2.9 Source Terms and Radiological Consequences Analyses

2.9.1 Source Terms for Radwaste Systems Analyses

Regulatory Evaluation

Exelon reviewed the radioactive source term associated with EPU to ensure adequacy of the sources of radioactivity used by PBAPS as input to calculations that verify the radioactive waste management systems have adequate capacity for treating radioactive liquid and gaseous wastes. The review included the parameters used to determine: (1) concentration of each radionuclide in the reactor coolant; (2) fraction of fission product activity released to the reactor coolant; (3) concentrations of all radionuclides other than fission products in the reactor coolant; (4) leakage rates and associated fluid activity of all potentially radioactive water and steam systems; and (5) potential sources of radioactive materials in effluents not considered in the plant's UFSAR related to LWMSs and gaseous waste management systems. The regulatory acceptance criteria for source terms are based on: (1) 10 CFR 20, insofar as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas; (2) 10 CFR 50, Appendix I, insofar as it establishes numerical guides for design objectives and LCOs to meet the ALARA criterion; and (3) GDC-60, insofar as it requires the plant design include means to control the release of radioactive effluents.

Peach Bottom Current Licensing Basis

Current GDC-60 is applicable to PBAPS as described in the NRC SER for PBAPS Unit 2 and Unit 3 ODCM Amendments 102 and 104 (Reference 35), respectively.

The radioactive waste systems are described in PBAPS UFSAR Chapter 9, "Radioactive Waste Systems."

Technical Evaluation

NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," Class III, July 2003 (also referred to as CLTR) was approved by the NRC as an acceptable method for evaluating the effects of CPPUs. Sections 8.3 and 8.4 of the CLTR address the effect of CPPU on the Radiation Sources in the Reactor Core and in the Reactor Coolant. The results of this evaluation are described below.

2.9.1.1 Radiation Sources in the Reactor Core

As explicitly stated in Section 8.3 of the CLTR, the radiation sources in the core are directly related to the fission rate during power operation. These sources include radiation from the fission process, accumulated fission products and neutron reactions as a secondary result of fission. Historically, these sources have been defined in terms of energy or activity released per unit of reactor power.

However, because PBAPS uses GNF2 fuel and is not enveloped by the bounding analysis performed for the CLTR, the CLTR is not applicable for fuel design dependent evaluations. Thus, the methods and assumptions for the CLTR radiological evaluations are not applicable.

For the EPU at PBAPS, the radiological evaluation has been performed using the methods and assumptions outlined in ELTR1 (Reference 2).

A bounding analysis has been performed to envelop the radiation sources evaluation. The ELTR1 bounding parameters used for core radiation source calculations, and the corresponding PBAPS values, are:

ELTR1 Generic Parameter Requirement	PBAPS Corresponding Values
[[	EOC final core average exposure = 33.087 GWd/ST
	Initial bundle enrichment ranging from 3.8 to 4.2 %
]]	Bundle average power = 5.171 MWt/bundle and multi-batch irradiation to a 711 EFPD cycle length

As stated in Appendix H of ELTR1, plants not conforming to the generic parameters require a plant-specific evaluation. Therefore, a plant-specific evaluation is performed using the following parameters:

Parameter	PBAPS EPU Plant-Specific Evaluation Value
Core Power	3951 MWt
Initial Bundle Enrichment	Ranging from 3.8 to 4.2% U-235
End of Cycle Core Average Exposure	33.087 GWd/ST (applying multi-batch irradiation methodology to a 711 EFPD cycle length)
Fuel Design	GNF2

Total core radiation sources increase approximately proportional to the increase in reactor power.

The post-operation radiation sources in the core are primarily the result of accumulated fission products. Two separate forms of post-operation source data are normally applied. The first of these is the core gamma-ray source, which is used in shielding calculations for the core and for individual fuel bundles. This source term is defined in terms of MeV/sec per Watt of reactor thermal power (or equivalent) at various times after shutdown. The total gamma energy source, therefore, increases in proportion to reactor power.

The second set of post-operation source data consists primarily of nuclide activity inventories for fission products in the fuel. These data are needed for post-accident and SFP evaluations, which are performed in compliance with regulatory guidance that applies different release and transport assumptions to different fission products. The core fission product inventories for these evaluations are based on an assumed fuel irradiation time, which develops "equilibrium" activities in the fuel (typically 3 years). Most radiologically significant fission products reach equilibrium within a 60-day period. [[

]] The radionuclide inventories of the full core at EOC are calculated in terms of Curies per MWt. A bounding core inventory has also been generated to support the radiological accident dose consequence evaluations. This core inventory considers both the EOC and BOC (100 effective full power days of irradiation) inventories and the higher value of the two is conservatively selected for each radioisotope.

The calculated source terms resulting from this evaluation have been used in the radiological consequence evaluation of the transient analyses discussed in Section 2.9.2. In addition, they have been used to evaluate the plant radiation levels as discussed in Section 2.10.1.2. The results are also used in EQ evaluations discussed in Section 2.3.1.

2.9.1.2 Radiation Sources in Reactor Coolant

For coolant activation products, the typical margin in the plant design basis for reactor coolant concentrations significantly exceeds the potential increases due to power uprate and needs to be verified. Also, because the transport time from core exit to downstream points will decrease with increased flow from EPU, the resultant dose rates in the MSLs, turbines, and condenser area will increase roughly proportional to power uprate. In the case of activated corrosion products and fission products, plant-specific analysis is required by the CLTR to verify that the corrosion product concentrations do not exceed the design basis concentrations.

Tables 2.9-1 through 2.9-4 contain the activity levels, concentrations, and release rates for these radiation sources for PBAPS. The topics addressed in this evaluation are:

Topic	CLTR Disposition	PBAPS Result
Coolant activation products	[[	Tables 2.9-2
Activated corrosion products and fission products	]]	Tables 2.9-1 through 2.9-4

2.9.1.2.1 *Coolant Activation Products*

The CLTR, Section 8.4.1, states that increases in reactor power will increase the activity of activation products found in reactor coolant. During reactor operation, the coolant passing through the core region becomes radioactive as a result of nuclear reactions. The coolant activation, especially N-16 activity, is the dominant source in the turbine building and in the lower regions of the DW. The activation of the water in the core region is in approximate proportion to the increase in thermal power. [[

]] Therefore, no change is required in the activation design basis reactor coolant concentrations for EPU and all CLTR dispositions are met for coolant activation products.

2.9.1.2.2 *Activated Corrosion Products and Fission Products*

The CLTR, Section 8.4.1, states that increases in reactor power will increase the activity of corrosion products and fission products found in reactor coolant. The reactor coolant contains activated corrosion products, which are the result of metallic materials entering the water and being activated in the reactor region. Under EPU conditions, the FW flow increases with power and the activation rate in the reactor region increases with power. The net result is an increase in the activated corrosion product present in the coolant.

Fission products in the reactor coolant are separable into the products in the steam and the products in the reactor water. The activity in the steam consists of noble gases released from the core plus carryover activity from the reactor water. This activity is the noble gas offgas that is included in the plant design. The calculated offgas concentrations at 30 minutes of decay for EPU are 3.5E-02 Curies/sec, within the original design basis of 3.5E-01 Curies/sec, per Table 2.9-1. Therefore, no change is required in the design basis for offgas activity for EPU.

The fission product activity in the reactor water, like the activity in the steam, is the result of normal fuel corrosion products. EPU fission product activity levels in the reactor water remain a fraction (2%) of the design basis fission product activity, per Table 2.9-1.

The total reactor water activated corrosion product activity was calculated to be a fraction (63%) of the design basis levels, as seen in Table 2.9-1. Therefore, the activated corrosion product and fission product activities design bases for PBAPS are unchanged for EPU.

For EPU, normal radiation sources are expected to increase slightly. Shielding aspects of the plant were conservatively designed for total normal radiation sources. Thus, the increase in radiation sources does not affect radiation zoning or shielding and plant radiation area procedural controls will compensate for increased normal radiation sources. Therefore, activated corrosion and fission products meet all CLTR dispositions.

Conclusion

The radioactive source term associated with the proposed EPU has been reviewed. Exelon concludes the proposed parameters and resultant composition and quantity of radionuclides are

appropriate for evaluating the radioactive waste management systems. Exelon further concludes the proposed radioactive source term meets the requirements of 10 CFR 20, 10 CFR 50, Appendix I, and the current licensing basis. Therefore, Exelon finds the proposed EPU acceptable with respect to source terms.

2.9.2 Radiological Consequences Analyses Using Alternative Source Terms

Regulatory Evaluation

Exelon has reviewed the DBA radiological consequences analyses. The radiological consequences analyses reviewed are the LOCA, FHA, CRDA, and MSLBA. The review for each accident analysis included: (1) the sequence of events; and (2) models, assumptions, and values of parameter inputs used for calculating the TEDE. The regulatory acceptance criteria for radiological consequences analyses using an alternative source term are based on: (1) 10 CFR 50.67, insofar as it sets standards for radiological consequences of a postulated accident; and (2) GDC-19, insofar as it requires adequate radiation protection be provided to permit access and occupancy of the CR under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE, as defined in 10 CFR 50.2, for the duration of the accident.

Peach Bottom Current Licensing Basis

AST was approved at PBAPS as described in the NRC SER for PBAPS Unit 2 and Unit 3 AST License Amendments 269 and 273 (Reference 50), respectively. Current GDC-19 in 10 CFR 50 Appendix A states that holders of operating licenses using an AST shall meet the requirements of current GDC-19. Therefore, current GDC-19 is applicable to PBAPS.

Radiological consequences associated with potential PBAPS accidents are addressed in PBAPS UFSAR Section 14.9, "Evaluations Using AEC Method."

Technical Evaluation

In accordance with current licensing basis documented in PBAPS UFSAR Chapter 14.9, dose consequences are evaluated for the following events.

- UFSAR Section 14.9.2.1 – LOCA
- UFSAR Section 14.9.2.2 –FHA
- UFSAR Section 14.9.2.3 –MSLBA
- UFSAR Section 14.9.2.4 – CRDA

The magnitude of radiological consequences of a DBA is proportional to the quantity of radioactivity released to the environment. This quantity is a function of the fission products released from the core as well as the transport mechanism between the core and the release point.

The effect of the proposed EPU on the radiological consequences of the LOCA, FHA, CRDA, and the MSLBA is based on an assessment of the impact of EPU changes on the dose consequence analyses that were evaluated by the NRC in Units 2 and 3 License Amendments 269 and 273 (Reference 50), which approved a full-scope implementation of an AST that

complies with the guidance given in RG 1.183 (Reference 57) and 10 CFR 50.67. The referenced amendments are based on 3,528 MWt (corresponding to the CLTP power level of 3,514 MWt with a 0.4% ECCS evaluation uncertainty factor applied). The EPU DBA analyses are performed for 102% of the EPU power level of 3,951 MWt, which is 4,030 MWt.

The LOCA, FHA, CRDA, and MSLBA were assessed for the EPU reactor operating domain (i.e., the EPU core power level with ECCS evaluation uncertainty factor applied, and other parameter changes that would be impacted by EPU operations) to confirm that the EPU doses remained within regulatory limits.

Loss of Coolant Accident

The post-LOCA doses at the exclusion area boundary (EAB), low population zone (LPZ), CR, and TSC were analyzed for EPU conditions. The analysis was performed based on plant operation at 102% of the EPU power level of 3,951 MWt. The EPU core inventory was used. The analysis methods were not changed from those used in License Amendments 269 and 273 (Reference 50). All design inputs and assumptions are the same as those in License Amendments 269 and 273 except for the design inputs related to EPU, MSIV leakage rates, and the elemental iodine removal efficiencies.

The MSIV failed line leakage is reduced from 205 to 150 scfh, and the total MSIV leakage is reduced from 360 to 300 scfh, to create CR dose margin for the EPU and for future operation of the plant including life extension. The reduction in the MSIV leakage increased the residence time of the steam in the MSLs, and consequently increased aerosol deposition in the MSLs.

The elemental iodine removal efficiencies are reestablished using the J.E. Cline methodology using the steam line temperature per RG 1.183, Appendix A, Section 6.3 (Reference 57). The resulting elemental iodine removal efficiencies are considerably reduced compared to those used in the CLTP LOCA analysis based on the AEB 98-03 methodology.

The reduction in the containment and MSIV leakages due to reduced containment pressure are no longer credited after 38 hours. These leakages remain constant for 720 hours.

The revised design inputs were confirmed to remain applicable or minimally impacted for EPU conditions.

The suppression pool pH response is impacted by a modification to the SLCS in conjunction with the EPU which includes utilization of enriched boron-10. The final SLC system design will deliver sufficient sodium pentaborate to the DW suppression pool liquid to maintain a pH greater than 7.0 thirty days post-LOCA taking into consideration increased acid production due to EPU radiation environments.

The EPU post-LOCA EAB, LPZ, CR, and TSC doses were determined to be within the applicable regulatory limits. The results and regulatory criteria are summarized in Table 2.9-5.

Fuel Handling Accident

The post-FHA EAB, LPZ, and CR doses were analyzed for EPU conditions. The analysis was performed based on plant operation at 102% of the EPU power level of 3,951 MWt. The EPU core inventory was used. The analysis methods were not changed from those used in License Amendments 269 and 273 (Reference 50). The updated design inputs were confirmed to remain applicable or minimally impacted for EPU conditions. The 172 failed fuel pins is unchanged, but the CLTP models 87.33 fuel pins per GE12 or GE14 fuel bundle, and the EPU analysis models 85.6 fuel pins per a GNF2 fuel bundle thereby increasing the number of damaged fuel bundles from the CLTP quantity of 1.97 failed fuel bundles to the EPU quantity of 2.009 failed fuel bundles in the core of 764 fuel assemblies.

The EPU post-FHA EAB and CR doses were determined to be within the applicable regulatory limits. The results and regulatory criteria are summarized in Table 2.9-6.

Control Rod Drop Accident

The post-CRDA EAB, LPZ, and CR doses were analyzed for EPU conditions. The analysis was performed based on plant operation at 102% of the EPU power level of 3,951 MWt. The EPU core inventory was used. The analysis methods were not changed from those used in License Amendments 269 and 273 (Reference 50). The updated design inputs were confirmed to remain applicable or minimally impacted for EPU conditions. The amount of fuel melt associated with the CRDA has been increased from the CLTP modeled value of 0.77% to the EPU modeled value of 5.0% for conservatism only.

The EPU post-CRDA EAB, LPZ, and CR doses were determined to be within the applicable regulatory limits. The results and regulatory criteria are summarized in Table 2.9-7.

Main Steam Line Break Accident

As discussed in the UFSAR Section 14.9.2.3, the MSLBA is based on reactor coolant and steam releases assuming maximum iodine spiking permitted by the plant TSs. The coolant and steam mass release information for CLTP was based on the proposed MSIV closure time of 10.5 seconds, which was not implemented. The release over the 5.5 second MSIV closure time will be significantly less than the 10.5 second current licensing basis mass release. For added conservatism, the 10.5 second current licensing basis mass releases are proportionately increased based on the change in the power levels with the EPU. Therefore, the MSLB accident is conservatively analyzed using coolant mass of 219,558 lbs and assuming that all iodine activity in the coolant mass is released to the environment in a single puff with the CR in a normal mode operation without MCREV system being credited. The methodology used complies with line-by-line regulatory requirements in RG 1.183, Appendix D (Reference 57) and accepted by the NRC in other AST license amendments. Consistent with the current analysis of record, because no fuel damage occurs during a MSLBA at PBAPS, the released activity is the maximum coolant activity allowed by the TSs. The iodine concentrations in the primary coolant are assumed corresponding to the maximum value of 4.0 μCi/gm Dose Equivalent I-131 (pre-accident iodine

spike) and a value of 0.2 μCi/gm Dose Equivalent I-131 equilibrium iodine activity for continued full power operation.

The EPU post-accident doses for the MSLBA were determined to be within the applicable regulatory limits. The results and regulatory criteria are summarized in Tables 2.9-8 and 2.9-9.

Post-LOCA Vital Area Mission Doses

An additional review of the doses associated with access to vital areas was conducted to determine the effect of EPU. The times required for transit to and work in vital areas are not changed with EPU.

Vital areas are defined in NUREG-0737, Item II.B.2, as those "which will or may require occupancy to permit an operator to aid in the mitigation of or recovery from an accident." Compliance to NUREG-0737, Item II.B.2, assures the shielding adequacy necessary to reduce the whole body (WB) dose (i.e., external dose) to an operator to perform the vital function in a given mission time to less than the allowable limit of 5 rem whole body dose.

Post-LOCA Vital Areas Requiring Continuous Occupancies

Control Room

The post-LOCA CR dose contributions from various radioactive sources are analyzed and listed in Table 2.9-5.

Technical Support Center (TSC)

The post-LOCA TSC dose contributions from various radioactive sources are analyzed and listed in Table 2.9-10.

Backup Counting Room (BCR)

Because the BCR and TSC are located in the same building at the different elevations, the post-LOCA TSC doses are conservatively applied to the BCR and listed in Table 2.9-10.

Post-LOCA Vital Areas Requiring Infrequent Occupancies

The vital areas requiring infrequent occupancies to perform the required vital functions are listed in Table 2.9-11, including the resulting doses. The radiation exposures to vital areas are calculated using the occupancy times determined based on the time-motion studies performed for the plant operating license. Projected WB doses for areas within Turbine Hall / Radwaste Building Complex, Operations Support Center (OSC) to CAD Building and TSC to refueling floor (EL-234') to exchange the radioactive effluent monitor cartridge (1 hour after a LOCA) and to maintain the spent fuel water level are expected to exceed the allowable dose limit of 5 rem because the CAD Building and reactor building refueling floor is not accessible during the early phase of the accident. The applicable plant procedures take complete control of the radiation exposure during vital functions by providing the RP coverage to perform radiation surveys, and determining occupancy and radiation protection requirements before the vital functions are performed to maintain the resulting WB exposure to ALARA and within the guideline value.

Conclusion

The Alternative Source Term accident analyses have been reviewed in support of the proposed EPU. Exelon concludes they adequately account for the effects of the proposed EPU. Exelon further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of postulated DBAs because, as set forth above, the calculated TEDE at the EAB, at the LPZ outer boundary, and in the CR meet the exposure guideline values specified in 10 CFR 50.67 and the current licensing basis. Therefore, Exelon has determined the Alternative Source Term License Amendment is acceptable with respect to the radiological consequences of DBAs following an EPU.

Table 2.9-1 Total Activity Levels

Item	Parameter	Unit	Calculated EPU Value	Design Basis Value	EPU to Design Basis Value Comparison
1	Activity concentrations of principal radionuclides in fluid streams for normal operation	μCi/g	Table 2.9-2	Tables 2.9-3, 2.9-4	Design basis values are bounding for EPU.
2	Total fission product offgas source term	μCi/sec, t = 30 min	3.5E+04	3.5E+05	Design basis values are bounding for EPU
3	Total fission product activity concentration in reactor water	μCi/g	1.5E-01	7.4E+00	Design basis values are bounding for EPU (2% of Design Basis)
4	Total activated corrosion product activity concentration in reactor water	μCi/g	4.4E-02	7.0E-02	Design basis values are bounding for EPU (63% of Design Basis)

Table 2.9-2 Activity Concentrations of Principal Radionuclides in Fluid Streams for Normal EPU Operation (Based on RWCU Flow equal to CLTP value of 133,000 lbm/hr)

Isotope	1.02 x EPU RTP Reactor Water (0.1% MCO)	1.02 x EPU RTP Reactor Steam (0.1% MCO)	1.02 x EPU RTP Reactor Water (0.3% MCO)	1.02 x EPU RTP Reactor Steam (0.3% MCO)
	µCi/g	µCi/g	µCi/g	µCi/g
Class 1				
Kr-83m		5.9E-04		5.9E-04
Kr-85m		1.0E-03		1.0E-03
Kr-85		4.0E-06		4.0E-06
Kr-87		3.3E-03		3.3E-03
Kr-88		3.3E-03		3.3E-03
Kr-89		2.1E-02		2.1E-02
Xe-131m		3.3E-06		3.3E-06
Xe-133m		4.9E-05		4.9E-05
Xe-133		1.4E-03		1.4E-03
Xe-135m		4.4E-03		4.4E-03
Xe-135		3.8E-03		3.8E-03
Xe-137		2.6E-02		2.6E-02
Xe-138		1.5E-02		1.5E-02
Class 2				
I-131	2.4E-03	4.7E-05	2.4E-03	5.2E-05
I-132	2.2E-02	4.4E-04	2.2E-02	4.8E-04
I-133	1.6E-02	3.2E-04	1.6E-02	3.5E-04
I-134	4.0E-02	8.0E-04	4.0E-02	8.7E-04
I-135	2.3E-02	4.6E-04	2.3E-02	5.0E-04
Class 3				
Rb-89	4.0E-03	4.0E-06	4.0E-03	1.2E-05
Cs-134	3.1E-05	3.1E-08	3.1E-05	9.2E-08
Cs-136	2.0E-05	2.0E-08	2.0E-05	6.1E-08
Cs-137	8.2E-05	8.2E-08	8.2E-05	2.5E-07
Cs-138	8.1E-03	8.1E-06	8.1E-03	2.4E-05
Ba-137m	8.2E-05	8.2E-08	8.2E-05	2.5E-07

Table 2.9-2 Activity Concentrations of Principal Radionuclides in Fluid Streams for Normal EPU Operation (Based on RWCU Flow equal to CLTP value of 133,000 lbm/hr) (continued)

Isotope	1.02 x EPU RTP Reactor Water (0.1% MCO)	1.02 x EPU RTP Reactor Steam (0.1% MCO)	1.02 x EPU RTP Reactor Water (0.3% MCO)	1.02 x EPU RTP Reactor Steam (0.3% MCO)
	µCi/g	µCi/g	µCi/g	µCi/g
Class 4				
N-16	4.8E+01	2.5E+02	4.8E+01	2.5E+02
Class 5				
H-3	1.0E-02	1.0E-02	1.0E-02	1.0E-02
Class 6				
Na-24	2.2E-03	2.2E-06	2.2E-03	6.5E-06
P-32	4.5E-05	4.5E-08	4.5E-05	1.4E-07
Cr-51	3.4E-03	3.4E-06	3.4E-03	1.0E-05
Mn-54	4.0E-05	4.0E-08	4.0E-05	1.2E-07
Mn-56	2.4E-02	2.4E-05	2.4E-02	7.1E-05
Fe-55	1.1E-03	1.1E-06	1.1E-03	3.4E-06
Fe-59	3.4E-05	3.4E-08	3.4E-05	1.0E-07
Co-58	1.1E-04	1.1E-07	1.1E-04	3.4E-07
Co-60	2.3E-04	2.3E-07	2.3E-04	6.8E-07
Ni-63	1.1E-06	1.1E-09	1.1E-06	3.4E-09
Cu-64	3.2E-03	3.2E-06	3.2E-03	9.6E-06
Zn-65	1.1E-04	1.1E-07	1.1E-04	3.4E-07
Sr-89	1.1E-04	1.1E-07	1.1E-04	3.4E-07
Sr-90	8.0E-06	8.0E-09	8.0E-06	2.4E-08
Y-90	8.0E-06	8.0E-09	8.0E-06	2.4E-08
Sr-91	4.2E-03	4.2E-06	4.2E-03	1.3E-05
Sr-92	9.5E-03	9.5E-06	9.5E-03	2.9E-05
Y-91	4.5E-05	4.5E-08	4.5E-05	1.4E-07
Y-92	5.9E-03	5.9E-06	5.9E-03	1.8E-05
Y-93	4.2E-03	4.2E-06	4.2E-03	1.3E-05
Zr-95	9.1E-06	9.1E-09	9.1E-06	2.7E-08
Nb-95	9.1E-06	9.1E-09	9.1E-06	2.7E-08
Mo-99	2.2E-03	2.2E-06	2.2E-03	6.7E-06

Table 2.9-2 Activity Concentrations of Principal Radionuclides in Fluid Streams for Normal EPU Operation (Based on RWCU Flow equal to CLTP value of 133,000 lbm/hr) (continued)

Isotope	1.02 x EPU RTP Reactor Water (0.1% MCO)	1.02 x EPU RTP Reactor Steam (0.1% MCO)	1.02 x EPU RTP Reactor Water (0.3% MCO)	1.02 x EPU RTP Reactor Steam (0.3% MCO)
	µCi/g	µCi/g	µCi/g	µCi/g
Tc-99m	2.2E-03	2.2E-06	2.2E-03	6.7E-06
Ru-103	2.3E-05	2.3E-08	2.3E-05	6.8E-08
Rh-103m	2.3E-05	2.3E-08	2.3E-05	6.8E-08
Ru-106	3.4E-06	3.4E-09	3.4E-06	1.0E-08
Rh-106	3.4E-06	3.4E-09	3.4E-06	1.0E-08
Ag-110m	1.1E-06	1.1E-09	1.1E-06	3.4E-09
Te-129m	4.5E-05	4.5E-08	4.5E-05	1.4E-07
Te-131m	1.1E-04	1.1E-07	1.1E-04	3.3E-07
Te-132	1.1E-05	1.1E-08	1.1E-05	3.4E-08
Ba-140	4.5E-04	4.5E-07	4.5E-04	1.4E-06
La-140	4.5E-04	4.5E-07	4.5E-04	1.4E-06
Ce-141	3.4E-05	3.4E-08	3.4E-05	1.0E-07
Ce-144	3.4E-06	3.4E-09	3.4E-06	1.0E-08
Pr-144	3.4E-06	3.4E-09	3.4E-06	1.0E-08
W-187	3.3E-04	3.3E-07	3.3E-04	9.9E-07
Np-239	9.0E-03	9.0E-06	9.0E-03	2.7E-05

Note: Activity concentrations were calculated based on 0.1% and 0.3% moisture carryover fraction (MCO) in the steam exiting the reactor steam dryer.

Table 2.9-3 1.02 x EPU RTP Noble Gas Radionuclide Source Term Comparison to PBAPS Design Basis Noble Gas Source Term

Isotope	Offgas Fission Product Concentration, Valid for t= 30 minutes	
	1.02 x EPU RTP*	**Design basis**
Class 1	**µCi/sec**	**µCi/sec**
Kr-83m	1.0E+03	[redacted]
Kr-85m	1.9E+03	[redacted]
Kr-85	8.4E+00	[redacted]
Kr-87	5.2E+03	[redacted]
Kr-88	6.1E+03	[redacted]
Kr-89	6.1E+01	[redacted]
Xe-131m	6.9E+00	[redacted]
Xe-133m	1.0E+02	[redacted]
Xe-133	2.9E+03	[redacted]
Xe-135m	2.4E+03	[redacted]
Xe-135	7.6E+03	[redacted]
Xe-137	2.4E+02	[redacted]
Xe-138	7.2E+03	[redacted]
Total	**3.5E+04**	**3.5E+05**

*Values apply for reactor steam dryer exit MCO values of 0.1% and 0.3%

Table 2.9-4 1.02 x EPU RTP Activation and Fission Product Reactor Water Comparisons to PBAPS Normal Operation Source Term

Isotope	1.02 x EPU RTP Analysis Values* µCi/gm	PBAPS CLTP Normal Operation Source Term µCi/gm
Activation Products		
Na-24	2.2E-03	8.8E-03
P-32	4.5E-05	2.0E-04
Cr-51	3.4E-03	5.1E-03
Mn-54	4.0E-05	6.2E-05
Mn 56	2.4E-02	4.3E-02
Fe-55	1.1E-03	1.0E-03
Fe-59	3.4E-05	3.1E-05
Co-58	1.1E-04	2.1E-04
Co-60	2.3E-04	4.1E-04
Ni-63	1.1E-06	1.0E-06
Cu-64	3.2E-03	2.9E-02
Zn-65	1.1E-04	2.1E-04
Zn-69m	N/A	1.9E-03
Zn-69	N/A	0.0E+00
W-187	3.3E-04	3.0E-04
Np-239	9.0E-03	7.1E-03
Fission Products		
Br-83	N/A	2.4E-03
Rb-89	4.0E-03	N/A
Sr-89	1.1E-04	1.0E-04
Sr-90	8.0E-06	6.2E-06
Y-90	8.0E-06	0.0E+00
Sr-91	4.2E-03	3.8E-03
Y-91m	N/A	0.0E+00
Y-91	4.5E-05	4.1E-05
Sr-92	9.5E-03	8.7E-03
Y-92	5.9E-03	5.3E-03
Y-93	4.2E-03	3.8E-03
Zr-95	9.1E-06	7.2E-06
Nb-95	9.1E-06	7.2E-06
Zr-97	N/A	4.9E-06
Nb-97m	N/A	0.0E+00
Nb-97	N/A	0.0E+00
Mo-99	2.2E-03	2.0E-03
Tc-99m	2.2E-03	1.9E-02
Ru-103	2.3E-05	2.0E-05
Rh-103m	2.3E-05	0.0E+00
Ru-105	N/A	1.8E-03
Rh-105m	N/A	0.0E+00
Rh-105	N/A	0.0E+00
Ru-106	3.4E-06	3.1E-06
Rh-106	3.4E-06	0.0E+00

Isotope	1.02 x EPU RTP Analysis Values* µCi/gm	PBAPS CLTP Normal Operation Source Term µCi/gm
Fission Products		
Ag-110m	1.1E-06	1.0E-06
Ag-110	N/A	0.0E+00
Te-129m	4.5E-05	4.1E-05
Te-129	N/A	0.0E+00
Te-131m	1.1E-04	1.0E-04
Te-131	N/A	0.0E+00
I-131	2.4E-03	5.1E-03
Te-132	1.1E-05	1.0E-05
I-132	2.2E-02	2.4E-02
I-133	1.6E-02	1.9E-02
Cs-134	3.1E-05	3.1E-05
I-134	4.0E-02	N/A
I-135	2.3E-02	1.8E-02
Cs-136	2.0E-05	2.0E-05
Cs-137	8.2E-05	7.2E-05
Ba-137m	8.2E-05	0.0E+00
Cs-138	8.1E-03	N/A
Ba-140	4.5E-04	4.1E-04
La-140	4.5E-04	0.0E+00
La-141	N/A	0.0E+00
Ce-141	3.4E-05	3.1E-05
Ce-143	N/A	3.0E-05
Pr-143	N/A	4.1E-05
Ce-144	3.4E-06	3.1E-06
Pr-144	3.4E-06	0.0E+00
Nd-147	N/A	3.1E-06

*Values apply for reactor steam dryer exit MCO values of 0.1% and 0.3%

Table 2.9-5 LOCA Radiological Consequences

	TEDE Dose (REM)			
	Receptor Location			
	CR	EAB	LPZ	TSC
Calculated Dose CLTP	4.69	10.70	8.99	3.76
Calculated Dose EPU	4.80	9.04	9.59	3.77
Allowable TEDE Limit	5.0	25.0	25.0	5.0

Table 2.9-6 FHA Radiological Consequences

	TEDE Dose (REM)		
	Receptor Location		
	CR	EAB	LPZ
Calculated Dose CLTP	3.79	2.49	0.38
Calculated Dose EPU	4.30	2.99	0.45
Allowable TEDE Limit	5.0	6.3	6.3

Table 2.9-7 CRDA Radiological Consequences

	TEDE Dose (REM)		
	Receptor Location		
	CR	EAB	LPZ
Calculated Dose CLTP	0.30	0.09	0.03
Calculated Dose EPU	0.42	0.31	0.09
Allowable TEDE Limit	5.0	6.3	6.3

Table 2.9-8 MSLBA Pre-Incident Iodine Spike Radiological Consequences

	TEDE Dose (REM)		
	Receptor Location		
	CR	EAB	LPZ
Calculated Dose CLTP	3.23	1.97	0.28
Calculated Dose EPU	2.10	5.43	0.82
Allowable TEDE Limit	5.0	25	25

Table 2.9-9 MSLBA Equilibrium Iodine Concentration Radiological Consequences

	TEDE Dose (REM)		
	Receptor Location		
	CR	EAB	LPZ
Calculated Dose CLTP	0.16	0.10	0.01
Calculated Dose EPU	0.11	0.27	0.04
Allowable TEDE Limit	5.0	2.5	2.5

Table 2.9-10 Post-LOCA Vital Areas Requiring Continuous Occupancies

Areas Requiring Continuous Occupancy	30-Day Dose (rem TEDE)	
	CLTP	EPU
Control Room	4.69	4.80
Technical Support Center	3.76	3.77
Backup Counting Room	3.76	3.77

Table 2.9-11 Post-LOCA Vital Areas Requiring Infrequent Occupancies

Access Route	Time After Accident (hr)	Projected Total Whole Body Dose	
		CLTP (rem)	EPU (rem)
Guard House to TSC & Backup Counting Room	8	0.214	0.245
Guard House to Control Room (EL 165')	8	0.860	0.798
Within Turbine Hall / Radwaste Building Complex (HP-OSC, OSC, Chem Lab / Counting Room, M-G Set Room, Radwaste Control Room, and Cable Spreading Room)	8	1.639	1.304**
OSC to Diesel Generator Building	24	0.818	0.868
OSC to CAD Building*	24	5.328	6.044
TSC to Refueling Floor (EL 234') – Cartridge Exchange at Rad Effluent Monitor*	1	5.491	6.027
TSC to Refueling Floor (EL 234') – Makeup Water to Spent Fuel Pool*	2	5.937	6.531

* Projected whole body (WB) doses for OSC to CAD Building and TSC to refueling floor (EL-234') to exchange the radioactive effluent monitor cartridge (1 hour after a LOCA) and to maintain the spent fuel water level exceeded the allowable dose limit of 5 rem because the CAD Building and reactor building refueling floor is not accessible during the early phase of the accident.

** The airborne WB doses in all vital access areas are reduced due to the reduced MSIV leakage modeled in the EPU dose analysis. The MSIV leakage related decrease is more than the EPU related increase, resulting in a net reduction in the airborne submergence WB dose. The 8-hour airborne average dose in the subject vital area is at least 2 orders of magnitude higher than secondary shine dose. Therefore, the reduction in the airborne WB dose resulted in a reduced total WB dose in the compartment.

2.10 Health Physics

2.10.1 Occupational and Public Radiation Doses

Regulatory Evaluation

Exelon conducted its review in this area to ascertain what overall effects the proposed EPU will have on both occupational and public radiation doses and to determine the necessary steps to ensure that any dose increases will be maintained ALARA. The review evaluated any increases in radiation sources and how such increases may affect plant area dose rates, plant radiation zones, and plant area accessibility. Exelon evaluated how personnel doses needed to access plant vital areas following an accident are affected. Exelon considered the effects of the proposed EPU on nitrogen-16 levels in the plant and any effects this increase may have on radiation doses outside the plant and at the site boundary from skyshine. Exelon also considered the effects of the proposed EPU on plant effluent levels and any effect this increase may have on radiation doses at the site boundary. The regulatory acceptance criteria for occupational and public radiation doses are based on 10 CFR 20 and GDC-19.

Peach Bottom Current Licensing Basis

AST was approved at PBAPS as described in the NRC SER for PBAPS Unit 2 and Unit 3 AST License Amendments 269 and 273 (Reference 50), respectively. Current GDC-19 in 10 CFR 50 Appendix A states that holders of operating licenses using an AST shall meet the requirements of current GDC-19. Therefore, current GDC-19 is applicable to PBAPS.

Occupational and Public Radiation Doses are discussed in UFSAR Section 14.9, "Evaluations Using AEC Method" and in the PBAPS Offsite Dose Calculation Manual (ODCM).

Technical Evaluation

NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," Class III, July 2003 (also referred to as CLTR) was approved by the NRC as an acceptable method for evaluating the effects of CPPUs. Sections 8.5 and 8.6 of the CLTR address the effect of CPPU on the Radiation Sources in the Reactor Core and in the Reactor Coolant. The results of this evaluation are described below.

2.10.1.1 Increases in Radiation Sources

The proposed EPU RTP level of 3951 MWt is a 20% increase over the OLTP level of 3293 MWt. All reported percentage increases throughout Section 2.10.1.1 are relative to OLTP unless otherwise specified.

The radiation sources that are affected by EPU are the sources generated inside the reactor during power operation. The production rate of reactor-generated sources is approximately proportional to the core power level because the fission rate and neutron flux are proportional to the power level. Therefore, EPU is assumed to increase the production rate of reactor generated sources by approximately 20% from the OLTP production rates. Specifically, an increase of approximately 20% (from the OLTP values) is assumed for the production rate of fission

products, the production rate of activation products (due to interaction of the neutron flux with the reactor water and water borne corrosion products), and radiation from the fission process itself (neutron and gamma).

The effects of EPU on doses were evaluated by assuming that the increase in fuel fission product inventory above CLTP is proportional to EPU, (i.e., 14.23%) and that the increase in reactor water fission and activation product concentrations is proportional to the EPU increased production rate (i.e.: 14.23%, 4030 MWt = 1.02 x EPU level / 3528 MWt = Current Accident Analysis Power).

PBAPS has observed that main steam line radiation monitor readings increase proportional to power, in the 85% to 100% power range. This is attributed to increased steam flow increasing the fraction of the total produced N-16 which leaves the reactor in steam (the balance of N-16 decays in the reactor coolant water). This suggests that N-16 in steam concentrations will continue to increase proportionally due to EPU conditions. Because of the increased steam flow, the transit times to turbine building equipment are reduced, which reduces the decay time for short–lived isotopes (such as N-16). As a result, the total inventory of N-16 does increase in turbine building equipment such as the turbines, cross-over piping, and condenser. A 1.3 factor of increase is used to address these effects. The increase in the N-16 related radiation exposure in the condensed water and downstream of the condenser hotwell up to the reactor vessel is negligible due to the delay time in the condenser hotwell, so resulting dose rates in the vicinity will be negligibly affected, but even rooms affected by the increased N-16 in the steam are expected to remain within the appropriate zone limits. No new radiation or high radiation areas around condensate systems and components in the turbine building are created. Despite the N-16 inventory increases with the reduction in transit time and directly with the power, actual plant measurements show the pre-EPU N-16 levels even with HWC result in acceptable dose levels such that EPU increases would remain acceptable.

Per Section 2.2.3.2.3, MCO in the steam flow leaving the RPV at EPU will be within the acceptance limit. The principal effect of the increase will be to change the distribution of the radionuclide activity in the waste streams. Specifically, a small fraction of the activity that would normally be accumulated on the RWCU system resin will be accumulated on the condensate cleanup media (i.e., filters and resin). The radionuclide inventory on the condensate cleanup media will remain a small fraction of the design basis values.

In summary, EPU is assumed to increase the reactor generated radiation sources by up to 20% compared to OLTP, with a factor of up to 30% based on OLTP possible for N-16 contributions in reactor steam containing turbine building equipment. In and downstream of the MC, the evaluation of the radiation sources in condensate credit the hotwell holdup time at EPU of at least the OLTP 120 second time. The margin in the OLTP design basis sources for reactor water and steam at and downstream of the reactor nozzle results in even the EPU source increases continuing to be bounded by the OLTP design basis.

The fission product activity in the reactor water is the result of a combination of tramp uranium and minute releases from the fuel rods. With an assumed increase of 20% above OLTP, the

fission product concentrations in reactor water remain bounded with adequate margin by the PBAPS shielding design basis value from the UFSAR, and the OLTP design basis sources remain bounding.

The fission product activity in reactor steam is a result of noble gas releases and halogen and moisture carry-over from the reactor water. With an assumed increase of 20% above OLTP, the fission products in the condenser offgas, and the offgas release rates after 30 minutes of decay, remain well below the OLTP design basis of 100,000 microCuries per second described in the UFSAR.

2.10.1.2 Occupational and Onsite Radiation Exposures

The CLTR topics regarding occupational and onsite radiation exposures are listed below. PBAPS meets all CLTR dispositions. The topics addressed in this evaluation are:

Topic	CLTR Disposition	PBAPS Result
Normal operational radiation levels	[[	Meets CLTR Disposition
Post-operation radiation levels		Meets CLTR Disposition
Post-accident radiation levels	]]	Meets CLTR Disposition

2.10.1.2.1 *Occupational and Onsite Radiation Exposures*

The CLTR states that normal operational radiation levels will increase slightly as a result of EPU. [[

]] Additionally, improvements in performance with respect to occupational doses, as documented in NUREG-0713 (Reference 103), exceed by an order of magnitude anticipated EPU effects

Inside containment, the radiation levels near the reactor vessel are assumed to increase by 20%. However, the reactor vessel is inaccessible during operation, and because of the margin in the shielding around the reactor vessel, the increase of 20% above OLTP will not measurably increase occupational doses during power operation.

The radiation levels due to spent fuel are assumed to increase by 20% above OLTP. Radiation exposures in accessible areas adjacent to the sides or bottom of the SFP are expected to be within the allowable dose rate limit of the existing radiation zone designation. Expected increases in these values will occur primarily during fuel handing operations during the refueling outage. The plant-specific pre-EPU radiation exposures around the SFP were analyzed in calculation PM-1024 using the spent fuel assembly activity with a discharged bundle exposure (fuel burnup) of 40 GWd/MTU. The dose rates adjusted for post-EPU conditions, including above the water surface on the bridge at the closest operator distance from freshly discharged spent fuel being handled, are well within the radiation dose rate limits. Because the analysis is performed for a freshly discharged spent fuel assembly and with minimum spent fuel water shielding based on the limitation of movement of the refueling bridge, the resulting exposures are the highest dose rates expected during the refueling. The old spent fuel assemblies discharged from the previous outages and stored in the spent fuel racks in accordance with normal operating water levels contribute small dose rates to the surrounding areas due to the associated shielding. Therefore, there is no need for any plan to rotate the spent fuel assemblies to further reduce the existing small radiation exposures from the stored spent fuel assemblies.

With the examination of the radiation dose rates in areas adjacent to the SFP, it is estimated that a core thermal power increase of 20% above would result in a 20% increase of dose rates related to SFP operations. Similarly, the increased dose rates at the SFP could potentially have proportionally increased dose rates in accessible areas adjacent to the SFP. Generally, the dose rates on the refuel floor are less than 10 mrem/hr and the doses rates in the accessible areas adjacent to the sides or bottom of the SFP are lower. Therefore, the dose rate limits in these areas are not expected to change as the result of EPU conditions. Any increase in dose rates around the SFP associated with EPU would not be seen until the first refueling outage following EPU implementation. Further, dose rates at the surface of the pool are primarily due to the presence of radionuclides suspended in the cooling water. The frequency of the backwash and precoats of the fuel pool demineralizers control these dose rates. Radiation protection surveys in accordance with the current radiation protection program will ensure that refueling activities will continue to be appropriately monitored during these activities.

The crud in the SFP would increase negligibly (less than 2%, based on the 15.4% maximum increase in FW flow for EPU times a RWCU system crud removal inefficiency of 10%) even assuming that all residual crud in the reactor cooling system is transported to the SFP. Per Section 2.5.3.1.2, the amount of crud activity and pool quality are operational considerations unrelated to safety, and SFP water clarity will not be affected by EPU. The condensate filter demineralizers are discussed in Section 2.5.4.4 of the PUSAR. With EPU, the system will experience slightly higher loadings resulting in slightly reduced condensate filter demineralizer run times. When the Reactor Coolant chemistry is changed from Normal Water Chemistry to Moderate HWC or NMCA with HWC, the crud in the RPV (primarily on the fuel) can restructure causing crud to be released into the water during power changes and on unit shutdowns. Crud bursts as a result of HWC and NMCA have been assessed and actions to reduce personnel radiation dose could include maximizing RWCU and Fuel Pool demineralizer

operation, additional temporary filters (Tri-Nuc), bleed-and-feed operations and temporary shielding. However, crud restructuring and release is not expected to occur at EPU conditions.

The N-16 dose is expected to increase in proportion to the N-16 inventory in the components. This increase, estimated to be by a maximum factor of 1.30, is due to a combination of reduced transit times from the reactor vessel nozzle to the component and the steam concentrations in some components. The areas with significant N-16 inventory in components are heavily shielded and therefore dose rate increases in these areas will be negligible. Additionally, these areas are not routinely occupied and N-16 is only present during operation.

Outside containment, radiation shielding was specified using the OLTP design basis radiation sources. Outside containment, it is the actual operating sources, not design basis sources, which may increase. For N-16, the increased steam flow rates and reduced transit times for EPU, resulting in up to a 30% increase in dose rates for affected areas of the plant are acceptable with respect to occupational dose rates based on past and current measurements. Other fission and activation product concentrations, and the resultant dose rates, may increase up to 20% over OLTP under EPU operating conditions. The total activity associated with the condensate cleanup system may be greater, but the activity is distributed among the filter-demineralizers (including two additional filter-demineralizers that will be added for EPU conditions), so the increase in dose rate is expected to be less than 20% above OLTP. There is sufficient margin in the PBAPS design to ensure that shielding is adequate to maintain occupational and onsite doses ALARA.

Annual cumulative occupational radiation exposure may increase by as much as 20% due to EPU compared to OLTP conditions. Individual worker exposure will continue to be maintained within acceptable limits by the ALARA program, which controls access to radiation areas. The radiation exposure in all affected plant areas is not expected to increase greater than the proposed 20% EPU compared to OLTP conditions with the exception of areas that contain N-16 containing components as noted above. The post-EPU increase in the radiation exposure in various areas housing the steam components remains within the currently established dose zone limits as described above. Therefore, no additional measures are required to maintain the plant exposure ALARA. The post-EPU plant operation and maintenance activities will be controlled by the existing radiation protection and ALARA procedures. For example, for the year 2008, the average dose per exposed worker at PBAPS (Total Combined Units) was 0.12 Rem, which is 0.024% of the limit allowed by 10 CFR 20.1201. Annual cumulative occupational radiation exposure may increase by approximately 14% due to EPU, which is well within the historical variation in station annual cumulative exposure. Additionally, improvements in performance with respect to occupational doses, as documented in NUREG-0713 (Reference 103), exceed by an order of magnitude anticipated EPU effects.

HWC and NMCA processes have been implemented at PBAPS. No additional increase in the N-16 doses, other than the acceptable changes associated with EPU (increase by a 1.30 factor from the reactor vessel to the condenser hotwell; negligible increase downstream of the condenser; radioactive gas increase of 1.1423 factor) is expected.

The existing radiation protection design (e.g., the maximum designed dose rates for each area of the plant) for areas outside the N-16 affected areas will not change as a result of the increased dose rates associated with EPU. A review was performed for areas expected to be affected by the increased dose rates as a result of EPU. Based on this review, it was concluded that no changes in the shielding requirements will need to be made as a result of EPU. N-16 dose rates may increase by no more than 30%. Steam containing components such as the turbine and condenser are heavily shielded as shown in radiation zone maps, and based on survey data, dose rate increases due to EPU will remain within acceptable zone designations with the current shielding designs.

PBAPS has the following options if necessary for the increased dose rates due to EPU.

1. Use of operational radiation survey data to establish available calculation method related margins.
2. Re-posting and locking areas, as needed, in accordance with 10 CFR 20 requirements and PBAPS policy.
3. Using additional permanent and/or temporary shielding where needed and feasible.
4. Operation of equipment in a manner that compensates for these relatively minor source increases.

In summary, individual worker exposures can be maintained within acceptable limits by controlling access to radiation areas using the site ALARA program. Procedural controls compensate for increased radiation levels.

The effect of EPU on access to plant vital areas following an accident (Item II.b.2 of NUREG-0737) was evaluated in the analyses that support the NRC Safety Evaluation for implementation of the Alternative Source Term. The evaluation determined that the existing OLTP analyses, which are based on TID-14844 (Reference 84) rather than the Alternative Source Term, are conservative and bounding.

An additional review of the doses associated with access to vital areas was conducted to determine the effect of EPU. The times required for transit to and work in vital access areas are not changed with EPU. The operator doses are expected to increase by up to 20% compared to OLTP. After evaluating this increase, it was concluded that all of the doses are within the limits of GDC-19.

In summary, analyses and measurements have confirmed that operation under EPU conditions will have a negligible effect on occupational and onsite radiation exposure. Therefore, occupational and onsite radiation exposure meets all CLTR dispositions.

A review was performed of the historical radiation zone maps, which have been historically acceptable, and recent radiation dose surveys to identify areas where the doses resulting from EPU could affect current radiation protection practices. Based on this review and post-EPU surveys, radiation zoning will be updated as necessary. Plant area locations where post-EPU radiation surveys are performed can be found in Section 2.12.1.

2.10.1.2.2 *Post-Operation Radiation Levels*

The CLTR states that [[

]]

Post-operation radiation levels in most areas of the plant increase by no more than the percentage increase in power level. In a few areas near the reactor water piping and liquid radwaste equipment, the increase could be slightly higher. Regardless, individual worker exposures can be maintained within acceptable limits by controlling access to radiation areas using the site ALARA program. Procedural controls compensate for increased radiation levels. Radiation measurements will be made at selected power levels to ensure the protection of personnel.

Therefore, post-operation radiation levels meet all CLTR dispositions.

2.10.1.2.3 *Post-Accident Radiation Levels*

The CLTR states that [[

]] The increased post-accident radiation levels have no adverse effect on safety-related plant equipment. A plant-specific analysis for NUREG-0737, Item ll.B.2, post-accident mission doses has been performed.

