), Core Spray (CS), and Condensate) injection systems have more than adequate flow margin for the post-uprate configuration. Credited RPV injection systems that were

considered marginal in the pre-uprate configuration such as CRD, and SLC for ATWS reactivity control, are still deemed marginal and are not adequate alone as an independent RPV makeup source during the initial stages of an accident in the post-uprate configuration. Fire Protection/Service Water cross-tie injection is credited for level-power control during ATWS scenarios in both the pre-EPU and EPU risk assessments. The EPU risk assessment also performs a sensitivity case that removes this credit. Other marginal alternative injection sources such as Heater Drain, Demineralized Water, and Condensate Transfer are not credited in either the pre-EPU or EPU risk assessments. Refer to Tables 4.1-2 through 4.1-7 of the Enclosure 2 for additional information pertaining to the minimum system requirements for RPV injection for various initiating events.

NRC Question 6-12

Section 10.5.4 (pages 10-15 and 10-16) refers to sensitivity studies that were performed, but does not provide a description or much discussion of these studies. Please provide a description of the sensitivity studies performed and the results (i.e., change in CDF and LERF) of each of these studies, both individually and collectively. In addition, please provide the change in CDF (the change in LERF was provided) for the collective sensitivity study that includes taking credit for the single train SLC system modification.

Response to Question 6-12

Section 5.7.1 of Enclosure 2 contains an extensive description and discussion of the sensitivity studies, including the SLC success criteria. A summary of the specific results regarding CDF and LERF is provided in Table 5.7-1.

NRC Question 6-13

The individual plant examination of external events (IPEEE) indicates that a number of seismic outliers, which were identified either through the A-46 or through the IPEEE processes, were being resolved. Have all seismic outliers been resolved in such a way to satisfy the IPEEE assumptions and conclusions that the plant high confidence of a low probability of failure (HCLPF) is at least at the review level earthquake (RLE) of 0.3g? If not, please identify the remaining unresolved seismic outliers, the schedule for resolution, a description of the proposed resolution, and a discussion of the risk implications of the plant at EPU conditions with the existence of these outliers.

Response to Question 6-13

CP&L has resolved seismic outliers at BSEP. In a letter dated September 11, 1998 (Serial: BSEP 98-0145), CP&L provided confirmation that all seismic outliers have been resolved. As committed in Appendix A of the "Brunswick Nuclear Plant IPEEE Submittal Final Report," dated June 1995, all seismic outliers (i.e., IPEEE and A-46) were resolved in a manner to satisfy the IPEEE assumptions and conclusions that the plant HCLPF is a least at the RLE of 0.3g.

NRC Question 6-14

Section 10.5.4 (page 10-16) provides a discussion on shutdown risk that is very brief. Does the licensee have a shutdown PRA that has been used to determine the change in shutdown risk associated with the EPU conditions? If so, please describe how this model was changed to reflect EPU conditions and evaluated and the results of this evaluation (i.e., change in risk from current, pre-uprate shutdown risk). This discussion will also need to address the quality of this shutdown PRA model to assure that the model reflects the shutdown conditions. If a shutdown PRA is not used, please describe the licensee's shutdown risk management philosophies/processes that are relied upon to ensure that the impact of EPU on shutdown risk is non-significant. Specifically, the licensee needs to address those aspects of shutdown risk that are impacted by the EPU conditions (e.g., greater decay heat removal, longer times to shutdown, longer times before alternative decay heat removal systems can be used, shorter times to boiling, and shorter times for operator responses).

Response to Question 6-14

BSEP does not have a shutdown PSA model. Rather, a shutdown risk management program, based on the guidelines in NUMARC 91-04, "Guidelines for Industry Actions to Assess Shutdown Safety Management," is used. The philosophy is to ensure adequate defense-in-depth exists for those systems that mitigate postulated accidents during a unit shutdown. Procedure 0AP-022, "BNP Outage Risk Management," describes BSEP's outage safety philosophy and provides guidance to be used in meeting the objectives and goals of that philosophy. The safety philosophy of integrated management, level of activities, defense-in-depth, and contingency planning is applied to planned and emergent activities for unit shutdowns.

BSEP's policy with respect to outage safety is to utilize the defense-in-depth concept to conduct outages which minimize risk to the public, to employees, and to the non-outage unit. This concept uses: (1) systems, structures and components to provide backup of key safety functions using redundant, alternate, or diverse methods; (2) planning and scheduling of outage activities in a manner that will optimize safety system availability; (3) administrative controls to support and/or supplement the above elements; and (4) a defense-in-depth computer analysis as an additional check of the details within the plan. Elements of this review include, but are not limited to, the defense-in-depth and high risk evolutions affecting the following functions:

- Decay Heat Removal
- Fuel Pool Cooling
- Makeup Capability
- Reactor Water Level Control
- Secondary Containment

- Reactivity Control
- Electrical Power Distribution

In addition, an engineering evaluation is required, prior to every refueling outage, to ensure that the BSEP Updated Final Safety Analysis Report Section 9.1.2 evaluation for the Spent Fuel Pool Cooling System with a partial core unload, bounds the expected heat load conditions for the outage.

The aspects of shutdown risk that are impacted by EPU conditions are items such as greater decay heat generation, longer times to shutdown, longer times before alternative decay heat removal systems can be used, shorter times to boiling, and shorter times for operator responses. These aspects are generally associated with the increased decay heat generation created by EPU. The BSEP shutdown risk procedure, 0AP-022, requires, as a minimum, a primary and backup means of decay heat removal to be available. Each system must be capable of maintaining fuel pool temperature at 150°F, or less, under the worst anticipated heat load. Heat loads and time to boil information are obtained from the engineering evaluation. Therefore, the aspects of shutdown risk that are impacted by EPU conditions are adequately controlled by the BSEP shutdown risk management process.

Table 1
Percent Contribution of Initiating Events to CDF and LERF

Initiating Event	Description	BSEP PSA Model		Base Case EPU Risk Study	
		CDF	LERF	CDF	LERF
%E	EXCESSIVE LOCA	0.20%	1.20%	0.20%	1.10%
%S2	SMALL LOCA	0.00%	0.00%	0.00%	0.00%
%T(C)	LOSS OF CONDENSER VACUUM	3.60%	3.50%	3.70%	3.60%
%T(DC2A1)	LOSS OF 125V DC PANEL 2A1	1.60%	0.10%	1.50%	0.10%
%T(DC2B2)	LOSS OF 125V DC PANEL 2B2	7.70%	0.70%	7.50%	0.70%
%T(F)	LOSS OF FEEDWATER	0.10%	0.10%	0.10%	0.10%
%T(M)	MSIV CLOSURE INITIATOR: T(M)	1.30%	1.10%	1.30%	1.10%
%T(S)	INADVERTENT OPENING OF SRV W/O CLOSURE	0.20%	0.20%	0.20%	0.20%
%T(T)	TURBINE TRIP INITIATOR	36.80%	75.00%	37.50%	75.70%
%TCRD	LOSS OF CONTROL ROD DRIVE	3.90%	3.00%	3.90%	3.00%
%TCSW	LOSS OF CONVENTIONAL SERVICE WATER	0.40%	1.70%	0.60%	1.60%
%TE(E3)	LOSS OF 4160V AC BUS E3	1.10%	0.20%	1.10%	0.20%
%TE(E4)	LOSS OF 4160V AC BUS E4	1.20%	1.70%	1.20%	1.60%
%TE(E7)	LOSS OF 480V AC SUBSTATION E7	1.10%	0.20%	1.10%	0.20%
%TE(E8)	LOSS OF 480V AC SUBSTATION E8	1.00%	0.30%	1.00%	0.30%
%TE(S)	LOSS OF OFFSITE POWER (SITE)	31.00%	2.40%	30.40%	2.30%
%TE(U2)	LOSS OF OFFSITE POWER TO UNIT 2	3.40%	0.20%	3.30%	0.20%
%TF14	INTERNAL FLOOD TF14: FAILS CONDENSATE AND FLOODS CABLE SPREADING ROOM	1.80%	0.20%	1.70%	0.20%
%TF4	INTERNAL FLOOD TF4: FAILS RHR PUMP ROOM A	0.00%	0.00%	0.00%	0.00%
%TF6	INTERNAL FLOOD TF6: FAILS ALL RHR PUMP ROOMS AND HPCI	0.00%	0.10%	0.00%	0.10%
%TF7	INTERNAL FLOOD TF7: FAILS ALL PUMPS AT -17 LEVEL	1.10%	0.10%	1.10%	0.10%
%TIAN	LOSS OF INSTRUMENT AIR	0.20%	0.20%	0.20%	0.20%
%TRCC	LOSS OF RBCCW	1.00%	0.70%	0.90%	0.70%
%TTBC	LOSS OF TBCCW	0.10%	0.10%	0.10%	0.10%
ISL-CS-LOOPA	CS LOOP A LARGE LOCA	0.20%	1.50%	0.20%	1.40%
ISL-CS-LOOPB	CS LOOP B LARGE LOCA	0.20%	1.50%	0.20%	1.40%
ISL-RHR-LPCI-A	RHR LPCI LOOP A LARGE LOCA	0.20%	1.50%	0.20%	1.40%
ISL-RHR-LPCI-B	RHR LPCI LOOP B LARGE LOCA	0.20%	1.50%	0.20%	1.40%
ISL-RHR-SDC	RHR SDC LARGE LOCA	0.20%	1.20%	0.20%	1.10%

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
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING
REQUEST FOR LICENSE AMENDMENTS - EXTENDED POWER UPRATE
(NRC TAC NOS. MB2700 AND MB2701)

Identification of Risk Implications Due to Extended Power Uprate at Brunswick

IDENTIFICATION OF RISK IMPLICATIONS DUE TO EXTENDED POWER UPRATE AT BRUNSWICK

IDENTIFICATION OF RISK IMPLICATIONS DUE TO EXTENDED POWER UPRATE AT BRUNSWICK

Prepared by:

V.M. Andersen
L.K. Lee
E.T. Burns
ERIN Engineering And Research, Inc.

Prepared for
CP&L

Project Manager
Bruce Morgen

IDENTIFICATION OF RISK IMPLICATIONS DUE TO EXTENDED POWER UPRATE AT BRUNSWICK

< refer to hard-copy for original signatures >

Prepared by: Vincent M. Andersen Date: 5/15/01

Reviewed by: Larry K. Lee Date: 5/15/01

Approved by: Edward T. Burns Date: 5/16/01

Revisions:

Rev.	Description	Preparer/Date	Reviewer/Date	Approver/Date

EXECUTIVE SUMMARY

The Extended Power Uprate (EPU) project for Brunswick has been reviewed to determine the net impact on the Brunswick risk profile.

The existing Brunswick PSA Model of Record (1998) is based on the original licensed thermal power (OLTP) level of 2436 MWt. Brunswick has, with NRC approval, increased power by 5% to 2558 MWt. In addition, CP&L is currently pursuing an additional 15% increase (i.e., Extended Power Uprate) of the original licensed power to 2923 MWt. Therefore, the aggregate power increase considered in the analysis is 20% above the original licensed thermal power. It is noted that the 5% increase in power results in negligible change in all risk inputs and risk parameters.

The enclosed assessment of the power uprate impacts on risk has been performed relative to the current PSA. The guidelines from the NRC (Regulatory Guide 1.174) are followed to assess the change in risk as characterized by core damage frequency (CDF) and Large Early Release Frequency (LERF) and to determine if the change in risk is anything but very low.

The methodology consists of an examination of the important elements of the Brunswick Probabilistic Safety Assessment (PSA) to assess the impact of the following EPU changes on the PSA elements:

- Hardware changes
- Procedural changes
- Set point changes
- Power level change

These changes are interpreted in terms of their PSA model effects, which can then be used to assess whether there are any resulting risk profile changes.

The scope of this report includes the complete risk contribution associated with the extended power uprate at Brunswick. Risk impacts due to internal events are assessed using the BNP Unit 2 Level 1 PSA Model of Record (1998) and the 2001 BNP Unit 2 Level 2 PSA model. [6,9] External events are evaluated using the analyses of the Brunswick Individual Plant Examination of External Events (IPEEE) Submittal. [10] The impacts on shutdown risk contributions are evaluated on a qualitative basis.

The results of the PSA evaluation are the following:

- Detailed thermal hydraulic analyses of the plant response using the EPU configuration indicate slight reductions in the operator action "allowable" times for some actions.
- The reduced operator action "allowable" times resulted in minor increases in the assessed Human Error Probabilities (HEPs) in the PSA model, specifically in RPV water level control errors during failure to scram sequences.
- Only small risk increases were identified for the changes associated with the EPU, those associated with: (1) slightly reduced times available for effective operator actions; and (2) changes in initial plant configuration (addressed as sensitivity case).
- The risk impact due to the implementation of the Extended Power Uprate is low and acceptable. The risk impact is in the "very low" category (i.e., Region III of the Regulatory Guide 1.174 Guidelines) for CDF and on the border of the "low" (Region II) and "very low" (Region III) categories for LERF.
- If the plant modification to SLC that would result in reducing the success criteria requirement to a single SLC pump and a single squib valve were instituted (currently being considered by BNP), the change in the current assessed plant risk (CDF and LERF) associated with EPU would be an overall reduction.

The EPU is estimated to increase the Brunswick Unit 2 internal events PSA CDF from the base value of 2.55E-5/yr to 2.59E-5/yr, an increase of 4E-7 (1.6%)(1). Based on the changes to the Level 1 model as input to the Level 2, the LERF increases from the base

(1) These quantifications are performed using a truncation limit of 2E-9/yr.

value of 4.27E-6/yr to 4.46E-6/yr, an increase of 1.9E-7/yr (4.5%)[(1)]. The best estimates for CDF and LERF also meet the EPRI PSA Applications Guide criteria for permanent plant changes. [24]

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Section 1
INTRODUCTION

Brunswick Units 1 and 2 are currently pursuing an increase in reactor power from the current licensed thermal power of 2558 MWth (105% of the original licensed thermal power) to 2923 MWth, an Extended Power Uprate (EPU), to a total of 120% OLTP. The purpose of this report is to:

(1) Identify any significant change in risk associated with the Extended Power Uprate (EPU) as measured by the Brunswick Probabilistic Safety Assessment (PSA) models;

(2) Provide the basis for the impacts on the risk model associated with the Extended Power Uprate;

1.1 BACKGROUND

The Brunswick PSA is a state-of-the-technology tool developed consistent with current PSA methods and approaches. The BNP probabilistic safety assessment (PSA) model uses the fault-tree linking methodology (also called "small event tree/large fault tree" method) and employs the CAFTA suite of programs.

The Brunswick PSA is derived based on realistic assessments of system capability over the 24 hour mission time of the PSA analysis. Therefore, PSA success criteria may be different than the design basis assumptions used for licensing Brunswick. This report examines the risk profile changes from this realistic perspective to identify changes in the risk profile on a best estimate basis that may result from postulated accidents, including severe accidents.

1.2 PSA QUALITY

The quality of the BNP PSA models used in performing the risk assessment for the BNP EPU is manifested by the following:

- Sufficient scope and level of detail in PSA
- Active maintenance of the PSA models and inputs
- Comprehensive Critical Reviews

Scope and Level of Detail

The BNP PSA is of sufficient quality and scope for this application. The BNP PSA modeling is highly detailed, including a wide variety of initiating events, modeled systems, extensive level of detail, operator actions, and common cause events. The BNP PSA model and documentation has been maintained living and is routinely updated to reflect the current plant configuration following refueling outages and to reflect the accumulation of additional plant operating history and component failure data. The Level 1 and Level 2 BNP PSA analyses were originally developed and submitted to the NRC in August, 1992 as the Brunswick Individual Plant Examination (IPE) Submittal. The BNP Level 1 PSA models supporting the IPE have been subsequently updated in 1993 and 1996; and, the Level 1 model has been fully upgraded during 1998-2000. The Level 2 analysis has been fully upgraded during 2000-2001 and the Level 2 report is currently being finalized.

Maintenance of Model, Inputs, Documentation

As part of the 1998-2000 upgrade, updated system notebooks were prepared, documenting each of the system models comprising the PSA. Each system notebook describes the system boundary, the components modeled within the system, the failure modes for each component and includes the system fault tree. Initiating events, plant specific data, and the human reliability assessment were updated, as was the recovery model. The Level 2 model was refined and an extensive series of MAAP runs documenting the success criteria were performed.

Critical Reviews

The Brunswick internal events PSA has not yet received a formal industry PRA Peer Review based on the NEI Guidelines. [4] The Peer Review of the BNP PSA is scheduled for September 2001. However, an independent peer review of the updated PSA model was completed in 2000. [11] This independent peer review was performed consistent with the NEI Peer Review technical criteria. The independent peer review did not identify any issues with the PSA that would limit the ability to provide a realistic assessment of the impact on CDF and LERF due to the EPU. Results of previous internal and external reviews have identified several items that could be modified in the models. These items may have a small impact on the absolute value of the CDF or LERF; however, they will not discernibly affect the change in CDF or LERF associated with the EPU change.

Refer to Appendix C for further details regarding the quality of the BNP PSA.

Summary

In summary, it is found that the Brunswick Level 1 and Level 2 PSAs provide the necessary and sufficient scope and level of detail to allow the calculation of CDF and LERF changes due to the Extended Power Uprate (EPU). This has been confirmed by the critical reviews performed on the PSA and their positive results.

1.3 PSA DEFINITIONS

The following PSA terms are used in this study:

CDF – Core Damage Frequency (CDF) is a risk measure for calculating the frequency of a severe core damage event at a nuclear facility. Core damage is the end state of the Level 1 Probabilistic Safety Assessment (PSA). A core damage event may be defined by one or more of the following:

- Maximum core temperature greater than 2200 degrees Fahrenheit,
- RPV water level at 1/3 core height and decreasing,
- Containment failure induced loss of injection.

CDF is calculated in units of events per year.

LERF – Large Early Release Frequency (LERF) is a risk measure for calculating the frequency of an offsite radionuclide release that is HIGH in fission product magnitude and EARLY in release timing. A HIGH magnitude release is defined as a radionuclide release of sufficient magnitude to have the potential to cause early fatalities (e.g., greater than 10% Cesium Iodide contribution to release). An EARLY timing release is defined as the timing in which minimal offsite protective measures can be implemented (e.g., less than 6 hours from accident initiation). LERF is calculated in units of events per year.

Initiating Event – Any event that causes a scram (e.g., Turbine Trip, MSIV Closure) and requires the initiation of mitigation systems to reach a safe and stable state. An initiating event is modeled in the PSA to represent the primary transient event that can lead to a core damage event given failure of adequate mitigation systems (i.e., adequate with respect to the transient in question).

Internal Events – Those initiating events caused by failures internal to the system boundaries. Examples include Turbine Trip, MSIV Closure, Loss of Feedwater, Loss of Service Water, Loss of an AC Bus, Loss of Offsite Power, and internal floods

External Events – Those initiating events caused by failures external to the system boundaries. Examples include fires, seismic events, and tornadoes.

HEP – Human Error Probability (HEP) is the probabilistic estimate that the operating crew fails to perform a specific action (either properly or within the necessary time frame) to support accident mitigation. The HEP is calculated using industry methodologies and considers a number of performance shaping factors such as:

- training of the operating crew,
- availability of adequate procedures,
- time required to perform action
- time available to perform action
- stress level while performing action

MAAP – The Modular Accident Analysis Package (MAAP) is an industry recognized thermal hydraulic code used to evaluate design basis and beyond design basis accidents. MAAP can be used to evaluate thermal hydraulic profiles within the primary system (e.g., RPV pressure, boildown timing) prior to core damage. MAAP also can be used to evaluate post core damage phenomena such as RPV breach, containment mitigation, and offsite radionuclide release magnitude and timing.

Level 1 PSA – The Level 1 PSA is the evaluation of accident scenarios that begin with an initiating event and progress to core damage. Core damage is the end state for the Level 1 PSA. The Level 1 PSA focuses on the capability of plant systems to mitigate a core damage event.

Level 2 PSA – The Level 2 PSA is a continuation of the Level 1 PSA evaluation. The Level 2 PSA begins with the accident scenarios that have progressed to core damage and evaluates the potential for offsite radionuclide releases. Offsite radionuclide release is the end state for the Level 2 PSA. The Level 2 PSA focuses on the capability of plant systems (including containment structures) to prevent a core damage event to result in an offsite release.

RAW – The Risk Achievement Worth (RAW) is the calculated increase in a risk measure (e.g., CDF or LERF) given that a specific system, component, operator action, etc. is assumed to fail (i.e., failure probability of 1.0). RAW is presented as a ratio of the risk measure given the component is failed divided by the risk measure given the component is assigned its base failure probability.

FV – The Fussell-Vesely (FV) importance is a measure of the contribution of a specific system, component, operator action, etc. to the overall risk. F-V is presented as the percentage of the overall risk to which the component failure contributes. In other words, the F-V importance represents the overall decrease in risk if the component is guaranteed to successfully operate as designed (i.e., failure probability of 0.0).