Therefore, post-accident radiation levels meet all CLTR dispositions.

2.10.1.2.4 *Public and Offsite Radiation Exposures*

PBAPS meets all CLTR dispositions. The CLTR topics regarding public and offsite radiation exposures are listed below.

Topic	CLTR Disposition	PBAPS Result
Off-site plant gaseous emissions	[[	Meets CLTR Disposition
Plant skyshine from the turbine	]]	Meets CLTR Disposition

The CLTR states that for EPU, normal operation gaseous activity levels increase slightly, while the level of N-16 in the turbine increases in proportion to the rated steam flow.

The sources responsible for offsite doses increase by varying factors depending upon the basis for each source. Dose evaluations detailing the contribution and effects of HWC (pre and post–EPU) to members of the public onsite personnel were performed; those results are airborne releases, liquid effluent releases from the radwaste system, and gamma skyshine from N-16 in the plant turbines and some unshielded MS piping.

Implementation of EPU could increase the components of offsite doses due to releases of airborne and liquid radioactivity by up to 30%. In general, the dose changes due to N-16 in the equipment above grade will be the most significant factor in skyshine although radiation scatter from other sources may be present. The equipment above grade at PBAPS includes steam piping, turbines, FW heaters, the upper portions of moisture separators, and the transition between the turbines and condenser. The component of the offsite dose due to N-16 skyshine could increase by 30% (this is described in Section 2.10.1.1). The expected post-EPU increase in the in-plant radiation exposure in the turbine building (TB) complex has a negligible effect on the estimated doses to members of the public. The TB concrete shielding and distance between the TB and offsite boundary are such that the post-EPU direct dose contribution from the steam components in the TB is negligible. The post-EPU N-16 skyshine dose rate at the nearest boundary is expected to be near the background radiation level. Therefore, it does not add into the total estimated doses to members of the public. Although the post-EPU direct dose and skyshine dose contribution to a member of the public are negligibly small, a 30% increase in the combined direct dose and skyshine dose contributions was applied to the pre-EPU member of the public doses.

The design basis normal offsite doses to members of the public based on the current power level and EPU are shown in Table 2.10-2. Dose value contributions for the primary sources of normal operation offsite doses (all effluent releases, gamma shine, storage and transfer of radioactive materials) to a member of the public at CLTP and EPU are provided in Table 2.10-2.

The dry storage of spent fuel is the major source of offsite dose, with a design basis contribution of approximately 10.8 mrem/year to the limiting dose receptor location subject to the limits of 40 CFR 190 (25 mrem/year from effluents and external shine). The maximum annual dose to members of the public from all contributing PBAPS fuel cycle components, with EPU, is conservatively estimated to be 12.9 mrem total body. The maximum dose to any organ from all gaseous pathways is 9.85 mrem/yr per unit (compared with 10 CFR 50, Appendix I limit of 15 mrem/yr/unit). The maximum dose to any organ from all liquid pathways is 1.89 rem/yr/unit (compared with 10 CFR 50, Appendix I limit of 10 mrem/yr/unit).

Currently, the offsite doses from operation of all PBAPS Units are well below regulatory guidelines as indicated in Table 2.10-2. The environmental monitoring program that is in place will continue to ensure that the offsite doses are well within regulatory limits and will provide indication should the doses increase above measured background levels.

In summary, analyses and measurements have confirmed that operation under EPU conditions will have a negligible effect on public and offsite radiation exposure. Therefore, public and offsite radiation exposures including gaseous emissions and turbine skyshine meet all CLTR dispositions.

2.10.1.3 Operational Radiation Protection Program

The increased production rates of fission and activation products could increase dose rates from contained sources, surface contamination, and airborne radioactivity. The current operational

programs (pre-job briefings, use of supplemental shielding, pre-job decontamination, contamination control practices, etc.) will continue to ensure that, with these increases, the occupational doses will continue to remain ALARA. Individual worker exposure will continue to be maintained within acceptable limits by the ALARA program, which controls access to radiation areas.

In summary, the current operational radiation protection programs are capable of controlling, and compensating for, the potential increases in contained sources and surface contamination.

Conclusion

The effects of the proposed EPU on radiation source terms and plant radiation levels have been reviewed. Exelon concludes the necessary steps have been taken to ensure any increases in radiation doses will be maintained ALARA. Exelon further concludes the proposed EPU meets the requirements of 10 CFR 20 and the current licensing basis. Therefore, Exelon finds the proposed EPU acceptable with respect to radiation protection and ensuring occupational radiation exposures will be maintained ALARA.

Table 2.10-1 Current and Anticipated Measured Radiation Fields in Selected Areas

Area Description	Radiation Zone* (As Shown in Zone Maps Unless Otherwise Stated)	Measured Survey Results (CLTP) (mrem/hr)	Anticipated Survey Results (EPU) (mrem/hr)
Turbine Building 165' 165' Open Area on operating floor between turbines	Zone II	< 2	< 2.5
Turbine Building 135' Open Area floor between turbines	Zone I	< 0.2	< 0.25
Turbine Building 135' Cond. Demin. Hatch Walkway	Zone II	0.8	0.9 to 1.0
Turbine Building 116' Condensate Demineralizer Area	Zone II and III outside vessel cubicles	< 2 to < 10	< 2 to < 10 (Assuming additional demineralizers, to be shielded similarly to the existing ones)
Turbine Building Roof	Zone IV	< 2 to 36	< 2.5 to 50
Recombiner Building	Zone II areas, outside Zone V equipment cubicles	< 2	< 2.5
Reactor Building General at Elevation 165	Zone II – III (Current Data)	< 2 to 8	< 2.3 to 9
Reactor Building CS Rooms	Zone II	< 2	< 2.3
Reactor Building RHR Rooms (not including on contact with piping or areas in the vicinity of the RHR heat exchangers)	Zone II – III (Current Data)	< 2 to 10	< 2.3 to 11

Table 2.10-1 Current and Anticipated Measured Radiation Fields in Selected Areas (continued)

Area Description	Radiation Zone* (As Shown in Zone Maps Unless Otherwise Stated)	Measured Survey Results (CLTP) (mrem/hr)	Anticipated Survey Results (EPU) (mrem/hr)
Reactor Building Primary Containment and Steam Tunnel	Zone V	> 100	> 100
Admin Building	Zone 1, effectively	0.01 to 0.1 mrem/hr	0.013 to 0.13 mrem/hr conservatively
PEARL Building	Zone 1, Zone IIA, in Chem. Lab	0.01 to 0.13 mrem/hr	0.013 to 0.17 mrem/hr conservatively

PBAPS Radiation Zoning System

Zone I - under 0.5 mrem/hr - Controlled, unlimited access

Zone II - 0.5 to 2.5 mrem/hr - Controlled, limited access for 40 hrs/week

Zone III - 2.5 to 15 mrem/hr - Controlled, limited access between 6 – 40 hrs/week

Zone IV - 15 to 100 mrem/hr - Controlled, limited access between 1 – 6 hrs/week

Zone V - over 100 mrem/hr - Normally inaccessible

Areas suffixed (A) may have increased zone level during system operation or abnormal conditions

Radiation Zoning is presented in UFSAR Figures 12.3-2 through 12.3-11, and supporting PBAPS drawings A-48 through A-61.

* Radiation zone maps at PBAPS are historical in nature and zoning designations are only presented here to show representative dose rate changes and changes anticipated with EPU. Specifically, the access control and radiation zones shown in the UFSAR Figures 12.3-2 through 12.3-11 and the supporting plant drawings are historical and reflect the anticipated levels at the original startup of the units. Occupational exposures are controlled under the Radiation Protection Program, based on survey data and appropriate work planning. The anticipated increases due to EPU will be managed under the same program, with exposures maintained ALARA. No procedural or programmatic changes have been determined to be required.

Normal Radiation Surveys for inside Turbine and Reactor Building Areas generally do not record values less than 2 mrem/hr.

Areas in the Admin Building and the PEARL Buildings office areas are monitored using TLDs, principally for the purpose of 10 CFR 20.1502 evaluations of the need for personnel dosimetry.

Table 2.10-2 Design Basis and Reported Annual Dose to Members of the Public

10 CFR 50 Appendix I Dose Analysis						
	Maximum Public Individual Doses for Gaseous and Liquid Releases					
Type of Dose	3440 MWt (Reference 104)	3528 MWt (Reference 105)	3528 MWt	4030 MWt	Actual Plant Data Effluent Release Average From 2005 to 2009 (References 106-110)	10 CFR 50 Appendix I Design Objectives
Liquid Effluents						
Maximum dose to total body from all pathways (mrem/yr)	2.40E-01	2.50E-01	4.71E-01	3.36E-01	3.70E-03	3 per unit
Maximum dose to any organ from all pathways (mrem/yr)	2.80E+00	2.90E+00	7.34E+00	1.89E+00	7.88E-03	10 per unit
Gaseous Effluents						
Gamma dose in air from noble gases (mrad/yr)	7.20E-01	7.60E-01	8.54E-01	9.34E-01	5.38E-02	10 per unit
Beta dose in air from noble gases (mrad/yr)	9.20E-01	9.70E-01	7.32E-01	5.30E-01	3.74E-02	20 per unit
Maximum dose to total body of an individual (mrem/yr)	4.80E-01	5.00E-01	5.76E-01	6.23E-01	1.52E-01	5 per unit
Maximum dose to skin of an individual (mrem/yr)	1.00E+00	1.10E+00	1.16E+00	1.11E+00	2.35E-01	15 per unit
Maximum dose to any organ from all pathways from radioiodines and particulates (mrem/yr)	5.40E+00	5.70E+00	1.25E+01	9.72E+00	3.40E-01	15 per unit

Table 2.10-2 Design Basis and Reported Annual Dose to Members of the Public (continued)

10 CFR 50 Appendix I Dose Analysis				
Calculation Methodology	Pre-Release Version of GALE Pre-Release Version of LADTAP Pre-Release Version of GASPAR Pre-Release Version of RG 1.109	Pre-Release Version of GALE NRCDose 2.3.16 - LADTAP (2010) NRCDose 2.3.16 - GASPAR (2010) RG 1.109, Rev. 1 (1977)	ANSI/ANS-18.1-1999 NRCDose 2.3.16 LADTAP (2010) NRCDose 2.3.16 GASPAR (2010) RG 1.109, Rev. 1 (1977)	N/A
Note: Some of the calculated EPU total activity levels are lower than the pre-EPU activity levels due to a change in calculation methodologies. The EPU analysis (4030 MWt) used the ANSI/ANS-18.1-1999 standard method, which was updated in 1999.				

10 CFR 20, Appendix B, Table 2, Liquid and Gaseous Effluent Concentration Analysis	
Liquid Effluents	0.00037
Gaseous Effluents	0.0107
Offsite Direct Dose Contributors	
Independent Spent Fuel Storage Installation (ISFSI)	10.8
Low Level Radioactive Waste Storage Facility (LLRWSF)	0.4
N-16 Shine	Negligible
40 CFR 190 Site Evaluation - 25 mrem/yr Limit	
Independent Spent Fuel Storage Installation (ISFSI)	10.8
Gaseous Effluent Releases for 2 Units	1.464
Liquid Effluent Releases for 2 Units	0.652
Total	12.916 mrem/year

2.11 Human Performance

2.11.1 Human Factors

Regulatory Evaluation

The area of human factors deals with programs, procedures, training, and plant design features related to operator performance during normal and accident conditions. The PBAPS human factors evaluation was conducted to ensure that operator performance is not adversely affected as a result of system changes made to implement the proposed EPU. The review covered changes to operator actions, human-system interfaces, and procedures and training needed for the proposed EPU. The regulatory acceptance criteria for human factors are based on GDC-19, 10 CFR 50.120, 10 CFR 55, and the guidance in GL 82-33 (Reference 111).

Peach Bottom Current Licensing Basis

The following sections of the PBAPS current licensing basis are related to the areas of Human Factors, operator actions, and procedures for normal, abnormal and emergency conditions.

GDC-19, Control Room, includes considerations for Human Factors in normal and accident conditions. The addition of GDC-19 to the PBAPS licensing basis came with the acceptance of AST in licensing amendments 269 (Unit 2) and 273 (Unit 3) (Reference 50).

As stated in UFSAR Section 13.3, PBAPS incorporates the requirements specified in ANSI N18.1-1971, 10 CFR 55, and 10 CFR 50 as promulgated in the NRC Final Rule 10 CFR 50.120 - "Training and Qualification of Nuclear Power Plant Personnel." The PBAPS training program is based on a systematic approach to training. The qualifications for licensed operators, including compliance with 10 CFR 55, are described in UFSAR Section 13.2. The operator training program is accredited by INPO.

PBAPS I&C systems are described in UFSAR Section 7, "Control and Instrumentation."

10 CFR 50 Appendix R approved operations that may be required to be performed outside the CR are contained in UFSAR Fire Protection Program, Appendix A, Table A-4.

Technical Evaluation

Human factors engineering and human performance initiatives are foundational characteristics that help ensure that plant operators can effectively and safely operate the facility under normal, abnormal, and emergency conditions. When initiating a plant change, the PBAPS configuration control process requires a review of human factors including the effect of a modification on EOPs, CR layout, alarms, indication and function. It also includes a review by qualified personnel to determine any effect on the simulator that would entail simulator modifications or modeling changes.

2.11.1.1 Changes in Emergency and Abnormal Operating Procedures

The changes in EOPs and the SAMPs reflect the change in power level and CAP credit elimination but will not be changed in a manner that involves a change in accident mitigation philosophy.

The following EOP curves and limits have been identified as being affected:

- Heat Capacity Temperature Limit (HCTL) - The EPU will result in additional heat being added to the SP during certain accident scenarios. The HCTL curve will be revised as a result of the increase in decay heat rejected to the SP. The change is not significant (approximately 1°F).
- Pressure Suppression Pressure (PSP) - The PSP curve will be revised as a result of the increase in reactor power and in decay heat loading. The change is not significant (<1 psi).
- Minimum Debris Retention Injection Rate (MDRIR) – The MDRIR will be revised as a result of the increase in decay heat loading. The injection flow will increase by approximately 12.5% of the CLTP flow.
- NPSH: The NPSH curves for RHR and CS pumps will be revised due to utilization of the $NPSHR_{3\%}$ curves.
- Hot Shutdown Boron Weight (HSBW) and Cold Shutdown Boron Weight (CSBW): The percentage of SLC tank volume required to achieve HSBW and CSBW will change due to the increase in Boron enrichment.

The following EOPs are planned to be revised as a result of EPU and CAP credit elimination (The modifications mentioned can be found in EPU LAR Attachment 9):

- T-101 and Bases, RPV CONTROL, are affected by both the CST and the condensate pump modifications.
- T-102, and Bases, PRIMARY CONTAINMENT CONTROL, are affected by the following three modifications: RHR heat exchanger cross-tie, HPSW cross-tie and the CST.
- T-111 and Bases, LEVEL RESTORATION, are affected by the CST modification.
- T-117 and Bases, LEVEL / POWER CONTROL, are affected by the SLC boron enrichment modification.
- T-204-2(3), INITIATION OF CONTAINMENT SPRAYS USING RHR, and T-205-2(3), INITIATION OF CONTAINMENT SPRAYS USING HPSW, are affected by the RHR heat exchanger cross-tie modification.
- T-210-2(3) CRD SYSTEM SBLC INJECTION, T-211-2(3), CRD SYSTEM NONENRICHED BORIC ACID AND BORAX INJECTION, and T-212-2(3), RWCU SYSTEM SBLC INJECTION, are affected by the SLC boron enrichment modification.

- T-242-2(3), ALTERNATE INJECTION USING THE REFUELING WATER TRANSFER SYSTEM, are affected by the modification to the condensate filter demineralizers.
- T-246-2(3), MAXIMIZING CRD FLOW TO THE REACTOR VESSEL, are affected by the CST modification.

AOPs at PBAPS are defined as Off-Normal Procedures (ONs), Operational Transient Procedures (OTs), Special Event Procedures (SEs), and Fire Safe Shutdown Directives (FSSDs). The planned changes to AOPs due to EPU and CAP credit elimination modifications are outlined below.

- ON-118 and Bases, LOSS OF TURBINE BUILDING CLOSED COOLING WATER (TBCCW) SYSTEM & BASES affect the bearing temperatures for the condensate pumps and load limitations on the isolated phase bus for loss of TBCCW. This will be affected by the condensate pump and the isolated phase bus modifications.
- OT-106 and Bases, CONDENSER LOW VACUUM, is being revised due to changes in the MC low vacuum alarm setpoint.
- OT-111 and Bases, REACTOR LOW PRESSURE, will be affected by changes to condensate pump discharge pressure resulting from the pump modification.
- OT-113 and Bases, LOSS OF STATOR COOLING & BASES, will be affected by changes to the operating temperature alarms due to the T-G modification.
- SE-10 and Bases, FIRE SAFE SHUTDOWN FROM THE REMOTE S/D PANEL will be affected by the CST modification.
- SE-11 and Bases, LOSS OF OFF-SITE POWER is affected by the RHR heat exchanger cross-tie and CST modifications.
- SE-16 and Bases, GRID EMERGENCY is being revised as a result of the change in MVAR capacity due to the T-G modification.

EOPs and AOPs will also be rescaled as required to reflect the power uprate.

2.11.1.2 Changes to Operator Actions Sensitive to Power Uprate

Most abnormal events result in automatic plant shutdown (scram). Some abnormal events result in SRV actuation, ADS actuation and/or automatic ECCS actuation. All analyzed events result in safety-related SSCs remaining within their design limits. EPU does not change any automatic safety function. Changes to subsequent operator action for maintaining core cooling, containment cooling, and safe shutdown are described below:

2.11.1.2.1 *Changes for DBAs and Events*

The following are changes for operator response time or manual actions for DBAs and events for all modes of RHR. These changes are the result of EPU and CAP credit elimination during these events.

- A new operator action will be created to place the RHR heat exchanger cross-tie valve in service if required to mitigate a rise in suppression pool temperature during the accident or event. This action has been evaluated from a human engineering standpoint and it has been determined to be consistent with current strategy for operator actions.
- A new operator action will be created to start a second HPSW pump and establish a flowpath through the second RHR heat exchanger when the RHR heat exchanger cross-tie is in service. In connection with this, there will be an operator action to place the HPSW cross-tie in service if required. These actions have been evaluated from a human engineering standpoint and it has been determined to be consistent with current strategy for operator actions.
- As part of the CAP credit elimination strategy, operators will manage entry into ASDC, when required, to ensure that suppression pool temperature remains below the limit needed to maintain adequate NPSH for operating ECCS pumps. This will be accomplished by providing guidance in the ASDC procedure for the operator to anticipate a 10°F rise in suppression pool temperature upon initiation of ASDC, and to verify that ECCS pump operation will remain within the limits of the NPSH curves.
- As part of the CAP credit elimination strategy and managing the interaction between units, operators will control the depressurization of the units to minimize the effect of a rise in suppression pool temperature associated with the interruption of containment cooling (SPC or sprays) that occurs upon receipt of a LOCA signal. Guidance will be provided for the operators to anticipate the rise in suppression pool temperature resulting from an interruption in SPC caused by receiving a LOCA signal when a unit is depressurized to less than 450 psig. The operators will then use the higher suppression pool temperature to verify that the ECCS pump operation will remain within the limits of the NPSH curves during the interruption in containment cooling.

2.11.1.2.2 *Appendix R Fire Safe Shutdown (FSSD) Events*

There are four methods designed to bring the plant to a cold shutdown condition for a postulated fire event. The RHR heat exchanger cross-tie modification is not relied upon in the methods.

- Safe Shutdown Method "A" utilizes the RCIC system, two SRVs, and one subsystem of RHR.
- Safe Shutdown Method "B" utilizes the HPCI system, two SRVs, and one subsystem of RHR.
- Safe Shutdown Method "C" utilizes manual control of three SRVs of the ADS for depressurization of the reactor, and either one CS pump or one RHR pump in both LPCI mode and the SPC mode.
- Alternative Shutdown Method "D" utilizes similar systems as method "B" except that operator control is taken outside the CR at designated alternative control stations.

The following changes in operator action and/or response times are required for FSSD events due to the CAP credit elimination. All of the operator actions below went through a qualitative review with the Operations and Training Departments. In addition, Method D was reviewed utilizing the station CR simulator.

- Operating procedures will require the operators to refill the CST from the RWST during Method "A", "B" and "D" shutdowns to maintain ECCS pump suction on the CST rather than the suppression pool and ensure NPSH margin without the need for CAP credit (see EPU LAR Attachment 9 Section 3.2, Overview of Improvement in NPSH Margin and CAP Credit Elimination). Because this will occur about 3 hours after the event and the fire is assumed to be extinguished at one hour, operators would not be hampered from reaching the necessary manual valves to perform the action.
- Operating procedures will be revised to provide guidance to manage entry into ASDC in a manner that will mitigate the effect of the rise in suppression pool temperature associated with ASDC initiation in order to maintain NPSH margin for the operating ECCS pumps.
- Operating procedures will be revised to reduce the time in which an operator is required to secure from the CR a HPCI pump that has spuriously started from 10 to 7.5 minutes during a Method "A" shutdown without a SORV.
- During a Method "A" shutdown with a SORV, the EPU analysis has determined that the time for entry into ASDC is reduced from 210 to 160 minutes. The most challenging of these actions involve establishing SPC. It has been determined that one operator can complete these actions in a maximum of 120 minutes including travel times. Additional operators can be used to reduce the time further.
- During Method "C" shutdowns, the EPU analysis has determined that the times for initiation of ASDC has increased from 30 minutes to 14 hours while the time after the event in which the operator must initiate RPV depressurization has decreased from 27.5 minutes to 26.5 minutes for case C1 and 15 minutes to 14.7 minutes for case C2. However, the actions required for RPV depressurization can all be completed within the new timeframe from the CR.
- During Method "D" shutdowns, without a SORV, the EPU analysis has determined that the times for initiation of ASDC has increased from 300 to 364 minutes while the time after the start of the event in which the operator must initiate RPV depressurization has decreased from 5 to 3.5 hours. This is acceptable because, per procedures, operators will depressurize maintaining acceptable vessel temperature.
- During Method "D" shutdowns, with a SORV, the EPU analysis has determined that the time after the event for initiation of SPC has decreased from 4 to 2.5 hours, while without a SORV the time for initiation of SPC has decreased from 180 to 150 minutes. However, a single operator is able to complete required actions in 2 hours or less.

- During Method "D" shutdowns, with a SORV, ASDC initiation time is increased from 240 to 270 minutes.

2.11.1.2.3 *Anticipated Transient Without Scram Event*

A new operator action will be created to refill the CST from the RWST about 90 minutes after the start of the event. This is a reasonable action because the reactor is shut down in approximately 30 minutes and the CST inventory would last for an additional hour at the estimated injection rate.

2.11.1.2.4 *Conclusion*

The changes to PBAPS Unit 2 and 3 operator actions as a result of the EPU do not significantly affect operator actions. The changes will be appropriately revised in the procedures and the operators will receive appropriate classroom and/or simulator training for implementation. There are no new or revised operator workarounds as a result of EPU.

2.11.1.3 Changes to Control Room Controls, Displays and Alarms

Changes to the CR are prepared in accordance with the plant design change process. Under this process, a Human Factors engineering review is performed for changes associated with the PBAPS CR. The change process also requires an effects review by Operations and Training personnel. Results of these reviews, including simulator effects and training requirements, are incorporated into the engineering change package and tracked to completion by the design change process.

The following changes will be made to the CR Controls, Displays and / or Alarms resulting from EPU:

- A switch and position indicating lights will be provided for the new RHR heat exchanger cross-tie MOV controls in each division of RHR and for each of the new flow control valves at the inlets to the RHR heat exchangers. New cross tie flow indicators allow operators to balance flow through the heat exchangers when operating with the RHR heat exchanger cross-tie open.
- Position indicating lights will be provided to indicate LPCI flow control valve position corresponding to minimum and maximum allowable flow. An alarm will also be provided to indicate when the valve is outside of the allowable flow range.
- A new selector switch is provided for manually controlling the transfer of power for the HPSW cross-tie MOV from the Normal to Alternate source or vice versa. The indicating lights will show if power is available on the Normal and Alternate sources.
- The T-G and auxiliaries modifications will require changes to CR controls and alarms due to the upgrades to the Alterrex rectifier and voltage regulator.
- The addition of the third MS SSV will include valve instrumentation (acoustic monitor and temperature element). The instrumentation indication will be available in the CR.

Instrumentation and alarms for the new SSV will be consistent with that of the existing SSVs.

TS instruments for instrument and control systems are affected by EPU as described in EPU LAR Attachments 1 and 2.

2.11.1.3.1 *Conclusion*

The changes to PBAPS CR interfaces as a result of the EPU do not significantly affect operator human performance. Operator training for changes to CR interfaces, alarms, and indications will be accomplished in accordance with the plant training and simulator program as described in Section 2.11.1.5.

2.11.1.4 Changes to the Safety Parameter Display System

The purpose of the PBAPS Safety Parameter Display System (SPDS) is to continuously display information from which plant safety status can be readily and reliably assessed. The principal function of the SPDS is to aid CR personnel during abnormal and emergency conditions in determining the safety status of the plant and in assessing whether abnormal conditions warrant corrective action by operators to avoid a degraded core.

The following changes will be made to the SPDS as a result of PBAPS EPU:

- HCTL curve: The HCTL curve will be revised as a result of the decay heat rejected to the suppression pool.
- PSP curve: The PSP curve will be revised as a result of the increase in reactor power and in decay heat loading.
- MDRIR: The MDRIR will be revised as a result of the increase in decay heat loading.
- NPSH: The NPSH curves for RHR and CS pumps will be revised due to utilization of the 3% NPSH curves.
- Position indication will be provided for the additional third SSV in each unit.
- RHR flow indication for each of the RHR subsystems. The display will show RHR flow rate through each subsystem effectively showing flow through the RHR cross tie piping.

2.11.1.4.1 *Conclusion*

The changes to PBAPS Unit 2 and 3 SPDS as a result of the EPU do not significantly affect operator actions and mitigation strategies. The changes will be made in accordance with the configuration change process and the operators will receive appropriate classroom and/or simulator training for implementation.

2.11.1.5 Changes to the Operator Training Program and the Control Room Simulator

Training of Operations personnel will occur on all EPU modifications necessary to support unit operation at EPU conditions. The operator training is presented in the classroom and on the

simulator. The major EPU change for the CR operators involves the installation of the RHR and HPSW cross-tie modifications (see Enclosures 9c and 9d to EPU LAR Attachment 9).

Licensed and non-licensed operator training will be provided prior to the cycle implementing the changes and will focus on plant modifications, procedure changes, startup test procedures, and other aspects of EPU including changes to parameters, set points, scales, and systems. The applicable lesson plans will be revised to reflect changes as a result of the EPU. Simulator training during this phase will also include training on performance effects of new modifications; this will support the power ascension plan. Prior to startup following the refueling outage for EPU, the operators will be given classroom and simulator Just-In-Time (JIT) training to cover last minute training items and perform startup training and startup testing evolutions on the simulator. Successful completion of training is verified, as required by plant procedures, as part of the turnover of the modification to operations.

The simulator is a duplicate of the PBAPS Unit 2 main control room and as such is modified when modifications affecting simulator fidelity are installed in the plant. Use of the simulator to support Unit 3 related training is performed when there are unit differences between the simulator and Unit 3. Classroom training is provided relative to the implementation of modifications to both PBAPS units. Human errors are prevented through rigorous training in the classroom and plant settings prior to completion of modifications at each unit. The training includes evaluation tools such as written exams, simulator evaluations, and task performance tools as deemed appropriate.

Installation of the EPU changes to the simulator are performed in accordance with ANSI/ANS-3.5 1998, "Nuclear Power Plant Simulators for Use in Operator Training and Evaluation." The simulator changes will include hardware changes for new and modified CR I&C, software updates for modeling changes due to EPU (i.e., reactor feed pump, condensate pump modifications), set point changes, and re-tuning of the core physics model for cycle specific data. The simulator process computer will be updated for EPU modifications.

Operating data will be collected during EPU implementation and start-up testing. This data will be compared to simulator data as required by ANSI/ANS-3.5 1998. Additionally, simulator acceptance testing will also be conducted to benchmark the simulator performance based on design and engineering analysis data.

Lessons learned from power ascension testing and operation at EPU conditions will be fed back into the training process to update the training material and processes as required.

Conclusion

The changes to operator actions, human-system interfaces, procedures, and training required for the proposed EPU have been evaluated. It has been concluded that there is no adverse effect to the existing programs, procedures, training, and other plant design features related to operator performance during normal and accident conditions. It has been further concluded that the requirements of the current licensing basis, 10 CFR 50.120 (Training and Qualification of Nuclear Power Plant Personnel), and guidance in GL 82-33 (Supplement 1, NUREG 0737

Requirement for Emergency Response Capability) will continue to be met following implementation of the proposed EPU.

Under the design configuration change process, a Human Factors engineering review is performed for changes associated with the CR. The change process also requires an impact review by Operations and Training personnel. Results of these reviews, including simulator effect and training requirements, are incorporated into the engineering change package and tracked to completion by the design change process.

2.12 Power Ascension and Testing Plan

2.12.1 Approach to EPU Power Level and Test Plan

Regulatory Evaluation

The purpose of the EPU test program is to demonstrate SSCs will perform satisfactorily in service at the proposed EPU power level. The test program also provides additional assurance the plant will continue to operate in accordance with design criteria at EPU conditions. The review evaluated: (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance; (2) transient testing necessary to demonstrate plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level; and (3) the test program's conformance with applicable regulations. The regulatory acceptance criteria for the proposed EPU test program are based on 10 CFR 50, Appendix B, Criterion XI, which requires establishment of a test program to demonstrate SSCs will perform satisfactorily in service.

Peach Bottom Current Licensing Basis

PBAPS is committed to conformance with 10 CFR 50, Appendix B, Criterion XI as described in the QATR Revision 86 (Reference 31).

Technical Evaluation

NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," Class III, July 2003 (also referred to as CLTR) was approved by the NRC as an acceptable method for evaluating the effects of CPPUs. Section 10.4 of the CLTR addresses the testing required for the initial power ascension following the implementation of EPU. The results of this evaluation are described below.

Testing is required for the initial power ascension during implementation of EPU. A standard set of tests is established for the initial power ascension steps of EPU, which supplement the normal TS testing requirements. The EPU testing program at PBAPS is based on the PBAPS specific initial EPU power ascension and TSs. The same performance criteria will be used as in the original power ascension tests, unless they have been replaced by updated criteria since the initial test program.

2.12.1.1 Testing Program

PBAPS meets all CLTR dispositions. The topics addressed in this section are:

Topic	CLTR Disposition	PBAPS Result
Testing Program	[[ ]]	Meets CLTR Disposition

The CLTR states that the increase in power level changes plant and system performance.

Based on the analyses and GEH BWR experience with uprated plants, a standard set of tests has been established for the initial power ascension steps of EPU. Testing will be done in accordance with the TS surveillance requirements on instrumentation that is re-calibrated for EPU conditions. These tests supplement the normal TS testing requirements.

Overlap between the WRNM and APRM will be assured.

Steady-state data will be taken at points from 90% up to 100% of the CLTP RTP, so that system performance parameters can be projected for EPU power before the CLTP RTP is exceeded.

EPU power increases above the 100% CLTP RTP will be made along an established flow control/rod line in increments of equal to or less than 5% power. Steady-state operating data, including fuel thermal margin, will be taken and evaluated at each step. Routine measurements of reactor and system pressures, flows, and vibration will be evaluated from each measurement point, prior to the next power increment. Radiation measurements will be made at selected power levels to ensure the protection of personnel.

Radiation surveys are located in EPU LAR Attachment 10.

Control system tests will be performed for the reactor FW/reactor water level controls and pressure controls. These operational tests will be made at the appropriate plant conditions for that test at each of the power increments, to show acceptable adjustments and operational capability. Testing will be done to confirm the power level near the turbine first-stage scram bypass setpoint.

Details on vibration monitoring are provided in EPU LAR Attachment 13.

The same performance criteria will be used as in the original power ascension tests, unless they have been replaced by updated criteria since the initial test program. [[

]] Vibrational testing is addressed in EPU LAR Attachment 13.

The EPU testing program at PBAPS, which is based on the specific testing required for the PBAPS initial EPU power ascension, supplemented by normal TS testing, meets all CLTR dispositions. EPU LAR Attachment 10 contains details of the testing program. The PBAPS power ascension testing program will provide management oversight and control to assure PBAPS can operate safely at the EPU licensed power level. Management review and approval of test results at each power level will be provided prior to increasing power to the next level.

2.12.1.2 Transient Tests and Modifications

Large transient testing is normally performed on new plants because experience does not exist to confirm a plant's operation and response to events. However, these tests are not normally performed for plant modifications following initial startup because of well-established QA and maintenance programs including component and system level post- modification testing and extensive experience with general behavior of unmodified equipment. When major modifications are made to the plant, large transient testing may be needed to confirm that the modifications

were correctly implemented. However, such testing should only be imposed if it is deemed necessary to demonstrate safe operation of the plant.

PBAPS [[ ]] large transient testing as part of EPU implementation. The justification for [[ ]] large transient testing is provided as EPU LAR Attachment 10. This justification will confirm that: a) all plant modifications have been evaluated and implemented properly, and b) integrated plant performance and transient operation is consistent with the analyses that have been completed. Transient experience at high powers at operating BWR plants has shown a close correlation of the plant transient data to the evaluated events. The operating history of PBAPS demonstrates that previous transient events from full power are within expected peak limiting values. The transient analysis performed for the PBAPS EPU demonstrates that all safety criteria are met and that this uprate does not cause any previous non-limiting events to become limiting. [[

]] Some instrument setpoints were changed. The instrument setpoints that were changed (see Table 2.4-1) do not contribute to the response to large transient events. [[

]] Should any future large transients occur, PBAPS procedures require verification that the actual plant response is in accordance with the predicted response. Existing plant event data recorders are capable of acquiring the necessary data to confirm the actual versus expected response.

Further, [[

]] In addition, the limiting transient analyses are included as part of the RLA.

Conclusion

The EPU test program, including plans for the initial approach to the proposed maximum licensed thermal power level, transient testing necessary to demonstrate plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and the test program's conformance with applicable regulations, has been reviewed. Exelon concludes the proposed EPU test program provides adequate assurance the plant will operate in accordance with design criteria and SSCs affected by the proposed EPU, or modified to support the proposed EPU, will perform satisfactorily in service. Further, Exelon finds there is reasonable assurance that the EPU testing program satisfies the requirements of 10 CFR 50, Appendix B, Criterion XI. Therefore, Exelon finds the proposed EPU test program acceptable.

2.13 Risk Evaluation

2.13.1 Risk Evaluation of EPU

Regulatory Evaluation

Exelon conducted a risk evaluation to: (1) demonstrate the risks associated with the proposed EPU are acceptable; and (2) determine if "special circumstances" are created by the proposed EPU. As described in Appendix D of SRP Chapter 19 (Reference 113), special circumstances are present if any issue would potentially rebut the presumption of adequate protection provided by Exelon to meet the deterministic requirements and regulations. Exelon's review covered the effect of the proposed EPU on core damage frequency (CDF) and large early release frequency (LERF) for the plant due to changes in the risks associated with internal events, external events, and shutdown operations. The NRC's risk acceptability guidelines are contained in RG 1.174 (Reference 114). In addition, Exelon's review covered the quality of the risk analyses used by Exelon to support the application for the proposed EPU. This included a review of Exelon's actions to address issues or weaknesses that have been raised in previous industry reviews of the probabilistic risk assessment (PRA) models, various self-assessments, and in a recent peer review that was performed in accordance with the combined ASME/ANS PRA Standard (Reference 115).

Technical Evaluation

NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," Class III, July 2003 (also referred to as CLTR) was approved by the NRC as an acceptable method for evaluating the effects of CPPUs. Section 10.5 of the CLTR addresses the effect of CPPU on CLTR Individual Plant Evaluation. The results of this evaluation are described below.

The PRA analysis covers both internal and external events. The plant-specific PRA is used to compare pre-EPU and post-EPU plant design and operation. A combination of quantitative and qualitative methods is used to assess the potential risk impacts of EPU from internal and external events hazards. The results from this assessment (Reference 116) are included as EPU LAR Attachment 12. The evaluation in Attachment 12 addresses initiating event frequency, component reliability, success criteria, operator response, external events, shutdown risk, and PRA quality in detail. The results are consistent with the CLTR description and analysis of this topic.

The risk impacts from internal events resulting from EPU have been assessed by reviewing the changes in plant design and operations resulting from EPU. The changes have been mapped to appropriate elements and the PRA has been modified as needed to estimate the risk impact (CDF and LERF) of the post-EPU plant. As a result of EPU, the best estimate of the risk increase for at-power internal events due to the EPU is a delta CDF of 1.0E-7/yr (an increase of 2.8% over the base CDF of 3.6E-6/yr). The best estimate at-power internal events LERF increase due to the EPU is a delta LERF of 1.6E-8 (an increase of 3.5% over the base LERF of 4.6E-7/yr).

Using the NRC guidelines established in RG 1.174 (Reference 114) and the calculated results from the Level 1 and 2 PRA, the best estimate for the PBAPS CDF risk increase due to the EPU (1.0E-7/yr.) is in Region III (i.e., "very small" risk changes). The best estimate for the LERF increase (1.6E-8/yr.) is also in the lower range of Region III. Additionally, based on the information available for external events impacts, it is estimated that the incorporation of these contributors would not change this conclusion.

The sensitivity cases performed in this analysis also showed that the delta CDF and the delta LERF remain within or very close to the lower region of Region III except for the combined sensitivity case which pessimistically increased all of the initiator frequencies from the individual sensitivity cases at once. When the bounding sensitivity analyses (which included increases to various initiating event frequencies as described in Section 5.7.1 of Attachment 12) were summed with the expected risk estimates, CDF was calculated to increase by 55% (2.0E- 6/yr. increase) and LERF was estimated to increase by 44% (2.0E-7/yr. increase). Even in that case, the above increase in risk meets the acceptance guidelines described in RG 1.174 (Reference 114), which states that an increase in CDF in the range of 1E-6 to 1E-5 will be considered when it can be reasonably shown that the total CDF is less than 1E-4. Similarly, an increase in LERF in the range of 1E-7 to 1E-6 will be considered when it can be reasonably shown that the total LERF is less than 1E-5.

A bounding assessment factoring in the results of the pessimistic sensitivity case is also provided to demonstrate that the total CDF is less than 1E-4 and the total LERF is less than 1E-5.

Conclusion

An assessment of the risk implications associated with the implementation of the proposed EPU has been performed. Exelon concludes it has adequately modeled and/or addressed the potential impacts associated with the implementation of the proposed EPU. Exelon further concludes the results of the risk analysis indicate that the risks associated with the proposed EPU are acceptable and do not create the "special circumstances" described in Appendix D of SRP Chapter 19. Therefore, Exelon finds the risk implications of the proposed EPU acceptable.

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Appendix – A

Limitations from Safety Evaluations for LTR NEDC-33173P-A Revision 3

The following table lists the limitations from the Safety Evaluation for LTR NEDC-33173P-A, Revision 3, "Applicability of GE Methods to Expanded Operating Domains," (Reference A-1) with their location for implementation in the PUSAR.

Limitation Number from NRC SER	Limitation Title	Limitation Description	Disposition	Section of PBAPS PUSAR Which Addresses the Limitation
9.1	TGBLA/PANAC Version	The neutronic methods used to simulate the reactor core response and that feed into the downstream safety analyses supporting operation at EPU/MELLLA+ will apply TGBLA06/PANAC11 or later NRC-approved version of neutronic method.	Comply	Note 4 in Table 1-1.
9.2	3D Monicore	For EPU/MELLLA+ applications, relying on TGBLA04/PANAC10 methods, the bundle RMS difference uncertainty will be established from plant-specific core-tracking data, based on TGBLA04/PANAC10. The use of plant-specific trendline based on the neutronic method employed will capture the actual bundle power uncertainty of the core monitoring system.	N/A	(1)
9.3	Power to Flow Ratio	Plant-specific EPU and expanded operating domain applications will confirm that the core thermal power to core flow ratio will not exceed 50 MWt/Mlbm/hr at any statepoint in the allowed operating domain. For plants that exceed the power-to-flow value of 50 MWt/Mlbm/hr, the application will provide power distribution assessment to establish that	Comply	Section 2.8.2.4.2. Consistent with Reference A-5.

Limitation Number from NRC SER	Limitation Title	Limitation Description	Disposition	Section of PBAPS PUSAR Which Addresses the Limitation
		neutronic methods axial and nodal power distribution uncertainties have not increased.		
9.4	SLMCPR1	Limitation has been removed per Ref. A-1.1.	N/A	N/A
9.5	SLMCPR2	For operation at MELLLA+, including operation at the EPU power levels at the achievable core flow state-point, a 0.01 value shall be added to the cycle-specific SLMCPR value for power-to-flow ratios up to 42 MWt/Mlbm/hr, and a 0.02 value shall be added to the cycle-specific SLMCPR value for power-to-flow ratios above 42 MWt/Mlbm/hr. (Revised Limitation per Ref. A-1.1)	N/A	(2)
9.6	R-Factor	The plant specific R-factor calculation at a bundle level will be consistent with lattice axial void conditions expected for the hot channel operating state. The plant-specific EPU/MELLLA+ application will confirm that the R-factor calculation is consistent with the hot channel axial void conditions.	Comply	Section 2.8.2.4.3.
9.7	ECCS-LOCA 1	For applications requesting implementation of EPU or expanded operating domains, including MELLLA+, the small and large break ECCS-LOCA analyses will include top-peaked and mid-peaked power shape in establishing the MAPLHGR and determining the PCT. This limitation is applicable to both the licensing bases PCT and the upper bound PCT. The plant-specific applications will report the limiting small and large break licensing basis and upper bound PCTs.	Comply	Section 2.8.5.6.2 and Table 2.8-6.

Limitation Number from NRC SER	Limitation Title	Limitation Description	Disposition	Section of PBAPS PUSAR Which Addresses the Limitation
9.8	ECCS-LOCA 2	The ECCS-LOCA will be performed for all statepoints in the upper boundary of the expanded operating domain, including the minimum core flow statepoints, the transition statepoint as defined in Reference A-2 and the 55 percent core flow statepoint. The plant-specific application will report the limiting ECCS-LOCA results as well as the rated power and flow results. The SRLR will include both the limiting statepoint ECCS-LOCA results and the rated conditions ECCS-LOCA results.	N/A	(2), (5)
9.9	Transient LHGR 1	Plant-specific EPU and MELLLA+ applications will demonstrate and document that during normal operation and core-wide AOOs, the T-M acceptance criteria as specified in Amendment 22 to GESTAR II will be met. Specifically, during an AOO, the licensing application will demonstrate that the: (1) loss of fuel rod mechanical integrity will not occur due to fuel melting and (2) loss of fuel rod mechanical integrity will not occur due to pellet–cladding mechanical interaction. The plant-specific application will demonstrate that the T-M acceptance criteria are met for the both the UO_2 and the limiting GdO_2 rods.	Comply	Section 2.8.5.2.1 (7)
9.10	Transient LHGR 2	Each EPU and MELLLA+ fuel reload will document the calculation results of the analyses demonstrating compliance to transient T-M acceptance criteria. The plant T-M response will be provided with the SRLR or COLR, or it will be reported directly to the NRC as an attachment to the SRLR or COLR.	Comply	Section 2.8.5.2.1

Limitation Number from NRC SER	Limitation Title	Limitation Description	Disposition	Section of PBAPS PUSAR Which Addresses the Limitation
9.11	Transient LHGR 3	To account for the impact of the void history bias, plant-specific EPU and MELLLA+ applications using either TRACG or ODYN will demonstrate an equivalent to 10 percent margin to the fuel centerline melt and the 1 percent cladding circumferential plastic strain acceptance criteria due to pellet-cladding mechanical interaction for all of limiting AOO transient events, including equipment out-of-service. Limiting transients in this case, refers to transients where the void reactivity coefficient plays a significant role (such as pressurization events). If the void history bias is incorporated into the transient model within the code, then the additional 10 percent margin to the fuel centerline melt and the 1 percent cladding circumferential plastic strain is no longer required.	Comply	Section 2.8.5.2.1 (7)
9.12	LHGR and Exposure Qualification	In MFN 06-481, GE committed to submit plenum fission gas and fuel exposure gamma scans as part of the revision to the T-M licensing process. The conclusions of the plenum fission gas and fuel exposure gamma scans of GE 10x10 fuel designs as operated will be submitted for NRC staff review and approval. This revision will be accomplished through Amendment to GESTAR II or in a T-M licensing LTR. PRIME (a newly developed T-M code) has been submitted to the NRC staff for review (Reference A-3). Once the PRIME LTR and its application are approved, future license applications for EPU and MELLLA+ referencing LTR NEDC-33173P must utilize the PRIME T-M methods.	Comply (6)	The implementation of PRIME into the PBAPS licensing basis is consistent with Ref. A-3.1 and A-6.

Limitation Number from NRC SER	Limitation Title	Limitation Description	Disposition	Section of PBAPS PUSAR Which Addresses the Limitation
9.13	Application of 10 weight percent Gd	Before applying 10 weight percent Gd to licensing applications, including EPU and expanded operating domain, the NRC staff needs to review and approve the T-M LTR demonstrating that the T-M acceptance criteria specified in GESTAR II and Amendment 22 to GESTAR II can be met for steady-state and transient conditions. Specifically, the T-M application must demonstrate that the T-M acceptance criteria can be met for Thermal Overpower (TOP) and Mechanical Overpower (MOP) conditions that bounds the response of plants operating at EPU and expanded operating domains at the most limiting statepoints, considering the operating flexibilities (e.g., equipment out-of-service). Before the use of 10 weight percent Gd for modern fuel designs, NRC must review and approve TGBLA06 qualification submittal. Where a fuel design refers to a design with Gd-bearing rods adjacent to vanished or water rods, the submittal should include specific information regarding acceptance criteria for the qualification and address any downstream impacts in terms of the safety analysis. The 10 weight percent Gd qualifications submittal can supplement this report.	N/A	Section 2.8.2.4.5.

Limitation Number from NRC SER	Limitation Title	Limitation Description	Disposition	Section of PBAPS PUSAR Which Addresses the Limitation
9.14	Part 21 Evaluation of GESTR-M Fuel Temperature Calculation	Any conclusions drawn from the NRC staff evaluation of the GE's Part 21 report will be applicable to the GESTR-M T-M assessment of this SE for future license application. GE submitted the T-M Part 21 evaluation, which is currently under NRC staff review. Upon completion of its review, NRC staff will inform GE of its conclusions.	(6), (7)	The implementation of PRIME into the PBAPS licensing basis is consistent with Ref. A-3.1 and A-6.
9.15	Void Reactivity 1	The void reactivity coefficient bias and uncertainties in TRACG for EPU and MELLLA+ must be representative of the lattice designs of the fuel loaded in the core	Comply	(4)
9.16	Void Reactivity 2	A supplement to TRACG /PANAC11 for AOO is under NRC staff review (Reference A-4). TRACG internally models the response surface for the void coefficient biases and uncertainties for known dependencies due to the relative moderator density and exposure on nodal basis. Therefore, the void history bias determined through the methods review can be incorporated into the response surface "known" bias or through changes in lattice physics/core simulator methods for establishing the instantaneous cross-sections. Including the bias in the calculations negates the need for ensuring that plant-specific applications show sufficient margin. For application of TRACG to EPU and MELLLA+ applications, the TRACG methodology must incorporate the void history bias. The manner in which this void history bias is accounted for will be established by the NRC staff SE approving NEDE-32906P, Supplement 3, "Migration to TRACG04/PANAC11 from	N/A	(3)

Limitation Number from NRC SER	Limitation Title	Limitation Description	Disposition	Section of PBAPS PUSAR Which Addresses the Limitation
		TRACG02/PANAC10," May 2006 (Reference A-4). This limitation applies until the new TRACG/PANAC methodology is approved by the NRC staff.		
9.17	Steady-State 5 Percent Bypass Voiding	The instrumentation specification design bases limit the presence of bypass voiding to 5 percent (LRPM levels). Limiting the bypass voiding to less than 5 percent for long-term steady operation ensures that instrumentation is operated within the specification. For EPU and MELLLA+ operation, the bypass voiding will be evaluated on a cycle-specific basis to confirm that the void fraction remains below 5 percent at all LPRM levels when operating at steady-state conditions within the MELLLA+ upper boundary. The highest calculated bypass voiding at any LPRM level will be provided with the plant-specific SRLR.	Comply	Section 2.8.2.4.1.
9.18	Stability Setpoints Adjustment	The NRC staff concludes that the presence bypass voiding at the low-flow conditions where instabilities are likely can result in calibration errors of less than 5 percent for OPRM cells and less than 2 percent for APRM signals. These calibration errors must be accounted for while determining the setpoints for any detect and suppress long term methodology. The calibration values for the different long-term solutions are specified in the associated sections of this SE, discussing the stability methodology.	N/A	Section 2.8.3.1.2

Limitation Number from NRC SER	Limitation Title	Limitation Description	Disposition	Section of PBAPS PUSAR Which Addresses the Limitation
9.19	Void-Quality Correlation 1	For applications involving PANCEA/ODYN/ISCOR/TASC for operation at EPU and MELLLA+, an additional 0.01 will be added to the OLMCPR, until such time that GE expands the experimental database supporting the Findlay-Dix void-quality correlation to demonstrate the accuracy and performance of the void-quality correlation based on experimental data representative of the current fuel designs and operating conditions during steady-state, transient, and accident conditions.	Comply	Section 2.8.2.2.2
9.20	Void-Quality Correlation 2	The NRC staff is currently reviewing Supplement 3 to NEDE-32906P, "Migration to TRACG04/PANAC11 from TRACG02/PANAC10," dated May 2006 (Reference A-4). The adequacy of the TRACG interfacial shear model qualification for application to EPU and MELLLA+ will be addressed under this review. Any conclusions specified in the NRC staff SE approving Supplement 3 to LTR NEDC-32906P (Reference A-4) will be applicable as approved.	N/A	(3)
9.21	Mixed Core Method 1	Plants implementing EPU or MELLLA+ with mixed fuel vendor cores will provide plant-specific justification for extension of GE's analytical methods or codes. The content of the plant-specific application will cover the topics addressed in this SE as well as subjects relevant to application of GE's methods to legacy fuel. Alternatively, GE may supplement or revise LTR NEDC-33173P (Reference A-1) for mixed core application.	N/A	Section 2.8.2.4.6.