Cutset – A cutset is a mathematical combination of initiating events, operator errors, phenomenological effects, equipment unavailabilities, and/or equipment failures required to reach a defined end state or risk measure (e.g., core damage or radionuclide release). A cutset always starts with an initiating event and is combined with subsequent system failures that result in an undesirable end state. A cutset is assigned a calculated frequency based on the value of the initiating event frequency multiplied by the probabilities of the subsequent events. CDF (and LERF) is based on the Boolean sum total of the cutsets.

1.4 GENERAL ASSUMPTIONS

The extended power uprate (EPU) risk evaluation includes a limited number of general assumptions as follows:

- The plant and procedural changes identified by CP&L [2,7] are assumed to reflect the as-built, as-operated plant after the extended power uprate is fully implemented. The information in References [2,7] is used as input to the current Brunswick PSA model [6] to evaluate the risk impact of the power uprate.

- This analysis is based on all the inputs provided by CP&L in support of this assessment. For systems where no hardware or procedural changes have been identified, the risk evaluation is performed assuming no impact as a result of the EPU. For example, no changes have been identified regarding the decay heat removal capacity of the RHR heat exchangers. Although a slightly longer time to reach Hot Shutdown or Cold Shutdown may be required due to the higher decay heat levels, the capability of the RHR system for shutdown cooling or suppression pool cooling is assumed to be the same as the pre-uprate condition.

- Replacement of components with enhanced like components does not result in any supportable significant increase in the long-term failure probability for the components.

- The PSA success criteria are different than the success criteria used for design basis accident evaluations. The PSA success criteria assume that systems that can realistically perform a mitigation function (e.g., main condenser or containment venting for decay heat removal) are credited in the PSA model. In addition, the PSA success criteria are based on the availability of a discrete number of systems or trains (e.g., number of pumps for RPV makeup).

- This risk assessment focuses on Unit 2 as typical of the results expected for either unit.

Section 2
SCOPE

The scope of this risk assessment for the Extended Power Uprate at Brunswick addresses the following plant risk contributors:

- Level 1 Internal Events At-Power (CDF)
- Level 2 Internal Events At-Power (LERF)
- External Events At-Power
  - Seismic Events
  - Internal Fires
  - Other External Events
- Shutdown Assessment

Risk impacts due to internal events are assessed using the BNP Unit 2 Level 1 PSA Model of Record (1998) and the 2001 BNP Unit 2 Level 2 PSA model. [6,9] External events are evaluated using the analyses of the Brunswick Individual Plant Examination of External Events (IPEEE) Submittal. [10] The impacts on shutdown risk contributions are evaluated on a qualitative basis.

The use of a single unit PSA for this analysis is consistent with U.S. industry PSA standard techniques and with the BNP PSA Groundrules and Assumptions. [25] The two BNP units are very similar in design and operation. The Unit 2 model is employed in this analysis because it is typical of both units. The single unit model accounts for inter-unit connections/dependencies.

As is discussed in Section 3, all the PSA elements are reviewed to ensure that identified EPU plant, procedural, or training changes that could affect the risk profile are addressed. The information input to this process consisted of preliminary design, procedural, and training information provided by CP&L [2, 7]. The final design, analytical calculations, and procedural changes had not been completed prior to this risk assessment.

Section 3
METHODOLOGY

This section of the report addresses the following:

- Analysis approach used in this risk assessment (Section 3.1)
- Identification of principal elements of the risk assessment that may be affected by the Extended Power Uprate and associated plant changes (Section 3.2)
- Plant changes used as input to the risk evaluation process (Section 3.3)
- Scoping assessment (Section 3.4)

3.1 ANALYSIS APPROACH

The approach used to examine risk profile changes is described in the following subsections.

3.1.1 Identify PSA Elements

This task is to identify the key PSA elements to be assessed as part of this analysis for potential impacts associated with plant changes. The identification of the PSA elements uses the NEI PRA Peer Review Guidelines.[4] Section 3.2 summarizes the PSA elements assessed for the Brunswick EPU.

3.1.2 Gather Input

The input required for this assessment is the identification of any plant hardware modifications, procedural or operational changes that are to be considered part of the extended power uprate. This includes changes such as a higher operating pressure (not part of Brunswick EPU), setpoint changes, added equipment, and procedural modifications.

Inputs also include:

- UFSAR changes that could influence the risk assessment such as revised Chapter 15 Analysis, revised DBA analysis.
- Technical Specification changes.
- New decay heat curve.
- Regulatory commitment changes with respect to Generic Letters, Information Notices, I&E Bulletins, USIs.

Section 3.3 summarizes the inputs to the risk assessment process.

3.1.3 Scoping Evaluation

This task is to perform a scoping evaluation by reviewing the plant input against the key PSA elements. The purpose is to identify those items that require further quantitative analysis and to screen out those items that are judged to have negligible or no impact on plant risk as modeled by the BNP PSA.

3.1.4 Qualitative Results

The result of this task is a summary which dispositions all the risk assessment elements regarding the effects of the extended power uprate. The disposition consists of three Qualitative Disposition Categories:

Category A: Potential PSA change due to power uprate. PSA modification desirable or necessary

Category B: Minor perturbation, negligible impact on PSA, no PSA changes required

Category C: No change

A short explanation providing the basis for the disposition is provided in Section 4.

3.1.5 Implement and Quantify Required PSA Changes

This task is to identify the specific PSA models changes required to address the EPU, implement them, and quantify the models. The BNP PSA elements were investigated with the aid of additional deterministic calculations performed in support of this analysis (see Appendix A). Section 4.1 summarizes the review of PSA analysis impacts associated with the increased power level. These effects and other effects related to plant or procedural changes are identified and documented in Section 4.

3.2 PSA ELEMENTS ASSESSED

The PSA elements to be evaluated and assessed can be derived from a number of sources. The NEI PRA Peer Review Guidelines [4] provide a convenient division into "elements" to be examined.

Each of the major risk assessment elements is examined in this evaluation. Most of the risk assessment elements are anticipated to be unaffected by the Extended Power Uprate. The risk assessment elements addressed in this evaluation for impact due to the EPU (refer to Section 4 for impact evaluation) include the following:

- Initiating Events
- Systemic/Functional Success Criteria, e.g.:
  - RPV Inventory Makeup
  - Heat Load to the Suppression Pool
  - Time to Boildown
  - Blowdown Loads
  - RPV Overpressure Margin
  - SRV Actuations
  - SRV Capacity for ATWS
- Accident Sequence Modeling
- System Modeling

- Failure Data
- Human Reliability Analysis
- Structural Evaluations
- Quantification
- Containment Response (Level 2)

3.3 INPUTS (PLANT CHANGES)

This section summarizes the inputs to the risk evaluation, which include hardware modifications, setpoint changes, procedural and operational changes associated with the extended power uprate.

3.3.1 Hardware Modifications

The hardware modifications associated with the extended power uprate have been identified by CP&L [2,7] as input to this assessment. The hardware modifications to be implemented as part of the power uprate are the following:

Mechanical[(1)]

- Replacement of the high pressure (HP) turbine rotor (necessary to achieve >5% power increase), also requires EHC conversion from 3 to 2 arc admission
- Main generator hydrogen cooling and stator cooling modifications
- Replacement of reactor feedwater pump turbines with higher horsepower turbines (to support new power level conditions, and the pump rotating assemblies)
- Replacement of Condensate pumps and motors with upgraded units that have sufficient margin to support new power level conditions

(1) GE14 fuel (initial loading occurred last operating cycle) was loaded to accommodate BNP's move to a 24 month cycle, and is not considered to be a plant "modification" as input to this risk assessment.[19] This is consistent with GE BWR EPU Guidelines which state [20]: "*New fuel designs are not needed for power uprate... new fuel enrichments or higher batch fractions may be used...[for]...fuel cycle length.*"

- Replacement of Condensate Booster pump motors with upgraded units that have sufficient margin to support new power level conditions
- Replacement of Feedwater heaters Unit 1 3A/B, 4A, 5A/B and Unit 2 4B (existing tube plugging prevents >5% power increase)
- Modifications to isophase bus duct cooling system (additional cooling capacity necessary to support new power level)
- Installation of a Supplemental Condensate Cooling System to provide additional cooling capacity during the warmer months (increased Condensate temperatures would otherwise result in sulfate release and potential resin breakdown)
- Replacement of Condensate Filter Demineralizers with longer filter elements
- Moisture Separator/Reheater (MSR) and MSR Relief Valve Modifications to support uprate conditions
- Standby Liquid Control (SLC) super pentaborate modification (to support new power level)

<u>Electrical</u>

- Upgrade to Nuclear Instrumentation to provide acceptable margin regarding power to flow reactor operating restrictions (replacement of the existing power range neutron monitoring to electronic NUMAC devices with 4 APRMs)
- LOCA voltage load shedding modification to maintain minimum switchyard voltage
- Rewind of main turbine generator (additional capacity necessary to achieve new power level)
- Replacement or rewind of main transformer (additional capacity necessary to achieve new power level)
- Power system stabilizer or static excitor (modifications to alleviate potential grid stability concerns caused by the increased electrical output

- Turbine generator out-of-step relaying (modifications to alleviate potential grid stability concerns caused by the increased electrical output

3.3.2 Procedural Changes

It is anticipated that slight adjustments to the BNP EOPs/SAMGs will be made to be consistent with the EPU condition. In almost all respects, the EOPs/SAMGs are expected to remain unchanged because they are symptom-based; however, certain parameter thresholds and graphs are dependent upon power and decay heat levels and will require slight modifications. However, the specifics of any procedural changes associated with the extended power uprate were not available prior to completion of this PSA evaluation.

Based on the GE EPU Evaluations [21], EOP variables that play a role in the PSA and which may require adjustment for the EPU include:

- Boron Injection Initiation Temperature (BIIT)
- Heat Capacity Temperature Limit (HCTL)
- Pressure Suppression Pressure Limit (PCPL)

These variables may require adjustment to reflect the change in power level, but will not be adjusted in a manner that involves a change in accident mitigation philosophy. The BIIT curve relates to short term scenarios; however, the BNP PSA already requires SLC initiation in a short time frame (4 minutes) prior to reaching the BIIT. The HCTL and PCPL relate to long-term scenarios, any changes in the scenario timings associated with EPU changes to these curves will be minor (e.g., changes on the order of 10 minutes over accident times greater than 3 hours) and would not significantly impact the human error probabilities in the PSA.

No identified EOP/SAMG changes as part of the EPU will significantly impact scenario timings or operator response times as modeled in the PSA. Brunswick has implemented the BWROG EPG/SAG update to the EPGs. This change has been factored into the PSA.

Any EPU related changes to the BNP EOPs or SAMGs are considered minor perturbations to the already assessed EPG/SAG changes. Therefore, the EOP/SAMG changes as a result of the EPU will not influence the risk profile.

3.3.3 Setpoint Changes

The operating pressure (1030 psig) and the operating temperature (550°F) are not being changed as part of the extended power uprate. [13] Setpoint or operating parameter changes were identified by CP&L and were provided in Reference [5]. Potential setpoint changes include:

- APRM fixed and flow-biased Scrams and Rod Blocks
- RBM Power Reference Rod blocks
- Main Steam Line (MSL) High Flow Isolation
- Turbine first stage pressure steam Scram Bypass
- Rod Worth Minimizer Low Power
- Steam Tunnel Leak Detection Temperature
- MSL High Radiation Isolation
- Reactor Building vent shaft, Refuel Floor exhaust shaft, and Offgas vent shaft High Radiation Isolation
- Setpoint analyses for changes in instrument Analytical Limits (ALs) due to EPU
- Setpoint analyses for changes in instrument Analytical Limits (ALs) due to EPU
- Moisture Separator/Reheater (MSR) relief valve setpoints. The current setpoints for the four (4) valves are 216 psig, 222 psig, and 227 psig (2 valves). The proposed setpoints will be 227 psig, 233 psig, and 238 psig (2 valves) [18]

Changes to RPV pressure setpoints (e.g., RPT, ATWS high dome pressure) or RPV level setpoints (e.g., high level trips, low level actuations) are not planned.

3.3.4 Plant Operating Conditions

The key plant operational modifications to be made in support of the EPU are:

- Feedwater/Condensate flow rates will increase by approximately 15% over the current values (20% over original licensed thermal power).
- Power/flow operation per a revised MELLLA (Maximum Extended Load Line Limit Analysis) analysis.

RPV pressure will remain unchanged for the EPU.

In addition, no significant changes in the operating conditions of the following systems are projected at this time:

- RCIC
- ECCS Systems
- Main Condenser Vacuum (e.g., number of SJAEs in operation)
- Circulating Water
- Service Water
- TBCCW

3.4 SCOPING EVALUATION

The scoping evaluation examines the hardware, procedural, setpoint, and operating condition changes to assess whether there are PSA impacts that need to be considered in addition to the increase in power level. These changes will also be examined in Section 4 relative to the PSA elements that may be affected. The scoping evaluation conclusions reached are discussed in the following subsections and summarized in Table 3.4-1.

3.4.1 Hardware Changes

The hardware changes required to support the EPU (see Section 3.3.1) were reviewed and determined not to result in new accident types or increased frequency of challenges to plant response. This assessment is based on review of the plant hardware modifications and engineering judgement based on knowledge of the PSA models. (Refer to Table 3.4-1.) The majority of the changes are characterized by either:

- Replacement of components with enhanced like components
- Upgrade of existing components

The BNP PSA program encompasses an effectively exhaustive list of hazards and accident types (i.e., from simple non-isolation transients to ATWS scenarios to internal fires to hurricanes to toxic releases to draindown events during refueling activities, and numerous others). Sabotage and acts of war are outside the scope of the PSA program. Extensive and unique changes to the plant would have to be implemented to result in new previously unidentified accidents.

Extensive changes to plant equipment have been shown by operating experience to result in an increase in system unavailability or failure rate during the initial testing and break-in period. It can be expected that there will be some short term increase in such events at Brunswick but the frequency and duration of such events can not be projected. Nevertheless, it is expected that a steady state condition equivalent to or better than current plant performance would result within approximately one year of operation with the new equipment.

Two modifications worthy of additional discussion are:

- Supplemental Condensate Cooling System
- SLC System Modifications

The Supplemental Condensate Cooling System is a fairly extensive modification. The purpose for installing the Supplemental Condensate Cooling System is to provide increased condensate cooling during the warmer months of the year (e.g., June to September). Given the increased heat loads due to EPU, there is the potential during the warmer months that the condensate water may reach 130°F and begin to degrade condensate demineralizer resin performance. [15] Supplemental Condensate Cooling will be provided using both regenerative and non-regenerative heat exchangers. For each condensate train (one per unit), the regenerative heat exchangers will be sized as three (3) 33% trains while the non-regenerative heat exchangers will be sized as two (2) 100% trains. The non-regenerative heat exchangers will be cooled with a Wet Cooling Tower/Pump set for each unit. Positive isolation gate valves with manual operators will be located above the Radwaste Building Roof to provide the capability to isolate the Supplemental Condensate Cooling System from the rest of the condensate system. Based on a review of the proposed modification [16], the Supplemental Condensate Cooling System is not judged to significantly impact component failure rates of the Condensate system, influence initiating event frequencies, or introduce new failure modes. The condensate system failure probability is overwhelmingly dominated by the following:

- Hotwell level control failures
- Instrument air support failures
- Service water support failures
- Common cause failure of CP/CBP components
- Initiating events that fail the system directly

The addition of this system to cool flow during a few months out of the year will have a insignificant impact on the failure probability of the condensate system.

One hardware modification with potential safety beneficial impacts on the PSA is related to the SLC system. The proposed SLC modifications would include the following: [17]

- Use of new super pentaborate in the SLC tank
- Decommission the SLC heat trace, tank heaters, power, and control circuits, and piping insulation
- Potential change to a 1 SLC pump and 1 squib valve success criteria

The chemical properties of the new super pentaborate eliminates the need for heat tracing [17]. Elimination of the SLC dependency on heat tracing would increase the reliability of the SLC system for ATWS mitigation. CP&L plans to remove both the SLC heat tracing requirement and the consequential dependency.

At the start of this assessment, the required SLC success criteria for the EPU condition was assumed (i.e., no decision had yet been made at the plant) to remain at 2 pumps and 2 explosive valves (the success criteria in the existing BNP PSA) to meet 10CFR50.62 ATWS requirements. However, an option to pursue further analyses and system modifications that would result in the requirement of a single SLC pump and valve was being considered at the plant during the final stages of this risk assessment. As such, the base risk assessment assumes BNP will eliminate the SLC heat tracing but will maintain the requirement for 2 of 2 SLC pumps and squib valves for injection. The potential 1 SLC pump and valve option is addressed as a sensitivity case.

3.4.2 Procedure Changes

Changes to the EOPs/SAMGs as a result of the EPU were not available prior to completion of the PSA evaluation. It is assumed that the procedural changes (e.g., modification to HCTL curve) have a minor impact on the PSA results. No changes to the PSA are identified as a result of potential EOP/SAMG procedural changes. See Section 3.3.2.

3.4.3 Setpoint Changes

None of the planned setpoint changes listed in Section 3.3.3 will result in any quantifiable impact to the PSA. Key setpoints that play a role in the PSA are planned to remain unchanged, such as:

- Main Steam SRV opening and closing setpoints
- RPV Level Setpoints (e.g., high level trips, low level actuations)
- RPV pressure setpoint (e.g., RPT/ARI)

The analyses regarding setpoint changes were not available prior to completion of the PSA evaluation. Based on similar setpoint changes to similar vintage BWRs pursuing EPU risk assessments (i.e., Monticello, Dresden and Quad Cities) the impact on trip margins and risk is judged to be minimal. No changes to the PSA are identified as a result of the planned setpoint changes.

3.4.4 Normal Plant Operational Changes

The Feedwater/Condensate flow rates will be increased by replacing the Feedwater pump turbines, the Condensate pumps and motors, and the Condensate Booster pump motors. Despite the increase in flow, there is no indication modeling-wise that these hardware modifications will significantly impact component failure rates or initiating event frequencies in the long term. In addition, the BNP PSA models loss of feedwater due to level control errors post plant trip. The probability of this modeling event is based on a review of BNP plant trip history. There is no evidence at this time that the EPU increase in FW flow will significantly impact this probability.

The Maximum Extended Load Line Limit Analysis (MELLLA) refers to a region on the Power-to-Flow Map where the plant will be licensed to operate at a higher rod line without increasing recirculation flow. For the current configuration, 105% of the original

licensed thermal power can be achieved at 81% recirculation flow. For the post-EPU configuration, 120% of the original licensed thermal power can be achieved at 99% recirculation flow. [7,14]

More frequent "downpowers" may be anticipated, caused by transition from a "controlled cell" to a "conventional cell" for control rod adjustments. CP&L reactor engineers postulate a factor of 2 increase in the frequency of downpowers where a single feed pump may be running and the other idling. However, these evolutions are routine actions for the plant operators. Although one may postulate an increase in plant trips due to operator errors during these evolutions, quantification of a significant increase in the long-term transient initiating event frequency is not supportable at this time. However, a sensitivity case is performed in this study that increases the Turbine Trip initiating event frequency to bound such postulations.

The current MELLLA, although close to the maximum recirculation flow boundary conditions, is judged to support the assessment that no increases in scram frequencies will result due to the EPU[(1)]. There is no measurable increase in the risk associated with EPU with respect to the current MELLLA.

[(1)] CP&L is pursuing a revised MELLLA analysis called MELLLA+. The MELLLA+ analysis will allow Brunswick to operate at the post-EPU power level with increased recirculation flow margin [14].

Table 3.4-1

SCOPING SUMMARY OF BNP PSA IMPACTS DUE TO PLANT CHANGES TO SUPPORT EPU

Category	Description of Plant Change	PSA Change?	Discussion[(1)]
Hardware (Mechanical)	Replacement of HP turbine rotor (necessary to achieve >5% power increase), also requires EHC conversion from 2 to 3 arc admission	No	The main turbine impacts the PSA in the area of initiating event frequencies (i.e., turbine related failures/trips are contributors to PSA transient initiating event frequencies). Although equipment reliability can be postulated theoretically to behave as a "bathtub" curve (i.e., the beginning and end of life phases being associated with higher failure rates than the steady-state period), no significant impact on the long-term average of the Turbine Trip initiating event frequency due to the replacement of the main turbine HP rotor is supportable at this time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant.[(2)]
	Main generator H2 cooling and stator cooling modifications	No	The EPU modifications to the generator hydrogen cooling system are to adequately cool the generator components. In addition, cooling flow to the stator water coolers is to be increased. Neither of these items has any quantifiable impact on the reliability of the main turbine/generator. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant.[(2)]

Table 3.4-1

SCOPING SUMMARY OF BNP PSA IMPACTS DUE TO PLANT CHANGES TO SUPPORT EPU

Category	Description of Plant Change	PSA Change?	Discussion[1]
Hardware (Mechanical) cont'd	Replacement of reactor Feedwater pump turbines with higher horsepower turbines (to support new power level conditions), and the pump rotating assemblies	No	The FW pumps impact the PSA in the area of initiating event frequencies (i.e., FW pump failures/trips are contributors to PSA transient initiating event frequencies) and the failure probability of the FW pumps during the 24 hr. PSA mission time. Although equipment reliability can be postulated theoretically to behave as a "bathtub" curve (i.e., the beginning and end of life phases being associated with higher failure rates than the steady-state period), no significant impact on the long-term average of the Turbine Trip or Loss of FW initiating event frequencies, or the FW pump reliability during the 24 hr. PSA mission time due to the replacement of the FW pump turbines is supportable at this time. Loss of a single FW pump could lead to a turbine trip, but not a complete loss of FW. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant.[2]
	Replacement of Condensate pumps and motors with upgraded units that have sufficient margin to support new power level conditions	No	The Condensate pumps impact the PSA in the area of initiating event frequencies (i.e., FW/Condensate systems failures/trips are contributors to PSA transient initiating event frequencies) and the failure probability of the Condensate pumps during the 24 hr. PSA mission time. Although equipment reliability can be postulated theoretically to behave as a "bathtub" curve (i.e., the beginning and end of life phases being associated with higher failure rates than the steady-state period), no significant impact on the long-term average of the Turbine Trip or Loss of FW initiating event frequencies, or the Condensate pump reliability during the 24 hr. PSA mission time due to the replacement of the Condensate pumps and motors is supportable at this time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant.[2]

Table 3.4-1

SCOPING SUMMARY OF BNP PSA IMPACTS DUE TO PLANT CHANGES TO SUPPORT EPU

Category	Description of Plant Change	PSA Change?	Discussion[1]
Hardware (Mechanical) cont'd	Replacement of Condensate Booster pump motors with upgraded units that have sufficient margin to support new power level conditions	No	The Condensate Booster pumps impact the PSA in the area of initiating event frequencies (i.e., FW/Condensate systems failures/trips are contributors to PSA transient initiating event frequencies) and the failure probability of the Condensate Booster pumps during the 24 hr. PSA mission time. Although equipment reliability can be postulated theoretically to behave as a "bathtub" curve (i.e., the beginning and end of life phases being associated with higher failure rates than the steady-state period), no significant impact on the long-term average of the Turbine Trip or Loss of FW initiating event frequencies, or the Condensate Booster pump reliability during the 24 hr. PSA mission time due to the replacement of the Condensate Booster pump motors is supportable at this time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant. [2]
	Replacement of Feedwater heaters Unit 1 3A/B, 4A, 5A/B and Unit 2 4B (existing tube plugging prevents >5% power increase)	No	The FW heaters impact the PSA in the area of initiating event frequencies (i.e., FW/Condensate system failures/trips are contributors to PSA transient initiating event frequencies) and the failure probability of the FW system during the 24 hr. PSA mission time. The PSA does not model the efficiency of the FW heaters, but rather failures that prevent injection flow (excessive plugging and external rupture/leak – both insignificant frequency failure modes). Although equipment reliability can be postulated theoretically to behave as a "bathtub" curve (i.e., the beginning and end of life phases being associated with higher failure rates than the steady-state period), no significant impact on the long-term average of the Turbine Trip or Loss of FW initiating event frequencies, or the FW heater plugging or rupture probabilities during the 24 hr. PSA mission time due to the replacement of the heaters is supportable at this time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant. [2]

Table 3.4-1

SCOPING SUMMARY OF BNP PSA IMPACTS DUE TO PLANT CHANGES TO SUPPORT EPU

Category	Description of Plant Change	PSA Change?	Discussion[1]
Hardware (Mechanical) cont'd	Modifications to isophase cooling system (additional cooling capacity necessary to support new power level)	No	This modification supports the power production aspect of the plant. As the PSA models plant risk by assessing the safe shutdown process following plant trips, this modification does not directly impact the PSA models. An impact to the Turbine Trip initiating event frequency may be conservatively postulated, but no significant numerical difference can be reasonably quantified at this time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant. [2]
	Installation of a Supplemental Condensate Cooling System to provide additional cooling capacity during the warmer months (increased Condensate temperatures would otherwise result in sulfate release and potential resin breakdown)	No	The Condensate system impacts the PSA in the area of initiating event frequencies (i.e., FW/Condensate systems failures/trips are contributors to PSA transient initiating event frequencies) and the failure probability of the Condensate system during the 24 hr. PSA mission time. The addition of the Supplemental Condensate Cooling system is judged not to result in any significant quantifiable difference in the initiating event frequencies or the failure probability of the system during the 24 hr. PSA mission time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant. [2]
	Replacement of Condensate Filter Demineralizers with longer filter elements	No	The Condensate demineralizers are appropriately modeled in the PSA FW/Condensate logic with the excessive plugging failure mode (a non-significant frequency failure mode compared to the overall system failure probability). The replacement of demineralizer filters with those of slightly different design would not result in any quantifiable difference in the initiating event frequencies or the failure probability of the system during the 24 hr. PSA mission time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant. [2]

Table 3.4-1

SCOPING SUMMARY OF BNP PSA IMPACTS DUE TO PLANT CHANGES TO SUPPORT EPU

Category	Description of Plant Change	PSA Change?	Discussion[1]
Hardware (Mechanical) cont'd	Moisture Separator/Reheater (MSR) and MSR Relief Valve Modifications to support uprate conditions	No	The MSR plays no explicit role in the PSA. An impact to the Turbine Trip initiating event frequency may be conservatively postulated due to the modifications, but no significant numerical difference can be reasonably quantified at this time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant. [2]
	SLC super pentaborate modification to support new power level	Yes	The changes in reactor power and the associated SLC system changes impact PSA modeling in the following areas: • SLC system success criteria • Time to achieve subcriticality • SLC heat tracing requirement At the start of this assessment, the required SLC success criteria for the EPU condition was assumed to remain at 2 pumps and 2 explosive valves (the success criteria in the existing BNP PSA) to meet 10CFR50.62 ATWS requirements. Therefore, no impact to the SLC system success criteria in the PSA resulted from this modification. However, an option to pursue a single pump and explosive valve success criteria for SLC has been considered at the plant during the final stages of the EPU process at CP&L. As such, a sensitivity case is quantified in this risk assessment to study the impact of the single SLC pump and squib valve success criteria on the reduction in risk that could be expected.

Table 3.4-1

SCOPING SUMMARY OF BNP PSA IMPACTS DUE TO PLANT CHANGES TO SUPPORT EPU

Category	Description of Plant Change	PSA Change?	Discussion[1]
Hardware (Mechanical) cont'd			The current BNP PSA assumes 15 minutes to achieve subcriticality with SLC injection. Given the increased pentaborate concentration and the assumed 2 SLC pump success criteria remaining the same, the time to subcriticality for the EPU condition may be somewhat less than 15 minutes. The 15 minute time frame is conservatively maintained in this risk assessment. The chemical properties of the super pentaborate SLC modification eliminates the requirement for heat tracing (required with the current SLC configuration). However, the current BNP PSA models, but does not explicitly quantify the heat tracing subsystem of SLC. As such, this modification does not impact the PSA models.
Hardware (Electrical / I&C)	Upgrade to Nuclear Instrumentation to provide acceptable margin regarding power to flow reactor operating restrictions (replacement of the existing power range neutron monitoring to electronic NUMAC devices with 4 APRMs)	No	Neutron monitoring could play two roles in PSA modeling: • Overly sensitive equipment could lead to increased turbine trips • Poor equipment could lead to increased electrical scram failure probability An impact to the Turbine Trip initiating event frequency may be conservatively postulated due to the new equipment, but no significant numerical difference can be reasonably quantified at this time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant. [2] A significant impact to the electrical scram failure probability due to the Nuclear Instrumentation changes is not supportable at this time. In addition, electrical scram failure is not a dominant contributor to ATWS core damage frequency (i.e., "electrical" scram failures can be mitigated by ARI, unlike mechanical scram failures).

Table 3.4-1

SCOPING SUMMARY OF BNP PSA IMPACTS DUE TO PLANT CHANGES TO SUPPORT EPU

Category	Description of Plant Change	PSA Change?	Discussion(1)
Hardware (Electrical / I&C) cont'd	LOCA voltage load shedding modification to maintain minimum switchyard voltage	No	On occurrence of a LOCA, load shedding of a running TB Chiller (existing design) and a running Circulating Water pump is required to offset the increase in the AC load management limit due to EPU plant modifications. [28] Two running Heater Drain pumps (not credited in the BNP PSA) will also be shed as part of the base unit trip signal as a result of EPU required modifications. The TB Chiller is auto load shed on a LOCA signal; the CW pump is auto load shed on the LOCA signal if the logic is enabled by a master switch during peak demand periods. The master switch is not enabled during low demand periods so that the CW pump is not load shed if not necessary. [28] <u>Successful</u> LOCA load shedding does not disable the main condenser from being used as a decay heat removal method. With regard to postulated failure of the LOCA load shed, the PSA models do not analyze to a level of detail that allows explicit quantification of this failure. However, even if the model did explicitly incorporate such detail, these modifications would not result in a significant numerical difference in the accident sequence analysis. Any postulated increase in calculated risk would be attributable to an assumed increase in the conditional failure probability of the SAT given a LOCA load shed <u>failure</u> during high grid demand. This delta CDF may be conservatively estimated as: (0.1/yr) x (1E-4) x (0.3) x (2E-2) x (0.5) = 3E-8/yr; where 0.1 is the frequency of "LOCA signal generating" initiating events; 1E-4 is the probability of LOCA load shed signal failure (based on BNP PSA modeling of similar signals); 0.3 is the probability of high grid demand; 2E-2 is the CCF of the unit EDGs (based on the BNP PSA); and 0.5 is the assumed increase in the conditional failure probability of the SAT given load shed failure under the EPU configuration. 3E-8/yr is approximately 0.1% of the base CDF and well within the uncertainty of this study. This delta CDF is judged to be conservatively estimated and still sufficiently small to be neglected in this assessment of the plant risk profile changes.

Table 3.4-1

SCOPING SUMMARY OF BNP PSA IMPACTS DUE TO PLANT CHANGES TO SUPPORT EPU

Category	Description of Plant Change	PSA Change?	Discussion[1]
Hardware (Electrical / I&C) cont'd	Rewind of main turbine generator (additional capacity necessary to achieve new power level)	No	Main turbine generator failures can lead to load rejection initiating events. An impact to the Turbine Trip initiating event frequency may be conservatively postulated due to the rewind, but no significant numerical difference can be reasonably quantified at this time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant. [2]
	Replacement or rewind of main transformer (additional capacity to achieve new power level)	No	Main transformer failures can lead to the loss of BOP equipment on the transformer bus, and the inability to perform back-feed to the UAT. With fast transfer available at BNP, little impact on shutdown equipment is found. Although equipment reliability can be postulated theoretically to behave as a "bathtub" curve (i.e., the beginning and end of life phases being associated with higher failure rates than the steady-state period), no significant impact on the long-term transient initiating event frequencies or transformer failure during the 24 hour PSA mission time due to replacement of the transformer is supportable at this time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant. [2]
	Power system stabilizer or static excitor (modifications to alleviate potential grid stability concerns caused by the increased electrical output)	No	The electrical power production components of the plant affect load rejection initiating event frequencies. An impact to the Turbine Trip initiating event frequency may be conservatively postulated due to these equipment modifications, but no significant numerical difference can be reasonably quantified at this time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant. [2]

Table 3.4-1

SCOPING SUMMARY OF BNP PSA IMPACTS DUE TO PLANT CHANGES TO SUPPORT EPU

Category	Description of Plant Change	PSA Change?	Discussion[1]
Hardware (Electrical / I&C) cont'd	Turbine generator out-of-step relaying (modifications to alleviate potential grid stability concerns caused by the increased electrical output)	No	Main turbine generator failure is a contributor to the turbine trip initiating event frequency. An impact to the Turbine Trip initiating event frequency may be conservatively postulated due to these control modifications, but no significant numerical difference can be reasonably quantified at this time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant. [2]
Procedures	Various potential impacts to EOPs/SAMGs	No	Changes to the EOPs/SAMGs (and other similar procedures that are used in the BNP PSA) as a result of the EPU were not available prior to the completion of this risk assessment. It is assumed that the procedural changes (e.g., modification to EOP HCTL curve) have a minor (although potentially quantifiable) impact on the PSA results, such that the conclusions of this risk assessment are not altered. See Section 3.2.2.

Table 3.4-1

SCOPING SUMMARY OF BNP PSA IMPACTS DUE TO PLANT CHANGES TO SUPPORT EPU

Category	Description of Plant Change	PSA Change?	Discussion[(1)]
Setpoints	Potential setpoint changes to: • APRM fixed and flow-biased Scrams and Rod Blocks • RBM Power Reference Rod blocks • Main Steam Line High Flow Isolation • Turbine first stage steam pressure Scram Bypass • Rod Worth Minimizer Low Power • Steam Tunnel Leak Detection Temperature • MSL High Radiation Isolation • Reactor Building vent shaft, Refuel Floor exhaust shaft, and Offgas vent shaft High Radiation Isolation • Setpoint analyses for changes in instrument Analytical Limits (ALs) due to EPU • Setpoint analyses for changes in instrument Analytical Limits (ALs) due to EPU • Moisture Separator/Reheater (MSR) relief valve setpoints.	No	None of the setpoint changes listed will result in any quantifiable impact to the PSA. An impact to the transient initiating event frequencies may be conservatively postulated due to these control modifications, but no significant numerical difference can be reasonably quantified at this time. Key setpoints that play a role in the PSA (e.g., RPV level trips, ATWS/ARI setpoints, etc.) are projected to remain unchanged.
Operational	Feedwater/Condensate flow rates to increase by approximately 15% over present values (20% over OLTP) to support the uprate conditions	No	Although FW/Cond. Flow will increase, no significant numerical difference in the PSA transient initiating event frequencies or the failure probability of FW/Condensate during the 24 hr. PSA mission time can be reasonably quantified at this time. However, an increase in the probability of FW trip on high water level post reactor trip is conservatively considered in this risk assessment as a sensitivity case. In addition, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant. [(2)]

Table 3.4-1

SCOPING SUMMARY OF BNP PSA IMPACTS DUE TO PLANT CHANGES TO SUPPORT EPU

Category	Description of Plant Change	PSA Change?	Discussion(1)
Operational cont'd	Revised MELLLA analysis to allow operation at the EPU power level with increased recirculation flow margin	No	No significant numerical difference in the PSA transient initiating event frequencies due to the revised MELLLA curve can be reasonably quantified at this time. However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant.

NOTES:

(1) Extensive changes to plant equipment have been shown by operating experience to result in an increase in system unavailability or failure rate during the initial testing and break-in period. It can be expected that there will be some short term increase in such events at Brunswick. The frequency and duration of such events can not be projected. Nevertheless, it is expected that a steady state condition equivalent to or better than current plant performance would result within approximately one year of operation with the new equipment. Therefore, this short term break-in period is not explicitly quantified as part of the steady state plant risk profile.

(2) Refer to Section 5.7 of this report for the bases for the 10% increase in the turbine trip initiating event frequency.

Section 4
PSA CHANGES RELATED TO EPU CHANGES

Section 3 has examined the plant changes (hardware, procedural, setpoint, and operational) that are part of the extended power uprate (EPU). Section 4 examines these changes to identify BNP PSA modeling changes necessary to quantify the risk impact of the EPU. This section discusses the following:

- Individual PSA elements potentially affected by extended power uprate (EPU) (4.1)
- Level 1 PSA (4.2)
- Internal Fires Induced Risk (4.3)
- Seismic Risk (4.4)
- Other External Hazards Risk (4.5)
- Shutdown Risk (4.6)
- Radionuclide Release (Level 2 PSA) (4.7)

4.1 PSA ELEMENTS POTENTIALLY AFFECTED BY POWER UPRATE

A review of the PSA elements has been performed to identify potential effects associated with the extended power uprate. The result of this task is a summary which dispositions all the PSA elements regarding the effects of the extended power uprate. The disposition consists of three Qualitative Disposition Categories.

Category A: Potential PSA change due to power uprate. PSA modification desirable or necessary

Category B: Minor perturbation, negligible impact on PSA, no PSA changes required

Category C: No change

Table 4.1-1 summarizes the results from this review. Based on Table 4.1-1, only a small number of the PSA elements are found to be potentially influenced by the power uprate.

The following PSA elements are discussed in Table 4.1-1 to summarize whether they may be affected by the extended power uprate and the associated changes.

- Initiating Events
- Systemic/Functional Success Criteria, e.g.:
  - RPV Inventory Makeup
  - Heat Load to the Suppression Pool
  - Time to Boildown
  - Blowdown Loads
  - RPV Overpressure Margin
  - SRV Actuations
  - SRV Capacity for ATWS
- Accident Sequence Modeling
- System Modeling
- Failure Data
- Human Reliability Analysis
- Structural Evaluations
- Quantification
- Containment Response (Level 2)

4.1.1 Initiating Events

The evaluation has examined whether there may be increases in the frequency of the initiating events or whether there may be new types of initiating events introduced into the risk profile.

The evaluation of the plant and procedural changes indicates no new initiators or increased frequencies of existing initiators are anticipated to result from the EPU increase.

However, a sensitivity case that increases the Turbine Trip frequency by 10% is quantified in this risk assessment to conservatively bound the various changes to the BOP side of the plant (refer to Section 5.7 of this report).

4.1.2 Success Criteria

The success criteria for the Brunswick PSA are derived based on realistic evaluations of system capability over the 24 hour mission time of the PSA analysis. These success criteria therefore may be different than the design basis assumptions used for licensing Brunswick. This report examines the risk profile changes, caused by EPU, from this realistic perspective to identify changes in the risk profile that may result from severe accidents on a best estimate basis. The following subsections discuss different aspects of the success criteria as used in the PSA. Appendix A provides the deterministic calculations performed to assess the impacts on success criteria and sequence timing.

4.1.2.1 Timing

Shorter times to boildown are likely on an absolute basis due to the increased power levels. For transient response (non-LOCA, non-ATWS), the increase in steady state, full power reduces the subsequent "boildown" times by several minutes if no injection systems or inventory control systems are available. Out of approximately 45-60 minutes to core damage for the worst case non-LOCA loss of coolant makeup scenarios, the several minute change in boildown time does not appreciably affect the operator response assessment. During ATWS scenarios, the short-term timing changes do impact certain HEP calculations. (See HRA discussion in Section 4.1.3.)

General Electric calculations, Appendix R calculations or the Modular Accident Analysis Package (MAAP) are used to calculate changes in the thermal hydraulic response for specific issues (e.g., boildown timing).

4.1.2.2 RPV Inventory Makeup Requirements

The PSA success criteria for RPV makeup remains the same for the post-uprate configuration. Both high pressure (e.g., FW, HPCI, and RCIC) and low pressure (e.g., LPCI, CS, and condensate) injection systems have more than adequate flow margin for the post-uprate configuration. RPV injection systems that were considered marginal in the pre-uprate configuration (e.g., CRD) as an independent RPV makeup source during the initial stages of an accident are still deemed marginal and are not adequate in the post-uprate configuration. CRD remains a viable RPV makeup source at high and low pressures in the post-EPU configuration following initial operation of FW for certain accidents (e.g., non-LOCA).

4.1.2.3 Heat Load to the Pool

Energy to be absorbed by the pool during an isolation event or RPV depressurization increases for the EPU case relative to the original license basis (OLB) power level. For non-ATWS scenarios, the RHR heat exchangers, the main condenser, and the containment vent all have capacities that far exceed the increase in heat load due to extended power uprating. The heat removal capability margins are sufficiently large such that the changes in power level associated with EPU do not affect the success criteria for these systems. Although a BNP "vent initiation" MAAP run was not performed in support of this risk assessment, MAAP runs for other BWR plants with similar containment vent designs as Brunswick (i.e., 8 inch vent pipe) show that once the containment vent is opened, per the EOPs, containment pressure decreases immediately and rapidly. The small percentage difference in decay heat level (i.e., pre-EPU vs. EPU) at the time of EOP vent initiation will not change this performance. Additional information on system capacity is available from the individual task reports associated with plant system capability under

EPU conditions. Therefore, if one of these systems is available as determined in the current PSA, then its capacity is also adequate for the uprated condition. This conclusion is based on MAAP calculations, individual task analyses as part of the EPU project, and engineering judgement recognizing the substantial margins that exist for these systems to perform the required function. No changes to the above DHR systems to augment their capabilities for the EPU configuration are planned. Specific MAAP calculations are not judged necessary to confirm that individual DHR systems could prevent containment temperatures and pressures from increasing beyond the limits of the PSA DHR success criteria for the EPU condition.