Limitation Number from NRC SER	Limitation Title	Limitation Description	Disposition	Section of PBAPS PUSAR Which Addresses the Limitation
9.22	Mixed Core Method 2	For any plant-specific applications of TGBLA06 with fuel type characteristics not covered in this review, GE needs to provide assessment data similar to that provided for the GEH/GNF fuels. The Interim Methods review is applicable to all GEH/GNF lattices up to GNF2. Fuel lattice designs, other than GEH/GNF lattices up to GNF2, with the following characteristics are not covered by this review: • square internal water channels water crosses • Gd rods simultaneously adjacent to water and vanished rods • 11x11 lattices • MOX fuel The acceptability of the modified epithermal slowing down models in TGBLA06 has not been demonstrated for application to these or other geometries for expanded operating domains. Significant changes in the Gd rod optical thickness will require an evaluation of the TGBLA06 radial flux and Gd depletion modeling before being applied. Increases in the lattice Gd loading that result in nodal reactivity biases beyond those previously established will require review before the GEH methods may be applied. (Limitation modified by Ref. A-1.2)	N/A	Section 2.8.2.4.7.
9.23	MELLLA+ Eigenvalue Tracking	In the first plant-specific implementation of MELLLA+, the cycle-specific eigenvalue tracking data will be evaluated and submitted to NRC to establish the performance of nuclear	N/A	(5)

Limitation Number from NRC SER	Limitation Title	Limitation Description	Disposition	Section of PBAPS PUSAR Which Addresses the Limitation
		methods under the operation in the new operating domain. The following data will be analyzed: • Hot critical eigenvalue, • Cold critical eigenvalue, • Nodal power distribution (measured and calculated TIP comparison), • Bundle power distribution (measured and calculated TIP comparison), • Thermal margin, • Core flow and pressure drop uncertainties, and • The MIP Criterion (e.g., determine if core and fuel design selected is expected to produce a plant response outside the prior experience base). Provision of evaluation of the core-tracking data will provide the NRC staff with bases to establish if operation at the expanded operating domain indicates: (1) changes in the performance of nuclear methods outside the EPU experience base; (2) changes in the available thermal margins; (3) need for changes in the uncertainties and NRC-approved criterion used in the SLMCPR methodology; or (4) any anomaly that may require corrective actions.		
9.24	Plant Specific Application	The plant-specific applications will provide prediction of key parameters for cycle exposures for operation at EPU (and MELLLA+ for MELLLA+ applications). The plant-specific	Comply	Section 2.8.2.4.4.

Limitation Number from NRC SER	Limitation Title	Limitation Description	Disposition	Section of PBAPS PUSAR Which Addresses the Limitation
		prediction of these key parameters will be plotted against the EPU Reference Plant experience base and MELLLA+ operating experience, if available. For evaluation of the margins available in the fuel design limits, plant-specific applications will also provide quarter core map (assuming core symmetry) showing bundle power, bundle operating LHGR, and MCPR for BOC, MOC, and EOC. Because the minimum margins to specific limits may occur at exposures other than the traditional BOC, MOC, and EOC, the data will be provided at these exposures.		

Notes:

(1) No reliance on TGBLA04/PANAC10 for PBAPS.

(2) Not applicable to EPU.

(3) The PBAPS EPU license application is not based on TRACG. Therefore, this limitation is not applicable.

(4) For the PBAPS EPU, TRACG is not applied in AOO or ATWS analysis. TRACG04 is applied for the thermal-hydraulic stability analysis for the PBAPS EPU. The void reactivity coefficient bias and uncertainties used in the stability analysis is representative of the lattice designs of the fuel loaded in the core. The TRACG application to the RIPD analysis does not involve reactor kinetics and is therefore not affected by this limitation.

(5) The limitation is applicable to MELLLA+ applications only. Therefore, this limitation is not applicable to the EPU application.

(6) Per Section 4.0 of Ref. A-3.1, "The NRC staff finds that Supplement 4 provides an acceptable process for cascading an approved, updated fuel thermal model into the suite of downstream safety analysis codes. Based on its detailed technical review, the NRC staff has determined that the proposed PRIME implementation plan is sufficient to address Limitation 12 from the NRC staff SE approving the IMLTR. The scope of the model updates is sufficient and addresses all relevant phenomena in the suite of

analysis methods. The process is generically acceptable for all operating domains. The NRC staff reviewed the software testing and implementation to ensure consistency with the requirements of 10 CFR 50, Appendix B, and 10 CFR 50.46 and found that the proposed activities described in Supplement 4 are in accordance with the Commission's regulations. At the conclusion of the code update and software testing process the NRC staff will audit the final documentation to ensure that the code updates were performed in accordance with the approved process described in Supplement 4. The NRC staff does not intend to review the approach taken to update these codes unless specific deviations are taken from the approved process."

(7) PRIME based T-M acceptance criteria were used in the EPU evaluations.

(8) Reference A-2.1 is the NRC approved revision to Ref. A-2. Reference A-2.1 contains the NRC final safety evaluation for NEDC-33006P.

References:

A-1 MFN 09-808, Thomas B. Blount, Deputy Director, Division of Policy and Rulemaking, Office of Nuclear Reactor Regulation to Jerald G. Head (GEH), "Final Safety Evaluation For General Electric (GE)-Hitachi Nuclear Energy Americas, LLC Licensing Topical Report NEDC-33173P, "Applicability Of GE Methods To Expanded Operating Domains" (TAC NO. MD0277)," July 21, 2009.

A-1.1 Robert A. Nelson (Deputy Director Division of Policy and Rulemaking Office of Nuclear Reactor Regulation United States Nuclear Regulatory Commission) to Jerald G. Head (GEH), "Final Safety Evaluation for GE Hitachi Nuclear Energy Americas Topical Report NEDC-33173P, Revision 2 and Supplement 2, Parts 1-3, "Analysis Of Gamma Scan Data and Removal of Safety Limit Critical Power Ratio (SLMCPR) Margin" (TAC NO. ME1891)," dated March 15, 2012.

A-1.2 John R. Jolicoeur (Acting Deputy Director Division of Policy and Rulemaking Office of Nuclear Reactor Regulation Unites States Nuclear Regulatory Commission) to Jerald G. Head. Head (GEH), "Final Safety Evaluation For GE Hitachi Nuclear Energy Americas Topical Report NEDC-33173P, Supplement 3, "Applicability Of GE Methods To Expanded Operating Domains – Supplement For GNF2 Fuel" (TAC NO. ME1815)," December 28, 2010.

A-2 MFN 05-141, L. M. Quintana (GEH) to NRC, "General Electric Boiling Water Reactor Maximum Extended Load Line Limit Analysis Plus," NEDC-33006P, Revision 2, November 28, 2005. (ADAMS Accession No. ML053360526).

A-2.1 GE Energy Nuclear, "General Electric Boiling Water Reactor Maximum Extended Load Line Limit Analysis Plus," NEDC-33006P-A, Revision 3, Class III (Proprietary), June 2009.

A-3 FLN-2007-001, A. A. Lingenfelter (GNF) to NRC, "The PRIME Model for Analysis of Fuel Rod Thermal-Mechanical Performance," January 19, 2007. (ADAMS Accession No. ML070250414).

A-3.1 Robert A. Nelson (Deputy Director Division of Policy and Rulemaking Office of Nuclear Reactor Regulation Unites States Nuclear Regulatory Commission) to J. Head (GEH), "Final Safety Evaluation for GE HITACHI Nuclear Energy Americas Topical Report NEDO-33173, Supplement 4, "Implementation Of Prime Models and Data In Downstream Methods" (TAC NO. ME1704), dated September 9, 2011.

A-4 GE Nuclear Energy, "Migration to TRACG04/PANAC11 from TRACG02/PANAC10," NEDE-32906P, Supplement 3, May 2006.

A-4.1 Thomas B. Blount, Deputy Director, Division of Policy and Rulemaking, Office of Nuclear Reactor Regulation to Jerald G. Head (GEH), "Final Safety Evaluation Of GE Hitachi Nuclear Energy Americas, LLC Licensing Topical Report NEDE-32906P, Supplement 3, "Migration to TRACG04/PANAC11 From TRACG02/PANAC10 for TRACG AOO AND ATWS Overpressure Transients" (TAC NO. MD2569)", July 10, 2009.

A-5 GEH Letter (MFN 08-693), "Implementation of Methods Limitations - NEDC-33173P (TAC No. MD0277)," September 18, 2008.

A-6 GEH Letter (MFN 12-033), "Response to NRC Letter Re: Nuclear Fuel Thermal Conductivity Degradation Evaluation for Light Water Reactors using GE-Hitachi Nuclear Energy Codes and Methods (TAC No. ME6598)," May 8, 2012.

Attachment 5

Peach Bottom Atomic Power Station Units 2 and 3

NRC Docket Nos. 50-277 and 50-278

Affidavit for Withholding Information Executed by GEH for Attachment 6

GE-Hitachi Nuclear Energy Americas LLC

AFFIDAVIT

I, **Edward D. Schrull, PE** state as follows:

(1) I am the Vice President, Regulatory Affairs, Services Licensing, GE-Hitachi Nuclear Energy Americas LLC (GEH), and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in GEH proprietary report NEDC-33566P, "Safety Analysis Report for Exelon Peach Bottom Atomic Power Station Units 2 and 3 Constant Pressure Power Uprate," Revision 0, dated September 2012. GEH proprietary information in NEDC-33566P is identified by a dotted underline inside double square brackets. [[This sentence is an example.{3}]]. Figures and large equation objects containing GEH proprietary information are identified with double square brackets before and after the object. In each case, the superscript notation {3} refers to Paragraph (3) of this affidavit, which provides the basis for the proprietary determination.

(3) In making this application for withholding of proprietary information of which it is the owner or licensee, GEH relies upon the exemption from disclosure set forth in the Freedom of Information Act (FOIA), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), and 2.390(a)(4) for trade secrets (Exemption 4). The material for which exemption from disclosure is here sought also qualify under the narrower definition of trade secret, within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) The information sought to be withheld is considered to be proprietary for the reasons set forth in paragraphs (4)a. and (4)b. Some examples of categories of information that fit into the definition of proprietary information are:

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

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

c. Information that reveals aspects of past, present, or future GEH customer-funded development plans and programs, that may include potential products to GEH.

d. Information that discloses trade secret and/or potentially patentable subject matter for which it may be desirable to obtain patent protection.

(5) To address 10 CFR 2.390(b)(4), the information sought to be withheld is being submitted to the NRC in confidence. The information is of a sort customarily held in confidence by GEH, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GEH, not been disclosed publicly, and not been made available in public sources. All disclosures to third parties, including any required transmittals to the NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary and/or confidentiality agreements that provide for maintaining the information in confidence. The initial designation of this information as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in the following paragraphs (6) and (7).

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, who is the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge, or who is the person most likely to be subject to the terms under which it was licensed to GEH. Access to such documents within GEH is limited to a "need to know" basis.

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

(8) The information identified in paragraph (2), above, is classified as proprietary because it contains detailed results and conclusions regarding supporting evaluations of the safety-significant changes necessary to demonstrate the regulatory acceptability of the Constant Pressure Power Uprate (CPPU) analysis for a GEH Boiling Water Reactor (BWR). The analysis utilized analytical models and methods, including computer codes, which GEH has developed, obtained NRC approval of, and applied to perform evaluations of CPPUs for a GEH BWR. The development of the evaluation process along with the interpretation and application of the analytical results is derived from the extensive experience database that constitutes a major GEH asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GEH's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GEH's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

GE-Hitachi Nuclear Energy Americas LLC

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GEH. The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial. GEH's competitive advantage will be lost if its competitors are able to use the results of the GEH experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GEH would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GEH of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing and obtaining these very valuable analytical tools.

I declare under penalty of perjury that the foregoing affidavit and the matters stated therein are true and correct to the best of my knowledge, information, and belief.

Executed on this 14th day of September 2012.

Edward D. Schrull
Vice President, Regulatory Affairs
Services Licensing
GE-Hitachi Nuclear Energy Americas LLC
3901 Castle Hayne Rd.
Wilmington, NC 28401

Attachment 7

Peach Bottom Atomic Power Station Units 2 and 3

NRC Docket Nos. 50-277 and 50-278

Summary of Regulatory Commitments

The following table identifies commitments made by Exelon Generation Company, LLC (EGC) in this document. Any other actions discussed in the submittal represent intended or planned actions. They are described to the NRC for the NRC's information and are not regulatory commitments.

COMMITMENT	SCHEDULED COMPLETION	COMMITMENT TYPE	
		ONE-TIME ACTION (Yes/No)	PROGRAMMATIC (Yes/No)
The modifications credited in the EPU safety analysis will be implemented as described in Attachment 9.	Prior to power ascension to EPU	Yes	No
The Replacement Steam Dryer, as described in Attachment 17, will be installed.	Prior to power ascension to EPU	Yes	No
EPU startup testing will be performed as described in Attachment 10.	As described	Yes	No
The simulator will be updated to model EPU operation including all modifications and transient analyses.	As described	Yes	No
The acceptance criterion for maximum allowable RHR heat exchanger fouling will be reduced resulting in an increase in RHR heat exchanger heat transfer capability as described in Enclosure 9c to Attachment 9.	Prior to power ascension to EPU	No	Yes

Attachment 8

Peach Bottom Atomic Power Station Units 2 and 3

NRC Docket Nos. 50-277 and 50-278

Supplemental Environmental Report

This Attachment 8 contains the Supplemental Environmental Report describing the impacts to the natural and human environment associated with the proposed Extended Power Uprate for the Peach Bottom Atomic Power Station (PBAPS).

Table of Contents

1.0 Executive Summary

This Supplemental Environmental Report contains the Exelon Generation Company, LLC (EGC) Peach Bottom Atomic Power Station Units 2 and 3 (PBAPS) assessment of the environmental impacts of the proposed extended power uprate (EPU) from the currently licensed thermal power level of 3514 megawatts-thermal (MWt) to nominally 3951 MWt per unit (Reference 1.1). The intent is to provide sufficient information for the U.S. Nuclear Regulatory Commission (NRC) to evaluate the environmental impact of the power uprate in accordance with the requirements of 10 CFR 51.

The environmental impacts of the proposed EPU are described and compared to those previously identified by the U.S. Atomic Energy Commission in the U.S. Atomic Energy Commission's (AEC) 1973 *Final Environmental Statement Related to Operation of Peach Bottom Atomic Power Plant Units 2 and 3 (FES)* and the NRC's Supplement 10 of the *Generic Environmental Impact Statement for the License Renewal of Nuclear Power Plants* (NUREG-1437)(GEIS) issued in January 2003 to address the license renewal of the PBAPS (Reference 1.2). This Supplemental Environmental Report demonstrates that the effects of operating under EPU conditions are within the original analyses documented in the FES, the more recent Supplement 10 of the GEIS, and current regulatory limits.

The PBAPS EPU will be implemented with changes to plant systems that directly or indirectly interface with the human and natural environment. However, all necessary plant modifications will be implemented within existing buildings at PBAPS. None of the proposed modifications will result in land disturbance or new construction outside of the established facility areas. There will be no change in the rate of water withdrawn from Conowingo Pond for condenser cooling. There will be an approximate 12.5 percent increase in the amount of waste heat discharged to Conowingo Pond or to the atmosphere through the existing cooling towers. The increase in waste heat discharged will increase the amount of water evaporated.

The extended power uprate will increase the effluent temperature by approximately 3°F. The maximum cooling water temperature rise as it passes through the Peach Bottom condensers will increase from 22°F under current thermal power conditions to approximately 25°F after the EPU. The increase in effluent temperature associated with the EPU is not anticipated to alter the aquatic environment.

EGC evaluated the compliance requirements associated with implementing the proposed EPU. EGC will maintain compliance with Pennsylvania State permits, licenses, approvals or other requirements currently held by the Plant. The National Pollutant Discharge Elimination System (NPDES) permit may be modified to reflect any actions identified to manage the thermal discharge prior to implementation of the EPU (Reference 1.3).

Although water withdrawal rate from Conowingo Pond will be unchanged for the EPU operation, EGC has received permission from the Susquehanna River Basin Commission (SRBC) to increase the consumptive water use at PBAPS to 49.000 MGD. EGC proposes to mitigate for this consumptive use with increased flows from sources as approved by the SRBC during low flow conditions. (Reference 1.4)

The generation of low-level radioactive waste will not increase significantly over the current generation rate. There will be minimal changes in the volume of radioactive effluents (liquid and gaseous) released to the environment. Although the radioactive contents of the liquid and gaseous releases will change slightly, they will remain bounded by the ANSI/ANS-18.1-1999 (Reference 1.5) analysis performed in support of the EPU and presented in the EPU License Application for Peach Bottom. All offsite radiation doses will remain small and within applicable regulatory requirements. As a result, EGC and our consultants have determined that the EPU operation will not significantly affect human health or the natural environment (40 CFR 1500-1508).

References

1.1 Sargent & Lundy. Exelon Peach Bottom Atomic Power Station Units 2 & 3, "Initial BOP Equipment Assessment for EPU". Evaluation No, 2009-07952, Revision 0A for Client Comment. S&L Project No. 11321-166.

1.2 NUREG-1437, Supplement 10, Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) Regarding Peach Bottom Atomic Power Station, Units 2 and 3, Final Report. NRC. January 2003. ML030270059

1.3 Authorization To Discharge Under The National Pollutant Discharge Elimination System NPDES Permit No. Pa 0009733, Peach Bottom Atomic Power Station. Pennsylvania Department of Environmental Protection. Effective January 1, 2011.

1.4 Susquehanna River Basin Commission Docket No. 20061209-1, Modified June 23, 2011 and SRBC letter of July 14, 2011.

1.5 ANSI/ANS-18.1-1999, Radioactive Source Term for Normal Operation of Light Water Reactors, American Nuclear Society, September 1999.

2.0 Introduction

Exelon Generation Company, LLC (EGC) and PSEG Nuclear, LLC of New Jersey co-own the PBAPS. EGC, as operator, is committed to operating PBAPS in an environmentally responsible manner. Plant activities including design, construction, maintenance, and operations are executed with intent to protect the human environment and to responsibly manage natural resources. EGC believes proper attention to the environment is essential to the well-being of the corporation, employees, neighbors to the site, and the broader global community. PBAPS has operated for more than 37 years consistent with state and federal environmental regulations, while providing safe, reliable, and economical electrical power to electric consumers.

This Supplemental Environmental Report is intended to provide sufficient detail on both the radiological and non-radiological environmental impacts of the proposed EPU to allow the NRC to make an informed decision regarding the proposed action. It does not reassess the current environmental licensing basis or justify the environmental impacts of operating at the currently licensed power level of 3514 MWt. Rather, this document demonstrates that the effects of operating under EPU conditions are bounded by the original analyses documented in the FES, the more recent Supplement 10 of the GEIS, or by current regulatory limits.

This environmental evaluation is provided pursuant to 10 CFR 51.41 ("Regulations to Submit Environmental Information") and is intended to support the U.S. Nuclear Regulatory Commission (NRC) environmental review of the proposed uprate. The proposed EPU will require the issuance of an operating license amendment for Units 2 and 3. The regulation (10 CFR 51.41) requires that applications to the NRC be in compliance with Section 102(2) of the National Environmental Policy Act (NEPA) and consistent with the procedural provisions of NEPA (40 CFR 1500-1508).

In 1973, the U.S. Atomic Energy Commission (AEC; predecessor agency to NRC) published the *Final Environmental Statement Related to the Operation of the Peach Bottom Atomic Power Station Units 2 and 3* (FES; AEC 1973)(Reference 2.1). The AEC concluded that the issuance of the full term operating license, subject to certain conditions related to monitoring, was the appropriate course of action under NEPA. This decision was based on the analysis presented in the FES and the weight of environmental, economic, and technical information reviewed by the AEC. It also took into consideration the environmental costs and economic benefits of operating PBAPS. The NRC subsequently issued the original operating license to PBAPS that authorized operation of each unit up to the maximum power level of 3293 MWt.

In 1994 through 1995 EGC implemented a Stretch Power Uprate (SPU) at PBAPS. Later in 2002 through 2003, EGC implemented a Measurement Uncertainty Recapture (MUR). Both uprates were reviewed by NRC and each included the preparation of environmental evaluations. These combined uprates increased the authorized maximum power level of each reactor from 3293 MWt to 3514 MWt.

In January 2003, the NRC published NUREG-1437 Supplement 10 of the *Generic Environmental Impact Statement for the License Renewal of Nuclear Power Plants* that addressed the license renewal of PBAPS (GEIS)(Reference 2.2). The NRC staff

recommended that the Commission determine that the adverse environmental impacts of license renewal for Peach Bottom Units 2 and 3 are not so great that preserving the option of license renewal for energy-planning decision makers would be unreasonable. This recommendation was based on; (1) the analysis and findings in the GEIS, (2) an Environmental Report submitted by EGC, (3) consultation with Federal, State, and local agencies, (4) the staff's own independent review, and (5) the staff's consideration of public comments.

General information about the design and operational features of PBAPS that are of interest from an environmental impact standpoint is available in several documents. In addition to the FES and Supplement 10 of the GEIS discussed above, another comprehensive source of information is the Updated Final Safety Analysis Report (Reference 2.3) prepared and maintained by EGC.

EGC has received and complies with the conditions within the permits identified in Table 2-1. No additional environmental permits are anticipated for the EPU.

Table 2-1
PBAPS PERMIT LISTING

Permit	Permit/Certificate No.	Regulation	Renewal Frequency
State Only Operating Permit - Air	67-05020	25 Pa. Code §127.401	5 Years
NPDES Permit	PA0009733	40 CFR §124.3; 25 Pa. Code §92a	5 Years
Registration / Permitting of Storage Tanks	67-60412	25 Pa. Code §245.201	Annual
Public Water Supply	6709503	25 Pa. Code §109.501	Indefinite[1]
Submerged Lands License Agreement	E67-503	25 Pa. Code §105.31-35	Indefinite[1]
Environmental Lab Accreditation	PA Certification 67-747 USEPA Laboratory ID # PA01098	25 Pa. Code §252	Initial Registration only for Accreditation By Rule (Section 252.6)
Water Obstruction & Encroachment	E36-693, E67-133, E67-391, E67-612, 16968, 16969, 18092, 18093, 17333	25 Pa. Code §105 & 106	5 Years if a PA issued Dredging Permit, if an Obstruction & Encroachment Permit it is Indefinite after construction.
Susquehanna River Basin Commission Docket	SRBC Docket 20061209-1	18 CFR §806	Expires 2034 Modified June 23, 2011

[1] Valid until system is modified

References

2.1 FES. 1973. "Final Environmental Statement Related to the Operation of Peach Bottom Atomic Power Station Units 2 and 3. Docket Nos. 50-277 and 50-278. April 1973. Prepared by United States Atomic Energy Commission, Directorate of Licensing.

2.2 NUREG-1437, Supplement 10, Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) Regarding Peach Bottom Atomic Power Station, Units 2 and 3, Final Report. NRC. January 2003. ML030270059

2.3 Updated Final Safety Analysis Report (UFSAR); PBAPS, Rev 23, 2011

3.0 Proposed Action and Need

PBAPS consists of Units 1, 2 and 3 located in Peach Bottom Township, York County, Pennsylvania on the west bank of the Conowingo Pond (Susquehanna River) (see Figure 3-1). Unit 1 is permanently shut down and is currently maintained in an operating SAFSTOR decommissioning condition. Unit 3, with the recent low pressure turbine upgrade is capable of generating approximately 1,230 megawatts of electricity (MWe), and Unit 2 is currently capable of generating approximately 1,151 MWe. These units began commercial operation in 1974. EGC operates PBAPS Units 2 and 3 pursuant to NRC Operating Licenses DPR-44 and DPR-56, respectively. The Unit 2 license will expire August 2033, and the Unit 3 license will expire July 2034. Each reactor unit produces steam to turn turbines to generate electricity. Plant cooling is provided by a once-through system using water from Conowingo Pond.

PBAPS is located approximately 38 miles north of Baltimore, Maryland. No major metropolitan areas occur within 6 miles of PBAPS (Figure 3-2). The site is 19 miles southwest of Lancaster, Pennsylvania and 30 miles southeast of York, Pennsylvania (Figure 3-1). The area within 6 miles of the site includes parts of York and Lancaster Counties in Pennsylvania and sections of Harford and Cecil Counties in Maryland.

The area around PBAPS is predominantly rural, characterized by farmland and woods.

3.1 Proposed Action

The proposed EPU will increase the licensed core thermal power for each of the PBAPS units from the currently licensed thermal power level of approximately 3514 MWt to nominally 3951 MWt. This will represent an increase of approximately 12.5 percent and will increase electrical output by approximately 142 MWe per unit or approximately 285 MWe total. This change in core thermal power will require the NRC to amend the facility's operating licenses. The PBAPS EPU will involve modifications to the power conversion systems. No new ground disturbing activities are planned. The increase in power level is scheduled to be accomplished for Unit 2 in 2014 and for Unit 3 in 2015. Capital spending is expected to be in the $800+ million range.

3.2 Need for Action

The proposed action provides EGC with the capability to increase the electrical output of PBAPS and to supply low cost, reliable, and efficient electrical generation to the State of Pennsylvania, the PJM ISO and the region without the need to site and construct new facilities or to impose new sources of air or water discharges on the environment. When compared with the costs of constructing new coal fired units and natural gas combustion turbine and combined cycle units, providing increased generation capacity through an EPU is an economical option for maintaining a highly reliable power supply network.

The proposed PBAPS EPU will provide significant economic benefits to Pennsylvania and the region. An additional 285 MWe of capacity at PBAPS could lower wholesale electricity prices in Pennsylvania by tens of millions of dollars per year, while maintaining and increasing grid reliability, which will enhance the competitiveness of Pennsylvania and PJM region businesses and industries.

Nuclear power plants generate about 20 percent of U.S. electricity. They do not burn anything when producing electricity, so they do not produce any combustion byproducts. By substituting for other fuels in electricity production, nuclear energy has significantly reduced U.S. emissions of nitrogen oxides, sulfur dioxide and carbon dioxide (Reference 3.1). Based on calculation tables 7-3 and 7-4 in the PBAPS License Renewal Application (Reference 3.2), and USEPA emissions data (Reference 3.3), the uprate will create environmental benefits as the addition of approximately 285 MWe from the EPU will replace an equivalent 285 MWe of fossil generation and its associated emissions. Sulfur oxides, nitrogen oxides, carbon monoxide, TSP and PM_{10} particulates were calculated using the same methodology as was used for the PBAPS License Renewal Application (Reference 3.2). Carbon dioxide has been calculated based on US EPA sources (Reference 3.3).

EGC estimates 285 MW of coal-fired generation emissions to be:

Sulfur oxides	=	1,767	tons per year
Nitrogen oxides	=	1,694	tons per year
Carbon monoxide	=	218	tons per year
TSP	=	52	tons per year
Particulates (PM10)	=	12	tons per year
Carbon dioxide	=	2,807,000	tons per year

EGC estimates 285 MW of gas-fired generation emissions to be:

Sulfur oxides	=	24	tons per year
Nitrogen oxides	=	79	tons per year
Carbon monoxide	=	16	tons per year
TSP - assumed all particulates are PM10			
Particulates (PM10)	=	14	tons per year
Carbon dioxide	=	1,417,000	tons per year

3.3 Alternatives to the Proposed Action

As an alternative to the proposed action, Exelon considered the consequences if the EPU were not approved for PBAPS (i.e. the "no action" alternative). In that case, Exelon and other agencies and electric power organizations may be required to pursue other means, such as fossil fuel or alternative fuel power generation, to provide electric generation capacity to offset future demand. Construction and operation of such a fossil-fueled or alternative-fueled plant may create impacts in air quality, land use, water, and waste management significantly greater than those identified for the proposed EPU at PBAPS. Furthermore, the proposed EPU does not involve environmental impacts that are significantly different from those originally identified in the PBAPS FES and the GEIS-supplement 10 (Reference 3.4).

References

3.1 Nuclear Energy Institute (NEI) Fact Sheet, *Nuclear Energy and the Environment*, October 2007.

3.2 PBAPS 2003. *Application of Renewed Operating License – Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3* – Appendix E – Environmental Report; Tables 7-3 and 7-4.

3.3 EPA (2011) eGRID2010 data; as reported on EPA websites reviewed 1/31/2012
http://www.epa.gov/cleanrgy/energy-and-you/affect/coal.html
http://www.epa.gov/cleanrgy/energy-and-you/affect/natural-gas.html

3.4 NUREG-1437, Supplement 10, Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) Regarding Peach Bottom Atomic Power Station, Units 2 and 3, Final Report. NRC. January 2003. ML030270059

Figure 3-1
50-Mile Region

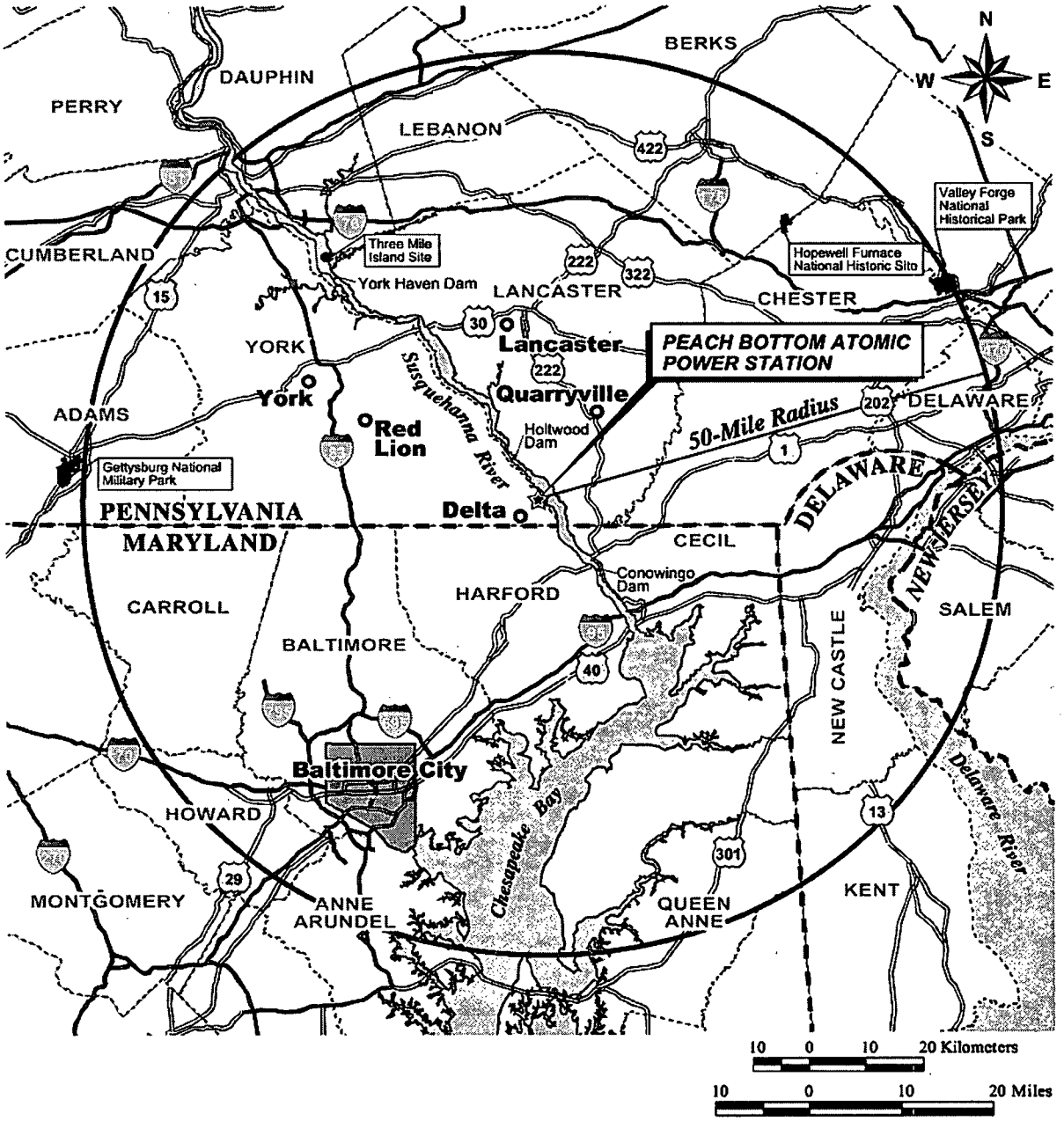


Figure 3-2
6-Mile Region

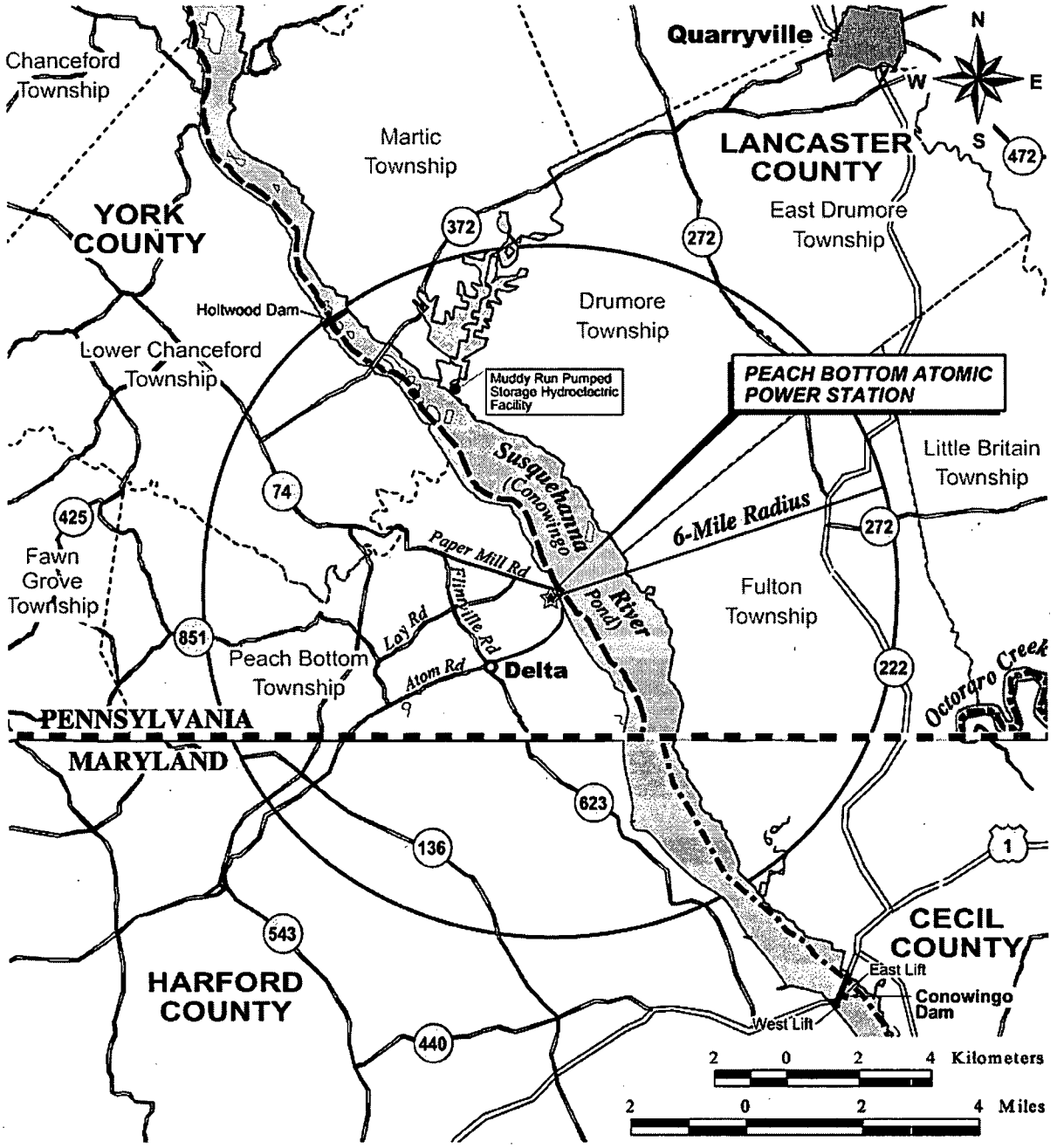
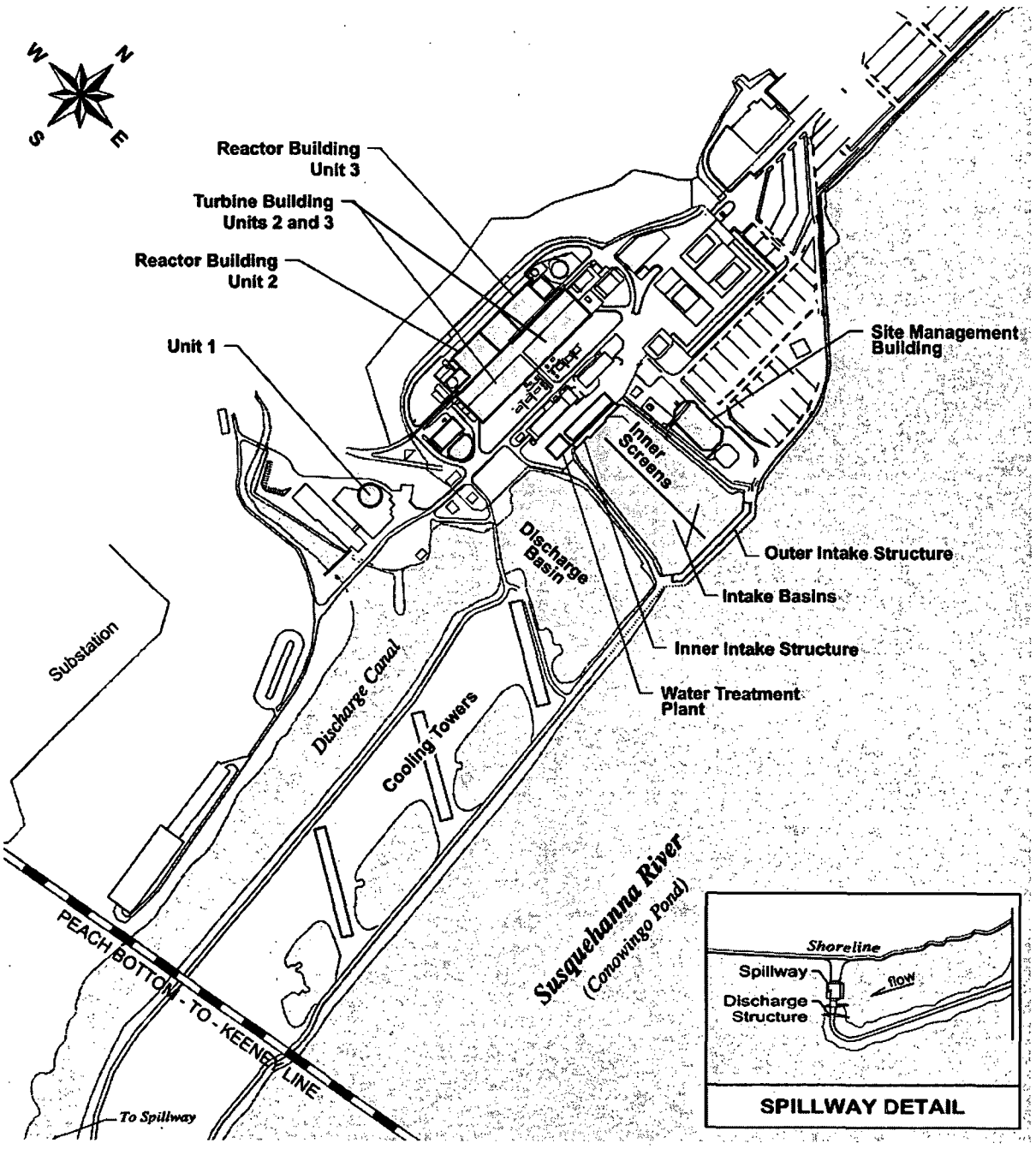


Figure 3-3
PBAPS Site Map



4.0 Overview of Operational and Equipment Changes

In general, light water reactors are designed with an as-built equipment capability to increase power up to 7 percent above the original licensed power level. EGC has already completed a Stretch Power Uprate (SPU) in 1994 and 1995 of 5 percent of Original Licensed Thermal Power (OLTP), and a 1.62 percent Appendix K Uprate in 2002 and 2003 at PBAPS. For power uprates beyond 7 percent several modifications are needed to the plant and fuel to produce the additional thermal power. The modifications are either to be able to accommodate the added steam flow or to allow the balance of plant equipment to support the additional feed water flow or heat rejection.

The activities needed to produce thermal power increases are a combination of those that directly produce more power and those that will accommodate the effects of the power increase. The primary means of producing more power are an operational change in reactor thermal-hydraulic parameters and upgrades of the balance of plant capacity by component replacement or modification. Other changes include replacing the high and low pressure turbines, providing additional cooling for some plant systems, replacement of condensate pumps, replacement of some feedwater heaters, modifications to accommodate greater steam and condensate flow rates, and instrumentation upgrades that include replacing parts, changing set-points, and modifying software. Attachments 1 and 9 of the License Amendment Request provides additional information on the modifications being performed to support EPU.

These modifications are expected to occur during the unit refueling outages from 2011 to 2015.

Upon NRC approval of the EPU LAR, PBAPS Units 2 and 3 are expected to begin operating at the EPU core power level of 3951 MWt in the Fall of 2014 and 2015, respectively, following completion of the scheduled outage periods and power ascension testing.

5.0 Socioeconomic Considerations

This chapter describes the employment associated with both the current operation of PBAPS, the additional workforce associated with implementation of the EPU, the taxes paid to the schools and county by PBAPS, and the racial and poverty characteristics (Environmental Justice considerations) of the region. The chapter also describes the potential impacts to these socioeconomic resources and conditions associated with the EPU.

5.1 Current Socioeconomic Status

EGC currently employs nearly 1100 employees at PBAPS; consisting of about 200 contract employees and 900 permanent employees. During regularly scheduled refueling outages (30 to 40 days on average for each unit on a 24-month cycle), this workforce is augmented by approximately 800 temporary workers for a total of approximately 1900 employees. The workforce to support EPU implementation, including modification installations, will be further augmented by approximately 1300 additional temporary workers for approximately 3200 people total.

Approximately 35 percent of PBAPS' employees live in York County, 30 percent live in Lancaster County, 13 percent live in Chester County (mostly on the western edge of the county), 10 percent live in Harford County, Maryland, and the rest live in other locations.

The continued employment of the local population with normal operation of PBAPS and the associated expenditures for goods and services and contributions to payroll taxes, sales taxes, and taxes on properties owned by PBAPS employees will positively impact the local and regional economy.

5.2 Extended Power Uprate Impacts to Socioeconomics

Workforce numbers for the 2014 outage, when the first phase of EPU modifications will be completed, will be approximately 3200 workers. However, the outage will be of short duration and of a small enough magnitude as to not adversely alter local housing availability, traffic patterns or public water supply and sewer systems in the general vicinity of PBAPS. Employee incomes and the purchases of goods and services afforded by those incomes, along with the personal property taxes paid by PBAPS employees will continue to contribute positively to the communities in the vicinity of PBAPS during and after the uprate related outage periods.

EGC payments to engineering and consulting firms, plant equipment suppliers, and local service industries for implementation of the proposed EPU will have a positive, though temporary impact on local and regional economies.

There will also be economic benefit to both the regional and local economies from the enhanced viability of PBAPS's long-term operation resulting from the additional electrical generation. That expanded financial viability over the long term, associated with PBAPS EPU operation, will help regional planners and local governments organize, plan and develop the long term sustained growth for the area.

EGC is a significant property taxpayer, paying taxes to York County, Peach Bottom Township, and to the South Eastern School District. In 2008, Exelon entered into an agreement with these local taxing bodies to set the assessment at a rate all parties agreed to. This settlement agreement included significant additional Payments in Lieu of Taxes (PILOTS) to each local taxing body to help mitigate the financial impact of lower assessments in recent years. This settlement provides budgetary consistency to both the local taxing bodies and to EGC. The Taxes and PILOT payments paid in 2010 totaled $1,442,630 for the 2010/2011 tax year. A chart of property taxes paid by EGC for the site follows:

Tax Year	PILOTs	Taxes	Total
2007/08	$ 1,021,200	$ 9,926	$ 1,031,126
2008/09	$ 1,200,054	$ 354,323	$ 1,554,377
2009/10	$ 972,570	$ 299,978	$ 1,341,636
2010/11	$ 972,570	$ 470,060	$ 1,442,630

These tax revenues will continue to benefit local communities, supporting public services such as public education, police and fire protection, road maintenance, local recreational facilities and programs, and other municipal services.

After the EPU, PBAPS will continue to provide a positive contribution to the local and regional economies with continued property taxes and payments in lieu of property taxes to the local governments, and additional payments for goods and services associated with the proposed EPU implementation.

5.3 Environmental Justice

This section compares the 1990 and 2000 census information used in the License Renewal Application with 2010 US Census data from the US EPA IDEAS data base to demonstrate the racial and socioeconomic conditions are little changed from the time of preparation of the 2001 License Renewal Application. This information also demonstrates that there are no environmental justice issues associated with the continued operation of PBAPS nor with the EPU action.

Table 5-1 is a reproduction of the first part of Table 2-5 from the License Renewal Application Appendix E (Reference 5.1) which provided the State Average Minority or Low-Income Population (%) based on 1990 data. EGC subsequently augmented this table with 2000 census data for comparison. The table displays the change in minority and low income populations in the 4 states that are within 50 miles of the Peach Bottom site, and demonstrates that at the state level, minority or low income populations have undergone minimal change in the interval between 1990 and 2000 census periods.

Table 5-1
State Average Minority or Low-Income Population (%)
U.S. Census Bureau data [1990[1] / 2000[2]]

	Delaware	Maryland	Pennsylvania	New Jersey
American Indian or Alaskan Native	<1 / **<1**	<1 / **<1**	<1 / **<1**	<1 / **<1**
Asian or Pacific Islander	1 / **2.1**	3 / **4.0**	1 / **1.8**	4 / **5.7**
Black (non-Hispanic Origin)	17 / **19.2**	25 / **27.9**	9 / **10.0**	13 / **13.6**
Hispanic	2 / **4.8**	3 / **4.3**	2 / **3.2**	10 / **13.3**
Low Income[3]	9 / **9.2**	8 / **8.5**	11 / **11.0**	8 / **8.5**

[1] Reference 5.1: PBAPS License Renewal Application TABLE 2-5 (U.S. Census Bureau 1990 data.)
[2] Reference 5.2: U.S. Census Bureau 2000 data (*QT-P3. Race and Hispanic or Latino: 2000*)
[3] Reference 5.3: U.S. Census Bureau 2000 data (*GCT-P14. Income and Poverty in 1999: 2000*)

In addition to the state by state comparison shown in Table 5-1, PBAPS has also evaluated the race and poverty levels at the county level.

Table 5-2 below compares the county poverty levels for every county within 50 miles of PBAPS to that of the state average poverty levels from 2010, as well as the historical poverty levels in these counties in 1990 and 2000. The table shows that with the exception of 5 of the 20 counties within 50 miles of PBAPS, the poverty rate is lower near PBAPS than the average of the state. For those 5 counties with higher than the state average poverty levels, including Salem County New Jersey, Kent County Delaware, Cecil County Maryland, and Dauphin and Berks Counties in Pennsylvania, the poverty levels were all less than 20 percent higher than the state averages.

Table 5-2
Poverty Levels by State and County within 50 Miles of PBAPS

	2010 State Average[1]	% Poverty 1990	% Poverty 2000	% Poverty 2010[1]
Gloucester New Jersey	10.5	6.2	6.2	6.8
Salem New Jersey	10.5	10.6	9.5	11.9
New Castle Delaware	11.9	7.5	8.4	11.2
Kent Delaware	11.9	11.3	10.7	12.1
Cecil Maryland	9.9	7.5	7.2	10.5
Queen Anne Maryland	9.9	6.7	6.3	7.3
Harford Maryland	9.9	5.1	4.9	6.9
Baltimore Maryland	9.9	5.5	6.5	8.2
Anne Arundel Maryland	9.9	4.5	5.1	6.6
Howard Maryland	9.9	3.1	3.9	5.2
Carroll Maryland	9.9	3.8	3.8	5.4
York Pennsylvania	13.4	6.3	6.7	9.2
Adams Pennsylvania	13.4	6.8	7.1	9.9
Lancaster Pennsylvania	13.4	8	7.8	10.5
Dauphin Pennsylvania	13.4	10.1	9.7	13.9
Lebanon Pennsylvania	13.4	7.2	7.5	11
Berks Pennsylvania	13.4	8	9.4	13.7
Chester Pennsylvania	13.4	4.7	5.2	6.4
Delaware Pennsylvania	13.4	7	7.5	10
Montgomery Pennsylvania	13.4	3.6	4.4	5.8

[1] Reference 5.4: U.S. Census Bureau 2010 data by State (http://2010.census.gov/2010census/data/)

Table 5-3 below compares the county minority population levels for every county within 50 miles of PBAPS to that of the state average minority population from 2010, as well as the historical poverty levels in these counties in 2000. The table shows that with the exception of 7 of the 20 counties within 50 miles of PBAPS, the minority population levels are lower near PBAPS than the average of the state. For 6 of those counties with higher than state average minority population levels, including New Castle and Kent Counties Delaware, Baltimore and Howard Counties Maryland, and Dauphin and Montgomery Counties Pennsylvania, levels were all less than 20 percent higher than the state averages. Delaware County in Pennsylvania has a 38 percent minority population level as compared to the 2010 state average of 18 percent.

Table 5-3
Minority Population by State and County within 50 Miles of PBAPS

	Percentage of Non-White by County		
	2010 State Average	2000	2010
Gloucester New Jersey	31	12.9	16
Salem, New Jersey	31	18.8	20
New Castle Delaware	31	37	34
Kent Delaware	31	36.5	32
Cecil Maryland	32	6.6	11
Queen Anne Maryland	32	11	11
Harford Maryland	32	13.2	19
Baltimore Maryland	32	25.6	35
Anne Arundel Maryland	32	18.8	25
Howard Maryland	32	25.7	38
Carroll Maryland	32	4.3	7
York Pennsylvania	18	7.2	11
Adams Pennsylvania	18	4.6	6
Lancaster Pennsylvania	18	8.5	11
Dauphin Pennsylvania	18	22.9	37
Lebanon Pennsylvania	18	5.5	9
Berks Pennsylvania	18	11.9	17
Chester Pennsylvania	18	10.8	14
Delaware Pennsylvania	18	19.7	38
Montgomery Pennsylvania	18	13.5	19

At a tighter scale to the plant, Table 5-4 taken from the US EPA IDEA Query; *Demographic Profile of Surrounding Area*, using U.S. Census Bureau 2010 census data (Reference 5.5) demonstrates the following racial and age breakdown of the population within 5 miles of the PBAPS.

Table 5-4
Race and Age within 5 Miles of PBAPS

Race and Age* (* Columns that add up to 100% are highlighted)			
Race Breakdown	**Persons (%)**	**Age Breakdown**	**Persons(%)**
White	8134 (97.6%)	**Child 5 years or less**	798 (9.6%)
African-American	61 (0.7%)	**Minors 17 years and younger**	2481 (29.8%)
Hispanic-Origin	63 (0.8%)	**Adults 18 years and older**	5850 (70.2%)
Asian/Pacific Islander	54 (0.6%)	**Seniors 65 years and older**	811 (9.7%)
American Indian	10 (0.1%)	*This space intentionally left blank*	
Other Race	26 (0.3%)		
Multiracial	48 (0.6%)		

As can be seen in Table 5-4, white populations are predominant in the immediate vicinity of PBAPS and other racial subsets are relatively rare. The minority population is less than the state average and less than any of the surrounding counties outside the 5 mile radius of the PBAPS.

The income and home ownership breakdown within 5 miles of the plant, taken from the US EPA IDEA Query (Reference 5.5), illustrated in Table 5-5, demonstrates the following income per household as well as housing tenure.

Table 5-5
Income per Household plus Housing Tenure within 5 Miles of PBAPS

Income	
Income Breakdown	**Households (%)**
Less than $15,000	242 (8.3%)
$15,000 - $25,000	358 (12.3%)
$25,000 - $50,000	1039 (35.8%)
$50,000 - $75,000	767 (26.4%)
Greater than $75,000	479 (16.5%)
Tenure	
Tenure Breakdown	**Households (%)**
Occupied Housing Units	2902 (100.0%)
Owner Occupied	2421 (83.4%)
Renter Occupied	482 (16.6%)

This table shows that a very high proportion of the local population owns their own housing unit.

The details of the US EPA IDEA Query (which are not shown on the above tables) of the 5 mile radius of PBAPS noted that only 6 percent of the population within 5 miles of the plant live below poverty level. This compares to 8.5 percent and 11 percent of the population in Pennsylvania and Maryland and this poverty rate is less than all the surrounding counties except Hartford County Maryland (at 4.9 percent).

This EPA and US Census based supplemental analysis confirms the results from the 2001 License Renewal Application Environmental Report with respect to Socioeconomic effects of license renewal where the NRC staff, "...concludes that offsite impacts from Peach Bottom Units 2 and 3 to minority and low-income populations would be small, and no additional mitigation actions are warranted." These analyses collectively demonstrate that the PBAPS site is not located in an area with larger than state average racial minorities nor higher than state average poverty levels. On the contrary the counties within 50 mile radius generally have fewer minorities and lower poverty than the state average. The one exception is Delaware County in Pennsylvania where the minority population is 38 percent in the most recent US Census compared to the Pennsylvania state average minority population of 18 percent.

5.4 Conclusion on Socioeconomics

The PBAPS currently employs 1100 staff and the operational staff will be unchanged operating at EPU. There will be an approximate maximum of 3200 staff on site to effect the EPU and PBAPS will continue to pay local property taxes after EPU. The PBAPS vicinity is characterized as having generally lower minority and poverty rates than the state averages and only one county has a moderately elevated minority population out of the 20 counties located within 50 miles of PBAPS. There are no environmental justice issues to address with either existing operation or the implementation of the EPU.

References

5.1 PBAPS 2003. *Application of Renewed Operating License – Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3* – Appendix E – Environmental Report.

5.2 U.S. Census Bureau 2000 data (QT-P3. Race and Hispanic or Latino: 2000)

5.3 U.S. Census Bureau 2000 data (GCT-P14. Income and Poverty in 1999: 2000)

5.4 U.S. Census Bureau 2010 data by State (http://2010.census.gov/2010census/data/)

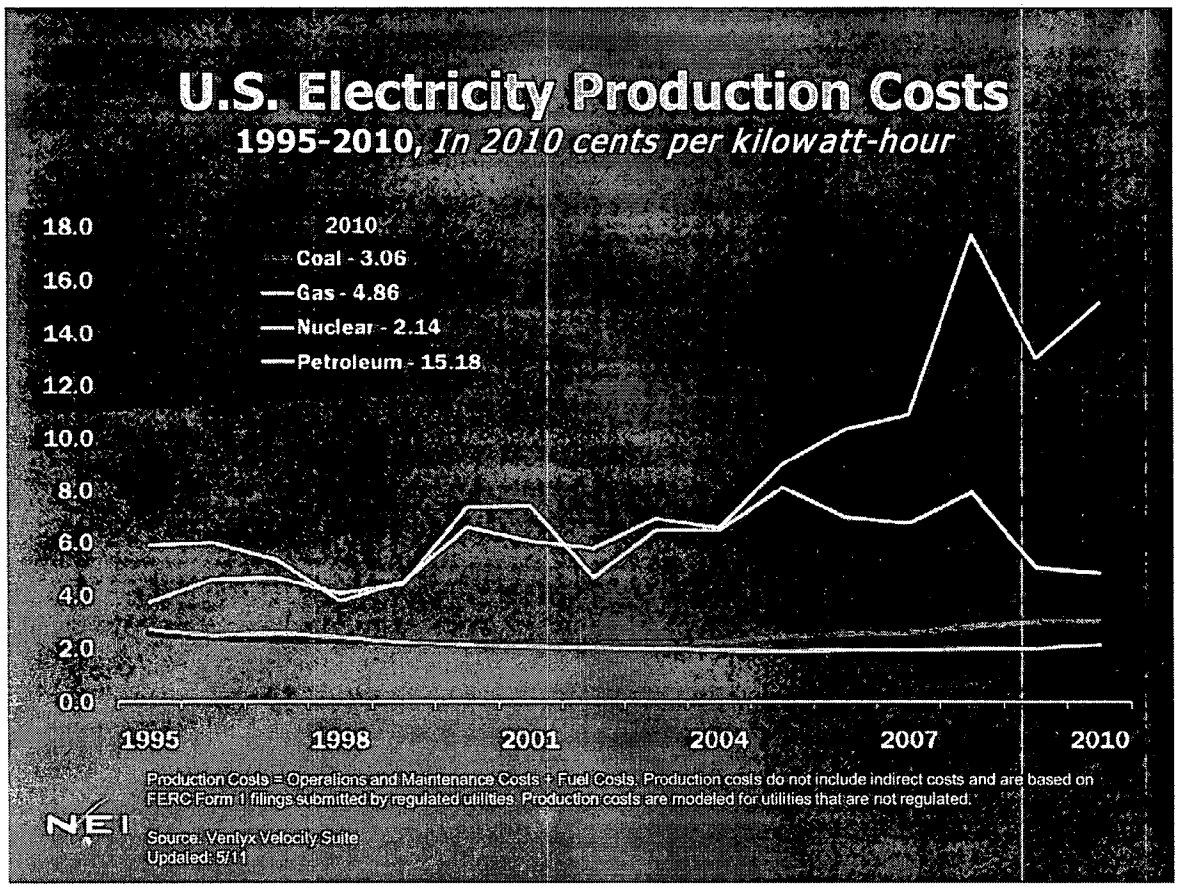
5.5 U.S. Census Bureau 2010 census data (http://oaspub.epa.gov/envjust/env_just_ejv.get_geom?report_type=html&census_type=bg2k&p_caller=self&coords=-76.275320,39.766300&feattype=point&radius=5.0)

6.0 Cost – Benefit Analysis

The largest direct benefit resulting from the proposed EPU to PBAPS' current capacity is the additional supply of approximately 142 megawatts electric per unit (or approximately 285 total) of reliable electrical power for residential and commercial consumers.

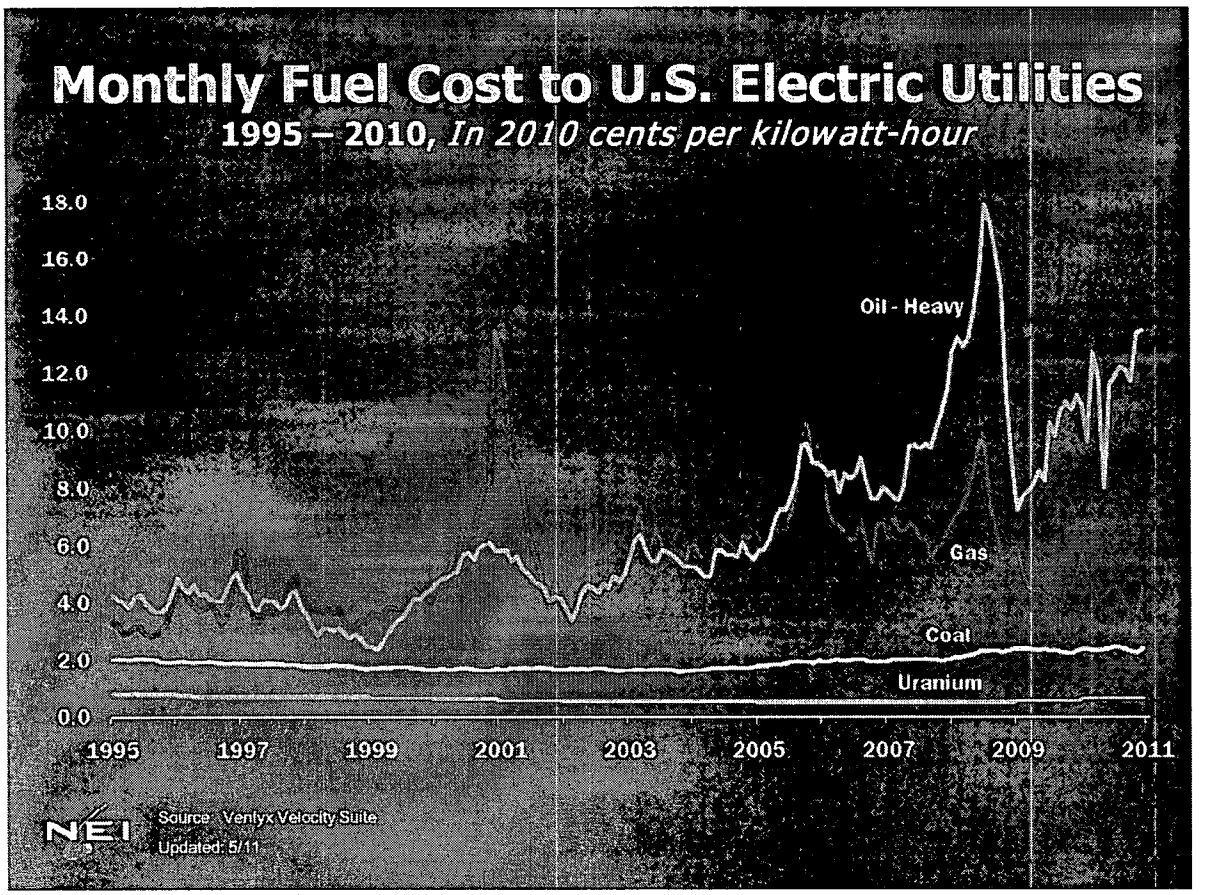
A national comparison of electric generation alternatives, updated in May 2011 with data through 2010, indicates that nuclear power generation production costs are lower than that of coal-fired power, oil-fired power, and natural gas-fired power production. Power production costs represent a combination of fuel, operations, and maintenance costs. The figures below, from the Nuclear Energy Institute (NEI), show that the production cost of existing nuclear generating facilities are considerably less than oil or natural gas fired steam electric generation sources and even less than that of coal. (Reference 6.1)

Figure 6-1



In addition, the US Nuclear industry continues to optimize the cost of nuclear fuel per kilowatt-hour each year as can be seen in the following graph of monthly fuel cost. This second NEI figure illustrates that the nuclear fuel costs associated with production of one kilowatt hour of electricity has generally decreased or remained similar over the years. Coal and nuclear generated electric power fuel costs are more steady and consistent and uranium costs per kilowatt-hour continue to be the lowest of the four alternatives. (Reference 6.2)

Figure 6-2



A quantitative evaluation of environmental costs of alternatives will not be necessary to recognize that a significant amount of new environmental impacts will be avoided by implementing an EPU at PBAPS compared with other new power development options to deliver additional capacity. Unlike fossil fuel plants, an EPU will not result in a significant source of air emissions such as nitrogen oxides, sulfur dioxide, carbon dioxide, or other regulated atmospheric pollutants as a part of normal operations. Routine operation of PBAPS at EPU conditions will not contribute to greenhouse gases or acid rain.

The radiological effects of the uranium fuel cycle are described in 10 CFR 51.51 and 51.52 and are classified as small. The PBAPS EPU radiological effects fall within the bounds of the tables in 10 CFR 51.52. PBAPS's existing spent fuel storage strategy remains the same for the EPU.

Based upon these considerations, it is reasonable to conclude that the proposed PBAPS EPU will provide a cost-effective utilization of an existing asset, with minimal environmental impact, making it the preferred means of securing additional generating capacity to support the growing electric demand in Pennsylvania.

References

6.1 NEI – Electricity production costs (1995 to 2010) updated 5/2011, accessed 1/25/2012 at NEI web site: www.nei.org/filefolder/US_Electricity_Production_Costs.ppt

6.2 NEI - U.S. Monthly Fuel Cost to U.S. Electric Utilities (1995-2010) updated 5/2011, accessed 1/25/2012 at NEI web site: http://www.nei.org/filefolder/Monthly_Fuel_Cost_to_US_Electric_Utilities.ppt

7.0 Non-Radiological Environmental Impacts

The existing terrestrial and aquatic natural environmental conditions in the vicinity of the PBAPS are well characterized in the Environmental Report (Appendix E) of the 2001 PBAPS License Renewal Application. See Appendix E of the Application of Renewed Operating License – Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3 (Reference 7.1) for a full characterization of the current natural and human environment conditions in the vicinity of PBAPS.

7.1 Terrestrial Impacts

7.1.1 Land Use

No EPU related land use impacts are anticipated. No new construction is planned outside the existing facility foot print, and no new permanent expansion of buildings, roads, parking lots, equipment storage areas, or transmission facilities on site will be required to either complete the proposed EPU modifications or operate PBAPS at EPU conditions. The proposed EPU will not require substantial additional storage of industrial chemicals, or create the need for additional storage tanks on site. The amount of diesel fuel oil stored on site will increase slightly with EPU, but will be stored in the current underground storage tanks. There will be no change in the Peach Bottom Storage Tank and Spill Prevention Response Plan and Spill Prevention, Control and Countermeasure Plan.

The proposed uprate will contribute more power to the PJM Interconnection grid which is managed by PJM ISO. The preliminary study prepared by PJM ISO for the PBAPS uprate indicates that a number of system upgrades may be needed. PJM ISO will include the PBAPS EPU project when they consider future plans for improvements to the transmission system to address local load changes and the capacity and reliability of existing transmission equipment. If modifications to the transmission system are required, the owners of the substations or transmission lines requiring modification will plan and design the upgrades and seek the appropriate regulatory and environmental approvals prior to implementation of construction.

Right-of-Way maintenance is conducted by PECO, an Exelon Company. However, there is no reason to expect changes in transmission line vegetation management as a result of the proposed PBAPS EPU.

The increase in electrical power output will cause a corresponding increase in current on the transmission system, and this will result in an increased electromagnetic field (EMF). However, in other environmental reviews, the NRC has determined that a scientific consensus has not been reached on the chronic effects of EMF on humans, and that no significant impacts to the terrestrial biota have been identified (Reference 7.2).

7.1.2 Noise

EPU construction will be contained within existing structures so no incremental noise effects, other than those incremental impacts associated with the typical refueling outage, are anticipated.

Operations under proposed EPU conditions will be no different than those under current conditions. New equipment for the EPU will be enclosed in existing structures and there should be no change in offsite noise conditions during operation.

7.1.3 Cultural Resources

The FES related to operation of PBAPS, prepared in 1973 by the AEC (Reference 7.3) stated that "no artifacts of historical or archaeological significance (were) found within the site boundary" during construction and none have been discovered in more than 25 years of station operation. An archaeologist from the William Penn Museum conducted an evaluation of the site in 1972 and observed that the impoundment of the Susquehanna River in the 1920s to create Conowingo Pond flooded the floodplain and terrace areas most likely to contain cultural artifacts. Within York and Lancaster Counties in Pennsylvania and Harford County in Maryland, there are 78, 198, and 76 sites, respectively, listed on the National Register of Historic Places. Nine of these sites are located within 6 miles of PBAPS

List of Historic Places:

1. Coulsontown Cottages Historic District located at Ridge Road and Main Street, Delta PA
2. Delta Historic District Main Street, Delta, PA
3. Muddy Creek Bridge for the Maryland and Pennsylvania Railroad – are the Maryland and Pennsylvania RR tracks over Muddy Creek, east of Creek Ridge Road, Peach Bottom and Lower Chanceford Townships, Sunnyburn
4. Scott Creek Bridge located at North Maryland and Pennsylvania Railroad-Maryland and Pennsylvania RR tracks over Scott Creek, west of Watson's Corner and south of PA 851, Peach Bottom Township, Bryansville
5. Duncan Island Address Restricted, Holtwood
6. Robert Fulton Birthplace 8 miles south of Quarryville on U.S. 222, Quarryville, PA
7. Broad Creek Soapstone Quarries, Address Restricted, Whiteford Maryland
8. Rigbie House Located southeast of Berkley off MD 623
9. Slate Ridge School, located on Old Pylesville Road, Whiteford.

With no changes proposed to surrounding land use patterns, and no new permanent structures associated with the proposed EPU, there will be no impacts to the cultural resources of the region. EGC has consulted with the PA Historic and Museum Commission and requested its concurrence with the conclusion that there will be no impacts to archeological or cultural resources in the area. Correspondence sent to the PA Historic and Museum Commission and their response letter are in Attachment 1 to this report.

7.1.4 Groundwater

PBAPS participates in the Nuclear Energy Institute (NEI) industry initiative to protect groundwater. As a part of Initiative 07-07 (Technical Report 07-07 "Industry Groundwater Protection Initiative – Final Guidance Document"), PBAPS participates in an active program of monitoring groundwater. PBAPS will inform the NRC, state agencies and local officials of unintended releases of radiological materials to groundwater, which meet the reporting requirements. PBAPS also will follow the principles of the NEI Technical Report 08-08 and NEI 9-14 program to monitor, inspect and improve buried piping and tank systems to prevent future unintended releases of radiological materials to groundwater. As a consequence of these voluntary industry initiatives, PBAPS has developed and implemented a NEI-approved radiological groundwater protection program to mitigate the potential for radiological releases to the groundwater. The NRC assesses the PBAPS voluntary implementation plan. No changes to this plan are required due to the proposed uprate.

7.2 Aquatic Impacts

The impacts on the aquatic ecosystem evaluated are those from the withdrawal of cooling water, and the discharge of the heated cooling water and other facility wastewater sources. The withdrawal of cooling water from Conowingo Pond and consumptive use of that water is regulated by the Susquehanna River Basin Commission (SRBC). The discharge of wastewater is regulated by the Pennsylvania Department of Environmental Protection (PADEP).

The Susquehanna River flows south more than 420 miles from its source, Lake Otsego in south-central New York, to Havre de Grace, Maryland, where it empties into the Chesapeake Bay. An average of 26 billion gallons of water per day flows from the Susquehanna River into the Chesapeake Bay (Reference 7.4). PBAPS withdraws water from and discharges to the Conowingo Pond, a Susquehanna River reservoir formed by the Conowingo Dam. The dam, completed in 1928, created a 14-mile long, 9,000-acre pond having 35 miles of shoreline, a width varying from 0.5 to 1.3 miles, and a maximum depth of 98 feet. The dam was built to provide hydroelectric power generation, but by virtue of the pond it created, it is also able to provide a stable source of water storage for other purposes. In addition to hydroelectric uses, the water in the Conowingo Pond is also used for public water supply, industrial cooling water, cooling water for PBAPS (Reference 7.5), and recreation, and provides a valuable fish and wildlife resource (Reference 7.6). The Conowingo Dam includes a fish passage feature to facilitate anadromous fish restoration and promote resident and migratory fish movement in the Susquehanna River Basin. PBAPS is located on the west bank of the Pond, approximately eight miles upstream from Conowingo Dam.

PBAPS is equipped with a once-through heat dissipation system that withdraws cooling water from and discharges to Conowingo Pond. Up to six circulating water pumps (each rated at 250,000 gallons per minute [gpm]) draw water from Conowingo Pond at a total rate of 1,500,000 gpm (2,160 million gallons per day [MGD]), circulate it through the two main condensers, and return it to the pond via a cooling basin and a discharge canal (Reference 7.7).

Other smaller systems withdraw water from the pond to cool auxiliary equipment at the facility. These include the Service Water System (84,000 gpm maximum), Emergency Service Water System (16,000 gpm maximum), and High Pressure Service Water (36,000 gpm maximum). The Emergency Service Water and High Pressure Service Water systems are operated mostly for compliance with USNRC testing requirements.

Cooling Water Effects

The proposed EPU will not change cooling water withdrawal rates from Conowingo Pond. There will be no changes in the intake structures or the cooling water pumps to implement the EPU. Therefore, there will be no change in either the rate of entrainment of fish and invertebrate eggs and larvae through the cooling system, or the rate of impingement of aquatic organisms on the traveling screens. The NPDES permit issued by the PADEP effective January 1, 2011 requires PBAPS to perform a one spawning season study which began in March 2012 for entrainment characterization (Reference 7.8) and PADEP has approved the entrainment study plan (Reference 7.9).

PBAPS's outer cooling water intake screen structure was designed and installed to reduce impingement. The Outer Screen Structure was designed to have a low approach velocity to allow fish to avoid the screens. To prevent large debris and ice chunks from entering the intake, there are 29 trash racks on the face of the outer intake structure. Divers manually clean the trash racks periodically when needed and collected debris is disposed at a permitted landfill offsite. Twenty-four single entry – single exit (through flow) traveling water screens (12 per unit) are located in the Outer Screen Structure. Each screen is 10 feet wide with a ⅜-inch square opening mesh. Debris, including fish, is removed from the screens by a high-pressure spray-wash system. The wash water is returned to the Conowingo Pond and the debris from the screens is collected and disposed at a permitted landfill offsite. This technology has minimized potential adverse environmental impacts of the operation of PBAPS. There is little effect on Conowingo Pond due to the water withdrawal of PBAPS.

Water flows from the outer screen structure into two 3-acre intake basins (one per unit) before reaching the inner screen structure. Water from the basins enters the inner screen structure through eight bays (four per unit). Six of the bays (three per unit), each with their own traveling screen, direct the water to six circulating water pumps (three per unit). These screens are dual-entry, single-exit (dual-flow) traveling screens with ¼-inch by ½-inch opening mesh. The remaining two bays (one bay per unit) have four traveling screens installed (two per bay), which are a single-entry, single-exit (through-flow) design. These bays feed six service water pumps (three per unit), each of which is designed for 14,000 gpm, as well as the Emergency Service Water and High Pressure Service Water systems. Debris, including fish, is removed from the screens by a high-pressure spray-wash system. The wash water is returned to the intake basin and the screenings are collected and disposed at a permitted landfill offsite.

The resident fish of Conowingo Pond are, for the most part, common warm-water species (e.g., gizzard shad, spotfin shiner, channel catfish, tessellated darter, and bluegill) that have a wide distribution from the southeastern U.S. to Canada (Reference 7.1). Conowingo Pond is well known for its largemouth and smallmouth bass fishing, and also provides opportunities for striped bass and walleye fishing (Reference 7.6).

The fish community in Conowingo Pond has changed little according to the historic and recent operational sampling performed (Table 7.2-1). Noticeable changes are the introduction of anadromous fish species, such as American shad (Reference 7.11), striped bass, and gizzard shad. These species were introduced to the Conowingo Pond as a result of the American Shad Restoration Project beginning in 1972. Two invasive species of mollusks have also been identified within the Conowingo Pond.

The cooling water discharges into an approximately 700 feet long and 400 feet wide discharge basin. From the discharge basin, the heated cooling water normally flows directly into a 4700 foot long discharge canal. Up to approximately 60 percent of the circulating water can also be diverted to the three mechanical-draft helper cooling towers for additional cooling, before being directed to the discharge canal. At the end of the discharge canal is the discharge structure, which is designed to maintain the velocity of the submerged jet discharge. The Discharge Structure also has a surface spillway in addition to the jet discharge. The Discharge Structure operations will be incorporated into the Thermal Study being performed under the NPDES Permit. At current power, the temperature of the cooling water can increase as much as 22° F as it passes through the condensers.

The PBAPS is permitted by the Pennsylvania Department of Environmental Protection (PADEP) to discharge the cooling water under NPDES permit PA 0009733 (Reference 7.10). The NPDES permit provides monitoring conditions and effluent limitations, including a maximum 110° F effluent temperature action level.

PBAPS submitted a Demonstration Study under Section 316(a) of the Clean Water Act (CWA) in July, 1975 which was accepted by the PADEP. Alternative thermal limitations in accordance with that demonstration have been included each subsequent renewal of the NPDES permit. From 1996 through 1999, PBAPS performed a four-year fishery and habitat exclusion study at variable cooling tower operating scenarios (zero to two towers in operation). Based on this work, PBAPS proposed to the PADEP that the operation of cooling towers was unnecessary, except possibly during extreme low flow and high temperature conditions. The PADEP concurred with the results of these studies and the PBAPS heated effluent was discharged into the Conowingo Pond without auxiliary cooling during the permit term. The NPDES permit which was most recently renewed effective January 1, 2011 requires operation of specific cooling towers for three months per year, from June 15 to September 15, as part of the thermal and biological studies.

The current NPDES permit requires thermal and biological sampling for the following purposes: (1) as a demonstration study of alternative thermal effluent limitations under Section 316(a) of the Clean Water Act; (2) to evaluate changes in the thermal plume created by operation of up to three helper cooling towers; and, (3) to create a predictive model of the changes to the thermal discharge associated with operation of the helper cooling towers, taking into account potential power uprates and other influences to the Conowingo Pond.

It has been estimated that the proposed EPU will increase the condenser effluent temperature by approximately 3° F. The maximum cooling water temperature rise as it passes through the condensers will increase from 22° F under current conditions to approximately 25° F after the EPU. As noted by the NRC in the license renewal process "[the] potential impacts of discharging heated water from the cooling water intake system are so minor that they will not noticeably alter any component of the aquatic ecosystem" (Reference 7.12).

As required by the NPDES permit, the thermal and biological study described above will be performed from 2010 to 2014. An application will be submitted to PADEP for any necessary modifications to the NPDES permit, these modifications may reflect actions to manage the thermal discharge under EPU conditions. Based on the historical studies, it is anticipated that the study will continue to demonstrate that the effluent temperature is protective of a balanced indigenous population of fish and wildlife.

The proposed EPU will not change the permitted quality or velocity of the water withdrawn from the Conowingo Pond. Nor will the proposed EPU change the impingement rate at the cooling water intake. The NRC concluded during the license renewal process that "potential impacts of impingement of fish and shellfish on the debris screens of the cooling water intake system are small" (Reference 7.2), and this condition should remain unchanged as a result of operation at EPU.

Other Effluents

PBAPS also manages other plant wastewaters in accordance with the NPDES permit issued by PADEP. The low volume wastewater discharges include discharges from the Water Treatment Wastewater Settling Basin, Auxiliary Boiler Blowdown, Dredging/Rehandling Basin, and Sewage Treatment Plant.

Except from the Sewage Treatment Plant, the low volume wastewater discharges are monitored for flow, suspended solids, and oil and grease. Sanitary waste is sent to the onsite sewage treatment plant, which treats a volume of approximately 18,000 to 22,000 gallons per day (gpd), and has a design capacity of 50,000 gpd. The effluent limitations and monitoring requirements for the Sewage Treatment Plant discharge include pH, flow, Carbonaceous Biological Oxygen Demand ($CBOD_5$), dissolved oxygen, total suspended solids, fecal coliform, total residual chlorine, and total phosphorus.

The proposed EPU will not alter the quality or quantity of these other regulated low volume discharge flows.

Consumptive Water Use

The Susquehanna River Basin Commission (SRBC) is a federal-interstate compact commission created by the Susquehanna River Basin Compact between the federal government and the states of Pennsylvania, New York, and Maryland. The purpose of the SRBC is to manage the water resources of the Susquehanna River Basin Watershed under comprehensive planning principles through its own programs and by coordinating the efforts of the three states and the federal government.

SRBC Docket 20061209-1 (Docket), approved December 5, 2006 and modified June 23, 2011, authorizes withdrawal of up to 2,363.620 million gallons per day (MGD) from Conowingo Pond and consumptive use of up to 49.000 MGD. (Reference 7.13) Consumptive water use at PBAPS consists of two key components, including: evaporation and drift in the helper cooling towers when the towers are in operation; and in-stream evaporation from Conowingo Pond due to the additional thermal loading from the plant.

The SRBC Docket requires PBAPS to provide consumptive use mitigation during low flow conditions through releases from Conowingo Pond or other SRBC approved sources (Reference 7.13).

PBAPS submits quarterly reports on daily withdrawal and consumptive water use to the SRBC as required under 18 C.F.R. § 806.30(b). The Conowingo Pond is also the source of potable water for the station. Since the proposed EPU will not require any additional permanent station personnel, the quantity of water being utilized for potable purposes during plant operation at the station will not change.

Coastal Zone Management Program Compliance

The Federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on applicants for a federal license to conduct an activity that could affect a state's coastal zone.

PBAPS, located in York County, is not within the Pennsylvania coastal zone (Reference 7.14) and, due to its distance (approximately 50 miles) from the Pennsylvania coastal zone, will not affect the Pennsylvania coastal zone. Certification from the Commonwealth coastal zone management program, therefore, is not required.

PBAPS, being in Pennsylvania, is not within the Maryland coastal zone, but the EPU is expected to have a minor effect on a small part of the Conowingo Reservoir that is located within the Maryland coastal zone. However, because the NRC's decision on the PBAPS EPU LAR is a federal action occurring wholly within Pennsylvania, and because Maryland lacks an interstate consistency listing that is approved by NOAA (15 CFR § 930.154(e)), certification from Maryland's coastal zone management program is not required.

Summary

The design and operation of PBAPS is directed toward minimizing environmental impact on aquatic resources. Regulatory agencies, including PADEP and SRBC, provide extensive oversight and impose conditions and requirements to monitor and protect these resources. Since the diversity and relative abundance of the aquatic community has remained relatively unchanged from the levels before operation of PBAPS, the lack of environmental impacts is confirmed. The proposed EPU will not change the permitted quality or rate of water withdrawal from Conowingo Pond.

Most PBAPS permitted discharges to the Conowingo Pond will not change due to EPU. One exception is the thermal discharge which is being evaluated by the PADEP through the described thermal and biological studies. The PADEP will determine if any additional actions are required to manage the thermal discharge and implement any required actions through modifications to the NPDES permit.

Therefore, there will be little or no impact on the aquatic resources from the EPU and the regulatory agencies will continue to ensure the protection of these aquatic resources.

Table 7.2-1
List of all Fish Species Collected During Studies of the Aquatic Resources in the Vicinity of the PBAPS

Common Name	Scientific Name	Community Sampling			Biological Studies		
		1999		1997-2006	1974-76		2005-06
		Present	No. % (a)	(b)	Present	No. % (c)	
River Herrings	Clupeidae						
Blueback herring	*Alosa aestivalis*			X			
Gizzard shad	*Dorosoma cepedianum*	X	19.70	X	X	2.4	X
American shad	*Alosa sapidissima*	X	0.01	X	X	<0.1	X
Alewife	*Alosa psuedoharengus*			X	X	<0.1	X
Pikes & Pickerels	Esocidae						
Muskellunge	*Esox masquinongy*				X	0.1	
Minnows and Carps	Cyprinidae						
Central stoneroller	*Campostoma anomalum*	X	0.01	X			X
Common shiner	*Luxilus cornutus*	X	0.36				X
Spotfin shiner	*Cyprinella spiloptera*	X	28.11	X	X	0.6	X
Common carp	*Cyprinus carpio*	X	0.96	X	X	0.5	X
Rosyside dace	*Clinostomus funduloides*	X	0.44				
Cutlips minnow	*Exoglossum maxillingua*	X	0.05				
Golden shiner	*Notemigonus crysoleucas*	X	0.10	X	X	0.1	X
Silverjaw Minnow	*Notropis buccatus*	X	0.01				
Rosyface shiner	*Notropis rubellus*	X	0.04		X	0.1	
Mimic shiner	*Notropis volucellus*	X	0.56	X			X
Bluntnose minnow	*Pimephales notatus*	X	5.77	X	X	<0.1	X
Fathead minnow	*Pimephales promelas*				X	<0.1	

Table 7.2-1
List of all Fish Species Collected During Studies of the Aquatic Resources in the Vicinity of the PBAPS

Common Name	Scientific Name	Community Sampling			Biological Studies		
		1999		1997-2006	1974-76		2005-06
		Present	No. % (a)	(b)	Present	No. % (c)	
Blacknose dace	*Rhinichthys atratulus*	X	0.15		X	<0.1	
Creek chub	*Semotilus atromaculatus*	X	0.31	X			X
Comley shiner	*Notropis amoenus*	X	0.97	X	X	0.3	X
Spottail shiner	*Notropis hudsonius*	X	0.52	X	X	4.3	X
Swallowtail shiner	*Notropis procne*	X	0.05	X	X	<0.1	X
Longnose dace	*Rhinichthys cataractae*	X	0.06				
Fallfish	*Semotilus corporalis*	X	0.02				

"X" indicated species present in the sample event

Table 7.2-1 (Cont)
List of all Fish Species Collected During Studies of the Aquatic Resources in the Vicinity of the PBAPS

Common Name	Scientific Name	Community Sampling			IM&E Studies		
		1999		1997-2006	1974-76		2005-06
		Present	No. % (a)	(b)	Present	No. % (c)	
Suckers	Catostomidae						
Quillback	*Carpiodes cyprinus*	X	0.55	X	X	0.2	X
White sucker	*Catostomus commersoni*	X	0.93	X	X	0.6	X
Northern hog sucker	*Hypentelium nigricans*	X	0.03	X	X	<0.1	X
Shorthead redhorse	*Moxostoma macrolepidotum*	X	0.27	X	X	0.2	X
Bullhead Catfishes	Ictaluridae						
White catfish	*Ameiurus catus*	X	0.05	X	X	<0.1	X
Yellow bullhead	*Ameiurus natalis*	X	0.09	X	X	0.6	X
Brown bullhead	*Ameiurus nebulosus*	X	0.19	X	X	0.8	
Channel catfish	*Ictalurus punctatus*	X	9.91	X	X	59.4	X
Flathead catfish	*Pylodictis olivaris*			X			X
Margined madtom	*Noturus insignis*				X	<0.1	X
Killifishes	Fundulidae						
Mummichog	*Fundulus heteroclitus*			X	X	<0.1	X
Banded killifish	*Fundulus diaphanus*	X	0.02				
Sunfishes	Centrarchidae						
Rock bass	*Ambloplites rupestris*	X	0.51		X	0.2	X
Green sunfish	*Lepomis cyanellus*	X	2.60		X	1.0	X
Pumpkinseed	*Lepomis gibbosus*	X	1.20		X	3.2	X
Bluegill	*Lepomis macrochirus*	X	8.92		X	14.4	X

Table 7.2-1 (Cont)
List of all Fish Species Collected During Studies of the Aquatic Resources in the Vicinity of the PBAPS

Common Name	Scientific Name	Community Sampling			IM&E Studies		
		1999		1997-2006	1974-76		2005-06
		Present	No. % (a)	(b)	Present	No. % (c)	
Smallmouth bass	*Micropterus dolomieu*	X	4.69		X	1.0	X
Largemouth bass	*Micropterus salmoides*	X	3.16		X	0.2	X
White crappie	*Pomoxis annularis*	X	1.00		X	5.4	X
Black crappie	*Pomoxis nigromaculatus*	X	0.01		X	0.2	X
Redbreast sunfish	*Lepomis auritus*	X	0.10		X	1.8	X

"X" indicated species present in the sample event

Table 7.2-1 (Cont)
List of all Fish Species Collected During Studies of the Aquatic Resources in the Vicinity of the PBAPS

Common Name	Scientific Name	Community Sampling			IM&E Studies		
		1999		1997-2006	1974-76		2005-06
		Present	No. % (a)	(b)	Present	No. % (c)	
Eels	Anguillidae						
American eel	*Anguilla rostrata*				X	<0.1	
Temperate Basses	Moronidae						
White perch	*Morone americana*	X	0.06	X			X
Striped Bass	*Morone saxatilis*			X			X
Hybrid striped bass	*M. chrysops x M. saxatilis*	X	0.01				
Perches	Percidae						
Tessellated darter	*Etheostoma olmstedi*	X	6.90		X	1.4	X
Banded darter	*Etheostoma zonale*						X
Yellow perch	*Perca flavescens*	X	0.05		X	2.0	X
Logperch	*Percina caprodes*	X	0.36		X	<0.1	X
Walleye	*Sander vitreus*	X	0.12		X	<0.1	X
Greenside darter	*Etheostoma blennioides*	X	0.03				X
Shield darter	*Percina peltata*	X	0.01				
Smelts	Osmeridae						
Rainbow smelt	*Osmerus mordax*			X			

(a) A Report on the Thermal Conditions and Fish Populations in Conowingo Pond Relative to Zero Cooling Tower Operation at the Peach Bottom Atomic Power Station (June – October 1999). Prepared by Normandeau Associates. February 2000. (Reference 7.15)

(b) 316(b) Compliance Report With Source Waterbody Information, Impingement Mortality Characterization Study, And Design And Construction Technology Plan, Peach Bottom Atomic Power Station. Exelon Corporation. October 2008. Appendix C. (Reference 7.7).

(c) Peach Bottom Atomic Power Station, Materials Prepared for the Environmental Protection Agency, 316(b) Demonstration for PBAPS Units No. 2 & 3 on Conowingo Pond. Philadelphia Electric Company. May, 1977. (Reference 7.16)

"X" indicated species present in the sample event

7.3 Air Impacts

Much of the EPU construction and equipment installation will occur over two short term outage periods. In those short outage periods, the additional air emissions will be from the increased work force driving to and from the site. This is an approximately 35 percent increase in the typical work force for an EPU event, so the short term impacts on air emissions could be similar. The major equipment and materials to support the outage will mostly be supplied and stored on site well before the start of the outage period and most of the smaller EPU outage supplies will be delivered on the same trucks that routinely supply similar tools and supplies to support plant operations. Therefore, during the construction of the EPU, only minor temporary changes in air emissions are expected.

The Cooling Towers emissions are incorporated in the PBAPS' State Only Operating Air Permit. The towers are currently operated as part of the on-going thermal and biological study. Any future operation of the cooling towers will be in accordance with the requirements of the air permit.

7.4 Threatened and Endangered Species

As noted in Section 2.4 of Appendix E of the Application of Renewed Operating License – Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3 (Reference 7.1) no areas designated by the U.S. Fish and Wildlife Service as "critical habitat" for endangered species exist at PBAPS. Much of the 620-acre PBAPS site consists of generation and maintenance facilities, laydown areas, parking lots, roads, and mowed grass. The primary terrestrial habitats at the site are remnants of hardwood (oak-hickory) forest on the ridges and slopes west of the generating and support facilities. Wildlife species found in the forested portions of PBAPS are those typically found in upland forests of southern Pennsylvania. These include a variety of amphibians (e.g., Northern dusky salamander, bullfrog, leopard frog), reptiles (e.g., Eastern hognose snake, copperhead, painted turtle, box turtle), songbirds (e.g., Carolina wren, wood thrush, song sparrow, rufous-sided towhee), woodpeckers (e.g., downy woodpecker, common flicker), birds of prey (e.g., red-tailed hawk, Eastern screech owl, barred owl), and mammals (e.g., gray squirrel, Southern flying squirrel, striped skunk, gray fox, raccoon, white-tailed deer).

On September 9, 2011, a formal Pennsylvania Natural Diversity Index (PNDI) request was submitted to the State of Pennsylvania. The results PNDI search indicated that there could be potential impacts due to any disturbance in and around the site and that further review from the PA Department of Conservation and Natural Resources and the PA Fish and Boat Commission would be required. The two agencies were contacted by letter and their responses are discussed below and attached to this report.

The PA Game Commission and the US Fish and Wildlife Service indicated that there will be no impacts to species of concern within their oversight, therefore no further action will be required.

The PA Department of Conservation and Natural Resources indicated that they had three terrestrial plant Species of Special Concern:

- Asplenia pinnatifidum (Lobed Spleenwort)
- Erigenia bulbosa (Harbinger-of-Spring)
- Ilex opaca (American Holly)

The response from the PA DCNR on the PNDI receipt indicated no further review required and conservation measures were recommended. The conservation measures included not planting invasive species using clean fill and mulch, and voluntarily clean equipment.

The PA Fish and Boat Commission indicated non-specific sensitive species were present and further review was required. EGC submitted the request for PA Fish and Boat Commission to provide their input for addressing potential environmental effects on January 23, 2012. The response from the PA Fish and Boat Commission concurs with the conclusion of no impacts expected. A copy of the letter and their response is in Attachment 1 of this report.

As the proposed project activities do not include land disturbance outside of the facility footprint, and all construction is anticipated to be within existing buildings and structures, any potential for impacts to species of regulatory concern appears to be small.

The GEIS concluded that that the impact on endangered, threatened, or candidate species of an additional 20 years of operation and maintenance of PBAPS and associated transmission lines would be small, and further mitigation is not warranted.

Since the proposed EPU will not have impact on any of the potential habitats of these species of concern and the consulted agencies concur with this conclusion, the NRC conclusion in the GEIS remains unchanged.

References

7.1 PBAPS License Renewal Application, Peach Bottom Atomic Power Station Units 2 and 3. Exelon Generation Company, LLC. Docket Nos. 50-277 and 50-278, License Nos. DPR-44 and DPR-56. Appendix E: Applicant's Environmental Report – Operating License Renewal Stage. July 2001.

7.2 NUREG-1437, Supplement 10, Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS) Regarding Peach Bottom Atomic Power Station, Units 2 and 3, Final Report. NRC. January 2003. ML030270059

7.3 U.S. Atomic Energy Commission. 1973. *Final Environmental Statement related to operation of Peach Bottom Atomic Power Station Units 2 and 3*. Philadelphia Electric Company. Docket Nos. 50-277 and 50-278. Directorate of Licensing. Washington, DC.

7.4 Comprehensive Plan For The Water Resources Of The Susquehanna River Basin. Susquehanna River Basin Commission. As amended, December 2009.

7.5 Conowingo Pond Management Plan, Publication No. 242. Susquehanna River Basin Commission. June 2006.

7.6 Pennsylvania's Wildlife Action Plan Version 1.0a. The Pennsylvania Game Commission and Pennsylvania Fish and Boat Commission. Updated May, 2008. Last viewed September 7, 2010 at: http://fishandboat.com/promo/grants/swg/00swg.htm

7.7 316(b) Compliance Report With Source Waterbody Information, Impingement Mortality Characterization Study, And Design And Construction Technology Plan, Peach Bottom Atomic Power Station. Exelon Corporation. October 2008.

7.8 Work Plan For An Entrainment Characterization Study At Peach Bottom Atomic Power Station. Prepared by Normandeau Associates, Inc. Exelon Nuclear. February 2011.

7.9 Pennsylvania Department of Environmental Protection, Water Management Program. Letter to Mr. Joseph Brozonis. Peach Bottom Atomic Power Station, NPDES No. 0009733. Approving the Work Plan For An Entrainment Characterization Study. May 5, 2011.

7.10 Authorization To Discharge Under The National Pollutant Discharge Elimination System NPDES Permit No. PA0009733, Peach Bottom Atomic Power Station. Pennsylvania Department of Environmental Protection. Effective January 1, 2011.

7.11 Abundance And Distribution Of Juvenile American Shad In The Susquehanna River, 2009. Abridged report for PFBC Website. Michael L. Hendricks, Pennsylvania Fish and Boat Commission. State College, Pennsylvania. Last viewed September7, 2010 at: http://fishandboat.com/pafish/shad/reports_technical/2009shadtech/juvenile2009.pdf

7.12 Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Supplement 10, Regarding Peach Bottom Atomic Power Station, Units 2 and 3. Final Report. USNRC. January 2003.

7.13 Susquehanna River Basin Commission Docket No. 20061209-1, Modified June 23, 2011.

7.14 Commonwealth Of Pennsylvania Coastal Resources Management Program. Document 394-0300-001. Technical Guidance Document. Prepared by Pennsylvania Coastal Resources Management Program. May 3, 2008

7.15 A Report on the Thermal Conditions and Fish Populations in Conowingo Pond Relative to Zero Cooling Tower Operation at the Peach Bottom Atomic Power Station (June – October 1999). Prepared by Normandeau Associates. February 2000.

7.16 Peach Bottom Atomic Power Station, Materials Prepared for the Environmental Protection Agency, 316(b) Demonstration for PBAPS Units No. 2 & 3 on Conowingo Pond. Philadelphia Electric Company. May, 1977.

8.0 Radiological Environmental Impacts

8.1 Radiological Waste Streams

The radioactive waste systems at Peach Bottom Atomic Power Station Units 2 and 3 are designed to collect, process, and dispose of radioactive wastes in a controlled and safe manner. The design basis for these systems during normal operations is to limit discharges in accordance with 10 CFR 50, Appendix I. The actual performance and operation of installed equipment, as well as reporting of actual offsite releases and doses, are controlled by the requirements of the Offsite Dose Calculation Manual (ODCM)(Reference 8.1). The ODCM is subject to NRC inspection and describes the methods and parameters used for calculating offsite doses resulting from radioactive gaseous and liquid effluents, and ensuring compliance with NRC regulations. Adherence to these limits and objectives would continue under the proposed EPU.