For ATWS events, the increased decay heat loads to the suppression pool result in a smaller margin in the DHR success criteria when compared to the non-ATWS events. Therefore, the DHR success criteria must be examined more closely for the ATWS EPU configuration. The proposed SLC modification to use "super pentaborate" is considered adequate to mitigate ATWS events for the EPU configuration. [17] However, the timing for SLC initiation needs to be evaluated to ensure containment failure can be prevented (i.e., peak bulk suppression pool temperatures are maintained below 260°F). For the post-uprate condition with SLC initiation delayed for 4 minutes, the peak suppression pool temperature remains below 260°F (MAAP Case BNP6b). Therefore, the current PSA assumption that assesses SLC initiation within 4 minutes as a success remains valid for the EPU configuration to maintain pool temperature below 260°F and prevent containment failure.

4.1.2.4 Blowdown Loads

Dynamic loads would increase slightly because of the increased stored thermal energy. This change would not quantitatively influence the PSA results. GE task analyses for LOCA under EPU conditions indicate that dynamic loads on containment remain acceptable for the EPU case.

4.1.2.5 RPV Overpressure Margin

The RPV dome operating pressure will not be increased as a result of the power uprate. However, the RPV pressure following a failure to scram is expected to increase slightly.

For turbine trip events (i.e., non-isolation, non-ATWS), the SRVs will not be challenged at BNP based on simulator runs and trip history. [22] For isolation events (non-ATWS), the SRVs may be challenged. However, the failure of all 11 SRVs to open is judged to be probabilistically insignificant and is not explicitly modeled in the base PSA. However, if implemented, a success criteria requiring 3 SRVs/SVs to be available for RPV overpressure protection is judged to be adequate (see MAAP Case BNP3a). MAAP Case BNP3a indicates that with 3 SRVs/SVs available the decay heat can be removed and RPV pressure will remain well below the Service Level C RPV pressure limit of 1500 psig. In addition, if the success criteria were to be conservatively increased from 3 SRVs to 4, the risk impact would be negligible because failure of an adequate number of SRVs/SVs to open is overwhelmingly dominated by common cause failure (the probability of which is effectively unchanged by a reduction in the number of required failures by one in the common cause failure group).

For ATWS events, the current BNP PSA requires 6 of 11 SRVs to be available for RPV overpressure protection. The increase in power due to the EPU is judged not to impact the appropriateness of this success criterion. In addition, if the success criteria were to be increased from 6 SRVs to some higher number, the risk impact would be negligible because failure of an adequate number of SRVs to open is dominated by common cause failure (the probability of which will be virtually unchanged by the reduction in the number of required failures in the common cause failure group).

4.1.2.6 SRV Actuations

The SRV and RPT setpoints have not been changed as a result of the power uprate. Therefore, no Level 1 PSA changes are required in the frequency of spurious SRV actuation (i.e., IORVs).

With the SRV setpoints remaining the same, the number of SRVs opening for power/pressure perturbations or transients may increase. This would result from the reduced margin for certain transient challenges between the operating pressure and the setpoints given the increased thermal energy in the RPV and the core. There is a small potential that the probability of a Stuck Open Relief Valve (SORV) as a result of plant transients may increase because of the reduced margin to the SRV setpoints.

However, the BNP PSA is currently conservative with regard to the modeling of SORVs. The models assume all SRVs open in response to any transient and, as such, each experiences a failure to close challenge. This existing conservative treatment bounds any postulated small increase in number of challenges resulting from the EPU.

4.1.2.7 Depressurization

The depressurization success criteria was confirmed with MAAP runs. [3] The results of the revised MAAP analyses for the extended power uprate evaluation are as follows:

- The existing BNP PSA success criterion of 3 SRVs required for RPV emergency depressurization during transients remains valid for the EPU condition. (MAAP Case BNP3a)
- The existing BNP PSA success criterion stating that a medium water break LOCA with HPCI initially operating is sufficient for RPV depressurization and to prevent core damage (given low pressure injection is available) is confirmed for the EPU by MAAP run BNP2.

The BNP PSA success criterion requiring 3 SRVs to fulfill the RPV emergency depressurization function may in fact be conservative (both for the pre-EPU and the EPU conditions). MAAP run BNP2ED shows that two SRVs are sufficient. Run BNP2ED is a loss of FW transient with MSIV closure. All injection to the RPV, with the exception of 1 LPCI pump, is assumed unavailable. Two SRVs are opened for RPV emergency depressurization when water level reaches the minimum steam cooling water level limit (-37"). A few minutes later LPCI injects and adequate core cooling is maintained (no core

damage). The EPU risk assessment maintains the 3 SRV criterion, consistent with the base PSA.

4.1.2.8 Success Criteria Summary

The Level 1 and Level 2 BNP PSAs have developed success criteria for the key safety functions. Tables 4.1-2 through 7 list these safety functions and the minimum success criteria under the current power configuration and that required under the extended power uprate configuration. Success criteria are summarized for the following:

- General Transients (Table 4.1-2)
- Small LOCA (Table 4.1-3)
- Medium LOCA (Table 4.1-4)
- Large LOCA (Table 4.1-5)
- ATWS Events (Table 4.1-6)
- Level 2 (Table 4.1-7)

Refer to the Brunswick Level 1 Success Criteria Notebook [8] and the Brunswick Level 2/LERF Evaluation [9] for detailed discussion of success criteria.

The PSA success criteria are affected by the increased boil off rate, the increased heat load to the suppression pool, the increase in blowdown loads, and the increase in containment pressure and temperatures. The changes in these parameters due to the EPU are generally small compared with the capability of the systems credited in the PSA.

Based on MAAP runs performed in support of this analysis, no changes in systemic success criteria for the Level 1 BNP PSA due to the EPU are identified for this risk assessment. Selected MAAP runs demonstrate the significant margins associated with the installed systems. However, MAAP runs were not performed to verify success criteria for all PSA systems. For example, the high pressure and low pressure ECCS system

success criteria is assumed in this assessment to remain the same for the EPU condition as for the pre-EPU condition based on the task analysis reports performed as part of the EPU program.

Regarding the SLC success criteria, the EPU risk assessment maintains the existing 2 SLC pump and 2 squib valve success criteria as in the BNP PSA. The potential plant modification that would allow credit of a single pump and valve is treated in this assessment as a sensitivity case.

The BNP PSA currently credits fire protection system water and service water crosstie for level-power control during ATWS scenarios. This success criteria item is also identified in this risk assessment for treatment as a sensitivity case.

No changes in success criteria have been identified with regard to the Level 2 containment evaluation. The slight changes in accident progression timing and decay heat load have only minor or negligible impacts on Level 2 PSA safety functions, such as containment isolation, ex-vessel debris coolability, and challenges to the ultimate containment strength.

4.1.3 Accident Sequence Modeling

The EPU does not change the plant configuration and operation in a manner such that new accident sequences or changes to existing accident scenario progressions result. A slight exception is the reduction in available accident progression timing for some scenarios and the associated impact on operator action HEPs (this aspect is addressed in the Human Reliability Analysis section).

This assessment for BNP is consistent with GE's generic conclusions on this issue [21]:

> *"The basic BWR configuration, operation and response is unchanged by power uprate. Generic analyses have shown that the same*

> *transients are limiting. ... Plant-specific analyses demonstrate that the accident progression is basically unchanged by the uprate."*

4.1.4 System Modeling

The BNP plant changes associated with the EPU do not result in the need to change any system modeling in support of this risk assessment.

Four system modifications are discussed here:

- Installation of the Supplemental Condensate Cooling System
- Replacement of Condensate Filter Demineralizers with longer filter elements
- SLC super pentaborate modification
- Potential SLC modification that would result in requiring a single SLC pump and squib valve.

A Supplemental Condensate Cooling system is to be added to the plant to support the EPU condition. This system will consist of 5 heat exchangers in parallel (three of these being regenerative). The system will be in service during the summer months, as required. This system addition is judged in this assessment to not result in a significant change in plant risk. However, future BNP PSA updates may incorporate this new hardware in the models to be fully reflective of as-built conditions of modeled systems.

Replacement of the demineralizer filters with those of a slightly different design would not result in any quantifiable difference in the PSA models as they are currently constructed. Nor is it anticipated that future PSA modeling updates will find a need to make any such distinctions in the models regarding filter design.

The chemical properties of the super pentaborate SLC eliminates the requirement for heat tracing (required with the current SLC configuration). However, the current BNP PSA

models, but does not explicitly quantify the heat tracing subsystem of SLC. As such, this modification does not impact the BNP PSA.

At the start of this assessment, the required SLC success criteria for the EPU condition was assumed (i.e., no discussion had yet been made at the plant) to remain at 2 pumps and 2 explosive valves (the success criteria in the existing BNP PSA) to meet 10CFR50.62 ATWS requirements. However, an option to pursue further analyses and system modifications that would result in the requirement of a single SLC pump and valve was being considered at the plant during the final stages of this risk assessment. As such, the base risk assessment assumes BNP will eliminate the SLC heat tracing, but will maintain the requirement for 2 of 2 SLC pumps and squib valves. The potential 1 SLC pump and valve option is addressed as a sensitivity case.

4.1.5 Failure Rate Data

Although equipment reliability as reflected in failure rates can be theoretically postulated to behave as a "bathtub" curve (i.e., the beginning and end of life phases being associated with higher failure rates than the steady-state period), no significant impact on the long-term average of initiating event frequencies, or equipment reliability during the 24 hr. PSA mission time due to the replacement/modification of plant components is anticipated, nor is such a quantification supportable at this time. However, a sensitivity case that increases the Turbine Trip initiating event frequency by 10% is quantified in the EPU analysis to conservatively bound the various changes to the BOP side of the plant (refer to Section 5.7 of this report).

4.1.6 Human Reliability Analysis

The Brunswick risk profile, like other plants, is dependent on the operating crew actions for successful accident mitigation. The success of these actions are in turn dependent on a number of performance shaping factors. The performance shaping factor that is principally influenced by the power uprate is the time available within which to detect,

diagnose, and perform required actions. The higher power level results in reduced times available for some actions. To quantify the potential impact of this performance shaping factor, deterministic thermal hydraulic calculations using the MAAP computer code are used.

MAAP Cases to Estimate Revised Operator Action Timing

Key results of the MAAP analyses performed in support of this EPU risk assessment [3] are as follows:

- The time available for emergency RPV depressurization and to recover adequate core cooling for loss of injection transients is on the order of 45 mins. to one hour (MAAP runs BNP3a and 3b). The existing BNP PSA HEP calculations assumes 30 minutes for such actions. Therefore, no change due to the EPU in HEPs for such actions is required.
- SLC injection initiated at 4 mins. (the existing BNP PSA timing) is found to be conservative for both the pre-EPU and EPU conditions (MAAP runs BNP6b, 7, and 8). Therefore, no reduction in assumed timing due to the EPU in the assessment of the SLC injection HEP is required.
- MAAP runs BNP8A and BNP8AP show that the allowable timing of 4 min. used in the base BNP PSA for inhibiting ADS remains an appropriate time frame for the EPU condition (i.e., approximately 2 minutes to reach LL3, the ADS timer initiation level, and an additional 2 minutes for the ADS timer to time out). Therefore, no change due to the EPU in the ADS inhibit HEP is required.
- MAAP runs BNP8A and BNP8AP show that the allowable time for level control actions during ATWS scenarios is reduced by 3-6 minutes for the EPU. Given the already short time frame (~30 min.), this time reduction has an impact on these HEPs.

Refer to Appendix A for a summary of MAAP cases performed to support the Brunswick power uprate.

Discussion of Impact on Human Error Probabilities

The increased power level reduces the time available for some operator actions by small increments. The reduction in the available time is generally small compared with the total time available to detect, diagnose, and perform the actions.

Table 4.1-8 summarizes the assessment of the operator actions explicitly reviewed in support of this analysis. The operator actions identified for explicit review were selected based on the following criteria:

1. Important operator action[(1)], as assessed by the Brunswick PSA, or
2. Time critical (<30 min. available) action

Twenty-six (26) operator actions of highest importance in the PSA (Fussell-Vesely Importance greater than 5E-3) were identified; and an additional 16 time critical HEPs (i.e., less than 30 minutes available for operator action) were identified.

As can be seen in Table 4.1-8, the changes in timing are estimated to result in minor changes in the HEPs. Only four actions are identified as warranting HEP re-calculation:

- OPER-LLEVEL1
- OPER-LLEVEL2
- XOP-COM2-14 (dependent action for OPER-DILUTE and OPER-LLEVEL1)
- XOP-COM2-15 (dependent action for OPER-DILUTE and OPER-LLEVEL2)

Therefore, a minor change in the Brunswick risk profile is expected. Section 5 summarizes the increase in the CDF and LERF associated with the changes in those HEPs that are explicitly modified in the EPU PSA.

Structural Evaluations

This assessment did not identify issues associated with postulated impacts from the EPU on the PSA modeling of structural (e.g., piping, vessel, containment) capacities. This is consistent with GE's generic conclusions [21]:

> *"The RPV is analyzed for power uprate conditions. Transients, accident conditions, increased fluence, and past operating history are considered to recertify the vessel. Plant specific analyses at power uprate conditions demonstrates that containment integrity will be maintained."*
>
> *"... no significant effect on LOCA probability. Increase in flow rates is addressed by compliance with Generic Letter 89-08, Erosion/Corrosion in Piping..."*

4.1.7 Quantification

No changes in the BNP PSA quantification process (e.g., truncation limit, flag settings, etc.) due to the EPU have been identified (nor were any anticipated). Small changes in the quantification results (accident sequence frequencies) were realized as a result of minor modeling changes (see HRA discussion in Section 4.1.6).

4.1.8 Level 2 Analysis

Given the minor change in Level 1 CDF results, minor changes in the Level 2 release frequencies can be anticipated. Such changes are directly attributable to the minor changes in short term accident sequence timing and the impact on HEPs. (Refer to Section 4.7 for additional discussion).

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(1) Those operator actions determined to have a Fussell-Vesely importance measure greater than 5E-3.

Table 4.1-1

REVIEW OF PSA ELEMENTS FOR POTENTIAL RISK MODEL EFFECTS

PSA Elements	Disposition Category	Basis
Initiating Events	C	No modifications due to power uprate that would create new initiating events or result in revised initiating event frequencies.
Success Criteria	B	There are a number of potential effects that could alter success criteria. These are discussed in the text. They include the following: • Time to boil down • Heat Load to the Pool • Blowdown Loads • RPV Overpressure Margin (number of SRVs/SVs required) • SRV Actuation • Depressurization (number of SRVs required) The latest MAAP calculations to support the reduced timing and modified success criteria should be included in the Brunswick PSA thermal hydraulics model documentation.
Accident Sequences (Structure, Progression)	C	No changes in the accident sequence structure result from the increase in power rating. The accident progression is slightly modified in timing. These changes are incorporated in the Human Reliability Analysis (HRA).
System Analysis	B	No new system failure modes or significant changes in system failure probabilities due to the EPU. [(1)(2)]
Data	C	No change to component failure probabilities.
Human Reliability Analysis	A	The change in initial power level in turn results in decreases in the time available for operator actions. See discussion of operator actions in Section 4.1.6.

Table 4.1-1

REVIEW OF PSA ELEMENTS FOR POTENTIAL RISK MODEL EFFECTS

PSA Elements	Disposition Category	Basis
Structural	C	No changes in the structural analyses are identified that would adversely impact the PSA models.
Quantification	B	No changes in PSA quantification process (e.g., truncation limit, flag settings, etc.) due to EPU. However, a small number of changes are identified in the accident sequence quantification results. Individual basic event quantification effects are addressed under HRA.
Level 2	B	Slight changes in accident progression timing result from the increased decay heat. However, the slight changes are negligible compared with the overall timing of the core melt accident progression.

(1) The SLC modification to support a single pump and squib valve success criteria is not listed in this table as it was not clear during the performance of this analysis whether or not the modification would be pursued. However, CP&L has decided during the final stages of this project to pursue this modification. This significant system modeling change is treated in this study as a sensitivity case.

(2) Refer to Table 3.4-1 of this report for discussions regarding individual modifications and the assessed impacts to the PSA.

Table 4.1-2

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 1) INITIATING EVENT: GENERAL TRANSIENTS

Safety Function	Minimum Systems Required	
	Current PSA Power (OLTP)	EPU Power(6) (120% OLTP)
Reactivity Control	Insertion of a substantial number of control rods	Same
Primary System Pressure Control (Overpressure)	Not modeled(1)	Same
Primary System Pressure Control (SRV reclose)	All must reclose	Same
High Pressure Injection	FW (2) and 1 CRD pump or HPCI or RCIC	Same
Depressurization	3 SRVs	Same
Low Pressure Injection	1 LPCI pump or 1 Core Spray Loop or 1 Condensate pump(7) or Fire Protection Water/Service Water via RHR Or 1 CRD pump(3)	Same
Containment Pressure Control	Main Condenser Or 1 RHR Hx Loop(4) or Wetwell Venting(5)	Same

Notes To Table 4.1-2:

(1) For turbine trip events (i.e., non-isolation, non-ATWS), the SRVs will not be challenged at BNP based on simulator runs and trip history. [22] For isolation events (non-ATWS), the SRVs may be challenged. However, failure of all 11 SRVs to open is judged to be probabilistically minor and not explicitly modeled in the base PSA.

(2) The BNP PSA Success Criteria Notebook states that it is considered probable that feedwater would not be capable of providing 24 hours of makeup due to the need for adequate steam pressure to operate the reactor feed pump turbines. Therefore, another high pressure makeup source (i.e., CRD) is required in combination with feedwater to satisfy the high pressure injection function for the entire 24 hour PSA mission time.

(3) CRD is a low flow systems that is successful for late RPV injection post containment challenge given that other high volume systems were initially providing RPV makeup.

(4) 1 RHRSW pump per RHR Hx loop is used for success.

(5) Wetwell venting is only credited for sequences with the RPV at low pressure per EOP direction.

(6) The success criteria applied for the power uprate configuration are based on MAAP calculations, GE calculations, or engineering judgement using conservative margins.

(7) One CP and one CBP pump both required.

Table 4.1-3

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 1) INITIATING EVENT: SMALL LOCA

Safety Function	Minimum Systems Required	
	Current PSA Power (OLTP)	EPU Power[3] (120% OLTP)
Reactivity Control	Insertion of a substantial number of control rods	Same
Primary System Pressure Control (Overpressure)	Not required	Same
High Pressure Injection	HPCI or RCIC	Same
Depressurization	3 SRVs	Same
Low Pressure Injection	1 LPCI pump or 1 Core Spray Loop or 1 Condensate pump[4] or Fire Protection Water/Service Water via RHR	Same
Containment Pressure Control	1 RHR Hx Loop[1] or Wetwell Venting[2]	Same

Notes To Table 4.1-3:

(1) 1 RHRSW pump per RHR Hx loop is used for success.

(2) Wetwell venting is only credited for sequences with the RPV at low pressure per EOP direction.

(3) The success criteria applied for the power uprate configuration are based on MAAP calculations, GE calculations, or engineering judgement using conservative margins.

(4) One CP and one CBP pump both required.

Table 4.1-4

KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 1) INITIATING EVENT: MEDIUM LOCA

Safety Function	Minimum Systems Required	
	Current PSA Power (OLTP)	EPU Power(3) (120% OLTP)
Reactivity Control	Insertion of a substantial number of control rods	Same
Primary System Pressure Control (Overpressure)	Not required	Same
High Pressure Injection	HPCI(1)	Same
Depressurization	3 SRVs or HPCI initially available	Same
Low Pressure Injection	1 LPCI pump or 1 Core Spray Loop	Same
Containment Pressure Control	1 RHR Hx Loop(2) or Wetwell Venting	Same

Notes To Table 4.1-4:

(1) HPCI may be available initially for high pressure injection. However, as the RPV pressure decreases due to the LOCA, low pressure injection from either Core Spray or LPCI is required.

(2) 1 RHRSW pump per RHR Hx loop is used for success.

(3) The success criteria applied for the power uprate configuration are based on MAAP calculations, GE calculations, or engineering judgement using conservative margins.

Table 4.1-5
KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS
FOR SUCCESS (LEVEL 1) INITIATING EVENT: LARGE LOCA

Safety Function	Minimum Systems Required	
	Current PSA Power (OLTP)	EPU Power[3] (120% OLTP)
Reactivity Control	Insertion of substantial number of control rods	Same
Primary System Pressure Control (Overpressure)	Not required	Same
Vapor Suppression	Not modeled[1]	Same
High Pressure Injection	(FW, HPCI, and RCIC not effective)	Same
Depressurization	Not required	Same
Low Pressure Injection	1 LPCI pump or 1 Core Spray Loop	Same
Containment Pressure Control	1 RHR Hx[2] or Wetwell Venting	Same

Notes To Table 4.1-5:

(1) Failure of the vapor suppression function is not explicitly modeled in the BNP PSA. Failure of vapor suppression requires both: 1) failure of any vacuum breaker to reclose, and 2) failure to emergency depressurize. Failure of the vapor suppression system during Large LOCA events is estimated to be probabilistically insignificant. Refer to the BNP success criteria notebook for additional discussion. [Ref. 8]

(2) 1 RHRSW pump per RHR Hx loop is used for success.