Operation at the proposed EPU conditions would not result in any physical changes to the solid waste, liquid waste, or gaseous waste systems. The safety and reliability of these systems would be unaffected by the proposed EPU. Also, the proposed action would not affect the environmental monitoring of any of these waste streams or the radiological monitoring requirements of the Peach Bottom Atomic Power Station Units 2 and 3 Radiation Protection Program. Under normal operating conditions, the proposed action would not introduce any new or different radiological release pathways and would not increase the probability of an operator error or equipment malfunction that would result in an uncontrolled radioactive release from the radioactive waste streams.

PUSAR Section 2.5.5.1, Gaseous Waste Management, PUSAR Section 2.5.5.2, Liquid Waste Management, and PUSAR Section 2.5.5.3, Solid Waste Management, provide an assessment of the effect of the proposed EPU on the gaseous, liquid and solid radioactive waste systems and the associated effluents based on a comparison of ANSI 18.1-1999 based Appendix I type analyses for both pre-EPU and EPU conditions using the ANSI 18.1-1999 Reference BWR concentrations (Table 5) as the starting point.

The following subsections summarize the results of a more realistic assessment of the effect of the proposed EPU on radwaste effluents and associated doses to the public. The impact of the EPU on the radwaste gaseous and liquid releases and doses to the public is assessed herein by applying EPU scaling factors (derived from the equations and methodology provided in NUREG-0016 Rev. 1)(Reference 8.2) to the radioactive effluent release and dose information reported in the annual Radioactive Effluent Reports for the years 2004 to 2008 for Peach Bottom Atomic Power Station Units 2 & 3. A conservative assumption is also employed for Moisture Carry Over increase to a design value of 0.3% for downstream components versus the normal operating value of 0.1% for the dryer design. This approach was selected to provide a realistic assessment of the impact of the EPU on plant radiological effluents, taking into consideration plant operational experience and operational philosophy.

The power weighted average effluent releases for the site for the years 2004 to 2008 are reported in Tables 8-2 & 8-3. Carbon-14, which was first reported in the 2010 Radioactive Effluent Release Report (Reference 8.3) for gaseous releases, is included as a normalized release in Table 8-3 and included in the doses presented in Table 8-5. It is noted that the sum of the values for activity and volume, reported in Tables 8-1 – 8-3 represent the combined operations of Peach Bottom Atomic Power Station Units 2 and 3.

8.1.1 Solid Waste

Solid radioactive wastes include solids recovered from reactor coolant systems, solids in contact with the liquids or gases associated with reactor coolant process systems, and solids used in support of the reactor coolant system operation.

The largest volume of solid radioactive waste is low-level radioactive waste (LLRW) which includes bead resin, spent filters, and dry active waste (DAW) from outages and routine maintenance. DAW includes paper, plastic, wood, rubber, glass, floor sweepings, cloth, metal, and other types of waste routinely generated during operation, maintenance and outages. Table 8-1 presents the average annual volume and activity of LLRW shipped offsite for burial or disposal by Peach Bottom Atomic Power Station Units 2 and 3, for the five-year period between 2004 through 2008.

Table 8-1
Average Annual Low-Level Radioactive Waste Shipped Offsite from Peach Bottom Atomic Power Station Units 2 and 3 During the 2004 – 2008 Time Period

	Cubic Meters	Curies
Spent Resins, Process Filters, etc.	9.85E+01	3.77E+02
Dry Compressible Waste (DAW)	7.12E+02	7.32E+00
Irradiated Components	8.42E-01	8.42E+03
Other (Oil & Ash)	2.06E+01	3.83E-02
Total [Annual Average Using Five Years (2004 – 2008) of Solid Waste Shipment Data]	8.32E+02	8.80E+03

References 8.4, 8.5, 8.6, 8.7 and 8.8

PUSAR Section 2.5.5.3, Solid Waste Management System, provides an evaluation of effects the proposed EPU may have on the solid waste management system. The results of the evaluation indicate that due to the inclusion of two new condensate polishing units, the proposed EPU will result in a 14.23 percent increase in the total volume of solid waste generated.

The EPU assessment performed for the Supplemental Environmental Report indicates that the activity levels for most of the solid waste would increase proportionately to the increase in activity of long-lived radionuclides in the reactor coolant bounded by a maximum increase of 14.7 percent. This increase percentage reflects the EPU increase in power level and is based on current operation at the licensed power level of 3514 MWt and EPU operation at the analyzed power level of 4030 MWt (includes a 2.0 percent margin for power uncertainty). The activity contained in the waste following uprate is estimated to be bounded by an increase of 22.5 percent, i.e., (1.147 / 0.936 – 1) to address the average (both units) weighted capacity factor of 0.936 for years 2004 – 2008.

In 2011, PBAPS Units 2 and 3 licenses were amended (Reference 8.9) to allow storage of radwaste expected to be shipped from the Limerick Generating Station at the PBAPS Low Level Radwaste Storage Facility (LLRWSF).

Section 8.2 of this attachment addresses the impact of the EPU increase in solid waste activity on the off-site doses.

8.1.2 Liquid Waste

Liquid radioactive wastes include liquids from the reactor process systems and liquids that have become contaminated with process system liquids. Table 8-2 presents liquid releases from Peach Bottom Atomic Power Station Units 2 and 3 for the five-year period from 2004 through 2008. As noted in Table 8-2, approximately 165 million liters and 0.403 Ci of fission and activation products were released in an average year.

Table 8-2
Liquid Effluent Releases (Activity Normalized to 100% Capacity Factor) from Peach Bottom Atomic Power Station Units 2 and 3, 2004 – 2008

Year	Volume of Waste Released (Liters)	Activity Released (Ci)	Tritium (Ci)
2004	5.59E+06	1.65E-01	3.20E+01
2005	3.60E+06	3.05E-02	1.66E+01
2006	1.66E+06	5.60E-01	8.37E+00
2007	4.23E+08	8.20E-01	4.27E+00
2008	3.91E+08	2.73E-01	3.08E+00
Annual Average	1.65E+08	4.03E-01	1.29E+01

References 8.4, 8.5, 8.6, 8.7 & 8.8

As indicated in PUSAR Section 2.5.5.2, "Liquid Waste Management System" the pre-EPU volume of liquid waste effluents is expected to be representative of future operation at EPU conditions. This conclusion is based on the observation that EPU implementation would not significantly increase the inventory of liquid normally processed by the liquid waste management system since system functions are not changing and the volume inputs remain approximately the same. The addition of 2 polishers in the condensate polishing system would have only a small impact on the total volume of liquid waste processed for release.

The assessment performed for the Supplemental Environmental Report indicates that the proposed EPU would have the following impact on the equilibrium radioactivity in the reactor coolant, which would in turn impact the concentrations of radioactive nuclides in the waste management systems. Specifically, the EPU would result in an increase in the tritium activity in the coolant by approximately 14.7 percent (due to the power increase ratio), and a reduction in the inventory of radionuclides with long half-lives by approximately 5 percent (due to the use of a bounding increase in moisture carryover following the EPU from 0.1 percent to 0.3 percent and associated transfer of activity to the condensate polishers through which all feedwater heater and moisture separator drains are also processed - small increases in moisture carryover for EPU are addressed below for liquid releases). The iodine concentration in reactor coolant

would remain approximately the same since the increased moisture carryover is a small fraction of the total iodine volatility, and they are also small contributors (<1 percent) to organ doses resulting from radioactive liquid effluent releases.

The assessment performed herein addresses the expected increase due to the EPU based on the reported average annual releases during this five year period. The estimated annual release is 14.8 Curies of tritium. As discussed above, based on a 0.3 percent moisture carryover fraction, the non-tritiated activity released post-EPU is bounded by the current estimate of 0.403 Curies. If the EPU moisture carryover fraction remained at the pre-EPU value of 0.1 percent, the concentrations in the reactor coolant system would increase by approximately 14.7 percent which would result in an estimated annual release of non-tritiated activity of 0.462 Curies.

It is also concluded that the projected releases following EPU discussed herein, remain bounded by values provided in the PUSAR which are based on an Appendix I type analysis which used the radioactive and volumetric source terms identified in ANSI-18.1-1999.

Section 8.2 of this attachment addresses the offsite radiation dose consequences of the EPU liquid effluent releases.

8.1.3 Gaseous Waste

Gaseous radioactive wastes are principally activation gases and noble gases resulting from radiolytic decomposition processes in the reactor coolant system, gases from the off gas charcoal treatment system, and gases collected during venting. Table 8-3 presents gaseous releases from Peach Bottom Atomic Power Station Units 2 and 3 from 2004 through 2008.

Table 8-3
Gaseous Effluent Releases (Normalized to 100% Capacity Factor) from Peach Bottom Atomic Power Station Units 2 and 3, 2004 – 2008
(C-14 from 2010)

Year	Noble Gases (Ci)	Particulates ($T_{1/2}$ > 8 days) (Ci)	Iodine-131 (Ci)	Tritium (Ci)	C-14 (Ci)
2004	7.93E+02	5.62E-04	1.19E-03	0.00E+00	
2005	1.16E+03	4.24E-03	2.82E-02	0.00E+00	
2006	1.07E+03	3.78E-03	7.15E-03	4.55E+01	
2007	5.74E+02	1.16E-02	8.90E-03	5.75E+01	
2008	6.50E+02	9.21E-03	7.20E-03	4.84E+01	
2010					3.55E+01
Annual Average	8.50E+02	5.88E-03	1.05E-02	3.03E+01	3.55E+01

References 8.3, 8.4, 8.5, 8.6, 8.7, and 8.8

The evaluation presented in PUSAR Section 2.5.5.1, Gaseous Waste Management Systems, indicates that implementation of the proposed EPU does not significantly increase the inventory of nonradioactive carrier gases, such as air, normally processed in the gaseous waste management system. The above is because plant system functions are not changing and the volume inputs remain the same.

The assessment performed for the Supplemental Environmental Report indicates that the proposed EPU would result in a bounding maximum 14.7 percent increase in noble gas activity in gaseous effluent releases, primarily through the off gas system. The increase in tritium and C-14 activity releases are also expected to be 14.7 percent. The estimated increase in iodine releases is expected to be approximately 9.1 percent (reflects the 14.7 percent increase in power level, the 15.6 percent increase in the I-131 removal rate developed using NUREG-0016 equations, and the 10 percent increase in the iodine carryover fraction in the steam).

For particulates, an approach using very conservative assumptions was dictated by the fact that the annual effluent release reports do not distinguish between the sources of particulates or iodines released. Thus, the moisture carryover becomes a major factor in determining the non-volatile activity in the steam. The conservatively estimated EPU multiplier (~2.8) applicable to radioactive particulates released from the turbine building via main steam leaks and air ejector exhaust is significantly higher than the percentage of the EPU (primarily due to a conservatively estimated 3 fold increase in moisture carryover that results from the use of the design moisture carryover fractions of 0.1 percent for pre-EPU and 0.3 percent as representative of EPU operation, coupled with the approximately 5 percent reduction in radionuclides with long half-lives in the equilibrium radioactivity in the reactor coolant).

It is also concluded that with the exception of C-14, the projected releases following EPU discussed herein remain bounded by values provided in the PUSAR which are based on an Appendix I type analysis which used the radioactive and volumetric source terms identified in ANSI-18.1-1999. The C-14 releases reported herein reflect the value identified in the plant radioactive effluent report for 2010 which is higher than that estimated for the PUSAR analysis.

Section 8.2 of this attachment addresses the offsite radiation dose consequences of the EPU effluent releases.

8.2 Radiation Levels and Offsite Doses

8.2.1 Operating and Shutdown In-Plant Levels

In-plant radiation levels and associated doses are controlled by the Peach Bottom Atomic Power Station Units 2 and 3 Radiation Protection Program to ensure that internal and external radiation exposures to station personnel, and the general population will be as low as reasonably achievable (ALARA), as required by 10 CFR 20. EGC's policy is to maintain occupational doses to individuals and the sum of dose equivalents received by all exposed workers ALARA.

PUSAR Section 2.10.1.2.1, "Normal Operation Radiation Levels and Shielding Adequacy" provides an analysis of the impact of the proposed EPU on radiation levels and shielding adequacy and the resulting occupational dose. The analysis considered the impact of increasing the core power level on neutron flux and gamma flux in and around the core, fission product and actinide activity inventory in the core and spent fuels, N-16 source in the reactor coolant, neutron activation source in the vicinity of the reactor core, and fission/corrosion products activity in the reactor coolant and downstream systems. The results indicate that in-plant gaseous radiation sources are anticipated to increase approximately 30 percent (N-16 due to shortened transit time, the steam concentrations of noble gases are expected to increase only ~2 percent) with the increase in core power level.

Shielding is used throughout Peach Bottom Atomic Power Station Units 2 and 3 to protect personnel against radiation from the reactor and auxiliary systems, and to limit radiation damage to operating equipment. The evaluation of the present shielding design has determined that it is adequate for the increase in radiation levels that may occur following power operation under EPU conditions since the increase is offset by:

- conservative analytical techniques typically used to establish shielding requirements,
- conservatism in the original design basis reactor coolant source terms used to establish the radiation zones, and
- Plant Technical Specification 3.4.6 which limits the reactor coolant concentrations to levels significantly below the original design basis source terms.

Therefore, no new dose reduction programs are planned and the ALARA program would continue in its current form.

8.2.2 Offsite Doses at Power Uprate Conditions

Using scaling techniques based on NUREG-0016, Revision 1 methodology, this analysis conservatively projects maximum doses from normal operation under the proposed EPU conditions taking into consideration the following:

- plant core power operating history during years 2004 through 2008,
- the reported gaseous and liquid effluent and dose data during that period,
- NUREG-0016 equations and assumptions,
- conservative methodology

Pre-EPU dose estimates are calculated by taking the average five-year doses during the period from 2004 through 2008 (organ and whole body – References 8.10, 8.11, 8.12, 8.13, 8.14) coupled with annual core power levels and normalizing the doses to those equivalent to operation at a 100 percent capacity factor (100 percent CF) and 100 percent availability.

To predict doses under the proposed EPU conditions, the analysis assumes that the maximum increase in radioactivity content of the liquid and gaseous releases is related to the maximum percentage change per chemical class (as defined in NUREG-0016, Rev. 1) in the reactor and steam coolants over that of the pre-EPU case. It should be noted that the Peach Bottom Atomic Power Station Units 2 and 3 feed water including the heater drains and the condensate is completely processed by the condensate polishers with no bypass during operation. This acts to slightly reduce the reactor water concentrations of all non volatiles, coupled with some increase of activity concentration in the reactor steam and condensate due to the assumed increased moisture carryover. Iodines, which have two components, volatile and non-volatile, with the non-volatile being a small fraction of the volatile, are less effected by the increased carryover and have an approximate 9 percent increase in reactor steam concentrations.

For liquid effluents, the pre-EPU offsite dose estimates are developed by weighting and averaging the dose information for the years 2004 through 2008. Following EPU, Exelon predicts that the maximum annual total body and organ doses (all pathways) from liquid effluent releases would decrease slightly (~ 5 percent) due to the increased removal rate from the RCS by the condensate polishers resulting from the assumed increased moisture carryover. As demonstrated in Table 8-4 below, the estimated EPU doses due to liquid effluents are significantly below the regulatory design objectives of 10 CFR 50, Appendix I.

Table 8-4
Average Off-Site Dose Commitments from Liquid Effluents (Peach Bottom Atomic Power Station Units 2 and 3)

Type of Dose	Appendix I Design Objectives (2 units)	Base Case 2004 – 2008 Adjusted Doses @100% CF	Scaled Post-EPU Annual Dose	Percentage of Appendix I Design Objectives for EPU Case
Liquid Effluents				
Dose to total body from all pathways[1]	6 mrem/yr	1.60E-02 mrem/yr (Adult)	1.52E-02 mrem/yr (Adult)	0.25%
Dose to any organ from all pathways[1]	20 mrem/yr	2.09E-02 mrem/yr (GI-LLI Adult)	1.98E-02 mrem/yr (GI-LLI Adult)	0.10%

Note:

1. The maximum annual total body and organ doses (all pathways) from liquid effluent releases would decrease slightly (~ 5 percent) following the EPU due to the increased removal rate from the RCS by the condensate polishers as a result of the assumed increased moisture carryover.

Similarly, for gaseous effluents, the pre-EPU offsite dose estimates are developed by averaging and adjusting the dose information for the years 2004 through 2008 using the methodology and dose conversion factors in the ODCM. Application of the scaling factors for various chemical/physical groups or classes provide an estimate of the maximum dose that could be attributed to normal operation post-EPU. In the particulate and iodine category, particulates and iodines, entrained in the steam, were calculated to have the highest scaling factor and were used for the bounding case. This produced a conservative increase in the limiting organ - the "infant thyroid". Regardless, as demonstrated in Table 8-5 below, the estimated EPU doses due to gaseous effluents are significantly below the regulatory design objectives of 10 CFR 50, Appendix I.

Table 8-5
Average Off-Site Dose Commitments from Gaseous Effluents (Peach Bottom Atomic Power Station Units 2 and 3)

Type of Dose	Appendix I Design Objectives (2 units)	Base Case 2004 – 2008 plus 2010 C-14 Adjusted Doses @100% CF	Scaled Post-EPU Annual Dose	Percentage of Appendix I Design Objectives for EPU Case
Gaseous Effluents				
Gamma Dose in Air[1]	20 mrad/yr	6.34E-01 mrad/yr	7.27E-01 mrad/yr	3.6%
Beta Dose in Air[1]	40 mrad/yr	1.24E-01 mrad/yr	1.42E-01 mrad/yr	0.36%
Dose to total body of an individual[1]	10 mrem/yr	5.47E-01 mrem/yr (child)	6.32E-01 mrem/yr (child)	6.3%
Dose to skin of an individual[1]	30 mrem/yr	5.95E-01 mrem/yr	6.86E-01 mrem/yr	2.2%
Radioiodines, Tritium, C-14 and Particulates Released to the Atmosphere				
Dose to any organ from all pathways[2]	30 mrem/yr	4.65E+00 mrem/yr (infant thyroid)	5.12E+00 mrem/yr (infant thyroid)	17.1%

Notes:

1. The gamma and beta dose in air is based on noble gases. The dose to skin of an individual due to gaseous effluents is primarily based on noble gases with some minor contribution from ground shine while the dose to the total body is primarily due to noble gases and C-14 with minor contributions from other pathways . The noble gas and C-14 EPU dose scaling factor (SF) is ~ 1.147.
2. With respect to dose due to iodines and particulates including tritium and C-14 in the gaseous effluent pathway, the infant thyroid is the dominant organ, and the associated EPU dose scaling factor is a combination of various contributors, the dominant contributor being iodine at a SF of 1.091.

Due to the activity increase in the waste, the maximum average direct shine dose due to solid waste is projected to increase by no more than 22.5 percent (=1.147/0.936 - 1, where 0.936 is the average capacity factor/availability factor during 2004-2008). This increase would occur over time as the current waste decays and its contribution decreases, and waste generated post EPU enters into storage. Radwaste storage facilities were analyzed and are expected to be managed to maintain offsite dose rates to less than 1 mrem/year to any 40CFR190 receptor. Waste characteristics used in the design basis for the Low Level Waste Radwaste Storage Facility bound expected EPU conditions including the radwaste expected to be shipped from the Limerick Generating Station.

The current ISFSI storage pad is projected to be filled on or before year 2020, prior to being loaded with EPU fuel. An additional storage pad is anticipated to be required, even if no EPU is

approved. ISFSI dose contributions will continue to be monitored using the ODCM process. The offsite doses due to the ISFSI would be negligibly affected by storage of EPU fuel, as changes in neutron and gamma sources are primarily a function of fuel burn up rather than power.

Under pre-EPU conditions, direct radiation measurements made at the site boundary indicated no increase in ambient radiation levels from the ISFSI operation, even though the offsite dose is conservatively calculated to be 10.8 mrem/yr. This is expected to continue under EPU conditions.

Although implementation of EPU could increase the skyshine component to the offsite doses up to 30 percent, due to N-16 in the equipment above grade, the expected post-EPU increase in the in-plant radiation exposure in the turbine building (TB) complex has a negligible effect on the estimated doses to members of the public. The TB concrete shielding and distance between the TB and offsite boundary are such that the post-EPU direct dose contribution from the steam components in the TB is negligible. The post-EPU N-16 skyshine dose rate at the nearest boundary is expected to be near the background radiation level. Therefore, it does not impact the total estimated doses to members of the public, and a 30 percent increase would still be a negligible dose.

The 40 CFR 190 whole body dose limit of 25 mrem to any member of the public includes a) contributions from direct radiation (including skyshine) from contained radioactive sources within the facility, b) the whole body dose from liquid release pathways, and c) the whole body dose to an individual via airborne pathways.

Taking into consideration the magnitude of the estimated annual EPU doses due to gaseous and liquid effluent releases and the negligible direct shine dose contribution from components within the facilities, ISFSI and skyshine, it is concluded that the 40CFR190 whole body dose limit of 25 mrem/yr will not be exceeded by operation at EPU conditions.

References:

8.1 Offsite Dose Calculation Manual including Appendix A, Rev. 13 Peach Bottom Atomic Power Station Units 2 and 3, Exelon Nuclear Docket Nos. 50-277 & 50-278. ML101250144

8.2 NUREG-0016, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Boiling Water Reactors," Revision 1, January 1979. ML091910213

8.3 Peach Bottom Atomic Power Station Unit Nos. 2 & 3, Radioactive Effluent Release Report No. 53, January 1, 2010 through December 31, 2010. ML11122A099

8.4 Peach Bottom Atomic Power Station Unit Nos. 2 & 3, Radioactive Effluent Release Report No. 47, January 1, 2004 through December 31, 2004. ML051250404

8.5 Peach Bottom Atomic Power Station Unit Nos. 2 & 3, Radioactive Effluent Release Report No. 48, January 1, 2005 through December 31, 2005. ML061220331

8.6 Peach Bottom Atomic Power Station Unit Nos. 2 & 3, Radioactive Effluent Release Report No. 49, January 1, 2006 through December 31, 2006. ML071230061

8.7 Peach Bottom Atomic Power Station Unit Nos. 2 & 3, Radioactive Effluent Release Report No. 50, January 1, 2007 through December 31, 2007. ML081220902

8.8 Peach Bottom Atomic Power Station Unit Nos. 2 & 3, Radioactive Effluent Release Report No. 51, January 1, 2008 through December 31, 2008. ML091250436

8.9 Peach Bottom Atomic Power Station, Units 2 and 3 – Issuance of Amendments RE: Storage of Low-Level Radioactive Waste Produced at Limerick Generating Station (TAC NOS. ME3092 and ME3093), 31 May 2011 (Amendment No. 280 to Renewed DPR-44 and Amendment No. 282 to Renewed DPR-56), ML110470320

8.10 Peach Bottom Atomic Power Station Unit Nos. 2 & 3, Annual Radiation Dose Assessment Report No. 20, January 1, 2004 through December 31, 2004 ML05120421

8.11 Peach Bottom Atomic Power Station Unit Nos. 2 & 3, Annual Radiation Dose Assessment Report No. 21, January 1, 2005 through December 31, 2005 ML061220629

8.12 Peach Bottom Atomic Power Station Unit Nos. 2 & 3, Annual Radiation Dose Assessment Report No. 22, January 1, 2006 through December 31, 2006 ML071230050

8.13 Peach Bottom Atomic Power Station Unit Nos. 2 & 3, Annual Radiation Dose Assessment Report No. 23, January 1, 2007 through December 31, 2007 ML081220280

8.14 Peach Bottom Atomic Power Station Unit Nos. 2 & 3, Annual Radiation Dose Assessment Report No. 24, January 1, 2008 through December 31, 2008 ML091250376

9.0 Environmental Effects of Uranium Fuel Cycle Activities and Fuel and Radioactive Waste Transport

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

In 1999, in connection with the Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants, NRC reviewed transporting higher enrichment and higher burn up fuel to a geologic repository (NRC 1999)(Reference 9.1). The conclusion of that evaluation was that Table S-4 applies to spent fuel enriched up to 5 percent uranium-235 with average burn up for the peak rod to current levels approved by NRC up to 62,000 MWd/MTU, provided higher burn up fuel is cooled for at least 5 years before being shipped.

Since the fuel enrichment for the EPU will not exceed 5.0 percent U-235 and the rod average discharge exposure will not exceed 62,000 MWd/MTU, the potential environmental impacts of the proposed PBAPS power uprate will remain bounded by these conclusions and will not be significant to human health or the environment.

PBAPS is currently licensed to use uranium-dioxide fuel that has a maximum enrichment of 5.0 percent by weight of uranium-235. The typical average enrichment for a fuel reload has increased over the life of the station up to approximately 4.2 percent.

For PBAPS under EPU conditions, the burn up limit is unchanged (the upper exposure limit is bounded by maintaining fuel within the NRC-approved vendor specific exposure limits), and the U-235 enrichment limit of 5 percent by weight is not exceeded; therefore, the PBAPS EPU fuel cycles will continue to remain bounded by the impacts listed in Tables S-3 and S-4 of 10 CFR Part 51.

Increasing the electrical output at PBAPS is accomplished primarily by generating higher steam flow to the turbine generator. The higher steam flow is achieved by increasing the reactor power level and feed water flow. The additional reactor energy requirements for EPU are met by increasing the reload fuel batch size. The EPU does not require any changes to fuel design.

The average fuel assembly discharge burn up for the uprate is expected to be approximately 51,000 MWd/MTU with no fuel pins exceeding the maximum fuel rod burnup limit of 62,000 MWd/MTU (GNF2 fuel has a maximum Bundle Average Discharge Exposure of 55,000 MWd/MTU). Reload design goals would maintain the PBAPS 24-month fuel cycles within the limits bounded by the impacts analyzed in Tables S-3 and S-4 of 10 CFR Part 51. Therefore, EGC concludes that impacts to the uranium cycle and transport of nuclear fuel from the proposed action would be insignificant and not require mitigation.

References

9.1 NRC (Nuclear Regulatory Commission). 1999. Generic Environmental Impact Statement for License Renewal of Nuclear Plants (NUREG-1437, Vol. 1, Addendum 1). Division of Regulatory Improvement Programs, Office of Nuclear Reactor Regulation, August 1999. ML040690720

10.0 Effects of Decommissioning

The original FES for PBAPS did not evaluate the environmental effects of decommissioning. Environmental impacts from the activities associated with the decommissioning of any nuclear power reactor before or at the end of an initial or renewed license period are evaluated in the Generic Environmental Impact Statement for Decommissioning of Nuclear Facilities, NUREG-0586, Original and Supplement 1 (References 10.1 and 10.2). The conclusion of these reports is that environmental impacts of decommissioning are generally small and that only two environmental issues would require site-specific evaluation; threatened and endangered species and environmental justice.

The incremental environmental impacts associated with decommissioning activities resulting from continued plant operation during the renewal term are evaluated in the Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS), NUREG-1437, Volumes 1 and 2 (U. S. Nuclear Regulatory Commission 1996; 1999 (Reference 10.3)). The evaluation in NUREG-1437 includes a determination of whether the analysis of the environmental issue could be applied to all plants and whether additional mitigation measures would be warranted. NUREG-1437 Supplement 10 discusses in Chapter 7, the effects of the later decommissioning on the local PBAPS environment. For all the environmental issues reviewed in NUREG-1437 Supplement 10, the NRC staff concluded that impacts of license renewal would be small and mitigation would not likely be sufficiently beneficial to be warranted.

Prior to any decommissioning activity at PBAPS, EGC would submit a post shutdown decommissioning activities report to describe planned decommissioning activities, any environmental impacts of those activities, a schedule, and estimated costs. Implementation of an EPU does not affect Exelon's ability to maintain financial reserves for decommissioning nor does the EPU alter the decommissioning process.

The potential environmental impacts on decommissioning associated with the proposed EPU would be due to the increased neutron fluence. As a result, the amount of activated corrosion products could increase, and consequently, the post-shutdown radiation levels could increase. EGC expects the increases in radiation levels as a result of operations under the proposed EPU conditions to be insignificant for two reasons; the radiological levels of plant equipment upon cessation of operations for either refueling or plant shutdown are minimal compared to operational radiological exposure potentials, and any residual radiological levels in plant equipment after shut down would be addressed in the post-shutdown decommissioning activities report.

References

10.1 NRC (Nuclear Regulatory Commission). 1988. *Final Generic Environmental Impact Statement on Decommissioning of Nuclear Facilities* issued in 1988 (NUREG-0586). ML060590157

10.2 NRC (Nuclear Regulatory Commission). 2002. NUREG-0586 - Generic Environmental Impact on Decommissioning of Nuclear Reactors. Supplement 1. Regarding the Decommissioning of Nuclear Power Reactors. Main Report, Appendices A through M. Final Report. November 2002. ML023500395 (Report) & ML023500410 (App A-M)

10.3 NRC (Nuclear Regulatory Commission). 2003. NUREG-1437 Generic Environmental Impact Assessment for License Renewal of Nuclear Plants. Supplement 10. Regarding Peach Bottom Atomic Power Station, Units 2 and 3. Final Report. Division of Regulatory Improvement Programs. January, 2003. ML030270059

Attachments

1. State Agency Consultations

Exelon.
Nuclear

Peach Bottom Atomic Power Station
1848 Lay Road
Delta, PA 17314

www.exeloncorp.com

January 23, 2012

PA Historical & Museum Commission
Bureau for Historic Preservation
400 North Street
Commonwealth Keystone Building 2nd Floor
Harrisburg, PA 17120-0093

Subject: Exelon Generation, LLC, Peach Bottom Atomic Power Station Units 2 & 3
Extended Power Uprate Supplemental Environmental Report
Request for Information

Dear Sir or Madam,

Exelon Generation Company, LLC (Exelon) is planning on submitting an application to the United States Nuclear Regulatory Commission (USNRC) in 2012 for a license amendment for a project to increase in reactor power and electricity production for Units 2 and 3 of Peach Bottom Atomic Power Station (PBAPS). The amendment will request an increase in power of approximately 12.4% above current power levels to 3951 MW. This project is entitled an extended power uprate (EPU).

The USNRC requires license amendment requests for this type of power uprate to include a Supplemental Environmental Report assessing potential environmental impacts. One area requiring assessment is to determine if any historic and archeological properties will be affected by the extended power uprate project.

The features of the PBAPS site relevant to the extended power uprate activities and historic and archeological properties are as follows:

PBAPS is located on the west shore of Conowingo Pond in York and Lancaster counties in Pennsylvania. The site is approximately 620 acres owned by Exelon Generation Co., LLC. The site contains two Boiling Water Reactors Units 2 & 3, and Unit 1, which is a retired unit in NRC SAFSTORE condition.

The area occupied by the reactors and other administrative buildings is mostly impervious surface and areas previously disturbed by construction activities. The activities to prepare for and implement the power uprate will be confined to these previously disturbed areas. Exelon does not expect the power uprate activities to adversely affect any historic or archeological properties.

The Final Environmental Statement related to operation of Peach Bottom Atomic Power Station Units 2 and 3 prepared in 1973 by the U.S. Atomic Energy Commission stated that "no artifacts of historical or archaeological significance (were) found within the site boundary' during construction. An archaeologist from the William Penn Museum who conducted an evaluation of the site in 1972 observed that the impoundment of the Susquehanna River in the 1920s to create Conowingo Pond flooded (the) floodplain and terrace areas most likely to contain cultural artifacts." Also, Exelon has found no artifacts at the site during the 37 years of plant operation.

We request your support to identify if there are any historic and archeological properties that could be affected by this project. Exelon requests your response by February 28, 2012 to support our schedule for submittal of the Supplemental Environmental Report to the USNRC.

Please call Tracy Siglin, Sr. Environmental Specialist, EPU Project at 610-765-5618, if there are questions or additional information is required for this request.

Sincerely,

Mark A. Ross
Radwaste/Environmental Supervisor
Peach Bottom Atomic Power Station

ccn 12-11

Commonwealth of Pennsylvania
Pennsylvania Historical and Museum Commission
Bureau for Historic Preservation
Commonwealth Keystone Building, 2nd Floor
400 North Street
Harrisburg, PA 17120-0093
www.phmc.state.pa.us

February 8, 2012

Mark A. Ross
Exelon Generation Company, LLC
Peach Bottom Atomic Power Station
1848 Lay Road
Delta, PA 17314

TO EXPEDITE REVIEW USE
BHP REFERENCE NUMBER

Re: File No. ER 2000-3210-133-M
NRC: Exelon Generation, LLC, Peach Bottom Atomic Power Station Units 2 & 3 Extended Power Uprate Supplemental Environmental Report, Peach Bottom Twp., York Co.

Dear Mr. Ross:

The Bureau for Historic Preservation (the State Historic Preservation Office) has reviewed the above named project in accordance with Section 106 of the National Historic Preservation Act of 1966, as amended in 1980 and 1992, and the regulations (36 CFR Part 800) of the Advisory Council on Historic Preservation. These requirements include consideration of the project's potential effect upon both historic and archaeological resources.

There is a high probability that prehistoric and historic archaeological resources are located in this project area. In our opinion, the activity described in your proposal should have no effect on such resources. Should the scope of the project be amended to include additional ground disturbing activity this office should be contacted immediately and a Phase I Archaeological Survey may be necessary to locate all potentially significant archaeological resources.

In our opinion no evaluation of historic structures will be necessary for this project area.

If you need further information in this matter please consult Doug McLearen at (717) 772-0925.

Sincerely,

Douglas C. McLearen, Chief
Division of Archaeology & Protection

DCM/tmw

Exelon.
Nuclear

Peach Bottom Atomic Power Station
1848 Lay Road
Delta, PA 17314

www.exeloncorp.com

January 23, 2012

Ellen Shultzabarger
PA Department of Conservation and Natural Resources
Bureau of Forestry, Ecological Services Section
400 Market Street
PO Box 8552
Harrisburg, PA 17105-8552

Subject: Exelon Generation, LLC, Peach Bottom Atomic Power Station Units 2 & 3
Extended Power Uprate Supplemental Environmental Report
Request for Information

Dear Ms. Shultzabarger

Exelon Generation Company, LLC (Exelon) is planning on submitting an application to the United States Nuclear Regulatory Commission (USNRC) in 2012 for a license amendment for a project to increase in reactor power and electricity production for Units 2 and 3 of Peach Bottom Atomic Power Station (PBAPS). The amendment will request an increase in power of approximately 12.4% above current power levels to 3951 MW. This project is entitled an extended power uprate (EPU).

The USNRC requires license amendment requests for this type of power uprate to include a Supplemental Environmental Report assessing potential environmental impacts. One potential environment impact is the effects of the extended power uprate on threatened and endangered species that are listed or proposed for listing in accordance with the Endangered Species Act (ESA) (16 USC 1531, et seq.) (10 CFR 51.53(c)(3)(ii)(E)). Accordingly, we are contacting you to obtain input for use in addressing potential environmental effects in the Supplemental Environmental Report.

The features of the PBAPS site relevant to the extended power uprate activities and threatened or endangered species are as follows:

PBAPS is located on the west shore of Conowingo Pond in York and Lancaster counties in Pennsylvania. The site is approximately 620 acres owned by Exelon Generation Co., LLC. The site contains two Boiling Water Reactors Units 2 & 3, and Unit 1, which is a retired unit in NRC SAFSTORE condition.

The area occupied by the reactors and other administrative buildings is mostly impervious surface and areas previously disturbed by construction activities. The activities to prepare for and implement the power uprate will be confined to these

previously disturbed areas. Exelon does not expect the power uprate activities to adversely affect any threatened or endangered species.

Exelon has reviewed the potential for the project to adversely affect known occurrences of species or natural communities of concern. This review was performed through use of the Pennsylvania Natural Diversity Inventory (PNDI) Environmental Review Tool, a web-based application sponsored by the Pennsylvania Natural Heritage Program (PNHP). The completed PNDI Receipt Project Search ID: 20110919316372 is attached for your information. Three plant species of concern to the PA Department of Conservation and Natural Resources (PA DCNR) have been identified. These species are Lobed Spleenwort (Asplenium Pinnatifidum) with Special Concern Species status; Harbinger-of-Spring (Erigenia bulbosa) with Threatened status; and American Holly (Ilex opaca) with Threatened status. The response under PA DCNR was listed as a Conservation Measure to avoid the introduction of invasive species. There are no plans for any fill or planting activity for this EPU project.

Exelon does not expect any adverse affects to threatened or endangered species at the site due to the activities associated with this project. We request your support to identify any other threatened or endangered species not identified and, as applicable, confirmation that the PBAPS extended power uprate would not adversely affect threatened and endangered species.

Exelon Generation Company, LLC requests your response by February 28, 2012 to support our schedule for submittal of the Supplemental Environmental Report to the USNRC.

Please call Tracy Siglin, Sr. Environmental Specialist, EPU Project at 610-765-5618, if there are questions or additional information is required for this request.

Sincerely,

Mark A. Ross
Radwaste/Environmental Supervisor
Peach Bottom Atomic Power Station

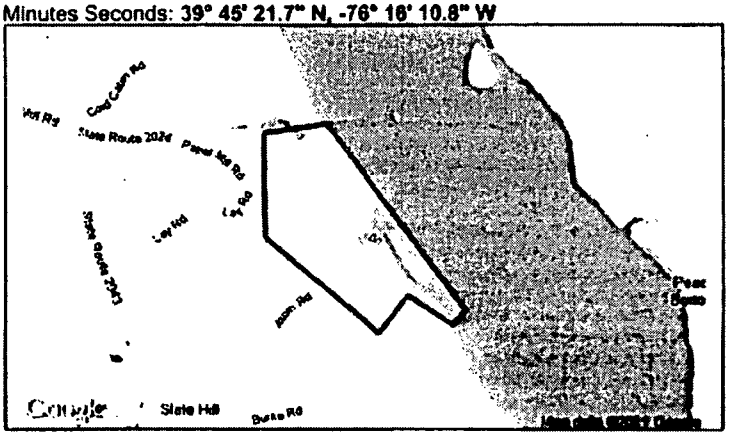
Attachment: PNDI Receipt Project Search ID: 20110919316372 and Topographic Map (6 pages)

ccn 12-13

PNDI Project Environmental Review Receipt Project Search ID: 20110919316372

1. PROJECT INFORMATION

Project Name: **Peach Bottom Atomic Power Station**
Date of review: **9/19/2011 12:37:59 PM**
Project Category: **Energy Storage, Production, and Transfer,Energy Production (generation),Nuclear Power Plant -- maintenance, modification, or expansion**
Project Area: **627.9 acres**
County: **Lancaster,York** Township/Municipality: **Fulton,Drumore,Peach Bottom**
Quadrangle Name: **HOLTWOOD** ~ ZIP Code: **17314,17314,17314**
Decimal Degrees: **39.756032 N, -76.269664 W**
Degrees Minutes Seconds: **39° 45' 21.7" N, -76° 16' 10.8" W**



2. SEARCH RESULTS

Agency	Results	Response
PA Game Commission	No Known Impact	No Further Review Required
PA Department of Conservation and Natural Resources	**Conservation Measure**	**No Further Review Required, See Agency Comments**
PA Fish and Boat Commission	**Potential Impact**	**FURTHER REVIEW IS REQUIRED, See Agency Response**
U.S. Fish and Wildlife Service	No Known Impact	No Further Review Required

As summarized above, Pennsylvania Natural Diversity Inventory (PNDI) records indicate there may be potential impacts to threatened and endangered and/or special concern species and resources within the project area. If the response above indicates "No Further Review Required" no additional communication with the respective agency is required. If the response is "Further Review Required" or "See Agency Response," refer to the appropriate agency comments below. Please see the DEP Information Section of this receipt if a PA Department of Environmental Protection Permit is required.

PNDI Project Environmental Review Receipt Project Search ID: 20110919316372

Note that regardless of PNDI search results, projects requiring a Chapter 105 DEP individual permit or GP 5, 6, 7, 8, 9 or 11 in certain counties (Adams, Berks, Bucks, Carbon, Chester, Cumberland, Delaware, Lancaster, Lebanon, Lehigh, Monroe, Montgomery, Northampton, Schuylkill and York) must comply with the bog turtle habitat screening requirements of the PASPGP.

RESPONSE TO QUESTION(S) ASKED

Q1: "Will the entire project area (including any discharge), plus a 300 feet buffer around the project area, all occur in or on an existing building, parking lot, driveway, road, road shoulder, street, runway, paved area, railroad bed, maintained (periodically mown) lawn, crop agriculture field or maintained orchard?"
Your answer is: **1. Yes**

3. AGENCY COMMENTS

Regardless of whether a DEP permit is necessary for this proposed project, any potential impacts to threatened and endangered species and/or special concern species and resources must be resolved with the appropriate jurisdictional agency. In some cases, a permit or authorization from the jurisdictional agency may be needed if adverse impacts to these species and habitats cannot be avoided.

These agency determinations and responses are **valid for one year** (from the date of the review), and are based on the project information that was provided, including the exact project location; the project type, description, and features; and any responses to questions that were generated during this search. If any of the following change: 1) project location, 2) project size or configuration, 3) project type, or 4) responses to the questions that were asked during the online review, the results of this review are not valid, and the review must be searched *again via the PNDI Environmental Review Tool and resubmitted to the jurisdictional agencies. The PNDI tool is a* primary screening tool, and a desktop review may reveal more or fewer impacts than what is listed on this PNDI receipt. The jurisdictional agencies **strongly advise against** conducting surveys for the species listed on the receipt prior to consultation with the agencies.

PA Game Commission

RESPONSE: No impact is anticipated to threatened and endangered species and/or special concern species and resources.

PA Department of Conservation and Natural Resources

RESPONSE: Conservation Measure: Please avoid the introduction of invasive species in order to protect the *integrity of nearby plant species of special concern. Voluntary cleaning of equipment/vehicles, using clean fill and* mulch, and avoiding planting invasive species (http://www.dcnr.state.pa.us/forestry/invasivetutorial/index.htm) will help to conserve sensitive plant habitats.

DCNR Species: (Note: The PNDI tool is a primary screening tool, and a desktop review may *reveal more or fewer species than what is listed below. After desktop review, if a botanical* survey is required by DCNR, we recommend the DCNR Botanical Survey Protocols, available here: http://www.gis.dcnr.state.pa.us/hgis-er/PNDI_DCNR.aspx.)
Scientific Name: Asplenium pinnatifidum
Common Name: Lobed Spleenwort
Current Status: Special Concern Species*
Proposed Status: Special Concern Species*

PNDI Project Environmental Review Receipt Project Search ID: 20110919316372

Scientific Name: Erigenia bulbosa
Common Name: Harbinger-of-spring
Current Status: Threatened
Proposed Status: Special Concern Species*

Scientific Name: Ilex opaca
Common Name: American Holly
Current Status: Threatened
Proposed Status: Threatened

PA Fish and Boat Commission

RESPONSE: Further review of this project is necessary to resolve the potential impacts(s). Please send project information to this agency for review (see WHAT TO SEND).

PFBC Species: (Note: The PNDI tool is a primary screening tool, and a desktop review may reveal more or fewer species than what is listed below.)
Scientific Name: Sensitive Species**
Common Name:
Current Status: Endangered
Proposed Status: Endangered

U.S. Fish and Wildlife Service

RESPONSE: No impacts to **federally** listed or proposed species are anticipated. Therefore, no further consultation/coordination under the Endangered Species Act (87 Stat. 884, as amended; 16 U.S.C. 1531 *et seq.* is required. Because no take of federally listed species is anticipated, none is authorized. This response does not reflect potential Fish and Wildlife Service concerns under the Fish and Wildlife Coordination Act or other authorities.

* Special Concern Species or Resource - Plant or animal species classified as rare, tentatively undetermined or candidate as well as other taxa of conservation concern, significant natural communities, special concern populations (plants or animals) and unique geologic features.
** Sensitive Species - Species identified by the jurisdictinal agency as collectible, having economic value, or being susceptible to decline as a result of visitation.

WHAT TO SEND TO JURISDICTIONAL AGENCIES

If project information was requested by one or more of the agencies above, send the following information to the agency(s) seeking this information (see AGENCY CONTACT INFORMATION).

Check-list of *Minimum* Materials to be submitted:

PNDI Project Environmental Review Receipt Project Search ID: 20110919316372

____**SIGNED** copy of this Project Environmental Review Receipt
____Project narrative with a description of the overall project, the work to be performed, current physical characteristics of the site and acreage to be impacted.
____Project location information (name of USGS Quadrangle, Township/Municipality, and County)
____USGS 7.5-minute Quadrangle with project boundary clearly indicated, and quad name on the map

The inclusion of the following information may expedite the review process.
____A basic site plan(particularly showing the relationship of the project to the physical features such as wetlands, streams, ponds, rock outcrops, etc.)
____Color photos keyed to the basic site plan (i.e. showing on the site plan where and in what direction each photo was taken and the date of the photos)
____Information about the presence and location of wetlands in the project area, and how this was determined (e.g., by a qualified wetlands biologist), if wetlands are present in the project area, provide project plans showing the location of all project features, as well as wetlands and streams
____The DEP permit(s) required for this project

4. DEP INFORMATION

The Pa Department of Environmental Protection (DEP) requires that a signed copy of this receipt, along with any required documentation from jurisdictional agencies concerning resolution of potential impacts, be submitted with applications for permits requiring PNDI review. For cases where a "Potential Impact" to threatened and endangered species has been identified before the application has been submitted to DEP, the application should not be submitted until the impact has been resolved. For cases where "Potential Impact" to special concern species and resources has been identified before the application has been submitted, the application should be submitted to DEP along with the PNDI receipt, a completed PNDI form and a USGS 7.5 minute quadrangle map with the project boundaries delineated on the map. The PNDI Receipt should also be submitted to the appropriate agency according to directions on the PNDI Receipt. DEP and the jurisdictional agency will work together to resolve the potential impact(s). See the DEP PNDI policy at http://www.naturalheritage.state.pa.us.

PNDI Project Environmental Review Receipt Project Search ID: 20110919316372

5. ADDITIONAL INFORMATION

The PNDI environmental review website is a **preliminary** screening tool. There are often delays in updating species status classifications. Because the proposed status represents the best available information regarding the conservation status of the species, state jurisdictional agency staff give the proposed statuses at least the same consideration as the current legal status. If surveys or further information reveal that a threatened and endangered and/or special concern species and resources exist in your project area, contact the appropriate jurisdictional agency/agencies immediately to identify and resolve any impacts.

For a list of species known to occur in the county where your project is located, please see the species lists by county found on the PA Natural Heritage Program (PNHP) home page (www.naturalheritage.state.pa.us). Also note that the PNDI Environmental Review Tool only contains information about species occurrences that have actually been reported to the PNHP.

6. AGENCY CONTACT INFORMATION

PA Department of Conservation and Natural Resources
Bureau of Forestry, Ecological Services Section
400 Market Street, PO Box 8552, Harrisburg, PA. 17105-8552
Fax:(717) 772-0271

U.S. Fish and Wildlife Service
Endangered Species Section
315 South Allen Street, Suite 322, State College, PA. 16801-4851
NO Faxes Please.

PA Fish and Boat Commission
Division of Environmental Services
450 Robinson Lane, Bellefonte, PA. 16823-7437
NO Faxes Please

PA Game Commission
Bureau of Wildlife Habitat Management
Division of Environmental Planning and Habitat Protection
2001 Elmerton Avenue, Harrisburg, PA. 17110-9797
Fax:(717) 787-6957

7. PROJECT CONTACT INFORMATION

Name: Tracy J Siglin
Company/Business Name: Exelon Generation Co LLC
Address: 200 Exelon Way.
City, State, Zip: Kennett Square PA 19348
Phone: (610) 765-5618 Fax: (610)-765-5807.
Email: tracy.Siglin@exeloncorp.com

8. CERTIFICATION

I certify that ALL of the project information contained in this receipt (including project location, project size/configuration, project type, answers to questions) is true, accurate and complete. In addition, if the project type, location, size or configuration changes, or if the answers to any questions that were asked during this online review change, I agree to re-do the online environmental review.