(3) The success criteria applied for the power uprate configuration are based on MAAP calculations, GE calculations, or engineering judgement using conservative margins.

Table 4.1-6
KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS
FOR SUCCESS (LEVEL 1) INITIATING EVENT: ATWS

Safety Function	Minimum Systems Required: Current PSA Power (OLTP)	Minimum Systems Required: EPU Power[5] (120% OLTP)
Reactivity Control	2 of 2 SLC trains	Same[6]
Primary System Pressure Control (Overpressure)	6 of 11 SRVs must open and 2 of 2 RPT	Same
Primary System Pressure Control (SRV reclose)	All SRVs must reclose	Same
High Pressure Injection	FW[1] and 1 CRD pump or HPCI or RCIC	Same
Depressurization	3 SRVs	Same
Low Pressure Injection	1 LPCI pump or 1 Core Spray Loop or 1 Condensate pump[8] or Fire Protection Water/Service Water via RHR or 1 CRD pump[2]	Same[7]
Containment Pressure Control	Main Condenser Or 1 RHR Hx Loop[3] or Wetwell Venting[4]	Same

Notes To Table 4.1-6:

(1) The BNP PSA Success Criteria Notebook states that it is considered probable that feedwater would not be capable of providing 24 hours of makeup due to the need for adequate steam pressure to operate the reactor feed pump turbines. Therefore, another high pressure makeup source (i.e., CRD) is required in combination with feedwater to satisfy the high pressure injection function for the entire 24 hour PSA mission time.

(2) CRD is a low flow systems that is successful for late RPV injection post containment challenge given that other high volume systems were initially providing RPV makeup.

(3) 1 RHRSW pump per RHR Hx loop is used for success.

(4) Wetwell venting is only credited for sequences with the RPV at low pressure per EOP direction.

(5) The success criteria applied for the power uprate configuration are based on MAAP calculations or engineering judgement using conservative margins.

(6) The potential plant modification that would allow credit of a single SLC pump and explosive valve is treated in this assessment as a sensitivity case.

(7) Removal of Fire Protection Water/Service Water crosstie as an injection option during ATWS scenarios is investigated as a sensitivity case in this risk assessment.

(8) One CP and one CBP pump both required.

Table 4.1-7
KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 2)

Safety Functions	Minimum Systems Required	
	Current PSA Power (OLTP)	EPU Power(2) (120% OLTP)
Containment Isolation	Containment penetrations >2" dia. closed or isolated	Same
RPV Depressurization	3 SRVs or Failure of the primary system due to high temperature during core melt progression or A large or medium LOCA	Same
Arrest Core Melt Progression In-Vessel	Coolant injection to the RPV (~ 1000 gpm)	Same
Combustible Gas Venting	Deinerted operation with no oxygen intrusion during the accident or Combustible gas purging and venting through the vent lines	Same
Containment Remains Intact at RPV Breach	Containment is isolated and No early containment failure modes (e.g., steam explosions) compromise the containment integrity	Same
Ex-vessel Debris Coolability	Availability of continuous water supply (> 1000 gpm): • LP makeup to the RPV or • Drywell Sprays	Same

Table 4.1-7
KEY SAFETY FUNCTIONS AND MINIMUM SYSTEM REQUIREMENTS FOR SUCCESS (LEVEL 2)

Safety Functions	Minimum Systems Required	
	Current PSA Power (OLTP)	EPU Power[(2)] (120% OLTP)
Containment Flooding	Adequate flooding capacity and availability of instrumentation to initiate flooding.	Same
Containment Flooded Above Debris	Drywell Venting	Same
Containment Pressure Control	RHR Containment Heat Removal (if no containment flooding) or Containment Venting	Same
Vapor Suppression	• No more than 1 stuck open vacuum breaker • The suppression pool level remains above bottom of downcomers • Vent pipes and downcomers do not rupture	Same

Notes To Table 4.1-7:

(1) The success criteria are discussed in detail in the Brunswick Level 2 analysis report March 2001.

(2) The success criteria applied for the power uprate configuration are based on MAAP calculations or engineering judgement using conservative margins and industry studies.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available		HEP Re-Calc. Necessary	Comment
			Current PSA Power (OLTP)	EPU Power (120% OLTP)		
X-AC-2H	Operator Fails To Recover Offsite Power In 2 Hours	F-V = 0.172	2 hrs.	2 hrs.	No	This is an offsite power recovery term. The time frame is based on nominal modeling time phases for LOOP scenarios. The recovery failure probability is based on statistical analysis of the duration of industry LOOP events and not directly on HEP calculations. The EPU will not impact the appropriateness of this time frame nor the recovery failure probability.
OPER-ALTUNITXC (XOP-ALTUNITXC, XOP-ALTUNITXC1)	Operators Fail To Manually Align Power From Opposite Unit	F-V = 0.115	1 hr.	(3)	No	The current HEP calculation is based on a conservative 1 hr. time frame allowable for operator action. This time frame does not include the additional time available due to RPV coolant inventory boiloff and the time for fuel heatup. The EPU will not impact the current calculational approach to this HEP.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available		HEP Re-Calc. Necessary	Comment
			Current PSA Power (OLTP)	EPU Power (120% OLTP)		
X-AC-12H	Operator Fails To Recover Offsite Power In 12 Hours	F-V = 0.072	12 hrs.	12 hrs.	No	This is an offsite power recovery term. The time frame is based on nominal modeling time phases for LOOP scenarios. The recovery failure probability is based on statistical analysis of the duration of industry LOOP events and not directly on HEP calculations. The EPU will not impact the appropriateness of this time frame nor the recovery failure probability.
OPER-DCPALTDC2 (XOP-DCPALTDC2)	Operator Fails To Align DC Bus To Standby DC Power Supply – Unit 2	F-V = 0.064	30 mins.	~ 45 mins.	No	The BNP PSA conservatively uses 30 mins. for HEP calculations for actions (such as this one) in which the time window is bounded by the time to core damage given no injection at t=0. MAAP runs #BNP3a, 3b, & 4, performed in support of this assessment, show that the realistic time window is about 45 mins. As such, the EPU has no impact on the current modeling of this operator action.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available: Current PSA Power (OLTP)	Action Time Available: EPU Power (120% OLTP)	HEP Re-Calc. Necessary	Comment
XOP-COM2-16	Operator Fails To Align DC Bus To Standby DC Power Supply And Fails To Manually Align Power From Opposite Unit	F-V = 0.058	30-60 mins.	(3)	No	The constituent events of this combination HEP are OPER-ALTUNITXC and OPER-DCPALTDC2. These constituent action timings have already been shown to be conservative. Therefore, the EPU will not impact the already conservative nature of this combination HEP.
OPER-480X2 (XOP-480X2)	Operators Fail To Manually Connect Unit 2 Substations E7 And E8	F-V = 0.052	1 hr.	(3)	No	The current HEP calculation is based on a conservative 1 hr. time frame allowable for operator action. This time frame does not include the additional time available due to RPV coolant inventory boiloff and the time for fuel heatup. The EPU will not impact the current calculational approach to this HEP.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available: Current PSA Power (OLTP)	Action Time Available: EPU Power (120% OLTP)	HEP Re-Calc. Necessary	Comment
X-AC-16H	Operator Fails To Recover Offsite Power In 16 Hours	F-V = 0.050	16 hrs.	16 hrs.	No	This is an offsite power recovery term. The time frame is based on nominal modeling time phases for LOOP scenarios. The recovery failure probability is based on statistical analysis of the duration of industry LOOP events and not directly on HEP calculations. The EPU will not impact the appropriateness of this time frame nor the recovery failure probability.
OPER-DILUTE (XOP-DILUTE)	Operator Fails To Preclude Boron Washout During Low Pressure Injection	F-V = 0.026	5 mins.	5 mins.	No	This action is not dependent on the power level but is a function of the ability to control RPV flow before certain flow parameters are exceeded (i.e., boron is washed from the core causing criticality or boron is washed from the RPV due to overfill).
OPER-DC2BALT	Operator Fails To Switch Charger To Alternate AC Power Supply-Unit 2	F-V = 0.022	~30 mins.	(3)	No	This operator action is conservatively modeled in the Brunswick PSA with an HEP of 1.0. As such, The EPU has no impact on the current modeling of this operator action.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available		HEP Re-Calc. Necessary	Comment
			Current PSA Power (OLTP)	EPU Power (120% OLTP)		
OPER-DEPRESS (XOP-DEPRESS)	Operator Fails To Manually Initiate And Align Low-Pressure Systems	F-V = 0.021	30 mins.	~ 45 mins.	No	The BNP PSA conservatively uses 30 mins. for HEP calculations for actions (such as this one) in which the time window is bounded by the time to core damage given no injection at t=0. MAAP runs #BNP3a, 3b, & 4, performed in support of this assessment, show that the realistic time window is about 45 mins. As such, the EPU has no impact on the current modeling of this operator action.
X-AC-1H	Operator Fails To Recover Offsite Power In 1 Hour	F-V = 0.021	1 hr.	1 hr.	No	This is an offsite power recovery term. The time frame is based on nominal modeling time phases for LOOP scenarios. The recovery failure probability is based on statistical analysis of the duration of industry LOOP events and not directly on HEP calculations. The EPU will not impact the appropriateness of this time frame nor the recovery failure probability.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available		HEP Re-Calc. Necessary	Comment
			Current PSA Power (OLTP)	EPU Power (120% OLTP)		
X-AC-5H	Operator Fails To Recover Offsite Power In 5 Hours	F-V = 0.019	5 hrs.	5 hrs.	No	This is an offsite power recovery term. The time frame is based on nominal modeling time phases for LOOP scenarios. The recovery failure probability is based on statistical analysis of the duration of industry LOOP events and not directly on HEP calculations. The EPU will not impact the appropriateness of this time frame nor the recovery failure probability.
OPER-FPS1 (XOP-FPS1)	Operator Fails To Align Firewater For Coolant Injection Flow (One Unit)	F-V = 0.017	30 mins.	~ 45 mins.	No	The BNP PSA conservatively uses 30 mins. for HEP calculations for actions (such as this one) in which the time window is bounded by the time to core damage given no injection at t=0. MAAP runs #BNP3a, 3b, & 4, performed in support of this assessment, show that the realistic time window is about 45 mins. As such, the EPU has no impact on the current modeling of this operator action.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available: Current PSA Power (OLTP)	Action Time Available: EPU Power (120% OLTP)	HEP Re-Calc. Necessary	Comment
OPER-LLEVEL1 (XOP-LLEVEL1)	Operator Fails To Control Lowered Water Level With HPCI During ATWS	F-V = 0.015	30 mins.	24 mins.	Yes	Two MAAP runs were performed to estimate the potential impact on operator action timing to lower RPV water level under the postulated ATWS condition. BNP8AP represents the OLTP case and BNP8A represents the EPU case. The results indicate a 17.6% reduction in time available to take the action. The current PSA (OLTP) uses a 30 min time frame to characterize the action. The MAAP results indicate that a reduction of 5-6 min would result due to the EPU. Therefore, 24 mins. is used as the action time for the EPU.
OPER-GENDISC (XOP-GENDISC)	Successful Bypass Of MSIV Low Level Interlock	F-V = 0.015	1 hr.	(3)	No	The current HEP calculation is based on a conservative 1 hr. time frame allowable for operator action. This time frame does not include the additional time available due to RPV coolant inventory boiloff and the time for fuel heatup. The EPU will not impact the current calculational approach to this HEP.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available: Current PSA Power (OLTP)	Action Time Available: EPU Power (120% OLTP)	HEP Re-Calc. Necessary	Comment
OPER-LLEVEL2 (XOP-LLEVEL2)	Operator Fails To Control Lowered Water Level With RCIC During ATWS	F-V = 0.012	30 mins.	24 mins.	Yes	Refer to comment for action OPEP-LLEVEL1.
XOP-COM2-15	Operator Fails To Control Lowered Water Level With RCIC During ATWS And Fails To Preclude Boron Washout During Low Pressure Injection	F-V = 0.010	5-30 mins.	5-24 mins.	Yes	This is a combination HEP for actions OPER-DILUTE and OPER-LLEVEL2. Refer to the comments in this table for the bases of the constituent action timing changes.
OPER-FWSCNT	Operator Fails To Control Feedwater Flow And Feedwater Lost After Trip	F-V = 0.008	n/a	n/a	No	The probability of this "action" is based on statistical analysis of BNP experience and not on HEP calculations. The EPU will not impact the appropriateness of the calculational method of this parameter nor necessarily the probability (i.e., there is no indication at this time that the probability of post-scram flow control induced loss of FW will increase due to the EPU).

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available: Current PSA Power (OLTP)	Action Time Available: EPU Power (120% OLTP)	HEP Re-Calc. Necessary	Comment
OPER-INHIBITADS (XOP-INHIBITADS)	Operator Fails To Inhibit ADS During ATWS	F-V = 0.008	4 mins.	(3)	No	The total time available can range from 4-5 minutes to approximately 10 minutes depending on various factors (e.g., number of control rods inserted; whether FW is initially injecting or not; how long it takes operators to terminate injection per the EOPs). BNP uses 4 mins. for this HEP calculation – this value is judged on the conservative side. No change in HEP is required due to the EPU.
X-AC-18H	Operator Fails To Recover Offsite Power In 18 Hours	F-V = 0.007	18 hrs.	18 hrs.	No	This is an offsite power recovery term. The time frame is based on nominal modeling time phases for LOOP scenarios. The recovery failure probability is based on statistical analysis of the duration of industry LOOP events and not directly on HEP calculations. The EPU will not impact the appropriateness of this time frame nor the recovery failure probability.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available: Current PSA Power (OLTP)	Action Time Available: EPU Power (120% OLTP)	HEP Re-Calc. Necessary	Comment
OPER-SPCATWS (XOP-SPCATWS)	Operators Fail To Initiate Suppression Pool Cooling During An ATWS	F-V = 0.007	10 mins.	(3)	No	The BNP PSA uses 10 mins. for this HEP calculation. This value is judged conservative. Typical PSAs have used times on the order of 15-20 mins using the results from GE analyses NEDE-24222.[29] No change in HEP required.
OPER-SCRAM (XOP-SCRAM)	Operator Fails To Initiate Manual Scram	F-V = 0.006	4 mins.	4 mins.	No	The BNP PSA uses 4 mins. for this HEP calculation. This value is judged conservative. Typical PSAs do not credit manual scram during ATWS. MAAP runs BNP6b, 7, and 8 confirm that 4 mins. remains successful for the EPU conditions. No change in HEP is required.
OPER-WVDHR (XOP-WVDHR)	Operators Fail To Initiate Wetwell Venting For DHR	F-V = 0.006	5 hrs.	(3)	No	This is a long term action for initiation of wetwell venting for containment decay heat removal. The HEP is based on a conservative time window (i.e., up to PCPL - not containment failure). Any changes in thermal hydraulic parameters due to the power uprate would not impact the already conservative nature of this HEP.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available		HEP Re-Calc. Necessary	Comment
			Current PSA Power (OLTP)	EPU Power (120% OLTP)		
OPER-FWS-INJ (XOP-FWS-INJ)	Operators Fail To Properly Control Condensate Injection Flow Rate	F-V = 0.006	30 mins.	~ 45 mins.	No	The BNP PSA conservatively uses 30 mins. for HEP calculations for actions (such as this one) in which the time window is bounded by the time to core damage given no injection at t=0. MAAP runs #BNP3a, 3b, & 4, performed in support of this assessment, show that the realistic time window is about 45 mins. As such, the EPU has no impact on the current modeling of this operator action.
XOP-COM2-09	Operator Fails To Align Firewater For Coolant Injection Flow (One Unit) And Fails To Properly Control Condensate Injection Flow Rate	F-V = 0.006	30 mins.	~ 45 mins.	No	The BNP PSA conservatively uses 30 mins. for HEP calculations for actions (such as this one) in which the time window is bounded by the time to core damage given no injection at t=0. MAAP runs #BNP3a, 3b, & 4, performed in support of this assessment, show that the realistic time window is about 45 mins. As such, the EPU has no impact on the current modeling of this operator action.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available		HEP Re-Calc. Necessary	Comment
			Current PSA Power (OLTP)	EPU Power (120% OLTP)		
OPER-DFPFUEL	Operator Fails To Refill Diesel Driven Pump Fuel Oil Tank In 8 Hours	F-V = 0.005	8 hrs.	8 hrs.	No	This operator action is conservatively modeled in the Brunswick PSA with an HEP of 1.0. As such, The EPU has no impact on the current modeling of this operator action.
OPER-SLCS (XOP-SLCS)	Operators Fail To Initiate SLCS	F-V < 0.005 but short time frame	4 mins.	(3)	No	The BNP PSA uses 4 mins. for this HEP calculation. This value is judged conservative. Typical PSAs have used times on the order of 6 mins. MAAP runs BNP6b, 7 and 8 confirm that 4 mins. remains successful for the EPU condition. No change in HEP required.
XOP-COM2-12	Operators Fail To Initiate Suppression Pool Cooling During An ATWS And Fail To Preclude Boron Washout During Low Pressure Injection	F-V < 0.005 but short time frame	5-10 mins.	5-10 mins.	No	There is no change in time available to the individual constituent operator actions due to the EPU. Therefore, this combination HEP remains valid for the EPU
XOP-COM2-13	Operator Fails To Inhibit ADS During ATWS And Fails To Preclude Boron Washout During Low Pressure Injection	F-V < 0.005 but short time frame	4-5 mins.	4-5 mins.	No	There is no change in time available to the individual constituent operator actions due to the EPU. Therefore, this combination HEP remains valid for the EPU

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available: Current PSA Power (OLTP)	Action Time Available: EPU Power (120% OLTP)	HEP Re-Calc. Necessary	Comment
XOP-COM2-14	Operator Fails To Control Lowered Water Level With HPCI During ATWS And Fails To Preclude Boron Washout During Low Pressure Injection	F-V < 0.005 but short time frame	5-30 mins.	5-24 mins.	Yes	This is combination a HEP for actions OPER-DILUTE and OPER-LLEVEL1. Refer to the comments in this table for the bases of the constituent action timing changes.
X-AC-0H	Operator Fails To Recover Offsite Power In 30 Minutes	F-V < 0.005 but short time frame	30 mins.	30 mins.	No	This is an offsite power recovery term. The time frame is based on nominal modeling time phases for LOOP scenarios. The recovery failure probability is based on statistical analysis of the duration of industry LOOP events and not directly on HEP calculations. The EPU will not impact the appropriateness of this time frame nor the recovery failure probability.
OPER-SWRHR-C (XOR-SWRHR-C)	Operators Fail To Locally Close The SW Valves For Fire Protection Water Injection	F-V < 0.005 but short time frame	~30 mins.	(3)	No	This operator recovery action is modeled in the Brunswick PSA using an HEP calculational method that considers three broad timing categories (Short, Intermediate, and Long). The Short time frame is defined as "less than 1 hour". As such, the power uprate has no impact on the current modeling of this operator action.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available: Current PSA Power (OLTP)	Action Time Available: EPU Power (120% OLTP)	HEP Re-Calc. Necessary	Comment
OPER-SWRHR-O (XOR-SWRHR-O)	Operators Fail To Locally Open The Discharge Valves For RHR Injection	F-V < 0.005 but short time frame	~30 mins.	(3)	No	This operator recovery action is modeled in the Brunswick PSA using an HEP calculational method that considers three broad timing categories (Short, Intermediate, and Long). The Short time frame is defined as "less than 1 hour". As such, the power uprate has no impact on the current modeling of this operator action.
OPER-ALTBUSXC1	Operators Fail To Manually Align Power from Opposite Bus (Unit 1)	F-V < 0.005 but short time frame	30 mins.	(3)	No	This operator action is conservatively modeled in the Brunswick PSA with an HEP of 1.0. As such, The EPU has no impact on the current modeling of this operator action.
OPER-ALTBUSXC2	Operators Fail To Manually Align Power from Opposite Bus (Unit 2)	F-V < 0.005 but short time frame	30 mins.	(3)	No	This operator action is conservatively modeled in the Brunswick PSA with an HEP of 1.0. As such, The EPU has no impact on the current modeling of this operator action.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID [(1)]	Action Description	Basis of Importance [(2)]	Action Time Available: Current PSA Power (OLTP)	Action Time Available: EPU Power (120% OLTP)	HEP Re-Calc. Necessary	Comment
OPER-CSTSWAP	Operator Fails To Manually Swap RCIC Suction Source Given Loss of CST Suction	F-V < 0.005 but short time frame	30 mins.	(3)	No	This operator action is conservatively modeled in the Brunswick PSA with a screening value of 0.3. As such, The EPU has no impact on the current modeling of this operator action.
OPER-DC1BALT	Operator Fails to Switch Charger to Alternate AC Power Supply – Unit 1	F-V < 0.005 but short time frame	30 mins.	(3)	No	This operator action is conservatively modeled in the Brunswick PSA with an HEP of 1.0. As such, The EPU has no impact on the current modeling of this operator action.
OPER-FPS2	Operator Fails To Align Firewater for Coolant Injection Flow (Both Units)	F-V < 0.005 but short time frame	30 mins.	(3)	No	This operator action is conservatively modeled in the Brunswick PSA with a screening value of 0.3. As such, The EPU has no impact on the current modeling of this operator action.
OPER-LDSHD	Operator Fails to Complete Load Shed	F-V < 0.005 but short time frame	30 mins.	(3)	No	This operator action is not credited (i.e., set to TRUE with logic flag) in the BNP PSA due to procedural guidance. As such, the EPU has no impact on the modeling of this action.