Tracy J Siglin — 12-15-11
applicant/project proponent signature — date

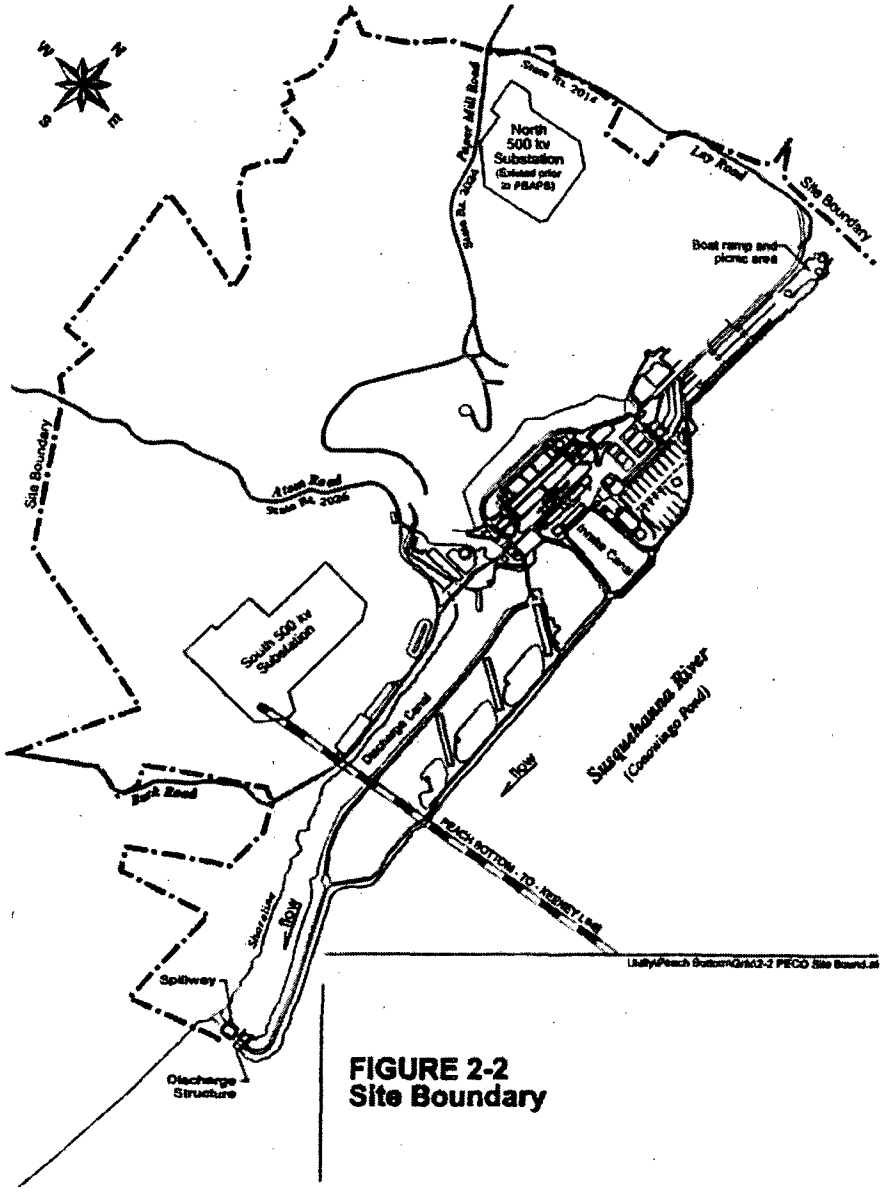
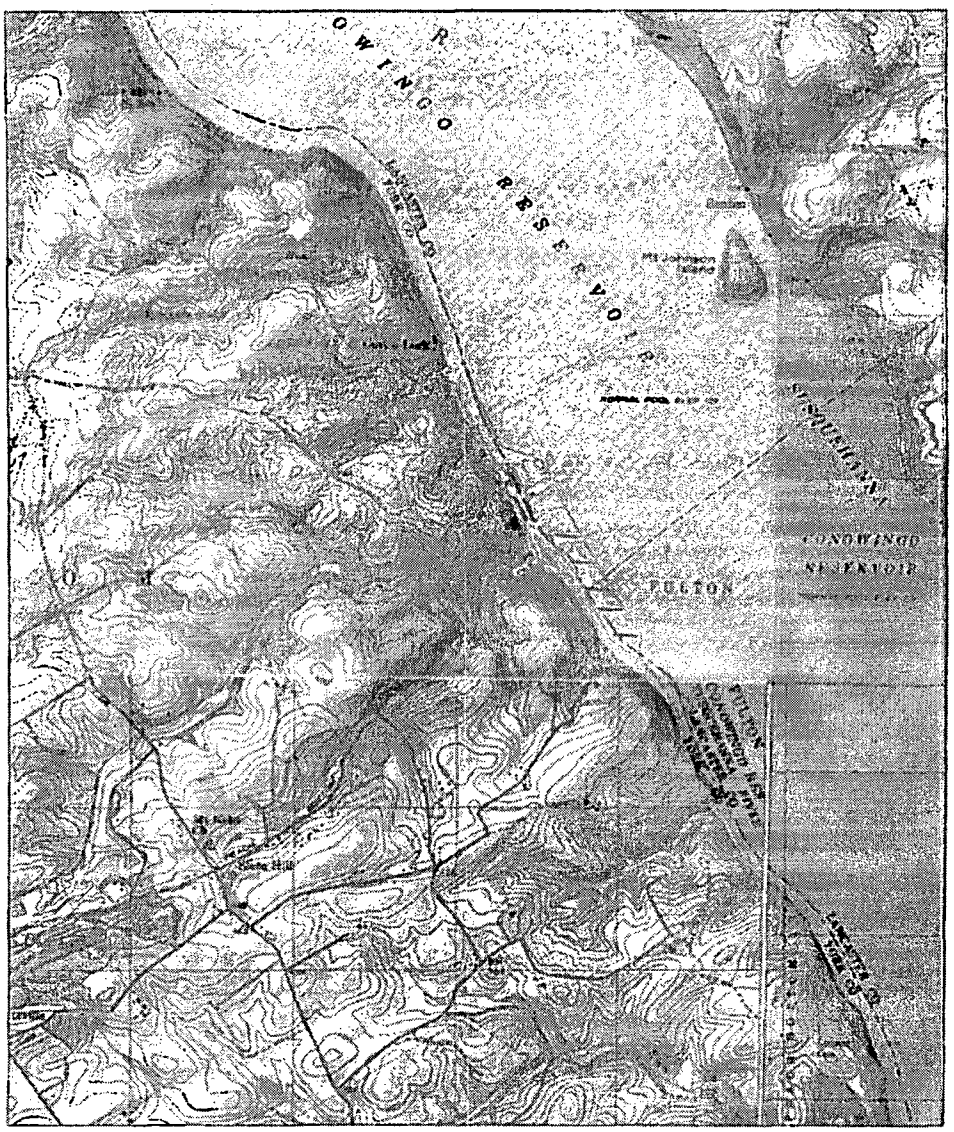


FIGURE 2-2
Site Boundary



Map provided by MyTopo.com

pennsylvania
DEPARTMENT OF CONSERVATION
AND NATURAL RESOURCES

BUREAU OF FORESTRY

February 21, 2012

PNDI Number: 20110919316372

Tracy J. Siglin
Exelon Generation Co., LLC
200 Exelon Way
Kennett Square, PA 19348

Re: Peach Bottom Atomic Power Station
Fulton/Drumore/Peach Bottom Townships, Lancaster, York Counties, PA

Dear Tracy,

Thank you for the submission of the Pennsylvania Natural Diversity Inventory (PNDI) Environmental Review Receipt Number 20110919316372 for review. PA Department of Conservation and Natural Resources screened this project for potential impacts to species and resources of concern under DCNR's responsibility, which includes plants, terrestrial invertebrates, natural communities, and geologic features only.

No Impact Anticipated

PNDI records indicate species or resources of concern are located in the vicinity of the project. However, based on the information you submitted concerning the nature of the project, the immediate location, and our detailed resource information, DCNR has determined that no impact is likely.

This response represents the most up-to-date summary of the PNDI data files and is valid for one (1) year from the date of this letter. An absence of recorded information does not necessarily imply actual conditions on-site. Should project plans change or additional information on listed or proposed species become available, this determination may be reconsidered.

Should the proposed work continue beyond the period covered by this letter, please resubmit the project to this agency as an "Update" (including an updated PNDI receipt, project narrative and accurate map). If the proposed work has not changed and no additional information concerning listed species is found, the project will be cleared for PNDI requirements under this agency for an additional year.

This finding applies to impacts to DCNR only. To complete your review of state and federally-listed threatened and endangered species and species of special concern, please be sure the U.S. Fish and Wildlife Service, PA Game Commission, and the Pennsylvania Fish and Boat Commission have been contacted regarding this project as directed by the online PNDI ER Tool found at www.naturalheritage.state.pa.us.

Sincerely,

Andrew Rohrbaugh, Environmental Review Specialist FOR Chris Firestone, Wild Plant Program Mgr.
Ph: 717-705-2823 ~ c-arohrbau@ pa.gov

Exelon.
Nuclear

Peach Bottom Atomic Power Station
1848 Lay Road
Delta, PA 17314

www.exeloncorp.com

January 23, 2012

PA Fish and Boat Commission
Division of Environmental Services
450 Robinson Lane
Bellefonte, PA. 16823-7437

Subject: Exelon Generation, LLC, Peach Bottom Atomic Power Station Units 2 & 3
Extended Power Uprate Supplemental Environmental Report
Request for Information

Dear Sir or Madam,

Exelon Generation Company, LLC (Exelon) is planning on submitting an application to the United States Nuclear Regulatory Commission (USNRC) in 2012 for a license amendment for a project to increase in reactor power and electricity production for Units 2 and 3 of Peach Bottom Atomic Power Station (PBAPS). The amendment will request an increase in power of approximately 12.4% above current power levels to 3951 MW. This project is entitled an extended power uprate (EPU).

The USNRC requires license amendment requests for this type of power uprate to include a Supplemental Environmental Report assessing potential environmental impacts. One potential environment impact is the effects of the extended power uprate on threatened and endangered species that are listed or proposed for listing in accordance with the Endangered Species Act (ESA) (16 USC 1531, et seq.) (10 CFR 51.53(c)(3)(ii)(E)). Accordingly, we are contacting you to obtain input for use in addressing potential environmental effects in the Supplemental Environmental Report.

The features of the PBAPS site relevant to the extended power uprate activities and threatened or endangered species are as follows:

PBAPS is located on the west shore of Conowingo Pond in York and Lancaster counties in Pennsylvania. The site is approximately 620 acres owned by Exelon Generation Co., LLC. The site contains two Boiling Water Reactors Units 2 & 3, and Unit 1, which is a retired unit in NRC SAFSTORE condition.

The area occupied by the reactors and other administrative buildings is mostly impervious surface and areas previously disturbed by construction activities. The activities to prepare for and implement the power uprate will be confined to these previously disturbed areas. Exelon does not expect the power uprate activities to adversely affect any threatened or endangered species.

Exelon has reviewed the potential for the project to adversely affect known occurrences of species or natural communities of concern. This review was performed through use of the Pennsylvania Natural Diversity Inventory (PNDI) Environmental Review Tool, a web-based application sponsored by the Pennsylvania Natural Heritage Program (PNHP). The completed PNDI Receipt Project Search ID: 20110919316372 is attached for your information. Three plant species of concern to the PA Department of Conservation and Natural Resources (PA DCNR) have been identified. These species are Lobed Spleenwort (Asplenium Pinnatifidum) with Special Concern Species status; Harbinger-of-Spring (Erigenia bulbosa) with Threatened status; and American Holly (Ilex opaca) with Threatened status. The response under PA DCNR was listed as a Conservation Measure to avoid the introduction of invasive species. There are no plans for any fill or planting activity for this project.

Exelon does not expect any adverse affects to threatened or endangered species at the site due to the activities associated with this project. We request your support to identify any other threatened or endangered species not identified and, as applicable, confirmation that the PBAPS extended power uprate would not adversely affect threatened and endangered species.

Exelon Generation Company, LLC requests your response by February 28, 2012 to support our schedule for submittal of the Supplemental Environmental Report to the USNRC.

Please call Tracy Siglin, Sr. Environmental Specialist, EPU Project at 610-765-5618, if there are questions or additional information is required for this request.

Sincerely,

Mark A. Ross
Radwaste/Environmental Supervisor
Peach Bottom Atomic Power Station

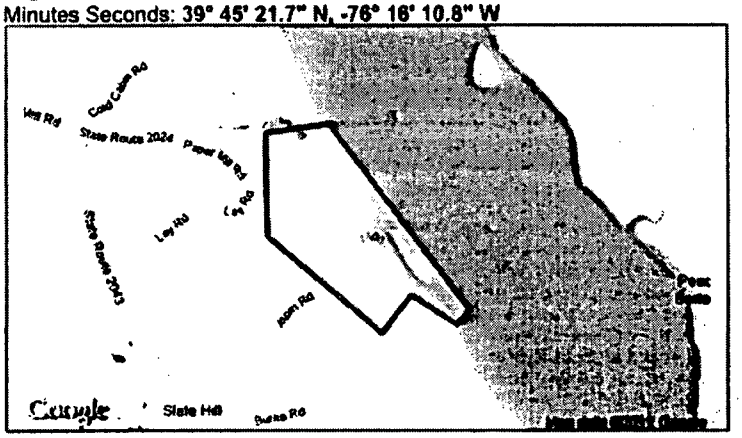
Attachment: PNDI Receipt Project Search ID: 20110919316372 and Topographic Map (6 pages)

ccn 12-12

PNDI Project Environmental Review Receipt Project Search ID: 20110919316372

1. PROJECT INFORMATION

Project Name: **Peach Bottom Atomic Power Station**
Date of review: **9/19/2011 12:37:59 PM**
Project Category: **Energy Storage, Production, and Transfer,Energy Production (generation),Nuclear Power Plant -- maintenance, modification, or expansion**
Project Area: **627.9** acres
County: **Lancaster,York** Township/Municipality: **Fulton,Drumore,Peach Bottom**
Quadrangle Name: **HOLTWOOD** ~ ZIP Code: **17314,17314,17314**
Decimal Degrees: **39.756032 N, -76.269664 W**
Degrees Minutes Seconds: **39° 45' 21.7" N, -76° 16' 10.8" W**



2. SEARCH RESULTS

Agency	Results	Response
PA Game Commission	No Known Impact	No Further Review Required
PA Department of Conservation and Natural Resources	**Conservation Measure**	**No Further Review Required, See Agency Comments**
PA Fish and Boat Commission	**Potential Impact**	**FURTHER REVIEW IS REQUIRED, See Agency Response**
U.S. Fish and Wildlife Service	No Known Impact	No Further Review Required

As summarized above, Pennsylvania Natural Diversity Inventory (PNDI) records indicate there may be potential impacts to threatened and endangered and/or special concern species and resources within the project area. If the response above indicates "No Further Review Required" no additional communication with the respective agency is required. If the response is "Further Review Required" or "See Agency Response," refer to the appropriate agency comments below. Please see the DEP Information Section of this receipt if a PA Department of Environmental Protection Permit is required.

PNDI Project Environmental Review Receipt Project Search ID: 20110919316372

Note that regardless of PNDI search results, projects requiring a Chapter 105 DEP individual permit or GP 5, 6, 7, 8, 9 or 11 in certain counties (Adams, Berks, Bucks, Carbon, Chester, Cumberland, Delaware, Lancaster, Lebanon, Lehigh, Monroe, Montgomery, Northampton, Schuylkill and York) must comply with the bog turtle habitat screening requirements of the PASPGP.

RESPONSE TO QUESTION(S) ASKED

Q1: "Will the entire project area (including any discharge), plus a 300 feet buffer around the project area, all occur in or on an existing building, parking lot, driveway, road, road shoulder, street, runway, paved area, railroad bed, maintained (periodically mown) lawn, crop agriculture field or maintained orchard?"
Your answer is: **1. Yes**

3. AGENCY COMMENTS

Regardless of whether a DEP permit is necessary for this proposed project, any potential impacts to threatened and endangered species and/or special concern species and resources must be resolved with the appropriate jurisdictional agency. In some cases, a permit or authorization from the jurisdictional agency may be needed if adverse impacts to these species and habitats cannot be avoided.

These agency determinations and responses are **valid for one year** (from the date of the review), and are based on the project information that was provided, including the exact project location; the project type, description, and features; and any responses to questions that were generated during this search. If any of the following change: 1) project location, 2) project size or configuration, 3) project type, or 4) responses to the questions that were asked during the online review, the results of this review are not valid, and the review must be searched again via the PNDI Environmental Review Tool and resubmitted to the jurisdictional agencies. The PNDI tool is a primary screening tool, and a desktop review may reveal more or fewer impacts than what is listed on this PNDI receipt. The jurisdictional agencies **strongly advise against** conducting surveys for the species listed on the receipt prior to consultation with the agencies.

PA Game Commission

RESPONSE: No impact is anticipated to threatened and endangered species and/or special concern species and resources.

PA Department of Conservation and Natural Resources

RESPONSE: Conservation Measure: Please avoid the introduction of invasive species in order to protect the integrity of nearby plant species of special concern. Voluntary cleaning of equipment/vehicles, using clean fill and mulch, and avoiding planting invasive species (http://www.dcnr.state.pa.us/forestry/invasivetutorial/index.htm) will help to conserve sensitive plant habitats.

DCNR Species: (Note: The PNDI tool is a primary screening tool, and a desktop review may reveal more or fewer species than what is listed below. After desktop review, if a botanical survey is required by DCNR, we recommend the DCNR Botanical Survey Protocols, available here: http://www.gis.dcnr.state.pa.us/hgis-er/PNDI_DCNR.aspx.)
Scientific Name: Asplenium pinnatifidum
Common Name: Lobed Spleenwort
Current Status: Special Concern Species*
Proposed Status: Special Concern Species*

PNDI Project Environmental Review Receipt Project Search ID: 20110919316372

Scientific Name: Erigenia bulbosa
Common Name: Harbinger-of-spring
Current Status: Threatened
Proposed Status: Special Concern Species*

Scientific Name: Ilex opaca
Common Name: American Holly
Current Status: Threatened
Proposed Status: Threatened

PA Fish and Boat Commission

RESPONSE: Further review of this project is necessary to resolve the potential impacts(s). Please send project information to this agency for review (see WHAT TO SEND).

PFBC Species: (Note: The PNDI tool is a primary screening tool, and a desktop review may reveal more or fewer species than what is listed below.)
Scientific Name: Sensitive Species**
Common Name:
Current Status: Endangered
Proposed Status: Endangered

U.S. Fish and Wildlife Service

RESPONSE: No impacts to **federally** listed or proposed species are anticipated. Therefore, no further consultation/coordination under the Endangered Species Act (87 Stat. 884, as amended; 16 U.S.C. 1531 *et seq.* is required. Because no take of federally listed species is anticipated, none is authorized. This response does not reflect potential Fish and Wildlife Service concerns under the Fish and Wildlife Coordination Act or other authorities.

* Special Concern Species or Resource - Plant or animal species classified as rare, tentatively undetermined or candidate as well as other taxa of conservation concern, significant natural communities, special concern populations (plants or animals) and unique geologic features.
** Sensitive Species - Species identified by the jurisdictinal agency as collectible, having economic value, or being susceptible to decline as a result of visitation.

WHAT TO SEND TO JURISDICTIONAL AGENCIES

If project information was requested by one or more of the agencies above, send the following information to the agency(s) seeking this information (see AGENCY CONTACT INFORMATION).

Check-list of *Minimum* Materials to be submitted:

____**SIGNED** copy of this Project Environmental Review Receipt
____Project narrative with a description of the overall project, the work to be performed, current physical characteristics of the site and acreage to be impacted.
____Project location information (name of USGS Quadrangle, Township/Municipality, and County)
____USGS 7.5-minute Quadrangle with project boundary clearly indicated, and quad name on the map

The inclusion of the following information may expedite the review process.
____A basic site plan(particularly showing the relationship of the project to the physical features such as wetlands, streams, ponds, rock outcrops, etc.)
____Color photos keyed to the basic site plan (i.e. showing on the site plan where and in what direction each photo was taken and the date of the photos)
____Information about the presence and location of wetlands in the project area, and how this was determined (e.g., by a qualified wetlands biologist), if wetlands are present in the project area, provide project plans showing the location of all project features, as well as wetlands and streams
____The DEP permit(s) required for this project

4. DEP INFORMATION

The Pa Department of Environmental Protection (DEP) requires that a signed copy of this receipt, along with any required documentation from jurisdictional agencies concerning resolution of potential impacts, be submitted with applications for permits requiring PNDI review. For cases where a "Potential Impact" to threatened and endangered species has been identified before the application has been submitted to DEP, the application should not be submitted until the impact has been resolved. For cases where "Potential Impact" to special concern species and resources has been identified before the application has been submitted, the application should be submitted to DEP along with the PNDI receipt, a completed PNDI form and a USGS 7.5 minute quadrangle map with the project boundaries delineated on the map. The PNDI Receipt should also be submitted to the appropriate agency according to directions on the PNDI Receipt. DEP and the jurisdictional agency will work together to resolve the potential impact(s). See the DEP PNDI policy at http://www.naturalheritage.state.pa.us.

PNDI Project Environmental Review Receipt Project Search ID: 20110919316372

5. ADDITIONAL INFORMATION

The PNDI environmental review website is a **preliminary** screening tool. There are often delays in updating species status classifications. Because the proposed status represents the best available information regarding the conservation status of the species, state jurisdictional agency staff give the proposed statuses at least the same consideration as the current legal status. If surveys or further information reveal that a threatened and endangered and/or special concern species and resources exist in your project area, contact the appropriate jurisdictional agency/agencies immediately to identify and resolve any impacts.

For a list of species known to occur in the county where your project is located, please see the species lists by county found on the PA Natural Heritage Program (PNHP) home page (www.naturalheritage.state.pa.us). Also note that the PNDI Environmental Review Tool only contains information about species occurrences that have actually been reported to the PNHP.

6. AGENCY CONTACT INFORMATION

PA Department of Conservation and Natural Resources
Bureau of Forestry, Ecological Services Section
400 Market Street, PO Box 8552, Harrisburg, PA. 17105-8552
Fax:(717) 772-0271

U.S. Fish and Wildlife Service
Endangered Species Section
315 South Allen Street, Suite 322, State College, PA. 16801-4851
NO Faxes Please.

PA Fish and Boat Commission
Division of Environmental Services
450 Robinson Lane, Bellefonte, PA. 16823-7437
NO Faxes Please

PA Game Commission
Bureau of Wildlife Habitat Management
Division of Environmental Planning and Habitat Protection
2001 Elmerton Avenue, Harrisburg, PA. 17110-9797
Fax:(717) 787-6957

7. PROJECT CONTACT INFORMATION

Name: Tracy J Siglin
Company/Business Name: Exelon Generation Co LLC
Address: 200 Exelon Way
City, State, Zip: Kennett Square PA 19348
Phone: (610) 765-5618 Fax: (610)-765-5807
Email: tracy.siglin@exeloncorp.com

8. CERTIFICATION

I certify that ALL of the project information contained in this receipt (including project location, project size/configuration, project type, answers to questions) is true, accurate and complete. In addition, if the project type, location, size or configuration changes, or if the answers to any questions that were asked during this online review change, I agree to re-do the online environmental review.

Tracy J Siglin — applicant/project proponent signature

12-15-11 — date

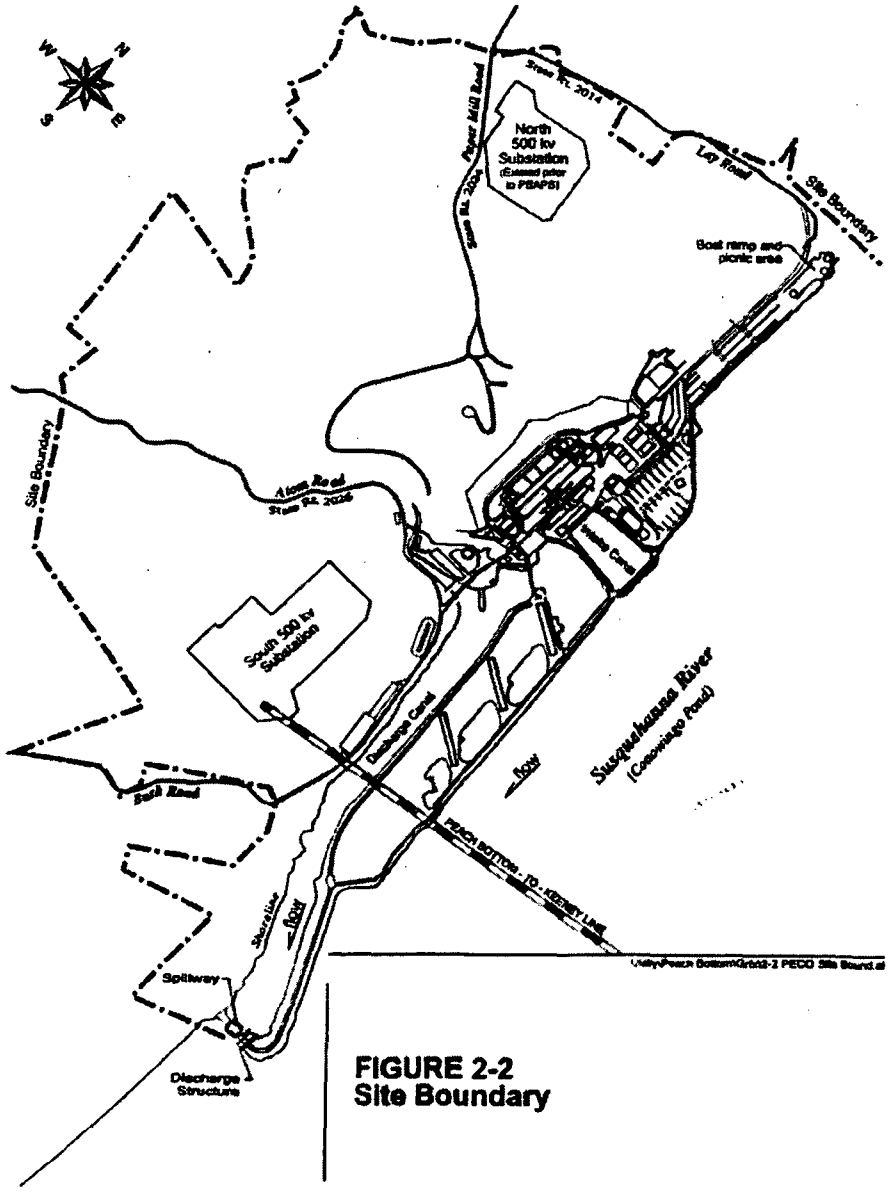
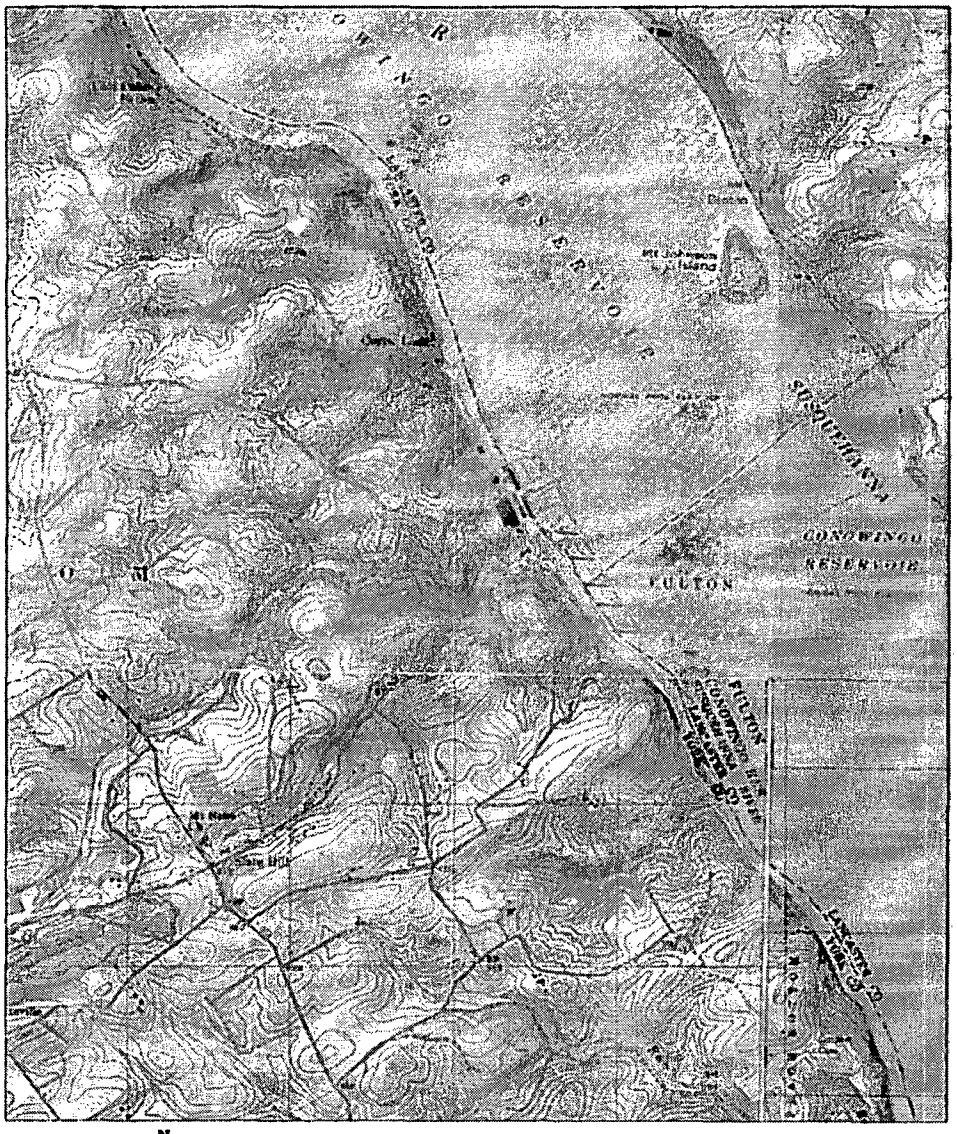


FIGURE 2-2
Site Boundary



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Map provided by MyTopo.com

Pennsylvania Fish & Boat Commission

FAX to: 610-765-5807

established 1866

Division of Environmental Services
Natural Diversity Section
450 Robinson Lane
Bellefonte, PA 16823-9620
(814) 359-5237 Fax: (814) 359-5175

February 24, 2012

IN REPLY REFER TO
SIR # 38039

MARK ROSS
EXELON NUCLEAR
1848 LAY ROAD
DELTA, PA 17314

RE: Species Impact Review (SIR) - Rare, Candidate, Threatened and Endangered Species
EXELON GENERATION PEACH BOTTOM ATOMIC POWER STATION UNITS 2 AND 3
EXTENDED POWER UPRATE
PNDI Search Number (if available): 20110919316372
FULTON, DRUMORE, PEACH BOTTOM Townships
LANCASTER, YORK Counties, Pennsylvania

This responds to your inquiry about a Pennsylvania Natural Diversity Inventory (PNDI) Internet Database search "potential conflict" or a threatened and endangered species impact review. These projects are screened for potential conflicts with rare, candidate, threatened or endangered species under Pennsylvania Fish & Boat Commission jurisdiction (fish, reptiles, amphibians, aquatic invertebrates only) using the Pennsylvania Natural Diversity Inventory (PNDI) database and our own files. These species of special concern are listed under the Endangered Species Act of 1973, the Wild Resource Conservation Act, and the Pennsylvania Fish & Boat Code (Chapter 75), or the Wildlife Code. The absence of recorded information from our files does not necessarily imply actual conditions on site. Future field investigations could alter this determination. The information contained in our files is routinely updated. A Species Impact Review is valid for one year only.

X ***NO ADVERSE IMPACTS EXPECTED FROM THE PROPOSED PROJECT***

___ Except for occasional transient species, rare, candidate, threatened or endangered species under our jurisdiction are not known to exist in the vicinity of the project area. Therefore, no biological assessment or further consultation regarding rare species is needed with the Commission. Should project plans change, or if additional information on listed or proposed species becomes available, this determination may be reconsidered.

X An element occurrence of a rare, candidate, threatened, or endangered species under our jurisdiction is known from the vicinity of the proposed project. However, given the nature of the proposed project, the immediate location, or the current status of the nearby element occurrence(s), no adverse impacts are expected to the species of special concern.

If you have any questions regarding this review, please contact the biologist indicated below:

X	Chris Urban	814-359-5113	___	Kathy Gipe	814-359-5186
___	Douglas Fischer	814-359-5195	___	Bob Morgan	814-359-5129

Thank you in advance for your cooperation and attention to this important matter of species conservation and habitat protection.

SIGNATURE: _____ DATE: February 24, 2012
Christopher A. Urban
Chief, Natural Diversity Section

Attachment 9

Peach Bottom Atomic Power Station Units 2 and 3

NRC Docket Nos. 50-277 and 50-278

Planned Modifications to Support Extended Power Uprate

1.0 Background

Physical plant changes to support EPU are required. Some are necessary to support the efficient electrical output of the unit to maximize the benefit of increases in rated thermal power (RTP). Others are necessary to support or compensate for analytical impacts of the RTP increase. The purpose of this attachment is to address the full range of modifications that relate to the Peach Bottom Atomic Power Station (PBAPS) EPU to allow the reader a more complete understanding of the overall scope for the PBAPS EPU Project.

1.1 Power Uprate Modifications

The PBAPS EPU project is being designed and implemented over several years, including refueling outages (P3R19, P2R20, and P3R20) and intervening operating cycles.

- In P2R19 (2012) and P3R19 (2013) PBAPS Units 2 and 3, respectively, a number of physical plant changes are scheduled to be installed. The significant changes are discussed briefly below.

- In P2R20 (2014) and P3R20 (2015), PBAPS Units 2 and 3, respectively, the balance of the EPU related modifications are scheduled to be installed. These modifications are discussed briefly below.

The modifications necessary to support EPU conditions also improve plant margins at existing power levels. Peach Bottom has or intends to implement these modifications pursuant to 10 CFR 50.59 and approved EGC Generation Company (EGC) Configuration Control Processes, including processes to evaluate piping supports' seismic consideration and probabilistic impacts. For those modifications that can be implemented under 10 CFR 50.59 evaluations, the installation of these modifications does not require prior NRC approval through this License Amendment Request (LAR). However, a number of the modifications are credited in the safety analysis revisions necessary to support EPU conditions and CAP elimination. Some aspects of these modifications also involve changes to the Technical Specifications or rely on safety analysis methodology changes. Therefore, greater detail is provided for significant modifications that are credited in the EPU supporting analysis or impact post-accident operator response requirements. These modifications are detailed in Section 3.0 of this Attachment, entitled, "Significant Modifications Explicitly Credited in the EPU Safety Analysis." Further, separate Enclosures are attached for the more involved modifications. Included in those Enclosure discussions are aspects of the modifications that do require prior NRC approval such as Technical Specification changes or methodology changes that are summarized in Attachment 1 of this LAR.

As stated above, all EPU modifications are being prepared in accordance with the EGC Configuration Change Process and are expected to be installed through evaluations pursuant to 10 CFR 50.59. Further evaluations may identify the need for additional modifications or obviate the need for some modifications currently identified. Additionally, the listing of modifications contained in this attachment constitutes planned actions on the part of EGC, and as such, are not formal commitments to implement the modifications exactly as described or per the proposed schedule.

Structural evaluations and required design calculations for pipe support evaluations associated with structures, systems, and components (SSCs) credited in the EPU safety analyses will be available at the time of application acceptance and controlled documentation will exist that finds

the applicable SSCs structurally adequate to perform their intended design functions under EPU conditions. These structural evaluations and analysis are completed by EGC or by a vendor with an approved 10 CFR 50, Appendix B, Quality Assurance Program, are owner reviewed and approved by EGC, and are EGC controlled documents. These documents are controlled by an EGC Configuration Change package but are entered separately in the EGC document control system. The EGC Configuration Change Process ensures that any revisions to the scope or final design of a modification are controlled and that any required reanalysis is performed in accordance with the PBAPS licensing and design basis. Implementation of the final designs will ensure SSCs are structurally and functionally capable of performing their intended design functions under EPU conditions.

2.0 Extended Power Uprate Modifications

The following discussion highlights the modification changes required to support operation at EPU power level. Each modification will be finalized and implemented in accordance with the EGC Configuration Change Process to meet the applicable design and licensing basis requirements for PBAPS. These modifications are scheduled to be implemented in 2012 through 2014 for Unit 2 and 2013 through 2015 for Unit 3.

2.1 High Pressure (HP) Turbine

Two HP Turbines (one per Unit) will be modified or replaced. The HP turbine retrofit is necessary due to capacity limitations on the current HP turbine and Main Turbine control system. The new HP turbine will fully utilize the increase in steam flow generated at EPU conditions as well as allowing for proper operating margin for the Main Turbine Control system.

2.2 Condenser

Atmospheric Relief Diaphragms (ARD) were added to allow for adequate pressure relief to protect the condenser at EPU conditions. The atmospheric relief diaphragms were added in 2011 for Unit 3 and are scheduled for installation on Unit 2 in 2012.

2.3 Turbine Cross Around Relief Valves (CARV)

All 12 CARVs (six per unit) will have setpoints adjusted for EPU operating conditions. There are no physical changes to the valves as the CARVs have sufficient capacity for operation at EPU conditions.

2.4 Reactor Feed Pump Turbines (RFPT)

All six RFPTs (three per unit) are scheduled to be modified. The turbine retrofit is needed to accommodate the higher blade stresses at EPU conditions. The retrofit will replace the 4th and 6th stage stationary and rotating blades.

2.5 Feedwater Heaters (FWH)

Five of the FWHs will be replaced for EPU. This includes the third stage C string FWH on Unit 2, and the second stage A and B string FWHs and the third stage A and C string FWH on Unit 3.

2.6 Reactor Water Clean Up (RWCU)

The RWCU system is sized to maintain an equilibrium contamination level in the reactor. For EPU, feedwater flow increases while the RWCU system flow will remain the same. This challenges reactor chemistry. To counteract the reduction in margin, the efficiency of the RWCU system will be improved. This modification will install flow diffusers on all four (two per unit) RWCU demineralizers. The flow diffusers increase the efficiency of the RWCU demineralizers thereby minimizing the impact of increased FW flow on Reactor Water Chemistry.

2.7 Flow Induced Vibration (FIV) Accelerometer (FW/MS)

The Main Steam and Feedwater systems, as well as portions of the Condensate, Extraction Steam and Heater Drain systems, will become susceptible to increased vibrations at EPU conditions as a result of higher flow rates. A confirmatory test program will be implemented to monitor piping and attached component vibration levels on these systems during initial power ascension to EPU conditions. Piping in the drywell and inaccessible piping outside containment will be monitored using accelerometers at selected locations on the piping and attached components. Attachment 13, Flow Induced Vibration, describes the details on the vibration monitoring program and the selected locations for the accelerometers.

2.8 Condensate Pumps/Motors

All six (three per unit) Condensate pumps and motors will be upgraded. The pump upgrade will change the impellers of the condensate pump. The condensate motor will be replaced with a larger motor to support the pump upgrade. The upgrades will increase the pump head at EPU flow rates. The increased pump head will provide adequate margin recovery for the Reactor Feed Pump suction trip setpoint at EPU conditions.

2.9 Condensate Filter/Demineralizer

Four (two per unit) additional condensate demineralizers will be installed on Unit 2 and on Unit 3. The additional demineralizers will increase the condensate demineralizer flow capacity by approximately 20 percent. The increased flow capacity exceeds the increase in Feedwater flow rate at EPU conditions.

2.10 MS Pipe Support Modifications

Attachment 6, PUSAR Section 2.2.2, "Pressure-Retaining Components and Component Supports," evaluated the MS piping system inside and outside of containment. The piping evaluations described in PUSAR Section 2.2.2.2 conclude that the piping systems meet all code criteria with the implementation of required pipe support modifications. These piping systems will continue to satisfy the design basis requirements when considering the temperature, pressure and flow rate effects resulting from EPU conditions with the addition of pipe support modifications and additions that will accommodate the revised loadings due to EPU. Summaries of the stress values for CLTP and EPU are reported in PUSAR Tables 2.2-5a through 2.2-5f.

The structural modifications and additions to MS piping supports have been identified and designed to the extent practicable. The evaluations supporting the structural modifications will be available at the time of application acceptance and controlled documentation will exist that finds the applicable SSCs structurally adequate to perform their intended design functions under EPU conditions. These structural evaluations are prepared in accordance with the PBAPS Configuration Control Process described in Section 1.0. PBAPS expects to perform additional refined analyses in accordance with the design and licensing basis, which may reduce the scope of these MS pipe support modifications. Final designs will ensure these SSCs are structurally adequate to perform their intended design functions under EPU conditions. Prior to EPU operation, PBAPS will implement the required MS modifications, which will include updating controlled documents and confirming applicable SSCs remain capable of performing their intended design function.

2.11 Reactor Pressure Vessel Internals

The design requirement for the minimum number of shroud head bolts has increased for EPU from 29 to 32. The additional shroud head bolts will be installed in 2014 for Unit 2 and in 2015 for Unit 3.

2.12 Hydrogen Chemistry/Noble Chemistry

The Hydrogen, Oxygen and Zinc injection systems will be modified. The majority of the modifications includes setpoint and control point adjustments to accommodate higher flow rates. In addition to the system setpoint changes, the Oxygen injection valve will have the valve trim changed to accommodate the increase in Oxygen flow rate.

2.13 Generator and Auxiliaries

Both main generators will be modified for EPU. The modifications will allow the generators to operate at 1530 MVA. Unit 2 will have a rewound rotor and Unit 3 will have a new rotor. In addition, the generator auxiliaries will be modified or retrofitted to accommodate the new generator rating. The modification to the generators and auxiliaries will allow the units to operate safely and reliable at a higher MVA output.

2.14 Isophase Bus Duct (IPBD)

The IPBD will be modified to support the Main Generator electrical output increase to 1530 MVA. The modification will require replacement of several portions of the existing IPBD.

2.15 Plant Instrumentation & Controls Update

EPU operating conditions require rescaling and setpoint changes of affected instruments in various plant systems. EPU operating conditions also reduce margin for some instruments and some of these will also require rescaling to gain back that margin. Instrument changes include tuning the parameters for Feedwater control and the display ranges for the Safety Parameter Display

System. Safety related thermowells and probes in the Main Steam (MS) and Feedwater (FW) systems have been evaluated for EPU conditions and found to be adequate as documented in Attachment 6, PUSAR Section 2.2.2.1.3, Safety Related Thermowells and Probes. Thermowells and probes in the Feedwater, Condensate and Main Steam systems will be reviewed for structural integrity and will be replaced as necessary through the EGC Configuration Control Process.

2.16 Recirculation Pump Trip timing for ATWS

The EPU Anticipated Transients Without Scram (ATWS) analysis requires a faster coast down of the recirculation pumps, reducing reactor power faster. This will be accomplished by either the relocation of the ATWS-Recirculation Pump Trip (RPT) from the MG Sets to the recirculation pump motor breaker or the elimination of the MG set inertia and coast down time delay by installation of Adjustable Speed Drives (ASDs). The EPU analysis has evaluated the system as acceptable for either modification (i.e., ATWS trip relocation or ASD).

2.17 Motor Operated Valves (MOV's)

The motor-operated valves affected by the post-LOCA Drywell and Wetwell pressure changes due to EPU were evaluated for change in differential pressure. Of these MOV's, eight have a negative margin impact and will be modified prior to implementation of EPU. An additional five MOV's were identified to have changed from medium to low margin and will be modified to return them to high acceptable margin. See PUSAR Section 2.2.4.1, Safety Related Valves and Pumps.

3.0 Significant Modifications Explicitly Credited in the EPU Safety Analysis or Licensing Bases

There are six modifications that support safety analysis or licensing basis changes and are necessary to support EPU conditions. These modifications warrant providing more complete design summaries. These are provided in Attachment 9 Enclosures 9a, 9b, 9c, 9d, and 9e and in Attachment 17. The enclosures to Attachment 9, where applicable, include figures that show the current and modified configuration, and provide more detailed discussions, to ensure clarity of the modification description. As noted in Section 1.0, each modification will be finalized and implemented in accordance with the EGC Configuration Change Process to meet the applicable design and licensing basis requirements as outlined in this submittal. Additionally, for the modifications that supported an increased NPSH margin for the ECCS pumps, an overall summary of how the modifications interact to eliminate reliance on CAP credit is provided below in Section 3.2.

3.1 EPU Related Modifications

PBAPS plans to install the following modifications to support implementation of EPU:

- Addition of a Main Steam Spring Safety Valve (SV) (Enclosure 9a)
  The addition of one MS spring SV on each unit addresses overpressure duty under EPU conditions. The addition of a third spring SV per unit is required in order to achieve acceptable margin for the ATWS analysis for EPU operation.

- Standby Liquid Control (SLC) System Modifications (Enclosure 9b)
  PBAPS is planning to increase the Boron-10 (B-10) enrichment, SLC system pump flow rate and discharge pressure, and minimum liquid level in the Standby Liquid Control (SLC) System. The proposed change in B-10 enrichment is required to keep the suppression pool temperature within the limits in the ATWS analysis, described in Attachment 6, PUSAR Section 2.8.5.7, "Anticipated Transient Without Scram," and to meet inlet temperature restrictions for the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) pumps. With a minimum B-10 enrichment of 92.0 atom percent in the SLC system storage tank solution, the SLC System is capable of reliably mitigating an ATWS event at EPU conditions. The increase in the minimum SLC system storage tank level to 52% will continue to maintain suppression pool pH level ≥ 7.0 following a LOCA involving significant fission product releases.

  An additional benefit of the increased B-10 enrichment and higher SLC system pump flow rate is the faster shutdown of the core. This effectively decreases the suppression pool temperature, which results in an increase in NPSH margin and supports elimination of CAP credit in ECCS pump NPSH analyses. Therefore, the B-10 modification is also discussed in Section 3.2 below for improvement in NPSH margin and CAP Elimination.

- Replacement Steam Dryer (Attachment 17)
  EGC evaluated the existing PBAPS original equipment manufacturer steam dryers and determined the steam dryers would not be suitable for EPU conditions without modifications. EGC decided to replace the original steam dryers with Westinghouse designed and manufactured Nordic Steam Dryers. The PBAPS Unit 2 RSD is scheduled for installation during the P2R20 outage in 2014. The PBAPS Unit 3 replacement steam dryer is scheduled for installation in the P3R20 outage in 2015. The analysis supporting EPU operation with the replacement steam dryers is provided in Attachment 17.

The three remaining modifications are associated with CAP credit elimination and are discussed below in Section 3.2.3.2.

3.2 Overview of Improvement in NPSH Margin and CAP Elimination

3.2.1 Current Licensing Basis

In the current design configuration, ECCS pumps that take suction from the suppression pool rely on some amount of containment accident pressure (CAP) for adequate Net Positive Suction Head (NPSH) at the elevated suppression pool temperatures experienced during design basis accidents and special events. Credit for CAP for the Residual Heat Removal (RHR) and Core Spray (CS) pumps during the short and long term following a LOCA was part of the PBAPS original licensing basis. Reliance on CAP increased after the power rerate and the increased debris loading postulated on the ECCS suction strainers as a result of the station's response to NRC Bulletin 96-03 (Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling-Water Reactors). A license amendment request submitted in August 1999 and approved by the NRC in August 2000 clarified the licensing basis for the use of CAP at

Peach Bottom Units 2 and 3 and provided specific information regarding the allowed containment accident pressure credit needed to ensure that adequate NPSH is available for the ECCS pumps. The 1999 Minimum Containment Pressure Available (MCPA) analysis performed to support the LAR included conservative assumptions that would minimize containment pressure during an event including the use of containment sprays, maximized torus water temperatures, maximum design basis containment leakage, maximum HPSW temperature, and minimum RHR heat exchanger performance. As noted in the 1999 LAR, the MCPA analysis indicated that adequate NPSH would be assured even with these conservative assumptions. The 1999 LAR also stated that a re-evaluation of the DBA LOCA analyses for NPSH using the MCPA analysis continued to indicate sufficient containment pressure. The MCPA analysis is documented in UFSAR 5.2.4.3.2, Minimum Containment Pressure Available.

As discussed above, CAP credit is required to achieve adequate NPSH margin for the RHR and CS pumps during the design basis large break loss of coolant accident (DBA LOCA) and small steam line break (SSLB) accidents concurrent with a loss of offsite power and a worst case single failure. CAP credit is also taken for the RHR and CS pumps for the safety relief valve transient consisting of a stuck open relief valve with reactor pressure vessel isolation (SRVT).

The NPSH calculations for special events, including SBO, ATWS and Appendix R Fire Safe Shutdown cases, also require CAP credit for the RHR and CS pumps. The Appendix R case has the least margin but it is still bounded by the DBA-LOCA.

Table 9-1 provides a summary of the CAP credit taken for the Residual Heat Removal and Core Spray pumps under the current licensing basis (CLB).

The HPCI pumps are not included in the table although they take suction from the suppression pool for all events in the CLB. They are limited to a suppression pool temperature of 180°F due to equipment constraints, and are normally turned off by procedure before exceeding the limit if not required for adequate core cooling. EPU does not affect the HPCI pump NPSH available and the NPSH margin for the HPCI pump at 180°F is 1.0 feet.

3.2.2 Extended Power Uprate NPSH

NPSH Available (NPSHa) is a function of the piping system design, the pump flow rate, temperature of the pumped water, and the height of water in the suppression pool. The increased reactor decay heat at EPU means more heat addition to the suppression pool for the design basis accidents and special events such as Station Blackout (SBO), ATWS, and Appendix R Fire Safe Shutdown cases. As a result, without modification or changes, suppression pool temperatures would be higher leading to decreased NPSHa and the need for additional CAP credit for NPSH at EPU conditions.