Table 4.1-8

DISPOSITION OF KEY OPERATOR ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID (1)	Action Description	Basis of Importance (2)	Action Time Available: Current PSA Power (OLTP)	Action Time Available: EPU Power (120% OLTP)	HEP Re-Calc. Necessary	Comment
OPER-LDSDN	Operator Succeeds with Load Shed	F-V < 0.005 but short time frame	30 mins.	(3)	No	This action is the "success complement" of operator action OPER-LDSDN (refer to comment above).
OPER-MANECCS	Operator Fails to Manually Initiate and Align ECCS	F-V < 0.005 but short time frame	30 mins.	(3)	No	This operator action is conservatively modeled in the Brunswick PSA with a screening value of 0.3. As such, The EPU has no impact on the current modeling of this operator action.
OPER-TTRIP	Operators Fail To Manually Trip Turbine - Locally	F-V < 0.005 but short time frame	5-10 mins.	(3)	No	This operator action is conservatively modeled in the Brunswick PSA with an HEP of 1.0. As such, the EPU has no impact on the current modeling of this operator action.

Notes To Table 4.1-8:

(1) Basic event IDs in parentheses represent the same operator action but are assigned a different basic event ID and HEP based on the PSA QRecover file.

(2) The criteria used to identify operator actions for explicit consideration are: 1) F-V >0.005 or 2) the time available in which to perform the action is short (< 30 min.).

(3) The time available to perform the action for the EPU case is expected to be approximately the same or slightly less than that for the OLTP; however, a formal assessment of the time available for the EPU case is not necessary in determining whether a change in the HEP calculation is warranted. The actions for which this note applies have HEPs that are based on more limiting assumed time available and are therefore conservative in nature and would not be affected by the potential changes in available timings due to the EPU.

4.2 LEVEL 1 PSA

Section 4.1 summarized possible effects of the EPU by examining each of the PSA elements. This section examines possible EPU effects from the perspective of accident sequence progression. The dominant accident scenario types (classes) that can lead to core damage are examined with respect to the changes in the individual PSA elements discussed in Section 4.1.

Loss of Inventory Makeup Transients

The loss of inventory accidents (non-LOCA) are determined by the number of systems, their success criteria, and operator actions for responding to their demands. The following bullets summarize key issues:

- HPCI/RCIC/FW and Low Pressure Makeup System(1) flow rates - all of these systems have substantial margin in their success criteria relative to the EPU power increase to match the coolant makeup flow required for postulated accidents. The success criteria for these systems are based on discrete sets of pumps being available. No changes to the above injection systems to augment their capabilities for the EPU configuration are planned. The EPU does not change decay heat such that it impacts the success criteria for the individual system pumps. This conclusion is based on engineering judgement. Specific MAAP calculations were not performed to confirm that individual makeup systems could prevent core damage.

- CRD - CRD is not initially an adequate makeup source to the RPV at the current Brunswick power rating for events initiated from full power. CRD is considered successful in the Brunswick PSA for late RPV injection given initial RPV injection from FW. The EPU does not impact these success criteria. Late RPV injection requires minimal flow rates (e.g., 100 gpm) to provide RPV makeup for boiloff. This is confirmed by MAAP run BNP10 performed in support of the EPU assessment

- The success criterion used in the current PSA for the number of SRVs required to be open to assure RPV depressurization is three (3).

(1) Core Spray, LPCI, Condensate Pumps and possibly the requirement for depressurization.

> Based on the MAAP evaluations (e.g., MAAP Cases BNP3a and 3b), the 3 SRVs success criterion remains adequate for the EPU condition.

Operator actions include emergency depressurization and system control and initiation. While the injection initiation/recovery and emergency depressurization timings are slightly impacted by the EPU, the current model (2558 MWth) has conservatively treated the time available for these operator actions. The HEPs remain conservative for the EPU condition also.

As described in Section 4.1, the only BNP PSA model changes necessary to model the EPU risk impact are changes to four ATWS-related human error probabilities. As such, no changes to the existing risk profile associated with loss of inventory makeup transients (i.e., Class I core damage sequences) result.

ATWS

Following a failure to scram coupled with additional failures, a higher power level and increase in suppression pool temperature would result for the EPU configuration compared with the current Brunswick configuration (assuming similar failures).

The power level increase would be approximately proportional to the power uprate. For example, currently power levels at TAF for an ATWS without SLC injection and at nominal operating pressure may be 18% of full power. This would correspond to 21.6% of the current PSA power level for the EPU. The SLC modification to use super pentaborate will ensure that the SLC system is still capable of shutting down the reactor. [14]

The necessary relief capacity to prevent exceeding the Service Level C RPV pressure limit of 1500 psig is modeled in the current BNP PSA as 6 SRVs/SVs. As discussed earlier in Section 4.1.2.5, 6 SRVs/SVs remain adequate for the EPU condition.

The increased power level reduces the time available to perform operator actions. Given the shorter time frames associated with ATWS scenarios, this time reduction has a more significant impact on ATWS scenarios than transient (non-ATWS) scenarios. As summarized in Table 4.1-8, four operator action basic events are identified in this assessment as warranting HEP re-calculation due to the EPU:

- OPER-LLEVEL1
- OPER-LLEVEL2
- XOP-COM2-15
- XOP-COM2-14

In fact, these are the only 4 modeling elements identified for modification. Each of these four actions relates to controlling RPV water level during an ATWS. As the BNP ATWS core damage results are dominated by SLC pump failures (refer to Appendix D), the change in the action HEPs will not have a pronounced impact on the ATWS results.

<u>LOCAs</u>

The blowdown loads may be slightly higher because of the higher initial power. The Mark I Containment Loads Program and the Brunswick specific containment loads program have shown that these loads are acceptable for the original licensing bases. The GE task analyses confirm that the SSCs remain acceptable after EPU.

The success criteria for the systems to respond to a LOCA are discretized by system trains. Sufficient margin is available in these success criteria to allow adequate core cooling for EPU.

As with the Class I sequences, the risk profile associated with Class III sequences (LOCAs) remains unchanged by the EPU.

<u>SBO</u>

Station Blackout represents a unique subset of the loss of inventory accidents identified above. The station blackout scenario response is almost totally dominated by AC and DC power responses. In all other respects, SBO sequences are like the transients discussed above. Extended power uprate will not increase the loads on diesel-generators or batteries.[7] With regard to offsite power recovery, the credit for early AC recovery ranges from 1 to 2 hours. It is based on battery depletion and depends upon which divisional battery is considered and assuming that load shedding cannot be credited due to procedural guidance. Nevertheless, offsite power recovery is unchanged by the EPU.

Minor effects due to increased decay heat levels would shorten the time to core uncovery and AC and DC restoration. However, these time differences are approximately: (1) 5 minutes over 1 hour(1); and, (2) 15-30 minutes over 4 hours. In addition, the time frames of the offsite power recovery terms are nominal time frames based on SBO accident functional characteristics and specific failure modes. The functional success criteria for SBO sequences may contribute to AC recovery timing, but the specific failure modes (e.g., 4 of 4 EDGs fail to start) are the primary determining factors of the recovery analysis. The associated recovery failure probabilities are based on statistical analyses of industry LOOP events and not directly on operators action time frames and associated HEP calculations.

The time frame for late offsite AC power recovery ranges from 12 to 19 hours depending on the specific types of failures in the sequences (e.g., 4 of 4 EDGs fail to run, 3 of 3 EDGs fail to run). [6] The probability of failure of late offsite power recovery is also unaffected by EPU for the reasons discussed above. (See HRA discussion in Table 4.1-8.)

(1) BNP MAAP run P25-1 performed for the 105% power level indicates a time to core damage of approximately 64 minutes for a transient with loss of injection. BNP MAAP run BNP3b indicates the time is about 60 minutes for the EPU.

As such, like the other Class I core damage accident sequences, no changes to the existing risk profile associated with Station Blackout scenarios result.

Loss of Containment Heat Removal

Sequences which involve the loss of containment heat removal are affected slightly in terms of the time to reach containment Primary Containment Pressure Limit (PCPL) or ultimate pressure, however the success criteria for the systems used in the PSA are not affected. Consider the following systems:

- RHR
- Main Condenser
- Wetwell Vent

These are judged all capable of adequate containment heat removal if used as determined in the probabilistic analysis regardless of the 15% power uprate status. Although a BNP "vent initiation" MAAP run was not performed in support of this risk assessment, MAAP runs for other BWR plants with similar containment vent designs as Brunswick (i.e., 8 inch vent pipe) show that once the containment vent is opened per the EOPs, containment pressure decreases immediately and rapidly. The small percentage difference in decay heat level (i.e., pre-EPU vs EPU) at the time of EOP vent initiation will not change this performance.

Other systems (e.g., RWCU) are considered marginal or inadequate for containment heat removal even for Brunswick's current power level. The power uprate would continue to judge that such system are inadequate.

The increased power level decreases the time before encroaching on HCTL and requiring emergency depressurization. However, the changes are relatively small (approximately 10 minutes in 2-3 hours) and do not significantly affect the human error probabilities for aligning decay heat removal systems.

No changes to the risk profile associated with Class II (loss of decay heat removal) accidents result.

4.3 INTERNAL FIRES INDUCED RISK

The Brunswick plant risk due to internal fires was originally evaluated in 1987 using a fire PSA. This original work was built upon and updated as part of the BNP Individual Plant Examination of External Events (IPEEE) Submittal. [10] EPRI FIVE Methodology screening approaches and data were used to update and enhance the original BNP fire PSA study. The CDF contribution due to internal fires was calculated at 3.44E-5/yr for Unit 2. [27] As the BNP internal fires electronic PSA models are currently archived, the IPEEE documentation for the fire induced core damage scenarios and the associated frequency results were reviewed in support of this assessment. Approximately two-thirds of the BNP internal fires induced core damage frequency is comprised of accident scenarios that would be negligibly impacted by reductions in scenario timings due to the EPU:

- Control Room fire scenarios resulting in Control Room evacuation and failure to safely shutdown the plant using the Remote Shutdown Panel (i.e., <u>all</u> Group 1 CR cabinet fire scenarios plus all Group 2 CR cabinet fire scenarios involving evacuation = 1.79E-5/yr) (52%)
- Control Spreading Room fire scenarios resulting in Control Room evacuation and failure to safely shutdown the plant using the Remote Shutdown Panel (i.e., CSR transient fires involving evacuation = 1.44E-6/yr) (4%)
- Fire scenarios resulting in loss of all decay heat removal (10%)[1]

[1] The 10% of DHR fire scenario contribution is a conservative judgement based on review of the BNP IPEEE Submittal. No detailed results (e.g., cutsets) are available and the IPEEE Submittal is not documented to a level of detail that would permit a more precise summation. This value is judged conservative because other BWR fire IPEEEs typically show a large (>10%) contribution to the fire CDF from loss of DHR accident scenarios. The primary impacts of EPU for fire scenarios are potential reductions in time available for operator response. Some scenarios such as loss of DHR sequences have exceedingly long times available for action, e.g., 5-40 hours. Changes caused by an EPU of 20% would not significantly alter the assessed HEPs for such accident scenarios. Nevertheless, these sequences have been shown to represent a fraction of the fire initiated accident sequences. Assuming a larger fraction of DHR sequences than 10% would result in reducing the fraction of other sequences that may be more sensitive to reduced time available for operation actions, hence the 10% is conservative.

With respect to the first two scenario categories, these scenarios are dominated by the high human error probability for failure to perform plant safe shutdown from outside the Control Room. This high HEP is due to a variety of factors, such as limited plant control from outside the Control Room, and would not be significantly impacted by a few minute reduction in available timings due to the EPU.

Consistent with the conclusions reached earlier in this assessment, the loss of decay heat removal scenarios are long term accidents and any reductions in already lengthy operator response times due to the EPU has an insignificant impact on calculated human error probabilities (and, thus, core damage sequence frequencies).

With regard to other potential impacts (i.e., other than reduction in scenario timings and their impact on HEPs), the key general conclusions identified earlier in this assessment are reconsidered here:

- No impact on modeled systemic/functional success criteria due to the EPU
- No new unanalyzed accidents are created by the EPU
- No significant changes to component failure rates due to the EPU are anticipated at this time

Given the above, it is estimated here that the 15% EPU will result in no more than a few percent increase (1% is the best estimate) in the calculated internal fires induced core damage frequency for BNP Unit 2. This estimate is calculated here as follows:

$$\text{DeltaCDF}_{\text{fire}(\%)} = \frac{[\,33\% \times 3.44\text{E-5/yr} \times (1 + (0.016 \times 2))\,] - (33\% \times 3.44\text{E-5/yr})}{3.44\text{E-5/yr}}$$

$$= 1\%$$

Where:

- The 33% term represents the fraction of internal fires CDF potentially impacted by reductions in scenario timings due to the EPU
- The 0.016 term represents the 1.6 percent increase manifested in the internal events CDF due to the EPU
- The 2 term represents an estimated multiplier applied to the 1.6% internal events delta CDF to address the potential for greater impact in fire scenarios given that fire scenarios typically proceed with a reduced set of available safe shutdown options compared to internal events. This factor of 2 is judged conservative given that the delta CDF increase in the Level 1 is entirely due to ATWS, and the fire CDF includes zero contribution from ATWS.

4.4 SEISMIC RISK

The Brunswick seismic risk analysis was performed as part of the Individual Plant Examination of External Events (IPEEE). [10] The seismic portion of the IPEEE program was completed in conjunction with the SQUG program. Brunswick performed a seismic margins assessment (SMA) following the guidance of NUREG-1407 and EPRI NP-6041. The SMA is a deterministic evaluation process that does not calculate risk on a probabilistic basis. No core damage frequency sequences were quantified as part of the seismic risk evaluation.

The conclusions of the Brunswick seismic risk analysis are as follows: [10]

> *"The principal conclusion is that there is no seismic vulnerability at Brunswick. ... The Seismic Review Team identified issues related to maintenance, housekeeping, and seismic interaction that required work orders to satisfy SRT field issues. Several components were identified for subsequent HCLPF evaluation. ... The IPEEE evaluation concluded that the Brunswick plant HCLPF is at least 0.30g"*

Based on a review of the Brunswick IPEEE and the key general conclusions identified earlier in this assessment, the conclusions of the SMA are judged to be unaffected by the EPU. The EPU has little or no impact on the seismic qualifications of the systems,

structures and components (SSCs). Specifically, the power uprate results in additional thermal energy stored in the RPV, but the additional blowdown loads on the RPV and containment given a coincident seismic event, are judged not to alter the results of the SMA.

The decrease in time available for operator actions due to the power uprate may be subsumed by the increased difficulty to perform operator actions during a seismic event (e.g., displaced control room panels or ceiling tiles prevent operators to perform duties); and for long term seismic scenarios, the impact on the HEPs has been shown earlier in this assessment to be negligible.

4.5 OTHER EXTERNAL EVENTS RISK

In addition to internal fires and seismic events, the BNP IPEEE Submittal analyzed a variety of other external hazards:

- Extreme Winds
- Transportation and Nearby Facility Accidents
- Other External Hazards

External flooding is addressed in the BNP IPEEE Submittal analyses under Hurricanes, categorized above under the broader category of Extreme Winds.

4.5.1 Extreme Winds

The extreme winds evaluated in the BNP IPEEE Submittal as applicable to the BNP site are:

- Tornadoes
- Winds from tropical and non-tropical storms

The calculated core damage frequency at BNP Unit 2 from all wind sources is 4.0E-6/yr. This facet of plant risk is dominated almost entirely by long term loss of offsite power scenarios. As discussed earlier in this assessment for other risk contributors, long term core damage scenarios are negligibly impacted by the EPU.

4.5.2 Transportation and Nearby Facility Accidents

The BNP IPEEE calculated a core damage frequency for one transportation and nearby facility accident – aircraft impacts. All other such accidents were assessed to have non-significant core damage frequencies.

The aircraft impact core damage risk was conservatively calculated as 1.3E-6/yr aircraft impact frequency (sum of various aircraft types) x 0.1 conditional core damage probability, resulting in a core damage frequency of 1.3E-7/yr. The 0.1 CCDP is conservative considering the design strength of the Class I buildings.

The EPU will not impact this conservative calculation.

4.5.3 Other External Hazards

All other external hazards were assessed in the Brunswick IPEEE Submittal as not applicable to the BNP site, bounded by other already analyzed hazards, or of negligible frequency.

4.6 SHUTDOWN RISK

The impact of the Extended Power Uprate (EPU) on shutdown risk is similar to the impact on the at-power Level 1 PSA. Based on the insights of the at-power PSA impact assessment, the areas of review appropriate to shutdown risk are the following:

- Initiating Events

- Success Criteria
- Human Reliability Analysis

The following qualitative discussion applies to the shutdown conditions of Hot Shutdown (Mode 3), Cold Shutdown (Mode 4), and Refueling (Mode 5). The EPU risk impact during the transitional periods such as at-power (Mode 1) to Hot Shutdown and Startup (Mode 2) to at-power are judged to be subsumed by the at-power Level 1 PSA. This is consistent with the U.S. PSA industry, and with NRC Regulatory Guide 1.174 which states that not all aspects of risk need to be addressed for every application. While higher conditional risk states may be postulated during these transition periods, the short time frames involved produce a insignificant impact on the long-term annualized plant risk profile.

4.6.1 Shutdown Initiating Events

Shutdown initiating events include the following major categories:

- Inadvertent Draindown
- LOCAs
- Loss of Decay Heat Removal (includes LOOP)

No new initiating events or increased potential for initiating events during shutdown (e.g., loss of DHR train) can be postulated due to the 15% EPU.

4.6.2 Shutdown Success Criteria

The impact of the EPU on the success criteria during shutdown is similar to the Level 1 PSA. The increased power level decreases the time to boildown. However, because the reactor is already shutdown, the boildown times are much longer compared to the at-power PSA. The boildown to TAF time is approximately 1 hour at 2 hours after shutdown (e.g., time of Hot Shutdown) and approximately 2-4 hours at 12-24 hours after

shutdown (e.g., time of Cold Shutdown). The decrease in the boildown time for the EPU is small because of the lower decay heat level relative to at-power conditions. Further discussion regarding boil down times is provided in Section 4.6.3 in the discussion of the impacts on shutdown operator action response times.

The increased decay heat loads associated with the EPU impacts the time when low capacity DHR systems such as Fuel Pool Cooling (FPC) and Reactor Water Cleanup (RWCU) can be considered successful alternate DHR systems. The EPU condition delays the time after shutdown when FPC or RWCU may be used as an alternative to Shutdown Cooling (SDC). However, shutdown risk is dominated during the early time frame soon after shutdown when the decay heat level is high and, in this time frame, FPC and RWCU are already not viable DHR systems. Therefore, the impact of the EPU on the FPC and RWCU success criteria has a negligible risk impact.

Other success criteria are marginally impacted by the EPU. The EPU has a minor impact on shutdown RPV inventory makeup requirements because of the low makeup requirements associated with the low decay heat level. The heat load to the suppression pool is also lower because of the low decay heat level such that the margins for suppression pool cooling capacity are adequate for the EPU condition.

The EPU impact on the success criteria for blowdown loads, RPV overpressure margin, and SRV actuation is estimated to be negligible because of the low RPV pressure and low decay heat level during shutdown.

4.6.3 Shutdown HRA Impact

Similar to the at-power Level 1 PSA, the decreased boildown time due to the EPU decreases the time available for operator actions. The significant, time critical operator actions impacted in the at-power Level 1 PSA are related to RPV depressurization, SLC injection, and SLC level control. These operator actions do not directly apply to

shutdown conditions because the RPV is at low pressure and the reactor is subcritical. The risk significant operator actions during shutdown conditions include recovering a failed DHR system or initiating alternate DHR systems. However, the longer boildown times during shutdown results in the EPU having a minor impact on the shutdown HEPs associated with recovering or initiating DHR systems.