Regulatory Guide 1.82 Rev 4 states that emergency core cooling and containment heat removal systems should be designed so that adequate available NPSH is provided to the system pumps, assuming the maximum expected temperature of the pumped fluid and no increase in containment pressure from that present prior to the postulated LOCA's. It also states that certain operating BWR's, for which the design cannot be practicably altered, may take CAP credit provided specified conservative guidance in the Regulatory Guide is followed. As part of the PBAPS EPU, however, EGC has decided to

voluntarily eliminate the reliance on CAP credit assumptions in the design and licensing basis. This will be achieved through the implementation of plant modifications and analysis methodology changes that increase the NPSH margin to the extent that adequate NPSH is available without CAP. Implementation of these modifications will meet the recommendation of the Regulatory Guide to make the predicted performance of the ECCS pumps independent of the calculated increases in containment pressure caused by postulated LOCA's and preserve the use of CAP as additional safety margin against any unanticipated and unanalyzed phenomena. PUSAR 2.6.5.1 provides a description of the suppression pool temperature response for design basis events to the increased decay heat conditions of EPU. PUSAR 2.6.5.2 describes the impact of EPU on the suppression pool during the special events of Station Blackout, ATWS and Appendix R and the resultant NPSH analyses without CAP. Table 2.6-5 in that section tabulates the results of those analyses including the peak suppression pool temperatures and the NPSH margin without CAP credit.

3.2.3 Changes to Improve NPSH Margin

A combination of changes to inputs to the NPSH analyses and plant modifications provide the additional NPSH margin for the ECCS pumps that allows CAP credit to be eliminated for all design basis and special events. Tables 9-2a through 9-2f summarize the input changes that provide additional NPSH margin. The RHR pump flow rates for long term cooling indicated in those tables are increased by a multiplier of 1 divided by the square root of 0.97 or 1.015 in determining NPSH margins to account for the effect on flow due to the head loss of 3% for the NPSH curves for the pumps. Thus the 8,600 gpm RHR flow rate for long term cooling under EPU, as shown on these tables, is increased to 8,732 gpm for the NPSH calculations. The NPSH analyses for the CS pumps also use flow values that are conservatively above the safety analysis values. Suppression pool temperature response was evaluated for a spectrum of steam break sizes at EPU in addition to the DBA LOCA. The smallest of these small breaks, 0.01 ft^2, results in a slightly higher peak suppression pool temperature than for the DBA LOCA although during the first ten minutes of the SSLB, the suppression pool temperature is at least 20°F lower than for the DBA LOCA. In addition, during the first ten minutes of the SSLB the RHR and CS pumps are either not operating or on minimum flow.

The NPSH analyses described in PUSAR 2.6.5.2 assume a pressure of 0 psig in the suppression pool. $NPSHR_{3\%}$ is the ECCS pump vendors recommended minimum based on a 3% reduction in pump head during testing. $NPSHr_{eff}$ includes any uncertainty applied in accordance with NRC draft guidance in SECY 11-0014. For PBAPS, 21% uncertainty is applied to the DBA-LOCA and the SSLB and 0% uncertainty for other events.

Table 9-3 summarizes the NPSH margins for the DBA and special events calculated for EPU without CAP.

3.2.3.1 Methodology Changes to Improve NPSH Margin

The following Methodology changes are applied to the EPU NPSH evaluations:

- Nominal rather than limiting values are used for certain input parameters for the SBO, ATWS and Appendix R Fire Safe Shutdown cases as indicated in Tables 9-2d, e and f. This is consistent with NRC guidance for these events including SECY 11-0014 which considers more realistic assumptions for beyond design basis NPSH calculations. The relaxation of bounding initial conditions to those more typical of nominal conditions was effective in providing a positive impact to NPSH margin by reducing peak suppression pool temperature.

- Credit is taken for passive heat sinks for the DBA LOCA, the SSLB, the Appendix R analyses and the Loss of RHR Normal Shutdown Cooling events for both the accident and non-accident units (see PUSAR 2.6.1.1.1 and 2.6.5.2 for a discussion of dual unit interaction). No heat loss, however, is assumed through the containment walls. The use of passive heat sinks and the transfer of heat taken mechanistically from the suppression pool reduce the heatup of the suppression pool and lower its peak temperature.

- Inventory addition to the suppression pool from the CST with the use of the RCIC or HPCI pumps for Reactor Pressure Vessel makeup without transfer to the suppression pool is credited during SRVT, SBO, ATWS and Appendix R Fire Safe Shutdown Cases A, B and D. This will improve NPSH margin and support the elimination of CAP credit during these events.

3.2.3.2 Modifications to Improve NPSH Margin

In addition to the methodology changes, the modifications summarized below and described in more detail in the indicated enclosures to Attachment 9 will act in combination to provide the additional NPSH margin that will allow elimination of CAP credit.

- RHR Heat Exchanger Cross-Tie Modification (Enclosure 9c)
- HPSW Cross-Tie Modification (Enclosure 9d)
- Condensate Storage Tank Modification (Enclosure 9e)

In the CLB, only one RHR pump and one heat exchanger are credited for post-LOCA containment cooling. At EPU power levels, the RHR Heat Exchanger Cross-Tie Modification includes a new cross-tie line with a cross-tie isolation valve on each RHR loop that will allow two RHR heat exchangers to be supplied from one RHR pump. It will also include flow control valves upstream of each heat exchanger that allow the operator to balance RHR flow between the two heat exchangers as required from the control room. The flow control valves also add hydraulic resistance in the RHR pump discharge lines to reduce the maximum RHR pump flow during the automatic LPCI mode in the first ten minutes following a DBA LOCA. The performance level of the individual heat exchangers (K-factor) will be improved by reducing allowable fouling with the design RHR heat exchanger K value increased from 270 BTU/sec-°F to 305 BTU/sec-°F per heat exchanger. These changes will improve the rate of suppression pool cooling and lower the peak suppression pool temperature while allowing a reduction in the required RHR flow.

The HPSW Cross-Tie Modification supports the RHR Heat Exchanger Cross-Tie Modification. It is credited for events in which only one RHR pump is available and the

RHR Heat Exchanger Cross-Tie must be opened to supply two RHR heat exchangers from the operating RHR pump. These include DBA LOCA, SSLB, an SRVT and Loss of RHR Normal Shutdown Cooling when the event includes a loss of offsite power. In these events, the analysis assumes that the operator cross-ties a second RHR heat exchanger to the operating RHR pump one hour after the event and starts a second HPSW pump to provide cooling to the second RHR heat exchanger. The HPSW Cross-Tie modification gives the operator the ability to manually align a second HPSW pump from the opposite Division to provide cooling water to the second operating RHR heat exchanger placed in service.

The reduction in suppression pool temperature and corresponding decrease in vapor pressure resulting from the RHR and HPSW Cross-Tie Modifications will increase NPSHa for both the RHR and CS pumps. The improved cooling rate will also be enough to allow a reduction in RHR flow while still meeting containment cooling requirements under design basis conditions. The reduced RHR flow will reduce $NPSHr_{eff}$ and further increase NPSHa for the RHR pumps as a result of reduced friction losses through the pump suction piping and strainers.

During SBO, ATWS, and Appendix R Methods A, B and D special events, the HPCI and RCIC pumps provide reactor pressure vessel makeup. At EPU conditions, these pumps will be assured adequate NPSH margin by the proposed CST Modification which will ensure that there is enough water to maintain the pump suctions on the CST for the duration of the event so that they will not have to be switched to the suppression pool.

The calculated maximum usage of the HPCI and RCIC pumps during SBO is well within the CST inventory. Although the CST is the primary suction source during an SBO, the suppression pool can be used if necessary. The PBAPS SBO event licensing basis requires an 8-hour coping capability with alternate AC power available within one hour. At 30 minutes into the event, operators secure HPCI and continue RCIC operation to maintain reactor water level.

In the limiting Appendix R Fire Safe Shutdown cases and during an ATWS at EPU conditions, the volume of water required to maintain the HPCI and RCIC pump suctions on the CST exceeds the current CST inventory. As described in Enclosure 9e to Attachment 9, this shortfall will be addressed with procedure changes that will require the operator to open the cross connect between the CST and the Refueling Water Storage Tank (RWST). Enough inventory of RWST water can be gravity drained to the CST to achieve and maintain cold shutdown conditions within 72 hours without reaching the CST low level setpoint, where the suction would be automatically switched to the suppression pool. In order to prevent a fire induced failure of the makeup or letdown valves from draining the CST to the hotwell and thereby possibly draining CST inventory to the CST low level setpoint, a standpipe is being installed as part of the CST Modification on the hotwell reject/makeup line. The standpipe will limit the volume of water within the tank available to the condenser hotwell makeup line in the event of such a failure and provide additional assurance that sufficient CST water volume will be available to the HPCI and RCIC pumps. Since the HPCI pump is switched to the suppression pool on torus high level, the torus high level setpoint is being raised to prevent premature switchover to the suppression pool before accommodating the water volume used in the analyses. Enclosure 9e describes the CST Modification including the procedure changes, the standpipe and the torus high level setpoint change.

By enabling the HPCI and RCIC pumps to maintain suction from the CST during the SBO, ATWS, and Appendix R Fire Safe Shutdown cases, the CST Modification provides for additional water volume to the RPV for makeup which produces the additional heat capacity in the torus that lowers suppression pool temperature. The additional volume also causes additional water height in the torus. The increased heat capacity and height of water increase NPSHa for the RHR and CS pumps.

Different aspects of the three modifications described above are relied upon for ensuring adequate NPSH margin in the different design basis and special event analyses. Table 9-4 correlates the design basis and special events with the proposed modifications as described in the Enclosures to Attachment 9 that improve NPSH margin.

In addition to the modifications discussed above that increase the NPSH margin for the ECCS pumps sufficient to preclude reliance on CAP, the SLC System Modifications (Enclosure 9b) also supports an increase in NPSH margin. The proposed change in B-10 enrichment is required to keep the suppression pool temperature within the limits of the ATWS analysis, described in PUSAR section 2.8.5.7 and to meet inlet temperature restrictions for the HPCI and RCIC pumps. Since the increase in B-10 enrichment in the SLC system will facilitate a faster reactor shutdown during an ATWS event, it results in a reduced heat load input into the suppression pool. The reduction in the heat load reduces the peak suppression pool temperature which improves NPSH margin.

3.2.4 Summary

Currently, ECCS pumps require CAP credit to provide adequate NPSH margin using conservative analytical methods described in the licensing basis. The increased decay heat generated at EPU power levels will increase suppression pool temperatures and further decrease NPSH margin for the ECCS pumps. Rather than proposing an increased reliance on CAP credit, EGC has voluntarily decided to make plant modifications and apply methodology changes that will increase NPSH margin for these pumps to the extent that reliance on CAP can be eliminated. When only one RHR pump is available for long-term cooling, the proposed modifications to the RHR and HPSW systems will enable operators to cross-tie a second RHR heat exchanger to the operating pump. Along with a change to increase the heat removal capacity of the heat exchangers through a reduction in allowable fouling, these modifications will significantly increase the rate of suppression pool cooling and allow a reduction in RHR flow requirements during long-term cooling. Even with the application of an uncertainty to the DBA LOCA and SSLB, these steps will provide enough additional NPSH margin to preclude reliance on the containment pressure present in the postulated loss-of-coolant accidents. In addition, for the special events of ATWS, SBO, and Appendix R fire shutdown cases, the CST modification will enable the HPCI pumps, as well as the non-ECCS RCIC pumps, to maintain suction from the CST. This will increase the volume of water and the heat capacity of the suppression pool thereby lowering its temperature and increasing the height of water in the torus which will preclude the need for CAP for the RHR and CS pumps. Although the NPSH margins are reduced from the current licensing basis, the comparison is not direct since CAP is not credited in EPU.

These voluntary changes are in accordance with and meet the intent of Regulatory Guide 1.82 Revision 4 and the guidance contained in SECY 11-0014. The containment pressure generated by the accident will be part of the safety margin against loss of NPSH and thereby enhance defense-in-depth.

Table 9-1
PBAPS CAP Credit Summary – CLB Analysis of Record
RHR and CS Pumps

Event	NSPHR (ft)	MCPA (psig)	CAP (psig)	NPSH Margin (ft)
RHR Pump / CS Pump				
DBA LOCA	26.00/26.75	7.03/7.03	6.14/4.78	2.11/5.38
Small Steam Line Break (SSLB)	26.00/26.75	Not Calculated	Not Calculated	Bounded by DBA LOCA
SBO	26.00/NA	4.63/NA	2.11/NA	6.01/NA
ATWS	26.00/NA	4.63/NA	2.11/NA	6.01/NA
SRVT	26.00/26.75	4.63/4.63	2.11/0.70	6.01/9.38
Appendix R	26.00/26.75	6.85/6.85	5.76/4.35	2.63/6.01

Table 9-2a
Key Changes in Inputs to NPSH Calculations for EPU

Long Term DBA LOCA and SSLB

	CLB	EPU	Notes
SP Initial Temperature (°F)	92	95	TS 3.6.2.1 limit
SP Initial Volume, ft^3	122,900	122,900	TS 3.6.2.2 low limit
DW Initial Temperature (°F)	145	70	145°F is the TS 3.6.1.4 limit. Initial conditions for EPU (70 °F) are assumed that maximize suppression pool temperature while also maximizing containment pressure response.
UHS Temperature (°F)	92	92	TS 3.7.2 limit.
Credit for Passive Heat Sinks	No	Yes	EPU for long term with no heat loss through containment walls.
Number of RHR Pumps/Heat Exchangers for LT Cooling	1/1	1/2	At EPU, the operating RHR pump is cross tied to 2 RHR heat exchangers
RHR Pump Flow Rate Long Term Cooling (gpm)	10,000	8732	8600 gpm is used in the EPU safety analyses
CS Pump Flow Rate Long Term Cooling (gpm)	3125	3493	3125 gpm is used in the EPU safety analyses.
RHR Heat Exchanger Heat Transfer Capacity (K, BTU/sec-°F) per HX	270	305/500	305 up to one hour and 500 after one hour when flow is split between 2 RHR HXs.
Source for HPCI	Suppression Pool	Suppression Pool	SSLB Only

Table 9-2b
Key Changes in Inputs to NPSH Calculations for EPU

Loss of RHR Normal Shutdown Cooling with Loss of Offsite Power

	CLB	EPU	Notes
SP Initial Temperature (°F)	92	95	TS 3.6.2.1 limit
SP Initial Volume, ft^3	122,900	122,900	TS 3.6.2.2 low limit
DW Initial Temperature (°F)	145	70	145 °F is the TS 3.6.1.4 limit. Initial conditions for EPU (70 °F) are assumed that maximize suppression pool temperature while also maximizing containment pressure response.
UHS Temperature (°F)	92	92	TS 3.7.2 limit.
Credit for Passive Heat Sinks	No	Yes	EPU for long term with no heat loss through containment walls.
Number of Pumps/RHR Heat Exchangers for LT Cooling	1/1	1/2	At EPU, the operating RHR pump is cross tied to 2 RHR heat exchangers.
RHR Pump Flow Rate Long Term Cooling (gpm)	10,000	8732	8600 gpm is used in the EPU safety analyses.
CS Pump Flow Rate Long Term Cooling (gpm)	NA	3493	3125 gpm is used in the EPU safety analyses.
RHR Heat Exchanger Heat Transfer Capacity (K, BTU/sec-°F) per HX	270	305/500	305 up to one hour and 500 after one hour when flow is split between 2 RHR HXs for loss of offsite power.
Source for HPCI	Suppression Pool	Suppression Pool	

Table 9-2c
Key Changes in Inputs to NPSH Calculations for EPU

SRVT

	CLB	EPU	Notes
SP Initial Temperature (°F)	92	95	TS 3.6.2.1 limit
SP Initial Volume, ft^3	122,900	122,900	TS 3.6.2.2 low limit
DW Initial Temperature (°F)	145	70	145 °F is the TS 3.6.1.4 limit. Initial conditions for EPU (70 °F) are assumed that maximize suppression pool temperature while also maximizing containment pressure response.
UHS Temperature (°F)	92	92	TS 3.7.2 limit
Credit for Passive Heat Sinks	No	No	
Number of RHR Pumps/Heat Exchangers for LT Cooling	1/1	1/2	At EPU, the operating RHR pump is cross tied to 2 RHR heat exchangers.
RHR Pump Flow Rate Long Term Cooling (gpm)	10,000	8732	8600 gpm is used in the EPU safety analyses
CS Pump Flow Rate Long Term Cooling (gpm)	3125	3493	3125 gpm is used in the EPU safety analyses.
RHR Heat Exchanger Heat Transfer Capacity (K, BTU/sec-°F) per HX	270	305/500	305 up to one hour and 500 after one hour when flow is split between 2 RHR HXs for loss of offsite power.
Source for HPCI	CST	CST	Limiting Case (1A)

Table 9-2d
Key Changes in Inputs to NPSH Calculations for EPU

SBO

	CLB	EPU	Notes
SP Initial Temperature (°F)	92	86	Change to nominal value for EPU from TS limit. The EPU value is the mean plus one standard deviation of a statistical analysis of a five year sampling of data.
SP Initial Volume, ft^3	122,900	125,100	Change from TS limit for CLB to nominal value for EPU.
DW Initial Temperature (°F)	145	145	145 is the TS 3.6.1.4 limit.
UHS Temperature (°F)	92	86	The EPU value is the mean of a statistical analysis of a five year sampling of data for the months of June, July, August, and September.
Credit for Passive Heat Sinks	Yes	Yes	EPU for long term with no heat loss through containment walls.
Number of RHR Pumps/Heat Exchangers for LT Cooling	1/1	1/1	At one hour, Alternate AC is available and one RHR pump and one RHR Heat Exchanger placed in service.
RHR Pump Flow Rate Long Term Cooling (gpm)	10,000	8732	8600 gpm is used in the EPU safety analyses.
CS Pump Flowrate Long Term Cooling (gpm)	NA	NA	
RHR Heat Exchanger Heat Transfer Capacity (K, BTU/sec-°F) per HX	270	305	
Source for HPCI/RCIC	Suppression Pool	CST	

Table 9-2e
Key Changes in Inputs to NPSH Calculations for EPU

ATWS

	CLB	EPU	Notes
SP Initial Temperature (°F)	92	86	Change to nominal value for EPU from TS limit. The EPU value is the mean plus one standard deviation of a statistical analysis of a five year sampling of data.
SP Initial Volume, ft^3	122,900	122,900	TS 3.6.2.2 low limit
DW Initial Temperature (°F)	NA	NA	There is no LOOP and no loss of containment cooling.
UHS Temperature (°F)	92	86	The EPU value is the mean of a statistical analysis of a five year sampling of data for the months of June, July, August, and September.
Credit for Passive Heat Sinks	No	No	
Number of RHR Heat Exchangers	2/2	2/2	
RHR Pump Flow Rate Long Term Cooling (gpm)	10,000	8732	8600 gpm is used in the EPU safety analyses.
CS Pump Flow Rate Long Term Cooling (gpm)	NA	NA	
RHR Heat Exchanger Heat Transfer Capacity (K, BTU/sec-°F) per HX	270	305	610 total heat exchanger effectiveness per loop.
Source for HPCI	Suppression Pool	CST	

Table 9-2f
Key Changes in Inputs to NPSH Calculations for EPU

Appendix R Fire Safe Shutdown Events

	CLB	EPU	Notes
SP Initial Temperature (°F)	92	86	Change to nominal value for EPU from TS limit. The EPU value is the mean plus one standard deviation of a statistical analysis of a five year sampling of data.
SP Initial Volume, ft^3	122,900	125,100	Change from TS limit for CLB to nominal value for EPU.
DW Initial Temperature (°F)	145	135	Change to nominal value from TS limit.
UHS Temperature (°F)	92	86	The EPU value is the mean of a statistical analysis of a five year sampling of data for the months of June, July, August, and September
Credit for Passive Heat Sinks	No	Yes	EPU for long term with no heat loss through containment walls.
Number of RHR Heat Exchangers	1	1	
RHR Pump Flow Rate Long Term Cooling (gpm)	10,000	8732	8600 gpm is used in the EPU safety analyses.
CS Pump Flow Rate Long Term Cooling (gpm)	3125	3493	Appendix R Case C1A. 3125 gpm is used in the safety analyses.
RHR Heat Exchanger Heat Transfer Capacity (K, BTU/sec-°F)	270	305	
Source for HPCI/RCIC	Suppression Pool	CST	

Table 9-3
ECCS Pump EPU NPSH Evaluation Summary
RHR and CS Pumps

Event	NPSHa (ft)	$NPSHr_{eff}$ (ft)	NPSH Margin (ft)	Uncertainty (%)
RHR Pump/CS Pump				
Short Term DBA LOCA(1)	31.97/32.91	30.25/26.62	1.72/6.29	21
Long Term DBA LOCA	23.21/24.98	19.36/24.20	3.85/0.78	21
Long Term DBA LOCA with Dual Unit Interaction (2)	22.69/24.46	19.36/24.20	3.33/0.26	21
Small Steam Line Break (SSLB)	22.78/24.54	19.36/24.20	3.42/0.34	21
Small Steam Line Break (SSLB) Dual Unit Interaction (2)	22.51/24.28	19.36/24.20	3.15/0.08	21
Loss of RHR NSDC	25.74/26.00	16.00/20.00	9.74/6.00	0
Loss of RHR NSDC with Dual Unit Interaction (2)	25.43/25.69	16.00/20.00	9.43/5.69	0
SRVT	28.22/28.48	16.00/20.00	12.22/8.48	0
Appendix R Case A1 (3)	17.21/NA	16.0/NA	1.21/NA	0
Appendix R Case C1A (3)	20.51/20.77	16.0/20.0	4.51/0.77	0
Appendix R Case C1B (3)	16.03/NA	16.0/NA	0.03/NA	0
SBO	21.30/NA	16.0/NA	5.30/NA	0
ATWS	31.54/NA	16.0/NA	15.54/NA	0
Second unit (non-accident)safe shutdown	16.49/NA	16.00/NA	0.49/NA	0

(1) Short term is defined as less than 10 minutes after event; long term as greater than 10 minutes after event.
(2) This event includes the impact of the dual unit interaction discussed in PUSAR 2.6.1.1.1 and 2.6.5.1.
(3) See PUSAR 2.6.5.2 for a discussion of the selection of Appendix R cases analyzed.

Table 9-4
SUMMARY OF MODIFICATIONS THAT IMPROVE NPSH MARGIN

Modification (EPU LAR Description)	ECCS Pump NPSH - Events	Proposed Changes
RHR Heat Exchanger Cross-Tie (Enclosure 9C)	DBA-LOCA Short term (first 10 minutes)	• Reduce RHR runout flow rate by adding hydraulic resistance with flow control valves
RHR Heat Exchanger Cross-Tie (Enclosure 9C) HPSW Cross-Tie (Enclosure 9D)	DBA-LOCA Long term and SSLB	• Cross Tie second RHR HX to operating RHR pump • Improve RHR performance (reduce allowable fouling) • Decrease RHR flow rate
RHR Heat Exchanger Cross-Tie (Enclosure 9C) CST (Enclosure 9E)	SBO	• Improve RHR performance (reduce allowable fouling) • Decrease RHR flow rate • Credit CST as suction source for HPCI and RCIC pumps
RHR Heat Exchanger Cross-Tie (Enclosure 9C) SLC System (Enclosure 9B) CST (Enclosure 9E)	ATWS	• Improve RHR performance (reduce allowable fouling) • Decrease RHR flow rate • Increase B-10 enrichment • Credit CST as suction source for HPCI pumps
RHR Heat Exchanger Cross-Tie (Enclosure 9C) CST (Enclosure 9E)	Appendix R	• Improve RHR performance (reduce allowable fouling) • Decrease RHR flow rate • Increase CST inventory • HPCI and RCIC pumps use CST only
RHR Heat Exchanger Cross-Tie (Enclosure 9C) HPSW Cross-Tie (Enclosure 9D)	Loss of RHR NSDC	• Cross Tie second RHR HX to operating RHR pump • Improve RHR performance (reduce allowable fouling) • Decrease RHR flow rate
RHR Heat Exchanger Cross-Tie (Enclosure 9C) CST (Enclosure 9E)	SRVT	• Improve RHR performance (reduce allowable fouling) • Decrease RHR flow rate • Credit CST as suction source for HPCI pumps

Enclosure 9a to Attachment 9

Peach Bottom Atomic Power Station Units 2 and 3

NRC Docket Nos. 50-277 and 50-278

<u>Addition of Main Steam Safety Valve</u>

1.0 Purpose

Exelon Generation Company (EGC) is pursuing an EPU of approximately 12.4 percent at the Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3. PBAPS proposes to install one additional Main Steam (MS) spring safety valve (SV) on each unit to address overpressure under EPU conditions. Specifically, the addition of a third spring SV per unit is required in order to achieve acceptable margin for the Anticipated Transients Without Scram (ATWS) analysis at EPU conditions. The addition of the third MS spring SV will also recover margin for the ASME Overpressure event analysis at EPU conditions.

This enclosure provides a summary of the proposed modification. The modification is expected to be installed during P2R20 (2014) refueling outage for Unit 2 and during the P3R20 (2015) refueling outage for Unit 3. Implementation of the modification includes installation of the new SV and valve position indication instrumentation for the new SV.

2.0 Background and Current Licensing/Design Basis

ASME Code, Section III, Article 9, "Protection Against Overpressure," requires the reactor pressure vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of Safety Relief Valves (SRVs) and the SVs are selected such that the peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB).

The SRVs and the SVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. There are currently two SVs and eleven SRVs mounted on the steam lines for each unit. These SVs and SRVs limit peak pressure in the primary system during plant transient conditions.

The SVs are spring loaded valves that actuate when steam pressure at the inlet overcomes the spring force holding the valve disc closed. The SVs discharge steam directly to the drywell. The eleven SRVs are unitized pilot-operated relief/safety valves that relieve to the suppression pool and are self-actuated by fluid pressure greater than the valve setpoints (range between 1135 to 1155 psig) or opened by remote operator actions, so they function as a dual purpose safety/relief valve.

The overpressure protection system must function to protect the reactor pressure vessel from the most severe pressurization transient for both an anticipated operational occurrence and the non-design bases ATWS. Currently, the most severe anticipated operational transient is a closure of all main steam isolation valves (MSIVs), followed by reactor scram on high neutron flux. The current analysis requires any combination of eleven SRVs and SVs be available to operate to satisfy the assumptions of the safety analysis. The analysis demonstrates that the current SRV and SV design capacity is capable of maintaining reactor pressure below the ASME Code limit of 110 percent of vessel design (1,375 psig). From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above.

As stated above, the overpressure protection system also must adequately protect the reactor vessel during an ATWS. Although the ATWS is not a design basis event, it is necessary to demonstrate the overpressure protection system is capable of maintaining reactor pressure below the ASME Code limit of 120 percent of vessel design to maintain reactor vessel pressure integrity during a postulated ATWS. One of the acceptance criteria for an ATWS event is to

maintain reactor vessel integrity. This is demonstrated by showing peak vessel bottom pressure is less than the ASME Service Level C limit of 1,500 psig. The current ATWS overpressure analysis requires that any combination of eleven SRVs and SVs be available to operate.

The current SVs have valve position indication as described in UFSAR Section 7.20.4.9. The valve position indication meets Regulatory Guide 1.97, Revision 3, May 1983. Safety Valve and SRV position indication are required to meet accident monitoring requirements of NUREG-0737, Action Plan Item II.D.3. Monitoring requirements are incorporated into TRM 3.6, "Post Accident Monitoring (PAM) Instrumentation."

UFSAR Section 4.4 provides the basis for overpressure protection during power operation. The Regulatory Evaluation section of Attachment 6, PUSAR Section 2.8.4.2, "Overpressure Protection During Power Operation," states that the NRC acceptance criteria for overpressure protection is GDC-15 and GDC-31. The corresponding Current Licensing Bases (CLB) discusses the PBAPS original licensing. PBAPS was not licensed to GDCs or the AEC Draft GDCs, but rather to plant specific principle design criteria. PBAPS UFSAR Appendix H contains a comparative evaluation of the principle design criteria to the AEC draft GDCs. As stated in the CLB section for PUSAR section 2.8.4.2, the applicable Draft AEC GDCs for overpressure protection are draft GDC-33, Draft GDC-34, and Draft GDC-35.

3.0 Scope of Modification/Design

3.1 Purpose/Technical Justification

PBAPS proposes to install one additional spring SV on each unit to address the overpressure duty under EPU conditions. The addition of a third spring SV per unit is required in order to achieve acceptable margin for the ATWS event analysis at EPU conditions. The additional SV will be installed at an existing flange that is currently blocked off. The existing flange is located on the MS line "C".

The addition of the third SV per unit does not change the design function of the nuclear boiler system (NBS). No changes to the existing SRVs or SVs are being made. The new SV will have the same design characteristics as the existing SVs with regard to outline dimensions, set pressure and ASME certified flow capacity. The new SVs will be constructed of an alternate set of materials that are recommended by the valve manufacturer. Any material enhancements are evaluated as part of the EGC Configuration Change Process, as described in Attachment 9, Section 1.1.

ASME Boiler and Pressure Vessel Code requires that a vessel designed to meet Section III be protected from pressures in excess of 110 percent of the vessel design pressure. The ASME overpressure limit for the reactor vessel will be 1,375 psig. The code specification for the safety valves require that (1) the lowest safety valve be set at or below vessel design pressure (1250 psig), and (2) the highest safety valve be set to open at or below 105 percent of the vessel design pressure (1313 psig). As stated above, the nominal setpoint for the new MS spring SV will be 1,260 psig, which is the same as for the existing two MS spring SVs. This is below 105 percent of the vessel design pressure. Thus, the setpoint for the new MSSV meets the requirements of the ASME Code for criterion 2 stated above. The setpoints for the SRVs meet the requirement of ASME Code for criterion 1 stated above. ASME Code certified flow capacity shall be the same as the existing MS spring SVs, which is 949,015 lbm/hr at a setpoint of 1,260 psig.

Attachment 6, PUSAR, Section 2.8.4.2, "Overpressure Protection During Power Operation," includes Table 2.8-14, "Parameters used for Transient Analysis," which indicates the assumption of an additional MS spring SV as part of EPU. For these events the pressure at the bottom of the vessel is 1,340 psig. The corresponding calculated maximum RPV dome pressure is 1,313 psig. The analysis results demonstrate that the design of SRV and SV capacity, including the addition of a MS spring SV, is capable of maintaining reactor pressure below the ASME Code limit of 110 percent of RPV design pressure (1,375 psig). The MSIV closure with flux scram event remains the bounding event for overpressure protection.

The adequacy of the pressure relief system is also demonstrated by the overpressure protection evaluation performed for each reload and by the ATWS evaluation performed for EPU. Attachment 6, PUSAR Section 2.8.5.7, "Anticipated Transient Without Scram," documents the ATWS overpressure analysis. Tables 2.8-7, "PBAPS Key Inputs for ATWS Analysis," and Table 2.8-8, "PBAPS Results for ATWS Analysis," provide the key input assumptions and limiting results. The analysis demonstrates that the design of SRV and SV capacity is capable of maintaining reactor vessel pressure below the ASME Service Limit C value of 1,500 psig.

3.2 Design Considerations

Classification

The classifications of the new valves and the valve position indicating systems (acoustic and temperature discharge monitoring) are based on the currently installed SVs and the associated position indicating systems. No classification changes will be made. The new SVs and the fuse installed in the circuit are safety related. While the valves and fuse are safety related, the instrumentation associated with the acoustic monitoring system is augmented quality or non-safety related and are based on the existing temperature elements and recorders. Both the sensors and main control room indicating equipment are classified as augmented quality. The instrumentation cables, temperature elements and the recorders are classified as non-safety related.

Seismic Classification and Seismic/Dynamic Qualification

Main steam lines are classified Seismic Class I. Therefore, SVs and installation work meet Seismic Class I criteria. Installation of the indicating lamps on the control board and the acoustic panel also meets Seismic Class I criteria. Only the new temperature elements and the recorders are Seismic Class II.

The seismic/dynamic qualification of the new valve is based on the current SVs. Indicating lamps, acoustic equipment, and fuses that will be added to the Main control room board will be seismically mounted to preclude interfering with the existing Seismic Class I equipment currently located in the panel. Acoustic sensors mounted on the piping in the drywell will be seismically mounted to preclude interfering with the existing equipment. All analysis supporting the mounting of this equipment will be performed in accordance with the EGC Configuration Change Process, as described in Attachment 9, Section 1.1.

Equipment Qualification Requirements

The valves are mechanical equipment and there is no mechanical Equipment Qualification (EQ) program applicable to PBAPS. The acoustic monitoring sensors are located in the drywell and are EQ qualified. The remaining equipment, temperature elements, amplifiers and fuses are not EQ. These designations are based on the existing SV's acoustic monitoring systems.

Single Failure Criterion

The third SV is to be installed in addition to the thirteen existing valves (two existing SVs and eleven SRVs) that lift at the designated set pressures. This provides the required overpressure protection. The addition of the third safety valve does not adversely affect the redundancy, diversity or separation requirements as it functions completely independent of the other system pressure relief devices. The consequences of a stuck open safety valve remain the same as the consequences of one of the two existing safety valves being stuck in the open position. Therefore, a single malfunction or failure of an active component, such as the SV, does not preclude the overpressure protection portion of the system from functioning as required.

Risk Assessment
As described in Attachment 12, the PBAPS Probabilistic Risk Assessment (PRA) model was updated to determine the impacts of EPU. The analysis concluded that overall Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) increases were very small: a 2.8% increase in CDF and 3.5% increase in LERF. The addition of a third SV on the main steam line was evaluated for impact on the PRA model for RPV overpressure protection. The PRA models overpressure failure via common cause failures of the 11 SRVs and does not include the current SV's directly in the model. Since the addition of the third SV ensures that the combined SV/SRV success criteria remain the same for EPU as it does for pre-EPU conditions, no PRA model change was required for this modification. A separate sensitivity study indicated that even if the RPV overpressure failure probability was doubled, the increases would still be very small with a 5.0% increase in CDF and a 4.6% increase in LERF.

3.3 Structural Evaluation

The new SV weight will be approximately 1,257 pounds, with a bounding weight limit of 1,300 pounds, per the valve supplier. Pipe stress calculations for Unit 2 and Unit 3 have been performed for the addition of the new SVs. Results demonstrate that stresses meet code allowables with implementation of modifications to existing supports and addition of new supports. Modifications to existing pipe supports and the addition of new pipe supports have been identified and will be implemented consistent with the EGC Configuration Change Process, as described in Attachment 9, Section 1.1 and 2.10, and consistent with the piping design criteria in UFSAR Appendix A.

3.4 Instrumentation

Instrument requirements for the new MS spring SV acoustic and temperature discharge monitoring system will be the same as existing MS spring SVs.

Acoustic Loop:

New instrumentation cables will be added from the new acoustic sensor to an existing Drywell Penetration and from that penetration to an existing pre-amp box. Existing instrumentation cables with spare conductors as well as new instrumentation cables will be used to support the acoustic sensor loop to the Main Control Room (MCR). New instrumentation includes a new acoustic monitor sensor, new acoustic monitor pre-amp, acoustic Bi-Stable Relay and new SV indicating lamps. There are three indicating lamps for the new SV. The indicating lamps are of the same color and orientation and are located directly below the indicating lamps for the existing two SVs. The indicating lamp circuit will be powered similar to the existing SV by 125 VDC power. Circuits of this panel currently provide power to the existing indication lamps. The new indication lamp circuit has a similar load and will be added in parallel with a new fuse to protect this new branch of the circuit.

Temperature Loop:

Existing instrumentation cables with spare conductors and new instrumentation cables will be used to support the temperature sensor loop to the MCR and the main steam reactor vessel temperature recorder located on the control boards. A new SV discharge thermocouple, same as on the existing SVs, will be used. An existing Temperature Recorder located in control board panel will be used. The output of this recorder illuminates a window alarm that is common to all devices connected to the recorder. No change to this alarm circuit is required. The setpoint (300 deg F) that is used for the A and B loops will be used for loop C as well.

Plant Computer:

Similar to the existing SVs, the new SV acoustic Bi-Stable will supply a digital signal to the Plant Computer. The availability of Plant Computer inputs and designation of a specific computer point will be confirmed as part of the EGC Configuration Change Process, as described in Attachment 9, Section 1.1.

3.5 Testing

Surveillance Requirements and In-Service Testing (IST) Program requirements for the currently installed SVs will apply to the new SVs. TS 3.4.3.1 will be updated to reflect the installation of the additional SV per unit. Current Technical Specification Surveillance Requirement 3.4.3.1 requires that the SVs setpoint be 1260 psig +/- 13.0 psi. This is demonstrated during shutdown by bench testing performed in accordance with the IST Program. The valve is removed and tested at an appropriate test facility to meet the IST Program requirements. The installation of a new SV will not change this surveillance testing, but will need to adhere to it.

3.6 Technical Specifications

Technical Specification changes are necessary to implement this modification. The TS LCO 3.4.3 and Surveillance Requirement SR 3.4.3.1 will change the number of SVs to three. These changes are described in Attachment 1 and demonstrated in the Attachment 2 markup. The associated TS Bases will be updated to reflect the addition of the new MS spring SV. TS Bases markups are provided in Attachment 3 for information only.

3.7 Operational changes

There will be no operational process changes due to this modification. The new SV equipment will function automatically, just as the current SVs function. The valve is a spring relief valve dependent on pressure overcoming the spring force. There are no operator actions required for functioning of the valve. The Operators will have the ability to determine valve leakage based on the acoustic and temperature monitoring systems. The same acoustic and temperature monitoring systems are currently employed on the two existing SVs. Under EPU conditions, the number of out-of-service SRVs/SVs will be reduced. The safety function of any combination of thirteen SRVs and SVs will be required to be operable to satisfy the assumptions of the safety analysis.

4.0 Summary

The addition of a third spring SV per unit is required in order to achieve acceptable margin for the ATWS analysis for EPU operation. The addition of the third SV per unit does not change the design function of the Nuclear Boundary System (NBS). The ASME Code certified flow capacity will be the same as the existing SVs, which is 949,015 lbm/hr at a setpoint of 1,260 psig. The nominal setpoint for the new SV will be 1,260 psig, which is the same as for the existing two SVs and is below 105 percent of the vessel design pressure. Thus the setpoint for the new MS spring SV meets the requirements of the ASME Code.

The overpressure protection system must accommodate the most severe pressurization transient from an anticipated operational transient and must adequately protect the reactor vessel integrity during an ATWS. Attachment 6, PUSAR, Section 2.8.4.2, "Overpressure Protection During Power Operation," details the analysis that demonstrates the design of the SRV and SV capacity (including the additional MS spring SV) is capable of maintaining reactor pressure below the ASME Code limit of 110 percent of RPV design pressure (1,375 psig). Additionally, Attachment 6, PUSAR Section 2.8.5.7, "Anticipated Transient Without Scram," documents the ATWS overpressure analysis. This analysis demonstrates that the design of the SRV and SV capacity (including the additional MS spring SV) is capable of maintaining reactor vessel pressure below the ASME Service Limit C value of 1,500 psig.

Enclosure 9b to Attachment 9

Peach Bottom Atomic Power Station Units 2 and 3

NRC Docket Nos. 50-277 and 50-278

Standby Liquid Control System (SLCS) Modifications

1.0 Purpose

Exelon Generation Company (EGC) is pursuing an Extended Power Uprate (EPU) of approximately 12.4 percent at the Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3. As part of the EPU, PBAPS proposes to increase the isotopic enrichment of the Boron-10 (B-10) in the Standby Liquid Control (SLC) System sodium pentaborate (SPB) solution, which is the credited neutron absorber. Increasing the isotopic enrichment of B-10 in the SPB solution effectively increases the amount of B-10 in the SPB solution. This increases the potential rate of available negative reactivity in the SLC system and which when inserted into the core, results in a faster shut down of the reactor. A faster shut down reduces the amount of heat that is generated in the reactor and ultimately transferred to the suppression pool. The proposed change in B-10 enrichment is required to keep the suppression pool temperature within the limits in the Anticipated Transient Without Scram (ATWS) analysis, described in PUSAR section 2.8.5.7, "Anticipated Transient Without Scram," and to meet inlet temperature restrictions for the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) pumps.

In addition to maintaining the peak suppression pool temperature below design limits, the proposed change in B-10 enrichment will help ensure adequate net positive suction head (NPSH) is available for the Emergency Core Cooling System (ECCS) pumps taking suction from the suppression pool. Therefore, this proposed change in B-10 enrichment, along with other proposed modifications and methodology changes, supports elimination of containment accident pressure (CAP) credit in the safety analysis by preventing greater increases in the post EPU ATWS suppression pool temperature.

2.0 Background and Current Licensing/Design Basis

The SLC system is described in Section 3.8 of the PBAPS UFSAR. The SLC system is designed to provide the capability of bringing the reactor, at any time in a fuel cycle, from full power and minimum control rod inventory (which is at the peak of a xenon transient) to a subcritical condition with the reactor in the most reactive, xenon free state without taking credit for control rod movement. The SLC system satisfies the injection requirements of 10 CFR 50.62(c) (4) regarding ATWS using enriched boron. The SLC system is also used to maintain suppression pool pH $\geq$ 7.0 following a LOCA involving significant fission product releases. Maintaining suppression pool pH levels $\geq$ 7.0 following an accident ensures that sufficient iodine will be retained in the suppression pool water and that control room and offsite doses remain within 10 CFR 50.67 limits.

The SLC system consists of a boron solution storage tank, the test tank, two positive displacement pumps, two explosive valves that are provided in parallel for redundancy, and associated piping and valves used to transfer the borated water from the storage tank to the reactor vessel. The borated solution is discharged just below the core support assembly, where it then mixes with the cooling water rising through the core.

Regulatory requirements for the system are described in the Regulatory Evaluation section of Attachment 6, PUSAR Section 2.8.4.5, Standby Liquid Control System as modified by the Current Licensing Basis section.

Scope of Modification

3.1 Purpose/Technical Justification

PBAPS proposes to increase the enrichment of the B-10 isotope in the SPB solution. There are no physical changes to the SLC system, structures and components due to the increase in B-10 enrichment in the SPB solution and there are no significant impacts to the mechanical or electrical aspects of the SLC system. As part of implementing this change, the required minimum level (volume) of SPB solution in the SLC system tank will increase from ≥ 46 percent to ≥ 52 percent. Changing the required minimum tank level will result in changes to the low level alarm setpoint. However, the SLC tank level normal operating band remains the same. The setpoint change for the low level alarm will be established, controlled and implemented though the EGC Configuration Change Process.

Analytically, the B-10 enrichment in the SPB solution of the SLC system is increasing from a minimum of 61.92 atom percent to a credited minimum of 92 atom percent. The total mass of B-10 required to be injected into the reactor pressure vessel (RPV) to comply with the ATWS rule of 10 CFR 50.62 remains the same (162.7 lbm). However, the rate of B-10 injection and quantity stored in solution in the SLC tank increases in proportion to the changes needed to achieve the proposed higher enrichment and tank level that are required by the PBAPS ATWS and Alternate Source Term (AST)safety analyses, respectively. The increase in the Technical Specification B-10 enrichment value does not change the concentration of the SLC system SPB solution.

Natural boron contains 19.8 atom percent of the B-10 isotope. The B-10 isotope, with its large thermal neutron capture cross-section, is the active neutron absorber component in SPB solution. Based on this characteristic, the use of an increased B-10 enriched SPB solution of 92 atom percent B-10 provides a faster negative reactivity insertion rate than the same quantity of SPB solution with natural boron or the 61.92 atom percent B-10. Regardless of the boron enrichment, the SPB physically and chemically remains the same with the exception of the molarities of the solution created by SPB powders having different enrichments. The molarity of the SPB solution slightly increases with the enrichment increase.

The SPB solution acts as a buffer in the suppression pool to inhibit the decrease in suppression pool pH due in part to the radiolysis of chlorinated polymer cable jacketing. The new minimum SLC tank level increases the amount of available SPB solution for SLC injection. The increased tank level supports installation of planned cabling while also ensuring the pH is maintained above 7.0 following a LOCA involving significant fission product releases at EPU conditions.

The EPU ATWS analysis in Attachment 6, PUSAR Section 2.8.5.7, documents that the analysis used the minimum SLC System pump flow rate of 49.1 gpm (Technical Specifications (TS) Surveillance Requirement (SR) 3.1.7.8), the minimum enrichment of 92 atom percent Boron-10 (TS SR 3.1.7.10) and the minimum SPB solution concentration of 8.32 weight percent (TS SR 3.1.7.5). The results show that the RPV lower plenum pressure increases by 10 psi from 1180 psig at the current licensed power level to 1190 psig at EPU conditions. As a result of this increase in lower plenum pressure, and accounting for the SLC system piping pressure drop, the SLC system pumps will be required to develop a new minimum flow rate of 49.1 gpm with a minimum discharge pressure of 1265 psig at EPU conditions. The flow rate and discharge pressure are located in TS SR 3.1.7.8. These changes are described in Attachment 1. Acceptance criteria for performance testing of the SLC system pumps will be updated in the In-service Testing (IST) Program (Attachment 6, PUSAR Section 2.2.4.2).

3.2 Modification Scope

The SLC System modification includes:

- Replacing the solution by first draining and flushing with demineralized water the existing solution of SPB from the SLC tank and associated piping.
- Increasing the TS SLC system minimum tank level to 52 percent, and changing the low level alarm setpoint to 56 percent.
- Mixing a SPB solution with the proper volume of demineralized water and quantity of SPB powder having ≥ 92 atom percent Boron-10 enrichment that will result in an acceptable SLC tank level, SPB concentration, and Boron-10 enrichment to refill the SLC tank and associated SLC System piping in compliance with the requirements that are specified in TS 3.1.7 for EPU conditions.

3.3 Core Shutdown Margin Requirements

SLC system shutdown capability is discussed in Attachment 6, PUSAR Section 2.8.4.5, "Standby Liquid Control System." SLC system shutdown capability is evaluated for each fuel reload. The boron shutdown concentration of 660 ppm does not change for EPU. Specifically, changes are not necessary to the SPB solution volume, the SPB concentration or B-10 enrichment for EPU to achieve the required reactor boron concentration for cold shutdown conditions and to comply with the ATWS rule in 10 CFR 50.62. However, the increase in the minimum B-10 enrichment from 61.92 atom percent to 92 atom percent for EPU is based on injection rate demands for the EPU ATWS analysis, which maintains the pool temperature below design limits to meet inlet temperature restrictions for the HPCI and RCIC pumps and support increasing NPSH margin for the ECCS pumps.

3.4 ATWS Requirements

The 10 CFR 50.62 requirements for reduction of risk from ATWS events, requires, in part, that:

> "Each boiling water reactor must have a standby liquid control system (SLCS) with the capability of injecting into the reactor pressure vessel a borated water solution at such a flow rate, level of boron concentration and boron-10 isotope enrichment, and accounting for reactor pressure vessel volume, that the resulting reactivity control is at least equivalent to that resulting from injection of 86 gallons per minute of 13 weight percent sodium pentaborate decahydrate solution at the natural boron-10 isotope abundance into a 251-inch inside diameter reactor pressure vessel for a given core design."

Attachment 6, PUSAR Section 2.8.5.7, demonstrates that PBAPS satisfies the boron injection equivalency requirement in 10 CFR 50.62. The equivalency requirement is satisfied at EPU power levels with the minimum SLC system pump flow rate of 49.1 gpm, the minimum concentration of 8.32 percent weight SPB, and the minimum B-10 enrichment of 92 atom percent. As shown in the PUSAR Section 2.8.5.7, the equivalency equation product is 1.69, which exceeds the requirement of 1.0. It is important to note that the use of the SLC system EPU parameters in the equivalency equation yields results greater than 1.0 because the parameters are also used to maintain suppression pool temperature below the design limits to meet inlet temperature analysis restrictions for the HPCI and RCIC pumps and to support increasing NPSH margin for the ECCS pumps.

The increase in B10 isotopic enrichment from 61.92 atom-percent to 92 atom-percent results in a proportional reduction in the minimum volume of sodium pentaborate solution required to be stored in the SLCS storage tank for the SLC system to mitigate an ATWS and achieve the same shutdown requirement of 660 ppm, plus a 25 percent margin of conservatism for leakage and mixing.

3.5 CAP Elimination Requirements

PBAPS has chosen to voluntarily eliminate CAP credit from the licensing basis by increasing NPSH margin for the ECCS pumps. Along with several other modifications and methodology changes, the B-10 enrichment modification supports an increase in the NPSH margin. Raising the minimum B-10 isotopic enrichment from 61.92 atom percent to 92 atom percent for EPU ensures that the peak suppression pool temperature is maintained below the design temperature limit where CAP credit is needed to ensure NPSH required for the ECCS pumps during an ATWS event. Mitigation of an ATWS event at EPU conditions requires a higher rate of negative reactivity injection than that required to meet the ATWS Rule, and therefore, the equivalency equation is not used to control SLC system parameters for EPU. Assurance of appropriate control of SLC system parameters is through implementation of TS SR 3.1.7.1 for minimum SLC tank level, SR 3.1.7.5 and Figure 3.1.7-1 for allowable SPB concentrations, SR 3.1.7.8 for SLC system pump minimum flow rate and minimum discharge pressure, and SR 3.1.7.10 for minimum boron enrichment. Therefore, the SLC system will also function to ensure no reliance on CAP credit for ECCS pump NPSH calculations following implementation of EPU.