The calculations in Appendix B of this assessment show that the times available to perform loss of decay heat removal response actions during shutdown is many hours. The reductions in these times due to the EPU is shown in Appendix B to be in the range of 1 to 3% (depending on time after shutdown and water level configuration). Such small changes in already lengthy operator action response times result in negligible changes in human error probabilities.

4.6.4 Shutdown Risk Summary

Based on a review of the potential impacts on initiating events, success criteria, and HRA, the 15% EPU is assessed to have a negligible impact (delta CDF <1%) on shutdown risk.

4.7 RADIONUCLIDE RELEASE (LEVEL 2 PSA)

The Level 2 PSA calculates the containment response under postulated severe accident conditions and provides an assessment of the containment adequacy. In the process of modeling severe accidents (i.e., the MAAP code), the complex plant structure has been reduced to a simplified mathematical model which uses basic thermal hydraulic principles and experimentally derived correlations to calculate the radionuclide release timing and magnitude. [9] Changes in plant response due to EPU represent relatively small changes to the overall challenge to containment under severe accident conditions.

The following aspects of the Level 2 analysis are briefly discussed:

- Level 1 input
- Accident Progression
- Human Reliability Analysis
- Success Criteria
- Containment Capability
- Radionuclide Release Magnitude and Timing

Level 1 Input

The formulation of a typical Probabilistic Safety Assessment (PSA) has three general phases:

- Front-end evaluation (Level 1)
- Back-end or containment response and source term evaluation (Level 2/LERF)
- Ex-plant public risk evaluation (Level 3).

The front-end evaluation (Level 1) involves the assessment of those scenarios that could lead to core damage. The subsequent treatment of mitigative actions and the inter-relationship with the containment after core damage is then treated in the Containment Event Tree (Level 2/LERF).

An offsite plant consequence analysis can also be performed within the PSA structure (Level 3) to determine the impact on public safety. This portion of a PSA was not required as part of the IPE process nor the application criteria from Regulatory Guide 1.174 or the PSA Applications Guide.

One link between the BNP Level 1 PSA accident sequences and the Level 2 occurs in the definition of the Level 1 end states. The definition of the end states is developed to transfer the maximum amount of information regarding the accident sequence characteristics to the CET assessment. In the Brunswick Level 1 PSA, accident sequences are postulated that lead to core damage and potentially challenge containment. The Brunswick Level 1 PSA has identified discrete accident sequences that contribute to the core damage frequency and represent the spectrum of possible challenges to containment.

The Level 1 core damage sequence results (i.e., cutsets) are then combined into a discrete number (approximately 15) of unique accident class bins, defined based on similar functional characteristics and impacts on containment. The individual bins of core damage cutsets are transferred directly into Level 2 containment event trees.

Although the binning process of the Level 1 core damage results is unaffected by the EPU, the Level 1 accident class bin cutsets frequencies will be slightly different due to the few Level 1 modeling changes made to reflect EPU. Therefore, the Level 2 needs to be quantified to identify any change in release frequency.

To simplify the modeling requantification effort of this risk assessment, the BNP Level 2 pre-solved cutset results model is used to perform the Level 2 quantification. This does not create an issue with respect to neglecting possible transfers into the Level 2 of new cutsets. The Level 1 PSA model quantification that provided input to the existing Level 2 PSA cutset model was performed at a quantification truncation limit of 2E-9/yr. New Level 1 cutsets (if any) postulated to result from the minor changes for the EPU will be in the low to mid E-9 range frequency and will contribute minimally to the Level 2 results. The Level 1 EPU model changes generated 11 additional cutsets above the 2E-9/yr truncation limit compared with the base BNP PSA model. The 11 cutsets are all ATWS (Class IVA) type accident sequences. The 11 cutsets contribute 3.5E-8/yr to the Level 1 EPU

(approximately 0.1% of the overall EPU CDF), with he highest individual cutset contributing 4.1E-9/yr.

Accident Progression

As discussed earlier in Section 4.1.3, the EPU does not change the plant configuration and operation in a manner that produces new accident sequences or changes accident sequence progression phenomenon. This is particularly true in the case of the Level 2 post-core damage accident progression phenomena. The minor changes in decay heat levels and system configurations of the EPU will not impact significantly quantification and modeling of post-core damage accident progression.

Therefore, no changes are made as part of this assessment to the Level 2 models (either in structure or basic event phenomenon probabilities) with respect to accident progression modeling.

Human Reliability Analysis

Risk significant Level 2 operator actions are, in general, conditional repair and recovery actions given that the operator failed in the Level 1 time frame (e.g., fail to depressurize the RPV in Level 2 Containment Event Tree "OP" node, or fail to align alternate injection systems in Level 2 CET "RX" or "TD" nodes). Any changes in the conditional HEPs due to the power uprate (based on reduced time available) are judged to be small and would have a minor impact on the Level 2 quantification results.

Success Criteria

No changes in success criteria have been identified with regard to the Level 2 containment evaluation. The slight changes in accident progression timing and decay heat load has a minor or negligible impact on Level 2 PSA safety functions, such as

containment isolation, ex-vessel debris coolability and challenges to the ultimate containment strength. (Refer to Section 4.1.2.8 of this report). Therefore, no changes to Level 2 modeling with respect to success criteria are made as part of this analysis.

Containment Capability

As discussed in Section 4.1.7 earlier in this report, no issues have been identified with respect to the EPU that have any impact on the capacity of the BNP containment as analyzed in the PSA.

The BNP containment capacity with respect to severe accidents is analyzed in the PSA using plant specific structural analyses as well as information from industry studies and experiments. The BNP containment capacity is assessed in the Level 2 with respect to five major challenge categories [9]:

1) Pressure Induced Containment Challenge: Containment pressures may increase from normal operating pressure along a saturation curve to very high pressures (i.e., beyond 100 psi), during accidents involving:

   - Insufficient long term decay heat removal; and
   - Inadequate reactivity control and consequential inadequate containment heat removal.

2) Temperature Induced Containment Challenge: Containment temperatures can rise without substantial pressure increases if containment pressure control measures (e.g., venting) are available. In such cases, containment temperature may increase from 300°F to above 1000°F with the containment at less than design pressure during accidents involving core melt progression.

3) Combined Pressure and Temperature Induced Containment Challenge: Containment pressures and temperatures can both rise during a severe accident due to molten debris effects following RPV failure and subsequent core concrete interaction. For instance:

- Containment temperatures can rise from approximately 300°F at core melt initiation to above 1000°F in time frames on the order of 10 hours.
- Additionally, containment pressure can rise due to non-condensible gas generation and RPV blowdown in the range of 40 psig to 100 psig over this same time frame.

4) Containment Dynamic Loading: Postulated accident sequences cover a broad spectrum of events, including failure of the containment under degraded conditions for which the following may be present:

   - High suppression pool temperature with substantial continuous blowdown occurring (i.e., equivalent to greater than 6% power),

     or

   - High suppression pool water levels coupled with equivalent LOCA loads and the consequential hydrodynamic loads, or
   - Other energetic events, such as steam explosion.

5) Containment Isolation: Pre-existing leakage or failures to isolate large penetrations during a core damage event lead to large early releases in the BNP Level 2.

The minor changes to the plant from the EPU have no impact on the definition of these containment loading profiles or the likelihood of containment isolation failure. The slightly higher decay heat levels associated with the EPU will result in a minor reductions in times to reach loading challenges; however, the time frames are long (many hours) and a reduction of a few minutes in timing (e.g., 5-10 minutes in few hours, to 30 minutes in almost 24 hours) has a negligible (even non-quantifiable) impact on the Level 2 results.

For example, MAAP run BNP10 (refer to Appendix A of this report) performed in support of this analysis shows that the time to reach the DW mean ultimate failure pressure (as assessed in the BNP PSA) for a loss of all decay heat removal sequence is over 31 hours. Whether this time is 31 hours, or 30 hours, or 25 hours, has no quantifiable impact on the Level 2 results.

Release Magnitude and Timing

The following issues can substantially increase or decrease the ability to retain fission products or mitigate their release:

- Removal processes
- Containment failure modes
- Phenomenology
- Timing

Each of these issues is considered and analyzed in the BNP Level 2 PSA. [9]

The BNP Level 2 PSA is a "LERF model" that focuses on analysis of post-core damage accident sequences that can lead to "large early" releases of radionuclides. Calculation of the LERF Level 2 end state is consistent with PSA application guidelines such as the EPRI PSA Applications Guide and the NRC Regulatory Guide 1.174.

The "Early" timing threshold is defined in the BNP PSA as a release from secondary containment beginning at 0 to 6 hours after accident initiation. The 0-6 hour time frame is based upon experience data concerning non-nuclear offsite accident response and is conservatively (i.e., 0-4 hours is a justifiable "Early" range) assumed to include cases in which minimal offsite protection measures have been performed.

The "Large" magnitude threshold is defined in the BNP Level 2 PSA as greater than 10% release of CsI inventory in the core. This is based on past industry studies that show once the average release fraction of CsI falls below approximately 0.1, the mean number of prompt fatalities is very small, or zero, except for a few outliers that correspond to pessimistic assumptions.

This release categorization and bases is consistent with U.S. BWR PSA industry techniques.

The BNP plant changes for the EPU have no impact on the usage and appropriateness of this release categorization scheme. As discussed earlier, the change in Level 1 core damage results will however impact the frequency of the calculated LERF end state.

<u>Level 2 Impact Summary</u>

Based on the above discussion, the impact of the EPU on the BNP Level 2 PSA results, independent of the Level 1 analysis, is judged to be minor. The only change in the Level 2 is due to changes in the Level 1 cutset frequencies (due to the HEP changes discussed in Section 4.1.6) used as input to the Level 2 quantification. When integrated with the impacts of the power uprate on the Level 1 analysis, the calculated increase in LERF is expected to be similar in magnitude to the calculated increase in CDF.

Section 5
CONCLUSIONS

The Extended Power Uprate (EPU) for Brunswick has been reviewed to determine the net impact on the risk profile associated with Brunswick operation at an increase in power level to 2923 MWt. This examination involved the identification and review of both plant and procedural changes, plus changes to the risk spectrum due to changes in the plant response.

The change in plant response, procedures, hardware, and setpoints associated with the increase in power have been investigated using the Brunswick Unit 2 PSA; the 1992 IPEEE study for seismic, internal fires and other external events; and a qualitative evaluation of shutdown events. This section provides overall conclusions with respect to success criteria, the Level 1 PSA, the Level 2 PSA, internal fires, seismic events, internal flooding, and shutdown events. The review has indicated that small perturbations on individual inputs could be identified.

This section summarizes the risk impacts of the EPU implementation on the following areas:

- Level 1 Internal Events PSA
- Fire Induced Risk
- Seismic Induced Risk
- Internal Flooding Risk
- Shutdown Risk
- Level 2 PSA

In addition, the guidelines from the NRC (Regulatory Guide 1.174) are followed to assess the change in risk as characterized by core damage frequency (CDF) and Large Early Release Frequency (LERF) and to determine if the change in risk is anything but very low.

5.1 LEVEL 1 PSA

Qualitative engineering insights regarding the adequacy of procedures and systems to prevent postulated core damage scenarios are among the principal results of the Level 1 portion of the PSA. These insights deal with the adequacy of, or improvements to, Brunswick procedures or systems (frontline or support) to accomplish their safety mission of preventing core damage. The severe accident scenarios that have been identified in the Level 1 PSA have been reviewed and the relatively small perturbations due to power uprate do not affect the scenario development or the qualitative insights.

Table 5.1-1 provides a summary of the PSA model changes incorporated as a result of the power uprate evaluation. Table 5.1-1 provides the following information:

- Basic event identification designator associated with the modification
- Basic event probability in the current model
- Revised probability for EPU
- Contribution of individual PSA modifications to CDF increase
- Description of PSA change

The EPU is estimated to increase the Brunswick Unit 2 internal events PSA CDF from the base value of 2.55E-5/yr to 2.59E-5/yr, an increase of 4E-7 (1.6%).

The composition and comparative distribution of the EPU results remain unchanged with respect to the base BNP PSA. The top ten CDF cutsets (refer to Appendix D) remain exactly the same, both with respect to order and individual frequencies. Changes in the order and frequency of cutsets begin at the 13th cutset, where cutsets involving the ATWS level control HEPs begin to show up (such cutsets first appear at cutset #30 in the base PSA).

Refer to Figure 5.1-1 for a graphical comparison between the pre-EPU and EPU CDF and LERF results (examined by accident class contribution)[1]. Note that the minor shift in the risk profile is in the increase in Class IV (ATWS) accidents. This is expected, given that the only explicit model changes found to be justified to model the EPU are to ATWS operator action HEPs.

5.2 FIRE INDUCED RISK

Based on the results of the internal events PSA evaluation for a 15% power uprate and a review of the BNP IPEEE, it is concluded that the effects on any increase in risk contribution associated with fire induced sequences is negligible, 1% or less change in CDF (refer to Section 4.3 of this report). A negligible change in the CDF due to fire is assessed to result from the implementation of the EPU.

5.3 SEISMIC RISK

Based on a review of the Brunswick IPEEE, the conclusions of the BNP seismic margins assessment (SMA) are judged to be unaffected by the EPU. The power uprate has little or no impact on the seismic qualifications of the systems, structures and components (SSCs). Specifically, the power uprate results in additional thermal energy stored in the RPV, but the additional blowdown loads on the RPV and containment given a coincident seismic event, are judged not to alter the results of the SMA. Refer to Section 4.4 of this report for further discussion.

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[1] The BNP PSA core damage accident classes shown in Figure 5.1.1 are the following (refer to the BNP Level 2 PSA for further core damage accident class discussions):

IA:	Loss of RPV coolant makeup with the RPV at high pressure
IBE:	SBO scenario with loss of RPV coolant makeup ("early" core damage)
IBL:	SBO scenario with loss of RPV coolant makeup ("late" core damage)
ID:	Loss of RPV coolant makeup with the RPV at low pressure
IIA:	Loss of containment heat removal with the RPV initially intact, core damage occurs post containment failure
IVA:	Unmitigated ATWS scenario with the RPV initially intact, core damage occurs post containment failure
IVL:	Unmitigated ATWS scenario with the RPV initially breached, core damage occurs post containment failure
V:	Unisolated LOCA outside containment

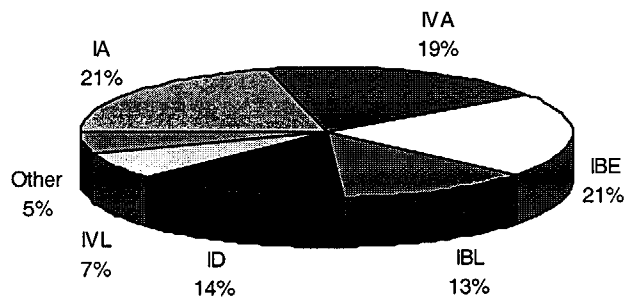
Table 5.1-1

BRUNSWICK PSA MODEL CHANGES TO REFLECT EPU PLANT CONFIGURATION

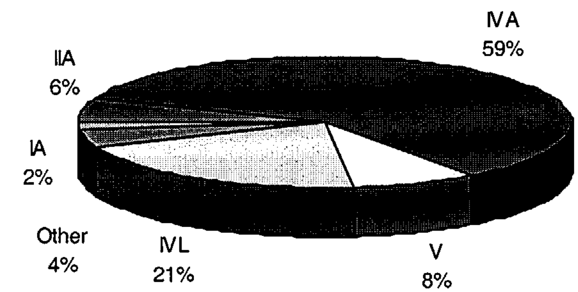
Description	Basic Event ID	Base Prob.	EPU Prob.	Contribution to CDF Increase	Comment
Operator Fails to Control Lowered Water Level with HPCI During ATWS	OPER-LLEVEL1	1.30E-02	3.10E-02	0%	Reduced available action timing due to the EPU increases HEP (refer to Table 4.1-8 and Appendix E). The individual independent ATWS level control HEPs do not appear in the Level 1 cutset results, resulting in zero impact on the CDF.
Operator Fails to Control Lowered Water Level with RCIC During ATWS	OPER-LLEVEL2	9.10E-03	1.90E-02	0%	Reduced available action timing due to the EPU increases HEP (refer to Table 4.1-8 and Appendix E). The individual independent ATWS level control HEPs do not appear in the Level 1 cutset results, resulting in zero impact on the CDF.
COMBINATION HEP: Operator Fails to Control Lowered Water Level with RCIC During ATWS AND Fails to Preclude Boron Washout During Low Pressure Injection	XOP-COM2-15	4.80E-03	1.00E-02	1.1%	Reduced available action timing due to the EPU increases the HEP of this dependent multiple operator action event (refer to Table 4.1-8 and Appendix E).
COMBINATION HEP: Operator Fails to Control Lowered Water Level with HPCI During ATWS AND Fails to Preclude Boron Washout During Low Pressure Injection	XOP-COM2-14	7.00E-03	1.60E-02	0.5%	Reduced available action timing due to the EPU increases the HEP of this dependent multiple operator action event (refer to Table 4.1-8 and Appendix E).

Figure 5.1-1
GRAPHICAL COMPARISON OF EPU BNP PSA RESULTS

PRE-EPU

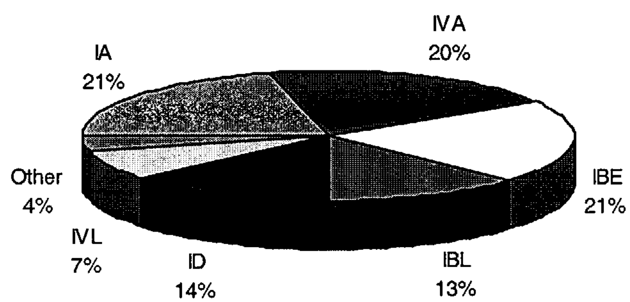


CDF by Accident Class
(2.55E-5/yr)

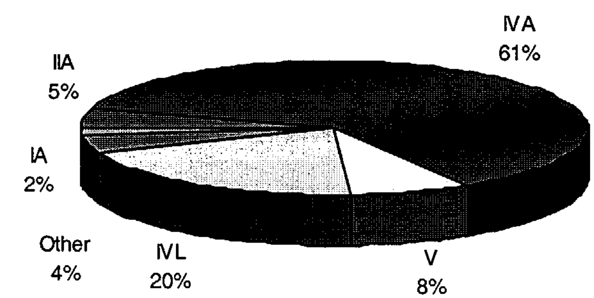


LERF by Accident Class
(4.27E-6/yr)

EPU



CDF by Accident Class
(2.59E-5/yr)



LERF by Accident Class
(4.46E-6/yr)

5.4 OTHER EXTERNAL HAZARDS

Based on review of the Brunswick IPEEE, the power uprate has no significant impact on the plant risk profile associated with tornadoes, hurricanes, transportation accident, and other external hazards. These elements of the BNP PSA risk profile are already conservatively calculated, and the EPU will not quantifiably impact these conservative calculations. In addition, these external hazards are dominated by long term core damage scenarios which are negligibly impacted by the EPU. Refer to Section 4.5 of this report for further discussion.

5.5 SHUTDOWN RISK

The impact of the Extended Power Uprate (EPU) on shutdown risk is similar to the impact on the at-power Level 1 PSA. Shutdown risk is affected by the increase in decay heat power. However, the lower power operating conditions during shutdown (e.g., lower decay heat level, lower RPV pressure) allow for additional margin for mitigation systems and operator actions. Based on a review of the potential impacts on initiating events, success criteria, and HRA, the EPU implementation is judged to have a minor impact (delta CDF <1%) on shutdown risk. Refer to Section 4.6 and Appendix B of this report for further discussion.

5.6 LEVEL 2 PSA

The Level 2 PSA calculates the containment response under postulated severe accident conditions and provides an assessment of the containment adequacy. The EPU change in power represents a relatively small change to the overall challenge to containment under severe accident conditions.

The Level 2 PSA radionuclide release magnitudes for postulated sequences are binned or grouped together into categories in the same manner as in the original NRC Reactor Safety Study, WASH-1400, and the update NUREG-1150. These bins tend to group

together releases that may be an order of magnitude different. Therefore, EPU differences will not result (in general) in moving the calculated releases from one category to another. In conclusion, the probabilistic evaluation of radionuclide release and the associated frequency can be modified slightly by the power up-rating. However, this increase is very small relative to uncertainties[1] and the absolute magnitude of the release.

Based on the changes to the Level 1 model as input to the Level 2, the at-power internal events LERF increased from the base value of 4.27E-6/yr[2] to 4.46E-6/yr, an increase of 1.9E-7 (4.5%). (Refer Table 5.1-1 and Figure 5.1-1.)

5.7 QUANTITATIVE BOUNDS ON RISK CHANGE

5.7.1 Sensitivity Studies

As discussed in the previous sections, the best estimate change in the BNP risk profile due to the EPU is a 1.6% increase in CDF and a 4.5% increase in LERF. One of the methods to provide valuable input into the decision-making process is to perform sensitivity calculations for situations with different assumed conditions to bound the results. This section describes:

- Sensitivity cases performed
- Process used for sensitivity evaluations
- Results of the sensitivity evaluations

(1) Changes in the code evaluation and modeling parameters of fission product mitigation or subtle sequence variations may alter the release magnitude (positive or negative) by more than that attributable to the power up-rating.

(2) Changes to the base Level 2 basic event data base file were identified during the Level 2 EPU quantification. These changes resulted in increasing the base Level 2 LERF value from 3.69E-6/yr to 4.27E-6/yr. Based on the modified Level 2 LERF results, the ATWS (Class IVA) conditional LERF probability increased form 0.453 to 0.513.

These sensitivity studies investigate the impact on the at-power internal events CDF and LERF.

5.7.1.1 Sensitivity Cases Performed

In addition to the base quantification, the following sensitivity cases were performed:

- Sensitivity #1: Base EPU w/Turbine Trip Initiating Event Frequency Increased 10%
- Sensitivity #2: Base EPU w/Probability of Operator Failure to Maintain FW Post-Trip Increased by Factor of 2.
- Sensitivity #3: Base EPU w/Revised SLC Success Criteria
- Sensitivity #4: Base EPU w/o Credit for Crosstie Injection during ATWS
- Sensitivity #5: Base EPU w/Sensitivity Cases #1, #2, and #4
- Sensitivity #6: Base EPU w/Sensitivity Cases #1, #2, #3, and #4

<u>Sensitivity #1</u>

This sensitivity case addresses the issue regarding whether or not the changes to the BOP side of the plant in support of the EPU will have a significant impact on plant trip frequency. The base quantification assumes no impact. In this sensitivity case the base Turbine Trip initiating event frequency is increased by 10%.

<u>Sensitivity #2</u>

One of the plant operational changes to support the EPU is an increase in Feedwater flow. This sensitivity case addresses the issue regarding whether or not this increase in FW flow will have a significant impact on the conditional probability of FW trip (following plant trip) due to the operators failing to control level. The base quantification assumes

no impact. In this sensitivity case the probability of failing to control FW post plant trip (resulting in FW trip on high level) is increased by a factor of 2.

Sensitivity #3

At the start of this assessment, the required SLC success criteria for the EPU condition was assumed (i.e., no decision had yet been made at the plant) to remain at 2 pumps and 2 explosive valves (the success criteria in the existing BNP PSA) to meet 10CFR50.62 ATWS requirements. However, an option to pursue further analyses and system modifications that would result in the requirement of a single SLC pump and valve was being considered at the plant during the final stages of this risk assessment. As such, the base risk assessment assumes BNP will eliminate the SLC heat tracing but will maintain the requirement for 2 of 2 SLC pumps and squib valves for injection. This sensitivity case addresses the impact of the single SLC pump and squib valve success criterion on the plant risk profile.

Sensitivity #4

The BNP PSA currently credits fire waters and service water crosstie for level-power control during ATWS scenarios. As no detailed analyses regarding available timings and flow rates are available to verify the adequacy of this success criteria for the EPU condition, this sensitivity case removes this credit from the ATWS sequence models.

Sensitivity #5

This sensitivity case tests the impact on the plant risk profile of the combined modeling modifications of sensitivity cases #1, #2, and #4. Sensitivity #3 is not included here as the risk reduction impact of the single train SLC success criteria will mask the impact of these other three issues.

Sensitivity #6

This sensitivity case tests the impact on the plant risk profile of the combined modeling modifications of sensitivity cases #1 - #4. This case is quantified to illustrate the risk reduction benefit of a single train SLC success criterion, even when modeling the pessimistic assumption of the other three sensitivity items.

5.7.1.2 Sensitivity Approaches

This subsection summarizes the modeling details of each of the sensitivity cases.

Sensitivity #1

The base BNP PSA and the base EPU quantification in this risk assessment use a Turbine trip initiating event, %T(T), frequency of 2.70/year. The BNP EPU is associated with a number of plant modifications to the BOP which are judged to have no risk impact on the plant as modeled in the PSA. Although equipment reliability can be theoretically postulated to behave as a "bathtub" curve (i.e., the beginning and the end of life phases being associated with higher failure rates than the steady-state period), no significant impact on the long-term average of the transient initiating event frequency is assumed in the base quantification due to the BOP modifications.

Postulating a "bathtub curve" impact on the Turbine Trip frequency, the change in the long-term average of the Turbine Trip frequency is calculated as follows for this sensitivity case:

- Base long-term %T(T) frequency is 2.70/yr
- 10 years is used as the "long-term" data period
- End of 10 years does not reach the end-of-life portion of the bathtub curve

- Model beginning-of-life portion of bathtub curve by assuming 2 additional turbine trips the first year and 1 additional turbine trip the second year

- Revised %T(T) frequency for this sensitivity case is calculated as:

$$\%T(T)_{NEW} = \frac{(10 \times 2.7) + 2 + 1}{10} = 3.0/yr$$

This sensitivity case was quantified using the pre-solved cutset models (i.e., the CDF cutset model and the LERF cutset model) and editing the %T(T) value from 2.70 to 3.00.

Sensitivity #2

The BNP PSA models the possibility of tripping FW on high level post plant trip due to operator error in controlling level. This event is modeled with basic event OPER-FWSCNT.

The base BNP PSA calculates the probability of OPER-FWSCNT based on review of BNP experience. Of 38 initiating events studied, none involved loss of FW due to failure of the operators to control level. The base probability was calculated by assuming 1 event in 38 (0.026) and rounding up to 0.03.

This sensitivity case conservatively doubles the base value to 6E-2. This case was quantified using the pre-solved cutset models (i.e., the CDF cutset model and the LERF cutset model) and editing the OPER-FWSCNT value from 3E-2 to 6E-2.

Sensitivity #3

The current BNP PSA models SLC with a two pump and two squib valve success criteria. The SLC pumps are modeled under OR gate SLC2G-PUMPS, and the squib valves are modeled under OR gate SLC2G-EXPLV.

In this sensitivity case the following model modifications were made to model the impact of moving to a single SLC train requirement:

- Fault tree gate SLC2G-EXPLV changed from an OR gate to an AND gate
- Gate SLC2G-PUMPS changed from an OR gate to an AND gate
- Existing basic event SLC2XHE-TMF01617 moved from under fault tree gate SLC2G-PUMPS to directly under gate SLC2G-EXPLV1
- New common cause failure basic events for pumps FTR and FTS, and squib valves FTO added under gate SLC2G-EXPLV1

The new common cause failure basic events were added to account for the fact that 2 pumps (or two squib valves) must fail in this sensitivity case, creating the need to model the possibility of dependent (common cause) failure events for the pumps and squib valves. These components are typically the dominant CCF contributors at other plants. Other CCF events (e.g., relief valves, I&C, etc.) are not considered in this sensitivity case.

The SLC pump common cause event probabilities were calculated using the existing random failure probabilities in the PSA and generic CCF parameter values from the INEEL CCF database. [23]

- CCF of SLC Pumps to Start (SLC2MDP-FS-PMPAB)

  (3.70E-3)(0.142) = 5.25E-4

- CCF of SLC Pumps to Run (SLC2MDP-FR-PMPAB)
  (2.60E-2)(3.4E-2) = 8.84E-4

The common cause failure of the squib valves (event SLC2EPV-CC-F04AB) is based on review of industry events. Operating experience related to squib valve operability indicates, at a minimum, the following potential common cause failures:

- Mis-wiring
- Fuse failure

Each of these has occurred in the BWR industry.

Vermont Yankee 1986 SLC Event (NPE B.07. B.0060): During a Standby Liquid Control system surveillance test during the 1986 refueling outage the squib valve being tested failed to fire. Further investigation revealed that the SLC squib valves were mis-wired in the terminal box and primer charge assembly connector. The duration of this event is assumed to be from the previous firing of the other division squib valve, 18 months earlier.

Monticello 1986 SLC Event: During refueling outage LC surveillance testing of the System 2 squib valve and demonstration of injection flow path, System 2 was initiated and the System 2 pump tripped after approximately 1 1/2 minutes. SLC System 1 was then tested. Investigation revealed that the control power transformer fuse was blown. The root cause was believed to be a fuse coordination problem as the investigation revealed disparities between the System 1 and 2 control power and squib detonation fuses. The squib valve detonators likely shorted during the testing or during meter relay re-wiring. Some meter relay re-wiring work was performed on the system 13 days prior to this event. From information given in the LER it cannot be determined whether the re-wiring work performed was the probable cause of shorting the squib valve detonators. If this is not the cause of the shorts it is construed that the shorting

occurred during the test firing of the squib valve. In either case the squib valve detonator short caused the System 2 SLC pump control power fuse to blow.

The LER did not determine when the wrong control power fuses were installed in the SLC pump. They may have been installed approximately 13 days earlier following the re-wiring work; or the improperly sized control power fuse may have been installed for one fuel cycle--assuming that was the last time SLC System 2 was required to demonstrate flow path integrity. If only one SLC division is required to be tested during each refueling outage, it can be assumed that the improperly sized fuse was installed for two fuel cycles.

Cooper 1976 SLC Event: This event is similar to Monticello event--system wiring error. Improperly sized fuses - "A" SBLC system inoperable October 1976 refueling outage. See NRCIE circular No. 77-09 and General Electric SIL No. 236.

The durations of the identified SLC events are estimated as follows:

	Minimum Estimate	Maximum Estimate
Vermont Yankee	1.0 year	3.0 years
Monticello	13 days*	3.0 years**
Cooper	1.0 year	3.0 years**
Total	2.036 years	9.0 years

* Assuming the improperly sized fuse was installed following meter relaying rewiring.

** Assuming the squib valve from only one division is tested during a refueling outage and the fuel cycle is 18 months in duration.

BWR Operating years through 1990 = 394 years.

Minimum Unavailability = 2.036/394 = 0.005

Maximum Unavailability = 9.0 years/394 years = .023

SLC Squib valve common cause unavailability is estimated at between 0.005 and 0.023. Current generic information with rectification included at specific plants would represent a best estimate unavailability of 0.014. [26]

After performing the SLC fault tree modifications described above, this sensitivity case was quantified using the BNP Level 1 linked single-top fault tree model to calculate the change in CDF. The LERF change was calculated by multiplying the delta CDF by the 0.514 conditional LERF multiplier for ATWS scenarios from the base BNP PSA.

Sensitivity #4

In the base BNP PSA gate #V is credited during ATWS events for level control. Gate #V is an AND gate of the following systems:

- CS/LPCI (gate #V-LP)
- Condensate (gate #V1)
- Fire Water/Service Water via RHR (gate #V3)

The base BNP Level 1 fault tree was modified to replace gate #V in all ATWS scenarios with the new gate #V-ATWS. Gate #V-ATWS is an AND gate of the following existing subtrees:

- CS/LPCI (gate #V-LP)
- Condensate (gate #V1)

Specifically, gate #V was replaced with gate #V-ATWS for the following accident sequence logic gates:

- ~S2C1UV

- ~S2C1WV
- ~TC1P1UV
- ~TC1P1WV
- ~TC1QUV
- ~TC1QWV
- ~TC1UV
- ~TC1XV

After performing the above described fault tree logic modifications, this sensitivity case was quantified using the BNP Level 1 linked single-top fault tree models to calculated the change in CDF. As no change in CDF resulted, there was no need to perform a LERF quantification – it would also not change.

Sensitivity #5

All of the model modifications described earlier for cases #1, #2, and #4 were made collectively for this case. This case was then quantified using the BNP Level 1 linked single-top fault tree model to calculate the change in CDF. The change in LERF was calculated using the pre-solved LERF cutset model.

Sensitivity #6

All of the model modifications described earlier for cases #1, #2, #3, and #4 were made collectively for this case. This case was then quantified using the BNP Level 1 linked single-top fault tree model to calculate the change in CDF. The change in LERF was calculated by applying the ATWS LERF multiplier to the CDF difference between cases #5 and #6.

5.7.1.3 Sensitivity Results

The results of the six sensitivity cases performed in support of this risk assessment are summarized in Table 5.7-1.

From Table 5.7-1 it can be seen that the sensitivities that do not include the single train SLC modifications, whether taken individually or collectively, increase the base case EPU delta CDF by less than 5 additional percentage points, and the base case EPU delta LERF by less than 10 additional percentage points. The most significant increase results from assuming a 10% increase in the Turbine Trip initiating event frequency. The sensitivity case involving removal of the crosstie injection alternatives during ATWS scenarios has no impact on the results.

Once the single train SLC modification is factored in, the net change in the plant risk profile is a significant reduction (9% reduction in CDF and 28% reduction in LERF). Even when calculated along with the other pessimistic sensitivities, the reduction in LERF is still significant (-23%). This illustrates the benefit of a single train SLC success criterion to the BNP PSA calculated risk profile.

5.7.2 Results Summary

The key result of the PSA evaluation is the following:

> Small risk increases were calculated for both CDF and LERF. The risk increase is associated with reduced times available for certain operator actions (specifically, RPV level control operator actions during ATWS scenarios).

Table 5.7-1

BRUNSWICK PSA SENSITIVITY CASES IN SUPPORT OF EPU

Case	Description	CDF[5] (% delta)	LERF[1][6] (% delta)
Base	Base Level 1 Model (pre-EPU)	2.55E-05 (n/a)	4.27E-06 (n/a)
Base EPU	Base Level 1 EPU Model	2.59E-05 (1.6%)	4.46E-06 (4.5%)
Sensitivity #1	Base EPU with Turbine Trip IE increased by 10%	2.71E-05 (6.3%)	4.84E-06 (13.3%)
Sensitivity #2	Base EPU with probability for Operator Failure to Maintain FW Post Trip increased by factor of 2 (basic event OPER-FWSCNT)	2.62E-05 (2.6%)	4.46E-06 (4.5%)
Sensitivity #3	Base EPU with revised SBLC success criteria[2], [3]	2.32E-05 (-9.0%)	3.07E-06 (-28.1%)
Sensitivity #4	Base EPU wit no credit for alternate RPV Injection (FP/RHRSW) during ATWS	2.59E-05 (1.6%)	4.46E-06 (4.5%)
Sensitivity #5	Base EPU with Sensitivity #1, #2, and #4	2.73E-05 (6.9%)	4.84E-06 (13.3%)
Sensitivity #6	Base EPU with Sensitivity #1, #2, #3, and #4[2], [4]	2.43E-05 (-4.8%)	3.30E-06 (-22.7%)

Notes to Table 5.7.1:

(1) Includes LERF contribution of 3.49E-7/yr from ISLOCA (2.99E-7/yr) and excessive LOCA (5E-8/yr); although, LERF cutsets are not included in the attached cutset printouts.

(2) LERF calculated based on the fact that decrease in CDF only applies to Class IVA. Decrease in LERF estimated using Class IVA LERF multiplier of 0.514.

(3) LERF for Sensitivity #3 estimated based on decrease in CDF compared between Base EPU and Sensitivity #3.

(4) LERF for Sensitivity #6 estimated based on decrease in CDF compared between Sensitivity #5 and Sensitivity #6.

(5) The Level 1 (single top model) PSA truncation limit used was 2E-9/yr.

(6) The truncation limit for the base Level 2 PRAQuant sequence quantification ranged from 1E-10/yr to 1E-11/yr on a sequence-by-sequence basis.

The best estimate of the risk increase for at-power internal events due to the EPU is a delta CDF of 4E-7 (an increase of 1.6% over the base CDF of 2.55E-5/yr). The best estimate at-power internal events LERF increase due to the EPU is a delta LERF of 1.9E-7 (an increase of 4.5% over the base LERF of 4.27E-6/yr).

Using the NRC guidelines established in Regulatory Guide 1.174 and the calculated results from the Level 1 and 2 PSA, the best estimate for the CDF risk increase (4E-7/yr) is well within Region III (i.e., changes that represent very small risk changes). The best estimate for the LERF increase (1.9E-7/yr) is in Region II, but close to the Region III criteria. Region II is identified as changes that represent small risk changes. (See Figures 5.7-1 and 5.7-2.)

The best estimates for CDF and LERF also meet the PSA Applications Guide criteria for permanent plant changes (which for BNP are delta CDF of 19.2% and delta LERF of 16.4%).

If shutdown risk and external events are included, the total change in delta CDF due to the EPU is estimated to be on the order of 5%.

As a final note, at the time of the completion of this study BNP confirmed their decision to implement the SLC modifications that would result in requiring a single SLC pump and squib valve. This modification will result in a net decrease in the current BNP risk profile. As discussed in Section 5.7.1.3, this modification will result in a 9% reduction in the internal events CDF and a corresponding 28% reduction in LERF. This significant reduction is due to the fact that the current risk profile has a large contribution from ATWS scenarios.

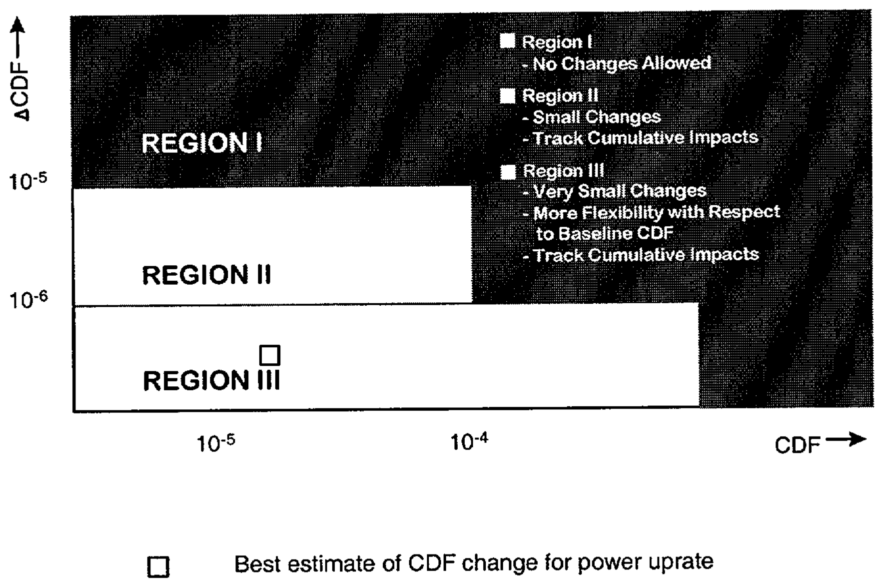


Figure 5.7-1 Acceptance Guidelines* for Core Damage Frequency (CDF) (Based on Brunswick Unit 2 Level 1 PSA for Internal Events)

* The analysis will be subject to increased technical review and management attention as indicated by the darkness of the shading of the figure. In the context of the integrated decision-making, the boundaries between regions should not be interpreted as being definitive; the numerical values associated with defining the regions in the figure are to be interpreted as indicative values only.

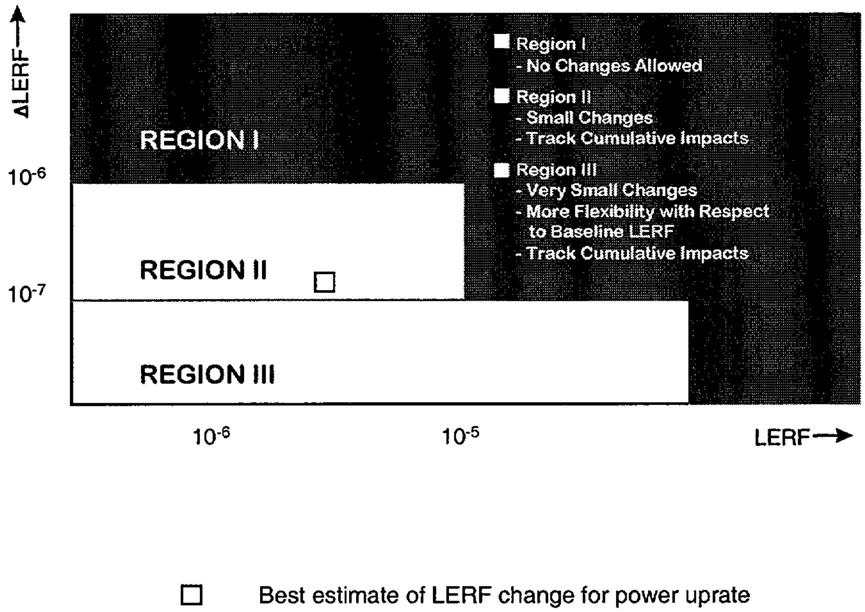


Figure 5.7-2 Acceptance Guidelines* for Large Early Release Frequency (LERF)
(Based on Brunswick Unit 2 Level 1 and 2 PSA for Internal Events)

* The analysis will be subject to increased technical review and management attention as indicated by the darkness of the shading of the figure. In the context of the integrated decision-making, the boundaries between regions should not be interpreted as being definitive; the numerical values associated with defining the regions in the figure are to be interpreted as indicative values only.

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