3.6 Post-LOCA Suppression Pool pH Control Requirements

In addition to controlling reactivity by injecting SPB solution into the RPV, the SLC system SPB solution is used to maintain the suppression pool pH $\geq$7.0 following a DBA LOCA involving significant fission product releases. Injecting SPB adds a chemical base to the water, maintaining a pH $\geq$7.0 to ensure control room and offsite doses remain within 10 CFR 50.67 limits.

A post-LOCA suppression pool pH analysis was performed considering the impact of the changes to the SLC system. The analysis demonstrated that the suppression pool pH will remain $\geq$7.0 but requires an increase in the minimum SLC system tank level from 46 percent to 52 percent to support assumptions in the AST analysis. The SPB solution acts as a buffer in the suppression pool to inhibit the decrease in suppression pool pH due in part to the radiolysis of chlorinated polymer cable jacketing. The current SLC system tank level of 46 percent would not provide adequate margin to encompass the planned installation of additional cable in the Unit 2 and 3 drywells to monitor flow induced vibration in the steam lines and in the Unit 2 steam dryer. Therefore, the SLC tank level is increased to 52 percent. This value supports installation of planned cabling while also ensuring the pH is maintained above 7.0 following a LOCA involving significant fission product releases at EPU conditions. TS SR 3.1.7.1 verifies the minimum tank level. The associated TS SR change is discussed in Attachment 1.

3.7 Impact on operating procedures/training

There is no change to how the SLC system will be operated following the B-10 enrichment modification. This is because the SLC system equipment, such as control panels, pumps, tanks, heaters, or instrument panels, will not be changing. Differences in the B-10 enrichment will have no effect on the storage, handling, and mixing procedures and existing station procedures will continue to be adequate to control these activities. Current surveillance procedures adequately address verification of B-10 enrichment; however, the existing procedures will be revised to address the new enrichment value, SPB concentration limits, SLC tank level requirements, and SLC system pump performance requirements. The increase in the negative reactivity insertion rate achieved by the higher boron enrichment will decrease the volume of SPB solution required to achieve a hot shutdown boron concentration in the RPV. Therefore, the change to a higher SLC pump minimum flow rate with a lower required solution volume will decrease the time to initiate reflood of the RPV during an ATWS event. This will be addressed by procedure changes and training.

Affected procedures and training are identified and revised as part of the EGC Configuration Control Process.

3.8 Changes to TS and TS Bases

The modification does affect SLC System TS 3.1.7. The associated TS changes are described in detail in Attachment 1 and are not repeated here.

4.0 Summary

The function of the SLC system, method of operation, redundancy and system configuration remain unchanged as a result of the proposed changes. The proposed changes to the SLC system TS continue to satisfy regulatory requirements. EPU analyses demonstrate that the system will continue to provide reactivity control independent of the control rod drive system, mitigation for ATWS events, and pH control following a LOCA. Additionally, the B-10 enrichment modification, along with other modifications and methodology changes described in this LAR, supports the elimination of CAP credit from the PBAPS licensing basis.

Enclosure 9c to Attachment 9

Peach Bottom Atomic Power Station Units 2 and 3

NRC Docket Nos. 50-277 and 50-278

Residual Heat Removal (RHR) Heat Exchanger Cross-Tie Modification

1.0 PURPOSE

Exelon Generation Company (Exelon) is pursuing an EPU of approximately 12.4 percent at the Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3. PBAPS proposes to install a Residual Heat Removal (RHR) system heat exchanger cross-tie on each loop (division) such that adequate NPSH for RHR and Core Spray (CS) pumps will no longer be dependent on Containment Accident Pressure (CAP) credit for Design Basis Accidents (DBA) and other analyzed events. The RHR heat exchanger cross-tie will be utilized in conjunction with the High Pressure Service Water (HPSW) Cross-tie Modification (see Attachment 9 Enclosure 9d).

The RHR heat exchanger cross-tie modification will enable one RHR pump to provide flow through two RHR heat exchangers. The modification will also include the installation of four new flow control valves on each of the RHR pump discharges, upstream of the RHR heat exchanger. The supporting analysis requires the RHR heat exchangers to be maintained to a higher cleanliness criterion. The RHR pump flows will also be reduced. The reduced RHR system flow will further increase NPSH available as a result of reduced friction losses through the pump suction piping and strainers. The pumps will also be allowed to operate closer to their optimal efficiency point, which will lower the NPSH required.

The modification will provide a significant increase in the minimum containment cooling capacity at EPU conditions. The resulting reduced suppression pool temperature and corresponding reduced vapor pressure will result in increased Net Positive Suction Head Available (NPSHa) to both the RHR and CS pumps while lowering the required flow will reduce NPSH Required (NPSHr). As a result, NPSH margin for the Emergency Core Cooling System (ECCS) pumps will be increased so that CAP credit is not required.

Figure 9c-1 is a schematic that shows the current configuration with the RHR heat exchanger cross-tie modification changes highlighted.

2.0 BACKGROUND

2.1 Existing Plant Configuration

The RHR system is described in UFSAR 4.8, Residual Heat Removal System. The analysis for Minimum Containment Pressure Available to ensure adequate NPSH for the ECCS pumps under the current design is discussed in UFSAR 5.2.4.3.2. Technical Specifications (TS) and/or Technical Specification Bases (TSB) associated with the RHR and Low Pressure Coolant Injection (LPCI) mode of the RHR system that are impacted by this modification include TS/B 3.5.1, ECCS-Operating; TS/TSB 3.5.2, ECCS-Shutdown; TS/TSB 3.6.2.3, RHR Suppression Pool Cooling; TS/TSB 3.6.2.4; and RHR Suppression Pool Spray.

The safety function of the RHR system is to restore and maintain the coolant inventory in the reactor vessel so that the core is adequately cooled after a LOCA. It also provides

cooling for the containment so that condensation of the steam resulting from the blowdown due to the design basis LOCA is ensured.

The major components in the RHR system are four main system RHR pumps and four RHR heat exchangers. Four HPSW pumps for each unit support the heat removal function of the RHR system. The RHR pumps are sized on the basis of the flow required by the LPCI mode of RHR operation. The heat exchangers are sized on the basis of their required duty for the shutdown cooling function. Large capacity passive pump suction strainers have been installed on each RHR suction line in the suppression pool in response to NRC I.E. Bulletin 96-03 "Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors." The functional components of the RHR system are designed in accordance with seismic Class I criteria.

The RHR pumps are powered from the 4-kV emergency auxiliary buses. Each of the four RHR pump motors together with its associated automatic motor-operated valve receives AC power from a separate 4-kV bus. Similarly, control power for each pump motor comes from separate DC buses.

RHR has multiple modes of operation including shutdown cooling, containment cooling and LPCI. In the shutdown cooling mode, it is capable of completing a normal cooldown to 125 deg F in about 30 hours after the main condenser is no longer available. In this mode, the RHR system pumps reactor coolant from one of the recirculation loops through the RHR heat exchangers where cooling takes place by transferring heat to the HPSW system. It is returned to the reactor vessel via either recirculation loop.

In the containment cooling mode, the RHR system provides a means to cool the containment either through suppression pool cooling or containment spray. The safety related function is to remove reactor core decay heat and sensible heat discharged to the suppression pool after a design basis event or accident in order to maintain the suppression pool temperature within an acceptable limit and containment pressure within an acceptable range. When in the containment cooling mode, the RHR pumps are aligned to pump water from the suppression pool through the heat exchangers. It is then either returned to the suppression pool via the full flow test line or diverted to the spray headers in the dry well and above the suppression pool.

In the LPCI mode, the RHR system operates with the high pressure coolant injection (HPCI), Core Spray and automatic depressurization systems to restore and, if necessary, maintain the coolant inventory in the reactor vessel after a LOCA so that the core is sufficiently cooled to preclude excessive fuel clad temperatures and subsequent energy release due to a metal-water reaction. During LPCI operation, the RHR pumps take suction from the suppression pool and discharge into the core region of the reactor vessel through the recirculation loops.

The RHR system is composed of two loops designated Division I and Division II. Each division includes two RHR pumps and two heat exchangers. The A and C pumps and heat exchangers are in Division I and the B and D pumps and heat exchangers are in Division II. Each division's two pumps, two heat exchangers and associated piping, is referred to as a loop. The RHR system has two loops for all modes of operation. Each loop is in a separate area of the reactor building to minimize the possibility of a single

physical event causing the loss of the entire system. Each loop in turn consists of two subsystems defined as one RHR pump, one RHR heat exchanger and associated piping.

In the current licensing basis, the heat removal capability of one RHR pump and one heat exchanger in one subsystem is sufficient to meet the overall DBA pool cooling requirement for loss of coolant accidents (LOCAs) with a loss of offsite power and failure of a 125 VDC safety related battery. The failure of a 125 VDC safety related battery causes the loss of the associated Emergency Diesel Generator (EDG) and 4 KV emergency auxiliary bus. The cooling capability of this stated RHR system equipment is also sufficient for transient events such as a turbine trip or stuck open safety/relief valve. As a result, any one of the four RHR suppression pool cooling subsystems can provide the required suppression pool cooling function.

2.2 Design Basis

2.2.1 Current Design Basis

The RHR system safety design bases are set forth as follows in UFSAR 4.8.2:

1. The RHR system acts automatically, in combination with other Core Standby Cooling Systems (CSCS), to restore and maintain the coolant inventory in the reactor vessel such that the core is adequately cooled to preclude fuel clad temperature in excess of 2,200°F following a design basis LOCA.

2. The RHR system, in conjunction with other CSCS's, has such diversity and redundancy that only a highly improbable combination of events could result in the inability to provide adequate core cooling.

3. The source of water for restoration of reactor vessel coolant inventory is located within the primary containment in such a manner that a closed cooling water path is established.

4. To provide a high degree of assurance that the RHR system operates satisfactorily during a LOCA, each active component is capable of being tested during operation of the nuclear system.

5. The functional components of the RHR system are designed to seismic Class I criteria.

The CSCS is also referred to as the ECCS. The proposed RHR heat exchanger cross-tie modification will not change these safety design bases.

2.2.2 Current Credit for Containment Accident Pressure (CAP)

The RHR pumps and the Core Spray pumps take suction from the suppression pool and rely on some amount of CAP during the DBA LOCA, the small steam line break (SSLB) and other special events to provide for adequate NPSH at elevated suppression pool temperatures. However, the bounding event for the CAP credit required is the design

basis LOCA and the CAP credit required for the RHR pumps bounds that of the Core Spray pumps.

The credit for CAP for the RHR and core spray pumps during the long term following a LOCA was part of the PBAPS original licensing basis as approved by the NRC (Ref. 9.1). Reliance on CAP credit increased after the power rerate and the increased debris loading postulated on the ECCS suction strainers as a result of the station's response to NRC Bulletin 96-03 (Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling-Water Reactors). This was addressed in a license amendment request submitted in August 1999 (Ref. 9.2) and approved by the NRC in August 2000 (Ref. 9.3) which clarified the licensing basis of the use of CAP at Peach Bottom Units 2 and 3. The 1999 LAR discussed the Minimum Containment Pressure Available (MCPA) analysis that included conservative assumptions to minimize containment pressure during an event including the use of containment sprays, maximized torus water temperatures and maximum design basis containment leakage as well as maximum HPSW temperature and minimum RHR heat exchanger performance. As noted in the 1999 LAR, the MCPA analysis indicated that adequate NPSH would be assured even with these conservative assumptions. The LAR also stated that a re-evaluation of the DBA LOCA analyses for NPSH using the MCPA analysis, the increase in torus water temperature due to Power Rerate and the new suction strainer debris loads based on NRC Bulletin 96-03 continued to indicate sufficient containment pressure. The MCPA analysis is documented in UFSAR 5.2.4.3.2, Minimum Containment Pressure Available.

2.2.3 EPU Safety Design Bases

The proposed RHR heat exchanger cross-tie modification will not change the RHR system safety design functions as set forth in UFSAR 4.8. It will, however, enable the RHR system to complete their safety functions without having to rely on containment pressure to ensure that there is adequate NPSH at elevated suppression pool temperatures.

3.0 EVENT SCENARIOS MITIGATED

The detailed description of the NPSH calculations for the ECCS pumps operating under EPU conditions during design basis and non-design basis events is presented in PUSAR 2.6.5.2, ECCS Pump Net Positive Suction Head. PUSAR Table 2.6-4 provides the current credit for CAP and NPSH margin for design and non-design basis events for the RHR and CS pumps. PUSAR Table 2.6-5 provides the NPSH data for those pumps with elimination of CAP through the RHR and HPSW cross-tie modifications.

During normal shutdown cooling, the cross-tie is not opened and time to cold shutdown is evaluated with the improved heat capacity of the RHR heat exchangers. The new flow control valves will provide additional flexibility over the current design which currently has only two flow control valves per unit that must be manually throttled with a hand wheel.

The following paragraphs provide a summary of the operation of the RHR heat exchanger cross-tie during design basis and non-design basis events.

3.1 Design Basis Events

In the current licensing basis, with the current RHR system configuration, CAP credit is required for the RHR and Core Spray pumps during the DBA LOCA and the small steam line breaks (SSLB). The bounding event for CAP, however, is the DBA LOCA with loss of offsite power (LOOP) and failure of a 125VDC safety related battery (and resulting loss of associated EDG).

For EPU, the ECCS pump NPSH analyses (see PUSAR 2.6.5.2, ECCS Pump Net Positive Suction Head) assume implementation of the RHR heat exchanger cross-tie modification and no credit for CAP. The Suppression Pool temperature response was evaluated for a spectrum of SSLB sizes (from 0.01 ft^2 to 1.00 ft^2) at EPU in addition to the DBA LOCA. The smallest of these breaks, 0.01 ft^2, results in a slightly higher peak suppression pool temperature than the DBA LOCA (187.6°F versus 187.2 °F). For all cases, during the first 10 minutes of the SSLB event the peak suppression pool temperature is at least 20°F lower than for the DBA LOCA and the RHR and CS pumps are either not operating or operating in minimum flow. Therefore, the RHR and CS NPSH margins for all events except for the long-term response of the 0.01 ft^2 break are bounded by the results of the DBA LOCA analysis (see PUSAR 2.6.5.2, ECCS Pump Net Positive Suction Head).

As with the current analyses, the containment response analyses at EPU conditions for the DBA LOCA and the limiting SSLB with Loss of Offsite Power and a single failure of a 125 VDC safety related battery assume no operator action for the first ten minutes. During this initial period of the DBA LOCA, the RHR pumps are operating in their LPCI mode with two pumps operating in one loop and one pump in the other. With implementation of the RHR heat exchanger cross-tie modification, the RHR runout flow in the LPCI mode is reduced to 10,600 gpm. At ten minutes after the event, the operator stops two of the LPCI/RHR pumps, switches the third LPCI/RHR pump into containment cooling mode using the one available heat exchanger, and establishes RHR flow at 8600 gpm with the new flow control valves. The analysis also assumes that the RHR heat exchanger K-value is increased from a CLTP value of 270 BTU/sec-°F to a minimum value of 305 BTU/sec-°F for EPU. Other than the flow rate, there is no change as a result of EPU to the automatic and manual actions at this point in the current analysis.

At one hour into the event, the analysis assumes that the operator opens the RHR cross-tie valve, establishes flow to the second RHR heat exchanger in that loop, and starts a second HPSW pump to provide cooling to the tube side of the RHR heat exchanger establishing a containment cooling configuration of one RHR pump with flow balanced through the two heat exchangers. With flow split between the two heat exchangers, the combined K-value is assumed to be 500 BTU/sec-°F. The result is an increase of about 1.6 times the cooling capacity of the RHR system with a single RHR heat exchanger. As discussed in PUSAR 2.6.5, Containment Heat Removal and shown in Table 2.6-1, PBAPS Containment Performance Results, the additional cooling capacity results in a peak suppression pool temperature at EPU that is lower than the current peak temperature determined by the analysis of record.

The NPSH analysis at EPU conditions for the Loss of RHR Normal Shutdown Cooling with a LOOP and a single failure of a 125 VDC safety related battery also assumes the opening of the RHR cross-tie valve with one RHR pump cross-tied to two heat exchangers and no CAP credit.

3.2 Special Events

The CLB also takes credit for CAP for the special events consisting of ATWS, SBO, and Appendix R Fire Safe Shutdown cases. Although CAP is eliminated for these events at EPU conditions, they will not rely on opening of the RHR cross-tie Valve for the following reasons:

- For ATWS, it is assumed that one loop with two RHR pumps and two RHR heat exchangers are operational for the limiting ATWS events. See PUSAR 2.8.5.7.
- For SBO, cooldown is conducted with one RHR pump and one heat exchanger. See PUSAR 2.3.5.
- For Appendix R shutdown, all shutdown methods are with one RHR pump and one heat exchanger. See PUSAR 2.5.1.4.2 10 CFR 50 Appendix R Fire Event.

Although the RHR cross-tie valve is not assumed to be open, these transients take credit for the improved heat exchanger performance and assume operation of the new flow control valves to control flow to provide adequate cooling with the design flow rate of 8,600 gpm. This will ensure that the NPSH required is below NPSH available with margin without CAP.

3.3 Other Events

CAP is credited in the current NPSH analyses for a safety relief valve transient (SRVT) consisting of a stuck open relief valve with reactor pressure vessel isolation[1]. With implementation of the RHR cross-tie modification, CAP credit is eliminated for the SRVT event at EPU conditions with a LOOP and a single failure of a 125VDC battery by opening the cross-tie valve and initiating flow through two RHR heat exchangers with one RHR pump.

[1] The Minimum Containment pressure Analysis in the current licensing basis analyzed for an Inadvertent Open Relief Valve (IORV) event. The SRVT as defined herein bounds the Stuck Open Relieve Valve (SORV) and the SRVT term will be used in this LAR.

4.0 SCOPE OF MODIFICATION

4.1 Physical Description

4.1.1 Overview

A safety-related cross-tie line will be installed between the discharge lines of RHR pumps A and C and, separately, between the discharge lines of RHR pumps B and D for both Unit 2 and Unit 3. Each cross-tie consists of 10-inch diameter pipe and one normally closed motor-operated isolation valve (MOV). Each cross-tie MOV will be normally closed. An administratively controlled, normally open manual valve will be installed on each side of the cross-tie MOV to allow isolation for maintenance. The cross-tie MOV in each division will be located downstream of the RHR pump discharge check valves and upstream of the RHR heat exchangers. Each RHR loop's pump and heat exchanger, within each Division, are located in separate compartments and the cross-tie piping penetrates the divisional wall. A qualified flexible boot will be clamped to the pipe and the sleeve projection to maintain the flood barrier integrity for the wall. This modification will enable the Control Room operator to manually align two RHR heat exchangers supplied from one RHR pump for post-LOCA containment cooling.

When only one RHR pump is available, the operator will initiate RHR cooling through one heat exchanger at 10 minutes. The operator will place the RHR cross-tie in service at no later than one hour resulting in a containment cooling configuration of one RHR pump and two RHR heat exchangers. With the RHR cross-tie so aligned, a second High Pressure Service Water (HPSW) pump will be started to deliver HPSW cooling water flow through the second RHR heat exchanger. There is no increase in the required design HPSW flow to either RHR heat exchanger. The RHR cross-tie modification and the increased minimum heat exchanger performance that will be instituted for EPU results in a significant increase in the minimum containment cooling capacity eliminating the need to credit CAP for RHR and CS pump NPSH margin.

The RHR heat exchanger cross tie modification includes other design changes necessary to support RHR flow balancing through the two heat exchangers. The existing flow restriction orifices upstream of the B and C RHR heat exchangers and the existing control valve upstream of the RHR heat exchangers A and D will be replaced with new motor operated flow control valves. In addition, new flow elements with Control Room flow indication will be installed at the outlet of all four RHR heat exchangers. These design features will enable the operator to balance RHR heat exchanger flow for containment cooling and prevent RHR pump runout. The new control valves will normally be positioned so that the minimum design basis flow requirements for the automatic RHR system LPCI function will continue to be met while also limiting the maximum flow to that which will sustain pump NPSH margin without CAP credit. No new operator actions are required to support automatic operation of LPCI following a design basis accident.

The RHR system and the Reactor Building structure in which the RHR pumps, heat exchangers and piping affected by this modification are installed are classified as Seismic Class I. New safety related piping, piping supports and components installed in this modification are designed in accordance with Seismic Category I requirements. Non-safety related components installed in Seismic Category I areas are designed to not adversely impact Seismic Category I structures, systems and components during or after a design basis seismic event.

4.1.2 Electrical

The modification includes the following new safety related loads:

- One new RHR cross-tie MOV per division.
- A new motor-operated flow control valve on the discharge of each RHR pump.
- Control room controls and indications.

Electrical separation of power, instrumentation and control cables associated with the RHR heat exchanger cross-tie modification shall conform to physical separation criteria as described in Chapter 8 of the UFSAR.

Since the RHR heat exchanger cross-tie MOVs are not credited to achieve and maintain safe shutdown during an Appendix R fire for EPU, protection of the cross-tie MOVs and associated cables from fire damage for the purpose of maintaining remote or manual control capability for safe shutdown is not required. However, the four new RHR flow control valve cables and power supplies will require protection from fire damage so that they can be controlled from the Control Room to support LPCI injection for Shutdown Method C (see PUSAR 2.5.1.4.2 for a description of the four Appendix R Shutdown Methods) and to support alternate shutdown cooling and suppression pool cooling as required for Shutdown Methods A, B, C, and D.

The RHR pumps are each powered from separate 4 KV emergency auxiliary buses and EDGs. The cross-tie MOVs will be powered from redundant safety-related power sources through separate 4KV buses from an EDG such that the failure of one EDG will not result in the loss of function of the cross-tie in both loops. The new control MOVs will be powered from the EDG associated with the RHR pump and automatic valves in that loop. The new RHR cross-tie MOVs are not considered in the EDG loading calculations since the stroke time is limited and they are an intermittent load that occurs after all the immediate actions in the first 10 minutes have been completed. Refer to section 5.0, Operating with the cross-tie for operation of the RHR heat exchanger cross-tie MOVs.

If operating on one RHR pump after a DBA LOCA, the cross-tie MOV will be opened and flow provided to a second RHR heat exchanger one hour after the event. A second HPSW pump (802 kw) will therefore have to be started to service the second RHR heat exchanger. This will increase the total EDG loading. Individual EDG loading remains below their 2000-hour (3000 kW) rating for all time periods due to the reduction in RHR pump motor operating load resulting from the reduction in flow rate. Since the increased total EDG loading is higher, there will be an increase in EDG fuel oil consumption that

requires a revision to the Technical Specification minimum required EDG fuel oil level but no physical changes to the EDG Fuel Oil and Transfer system are necessary. A change to the Fuel Oil level alarm will be implemented to adjust to the increase in minimum required level. (See PUSAR 2.5.6.1).

4.1.3 Instrumentation

RHR Cross-Tie Isolation MOV

This valve is normally closed, and will need to be manually opened to enter the RHR heat exchanger cross-tie mode of operation. Control room operators will be provided with manual controls for the RHR heat exchanger cross-tie isolation MOV with full open and full closed indicating lights. When the valve is in mid-travel, both the red and green lights will be illuminated. All controls associated with the RHR heat exchanger cross-tie isolation MOV are classified as safety-related.

RHR Heat Exchange Flow Control Valves

Manual controls are provided for the RHR flow control valves located downstream of the RHR pumps allowing the operator to throttle the valve position. Full travel indicating red and green lights are provided for the full open and full closed positions. These valves will be verified in the proper alignment for LPCI operation during RHR system surveillance testing (See Section 5.0, Operations with the RHR heat exchanger cross-tie). LPCI position lights are also provided in the control room to indicate to the operator that the throttling control valves are in the proper alignment for LPCI operation. One white light will correspond to the valve position at the minimum LPCI flow rate, and the second white light will correspond to the valve position at the maximum allowable flow precluding RHR pump runout. An annunciator alarm is provided in the control room that will alarm when the valve position has moved outside of its allowable range of travel. All components in the control circuit shall be classified as Active Safety-Related components.

RHR Heat Exchanger Flow Loops

Flow indication is provided in the main control room to allow the operator to balance flows through the RHR heat exchangers when the system is in the RHR heat exchanger cross-tie mode. The flow loop will be safety-related and powered from a class 1E power supply. Like the existing flow instrumentation, the new flow indicators will be classified as Regulatory Guide 1.97 Type 2, Type D variables. They will, however, meet the design requirements of Type 1 variables for equipment qualification, redundancy, continuous display and power supply.

4.1.4 Piping Stress Analyses and Supports

Structural evaluations and required design calculations for pipe stress evaluations associated with the RHR heat exchanger cross-tie modification have determined that the applicable SSCs are structurally adequate to perform their intended design functions under EPU conditions with support additions and modifications. New supports and support modifications for the RHR heat exchanger cross-tie will be designed and installed under the EGC configuration change process. Design details for individual piping support and support modifications will be performed under 10 CFR 50.59. The

modification analysis including design calculations and drawings will be complete at time of application acceptance.

5.0 OPERATING WITH RHR HEAT EXCHANGER CROSS-TIE

With EPU, changes to the operation of the RHR and HPSW systems are necessary to be consistent with changes to the plant design basis and implementation of the RHR heat exchanger cross-tie modifications. The changes to operator actions for EPU, including those associated with the RHR heat exchanger cross-tie, have been evaluated from a human engineering standpoint, Human Factors, and it has been determined that they are consistent with the current strategy for operator actions of ensuring the lineup is consistent with EDG loading requirements and adequate margin for NPSH and will not significantly impact operator actions and mitigation strategies.

The current Technical Specifications for the RHR system are based on the operability of at least one subsystem where a subsystem is defined as one RHR pump, one heat exchanger and associated piping and valves. With implementation of the RHR heat exchanger cross-tie modification, a subsystem will be defined as two RHR pumps, two heat exchangers, the associated cross-tie valve and other associated piping and valves. Operability of an RHR subsystem will require the availability of at least one RHR pump, two RHR heat exchangers in the same RHR subsystem, the associated RHR heat exchanger cross-tie, two HPSW pumps capable of providing cooling to the two heat exchangers, and associated piping and valves. Details and justifications for the proposed Technical Specification Bases changes resulting from the modification are provided in the EPU LAR Attachments 2 and 3.

Normal Operation and Shutdown Cooling

The new RHR flow control valves will normally be positioned to deliver LPCI flow rates between minimum and maximum acceptance limits for core cooling and RHR pump NPSH. This equates to a position that will ensure LPCI flow after a DBA LOCA will be between 8,600 gpm and 10,600 gpm where 8,600 gpm is the minimum LPCI mode (torus to vessel intact loop) to ensure adequate core cooling and 10,600 gpm to limit the maximum flow (torus to broken loop) to prevent pump runout. Technical Specifications will be revised to ensure proper positioning of these valves for minimum LPCI flow. Procedures will be revised to ensure proper position of these valves for maximum flow (runout). Procedures that reposition the flow control valves (e.g., shutdown cooling, torus cooling, HPCI testing) outside of the LPCI range will have additional steps to restore them to their LPCI positions.

The new RHR flow control valves will be remotely operated from the Control Room. The new flow elements at the discharge of the RHR heat exchangers will be used for balancing the cross-tie flow when in operation. Any of the four flow control valves in either unit can be utilized for regulation of RHR flow during shutdown cooling or torus cooling operations. This provides additional flexibility over the current design with only two flow control valves per unit, which must be manually throttled with the handwheel.

Design Basis Accident Response

As discussed above, the flow control valves will be pre-positioned so that adequate LPCI flow for core cooling is immediately available after a DBA LOCA without any operator action.

For the first ten minutes of the event, no operator action is required. RHR flow is maintained to maximize containment cooling, within constraints for EDG loading and RHR pump NPSH curves. In the most limiting scenario with no CAP available and torus temperatures reaching maximum analysis values, the revised NPSH curves will direct a reduction in RHR flow down to as low as 8,600 gpm. The RHR flow is throttled by positioning the pump discharge control valves as required to satisfy the NPSH curves.

If torus temperature exceeds a specified limit and only one RHR pump is operating, the operator will open the RHR heat exchanger cross-tie valve and establish an equal flow of about 4300 gpm through each of the two heat exchangers (i.e. either A and C or B and D RHR heat exchangers) in that subsystem by throttling the flow control valves. Procedures will direct the operator to balance RHR flows between the two operating heat exchangers. A second HPSW pump will also be started and lined up to the second RHR heat exchanger in that subsystem. The table below summarizes the EPU RHR system flow requirements with the RHR modification and compares them to the current configuration.

RHR Flow Path/Mode	CLTP (gpm)	EPU (gpm)
Maximum LPCI runout to broken loop	12,000	10,600
Minimum LPCI Injection flow rate	10,900	8,600
Long term RHR cooling	10,000	8,600

The Emergency Operating Procedures (EOP's) will be revised to accomplish the details of these actions.

Surveillance Testing and Inservice Inspection

The minimum and maximum LPCI injection flows (8,600 and 10,600 gpm) are correlated to an equivalent range of RHR system flows in the testable torus-to-torus mode via hydraulic analysis which can then be used as acceptance criteria for surveillance testing. The flow control valve position corresponding to these flows is then determined. During quarterly surveillance testing, the valve can then be verified to be at an intermediate position between the minimum and maximum allowing LPCI flow to meet its acceptance criterion. The adjustable flow control valves themselves provide a variable system hydraulic resistance which allows surveillance test flow acceptance criteria to be met even with significant system hydraulic degradation.

Periodic surveillance testing will also include performance verification of the RHR heat exchanger cross-tie and flow control valves in accordance with the MOV program and

flow loop instrumentation calibration. A functional test of the normally closed cross-tie MOVs and flow control valves will be performed by stroking the valves during the test.

RHR heat exchanger performance test acceptance criteria for allowable fouling will ensure that the increased heat exchanger performance credited for containment heat removal and for the maximum suppression pool temperature assumed in the NPSH calculations is met.

Inservice inspections and testing on the RHR system, including the cross-tie modifications, as required by the station's ISI and IST programs will be performed.

6.0 SINGLE FAILURE ANALYSIS

The RHR heat exchanger cross-tie MOV is maintained closed during all normal operating conditions, abnormal operating events, and accident conditions (other than during long term cooling following a design basis accident concurrent with a single active failure and during periodic surveillance testing). The RHR heat exchanger cross-tie modification – Failure Modes and Effects Analysis (FMEA) below looks at the effect of component failures on the ability of the RHR System to perform its design functions.

6.1. With Single Failure of a 125 VDC Safety Related Battery:

If the input condition that requires the RHR heat exchanger cross-tie MOV to be opened includes a single failure (e.g., single failure of an EDG or 4 KV bus on the LOCA unit), no additional failures are required to be assumed. Sufficient redundancy in the RHR heat exchanger cross-tie and associated control valves and instrumentation exists. The RHR heat exchanger cross-tie and associated control valves and instrumentation will be installed in both RHR Divisions I and II. The components will be powered from redundant power supplies. Therefore, the RHR heat exchanger cross-tie will perform its function with the loss of one EDG or 4 kV bus.

6.2. Without a Single Failure of a 125 VDC Safety Related Battery:

If the accident initiating condition does not include the loss of an EDG or 4 KV bus, then a failure within the RHR system is considered as follows.

a. Normally Closed cross-tie MOV fails full open or throttled:
    1. If the cross-Tie MOV fails open or throttled, with no RHR pumps operating, there is no effect on system operation.
    2. If the cross-tie MOV fails open or throttled, with both RHR pumps associated with the cross-tied RHR loops operating, there would be no adverse effect on the system. Both pumps could continue to operate with approximately the same flow rates depending on the flow control MOV positions.
    3. If the cross-tie MOV fails open or throttled, with one RHR pump operating, the hydraulic effect would be the same as if the cross-tie were intentionally placed in service. A portion of the operating pump flow would be diverted to the other loop in that division. There would be an increase in total pump flow

due to the reduced resistance of a parallel flow path up to the point where the RHR heat exchanger discharge lines join back together downstream of the heat exchangers. This may result in pump runout conditions and a loss of NPSH.

If it is also assumed that there is no HPSW cooling water supplied to the non-operating RHR heat exchanger, then the valve opening would result in a partial loss of RHR heat exchanger cooling. This could be a concern in the SDC mode when one RHR pump is in operation. This failure is bounded by a single failure which fails the entire division in the current design basis. The loss of one RHR division (I or II) is acceptable since the remaining RHR division would be available. This failure would not need to be considered in the elimination of CAP credit evaluation since it assumes the worst case single failure is loss of a 125 VDC safety related battery.

b. Normally closed cross-tie MOV fails Closed from Open position (or remains Closed)

   If the RHR cross-tie MOV fails closed while one or both RHR pumps are operating, there would be a loss of capability to use the RHR heat exchanger cross-tie. The cross-tie is not required to be open for events other than the design basis cases that also assume single failure of a 125 VDC safety related battery. This failure would not need to be considered for the design basis cases.

c. Normally throttled RHR heat exchanger flow control valve fails closed.

   1. If the RHR heat exchanger flow control valve fails closed while the RHR heat exchanger cross-tie MOV is closed and no RHR pumps are operating, there is no effect on system operation.

   2. If the RHR heat exchanger flow control valve fails closed while the RHR heat exchanger cross-tie MOV is closed and both RHR pumps are operating, the RHR pump in line with the failed closed valve would be dead-headed except for minimum flow valve capacity. Partial loss of system flow capability through the loop with the closed valve would result. Minimum design flow of 4,000 gpm through the control valve would remain. The flow through the other loop within this division would not be affected.

      This failure is bounded by a single failure of a valve (failing closed) in the common RHR heat exchanger discharge piping, which is a potential failure for the existing design.

   3. If the RHR heat exchanger flow control valve fails closed while the RHR heat exchanger cross-tie MOV is closed and one RHR pump is operating, a partial loss of system flow capability through the operating loop would result. This is similar to the failure with both pumps operating. Minimum design flow of 4000 gpm through the control valve would remain.

      The consequences of this failure are bounded by a single failure of a valve (failing closed) in the common RHR heat exchanger discharge piping, which is a potential single failure for the existing design.

4. If the RHR heat exchanger flow control valve fails closed while the RHR heat exchanger cross-tie MOV is open and one RHR pump is operating, a partial loss of RHR flow capability through the cross-tied heat exchanger, returning the division to a one RHR pump/one HPSW pump/one RHR heat exchanger configuration. Minimum design flow of 4000 gpm through the control valve would remain. This failure is bounded by the single failure of one RHR pump or a single failure of a valve (failing closed) in the common RHR heat exchanger discharge line which fails the entire division. The loss of one RHR division (I or II) is acceptable since the remaining RHR division would be available. Note that the cross-tie is not required to be open for events other than the design basis cases that also assume single failure of a 125 VDC safety related battery

d. Normally throttled RHR heat exchanger flow control valve fails full open

1. If the RHR heat exchanger flow control valve fails full open while the RHR heat exchanger cross-tie MOV is closed and no RHR pumps are operating, there is no effect on the system operation.

2. If the RHR heat exchanger flow control valve fails full open (in excess of LPCI position) while the RHR heat exchanger cross-tie MOV is closed and both RHR pumps are operating, pump runout and potential loss of NPSH could occur. However, the flow control valves are administratively controlled from excessive opening in order to prevent this failure condition. The single failure is assumed to defeat the administrative control. For RHR modes of operation that take suction from the torus, the operator would be required to take action to prevent pump runout and/or place the redundant RHR division into operation.

3. If the RHR heat exchanger flow control valve fails full open while the RHR heat exchanger cross-tie MOV is closed and one RHR pump is operating, pump runout and potential loss of NPSH could occur. This is similar to failure with both pumps operating. For RHR modes of operation that take suction from the torus, the operator would be required to take action to prevent pump runout and/or place the other RHR loop within the division or the redundant RHR division into operation.

4. If the RHR heat exchanger flow control valve fails full open while the RHR heat exchanger cross-tie MOV is open and one RHR pump is operating, the result is similar to failure with both pumps operating. For RHR modes of operation that take suction from the torus, the operator would be required to take action to prevent pump runout and/or place the redundant RHR division into operation. Note that the RHR heat exchanger cross-tie is not required to be open for events other than the design basis cases that also assume single failure of a 125 VDC safety related battery

e. RHR heat exchanger outlet flow indicator loss of power or indicator loop failure

1. If the flow indicator fails with no RHR pumps operating, there is no effect on system operation.
2. If the flow indicator fails while the RHR heat exchanger cross-tie MOV is closed and both RHR pumps are operating, there is no effect on system operation. The flow indicator is not required when the cross-tie MOV is closed. Existing indicators provide RHR total flow indication on the respective common RHR heat exchanger discharge piping.
3. If the flow indicator fails while the RHR heat exchanger cross-tie MOV is closed and one RHR pump is operating, there is no effect on system operation. This indicator is not required when the c-tie MOV is closed. Existing flow indicators provide RHR total flow indication on the respective common RHR heat exchanger discharge piping.
4. If the flow indicator fails while the RHR heat exchanger cross-tie MOV is open and one RHR pump is operating, a reduction in capability for remote manual balance of RHR flow between the cross-tied RHR heat exchangers results. Existing flow indicators could be used to determine approximate flow through the heat exchanger with the failed indicator. Note that the RHR cross-tie is not required to be open for events other than the design basis cases that also assume single failure of a 125 VDC safety related battery

f. Loss of one EDG E1, E2, E3, or E4 (assumes all four EDGs are operable at start of event) due to operator error. Loss of one EDG due to failure to shed loads from EDG before loading additional HPSW pump required for the RHR heat exchanger cross-tie.

The RHR heat exchanger cross-tie will perform its function with loss of one EDG or 4 kV bus. The cross-tie and associated control valves and instrumentation are installed in both RHR Divisions I and II. The components are powered from redundant power supplies. To recover from the failure, the Operator would need to perform load shedding on one of the remaining three operable EDGs and load the additional HPSW pump. This failure would not need to be considered for the design basis cases, which assume single failure of a 125 VDC safety related battery that includes a loss of one EDG.

7.0 POST-MODIFICATION FUNCTIONAL TESTING

Post modification testing for the RHR heat exchanger cross-tie modification will be conducted in accordance with the PBAPS modification program and the surveillance test program.

8.0 SUMMARY

As a result of the implementation of the RHR heat exchanger cross-tie modification, the operator has the ability to cross-tie two heat exchangers to the operating RHR pump for the DBA LOCA and SSLB as well as for SRVT and the Loss of Normal Shutdown Cooling with a LOOP event. This significantly increases suppression pool cooling and provides adequate NPSH margin for the RHR and CS pumps without CAP. For the ATWS, SBO and Appendix R special events, the operator will not be required to open the RHR heat exchanger cross-tie valve but their dependence on CAP will also be eliminated through the reduced RHR system flow requirements and improved heat exchanger performance included as part of the RHR heat exchanger cross-tie modification. For the SBO, ATWS and Appendix R (Cases A,B and D) events, the NPSH requirements of the ECCS pumps will also be supported by the lowering of peak suppression pool temperature and an increase in the height of water in the torus afforded by the CST modifications (Enclosure 9e). No automatic safety functions are changed by this modification.

As described in Attachment 12, the PBAPS PRA model was updated to determine the impacts of EPU and the CAP elimination modifications. Specific representation of the RHR heat exchanger cross-tie modification including throttling the RHR system flow and the HPSW modification was included in the PRA model for EPU conditions. The analysis concluded that overall Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) increases were very small: a 2.8% increase in CDF and 3.5% increase in LERF. A separate sensitivity study indicated that without the CAP modifications, the CDF increase would have been 3.3% and the LERF increase would have been 7.9%. The results of the sensitivity cases demonstrate the PRA benefits of the CAP elimination modifications in addition to the enhancements to the defense-in-depth achieved by removing dependence on containment accident pressure in the determining adequate NPSH.

9.0 REFERENCES

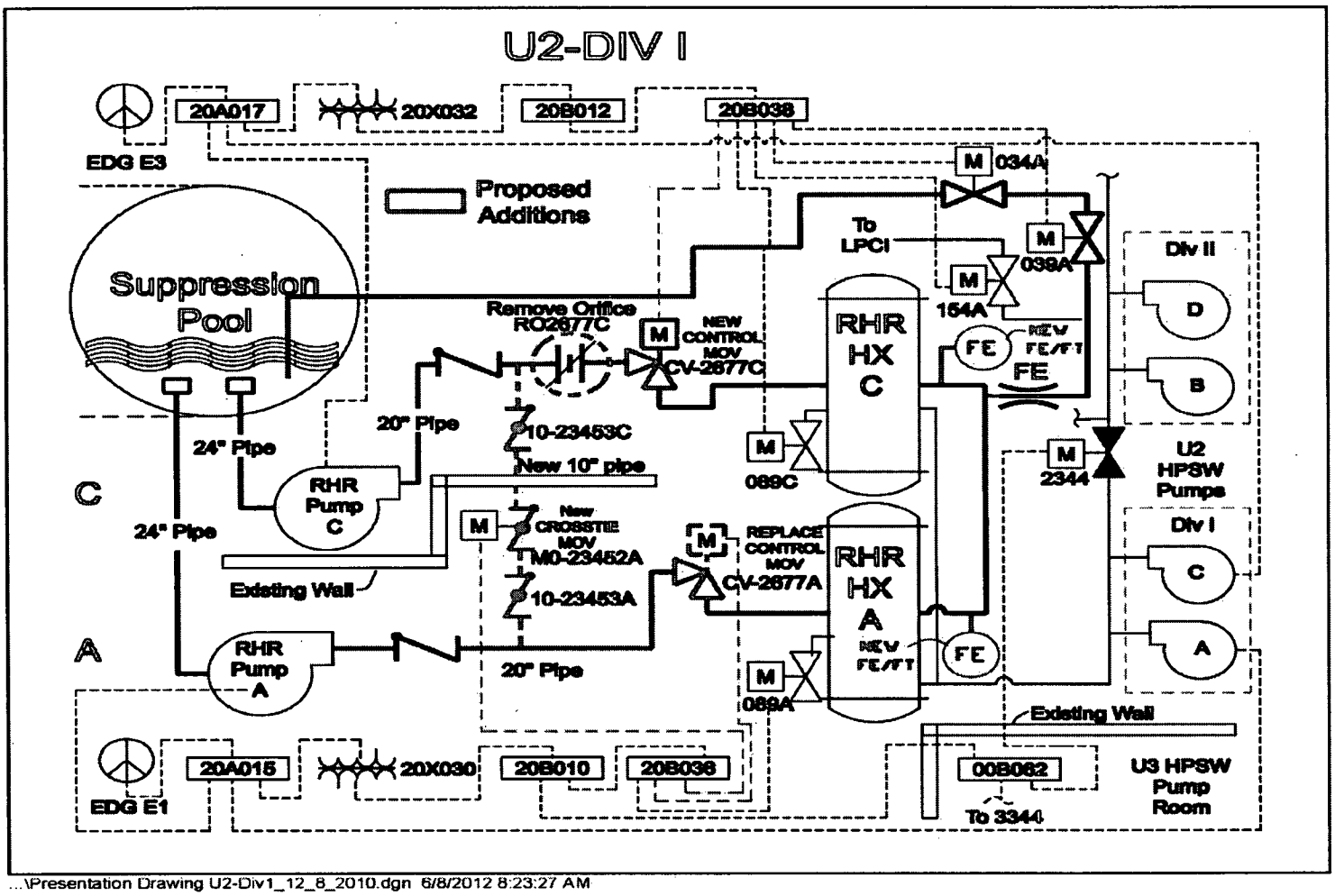
9.1. NRC Safety Evaluation of PBAPS dated August 11, 1972.

9.2 Hutton, J. A., PECO Energy Company, to USNRC, "Peach Bottom Atomic Power Station, Units 2 and 3 Request for License Amendment Regarding Clarification on Use of Containment Overpressure for Ensuring Adequate NPSH," August 11, 1999.

9.3 Safety Evaluation by USNRC, Peach Bottom Atomic Power Station, Unit Nos. 2 and 3 – Issuance of Amendment Regarding Crediting of Containment Overpressure for Net Positive Suction Head Calculations for Emergency Core Cooling Pumps (TAC NOS. MA6291 and MA6292), dated August 14, 2000

FIGURE 9c-1

RESIDUAL HEAT REMOVAL SYSTEM
CURRENT CONFIGURATION WITH RHR MODIFICATION CHANGES
FOR INFORMATION ONLY
NOT A CONTROLLED DRAWING



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Enclosure 9d to Attachment 9

Peach Bottom Atomic Power Station Units 2 and 3

NRC Docket Nos. 50-277 and 50-278

High Pressure Service Water (HPSW) System Cross-Tie Modification

1.0 PURPOSE

Exelon Generation Company (Exelon) is pursuing an EPU of approximately 12.4 percent at the Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3. As part of this request, PBAPS proposes a modification to the High Pressure Service Water (HPSW) system cross-tie that enables the Control Room Operator to manually align HPSW pumps from the opposite Division in order to provide cooling water to the two operating Residual Heat Removal (RHR) heat exchangers placed in service to provide the post-LOCA suppression pool cooling. As such, the HPSW Cross-tie Modification will be utilized in conjunction with the RHR Cross-tie Modification (Attachment 9, Enclosure 9c).

The HPSW Cross-tie Modification will provide a motor operated valve (MOV) on the existing crosstie-header connecting the two Division I HPSW pumps (A and C) with the two Division II HPSW pumps (B and D) for each unit that will be able to open under the assumed conditions for these accidents. The existing HPSW cross-tie motor operated valve and its associated header are being replaced to accommodate this.

The RHR Cross-tie Modification (Attachment 9, Enclosure 9c) enables a second RHR heat exchanger to be cross-tied to the operating RHR pump. Use of two RHR heat exchangers increases the cooling capacity of the system resulting in reduced suppression pool temperature during events that add heat to the suppression pool. The lower suppression pool temperature increases the Net Positive Suction Head (NPSH) margin available to the RHR and Core Spray pumps. This increase in NPSH margin eliminates the need to take credit for Containment Accident Pressure (CAP) for design basis accidents and transients in which only one RHR pump is available and the suppression pool temperature is elevated. In these cases, a second HPSW pump must be started to provide cooling water to the tube side of the second RHR heat exchanger. As a result of EDG loading limitations, two HPSW pumps within a single division may not always be available. The capability to provide HPSW flow from one of the opposite Division's HPSW pumps through the HPSW loop cross-tie is, therefore, required to provide the cooling requirements for the two RHR heat exchangers.

2.0 BACKGROUND

2.1 Existing Plant Configuration

The HPSW system is described in UFSAR 10.7, High Pressure Service Water System. Technical Specification 3.7.1, High Pressure Service Water System, and its Bases (TSB) are associated with this system. Its safety objective is to supply a reliable supply of cooling water for RHR under post-accident conditions.

The HPSW system consists of two independent and redundant loops. Each loop is made up of a header, two 4,500 gpm HPSW pumps installed in parallel in the Circulating Water Pump structure, a suction source, valves, piping and associated instrumentation. Either of the two loops is capable of providing the required cooling capacity with one pump operating to maintain safe shutdown conditions. For purposes of operability, the Technical Specifications define two HPSW subsystems with each subsystem consisting of a HPSW loop with one operable HPSW pump in the loop. The two subsystems are separated from each other by normally closed motor operated cross tie valves, so that failure of one subsystem will not affect the operability of the other. In addition to

subsystem separation, a cross connection line with two normally closed manual isolation valves (See valves 516A and 516B on Figure 9d-1) is provided between one Unit 2 HPSW system loop and one Unit 3 HPSW system loop. Separation of the two units HPSW Systems is provided by a series of two locked closed, manually operated valves. The HPSW System is designed with sufficient redundancy so that no single active component failure can prevent it from achieving its design function.

The HPSW pumps are each powered from separate 4 kV emergency auxiliary buses with control power for each pump motor coming from separate dc buses. The major flow paths of the current configuration of the HPSW system are shown in Figure 9d-1 and consist of two independent parallel flow loops serving each unit. Each flow loop contains two HPSW pumps, which take suction from the Conowingo Pond through the Service Water Pump Bay, then pump service water to a common header serving two RHR Heat Exchangers, connected in parallel, and discharge through a pipe common to both loops to the discharge pond. The service water pressure is maintained at a higher pressure than the RHR system to inhibit leakage of radioactive material into the environment.

The design of the HPSW system requires the cooling flow from one HPSW pump to cool each operating RHR heat exchanger. During a LOCA, this could include two RHR heat exchangers per Division although one RHR pump with one heat exchanger and associated piping and valves, is capable of meeting the suppression pool cooling requirement for a DBA LOCA as well as transient events such as a turbine trip or stuck open safety/relief valve.

Within the present design basis, the HPSW cross-tie MOV is a passive component required to maintain its pressure boundary and remains closed to maintain loop separation during all modes of operation, all abnormal events and DBAs to ensure its availability to provide cooling water flow as required to support the RHR System. The valve is not required to open during any accident or transient condition. The safety function of the normally closed HPSW cross-tie valve in the current configuration is to ensure subsystem redundancy subsequent to a single failure occurrence in either subsystem. The HPSW Cross tie valves are key-locked in the closed position. Emergency power is provided from a single source as shown in Figure 9d-1. The cross connection lines provide the flexibility to establish alternate flow alignments if required under emergency conditions.

2.2 Design Basis

2.2.1 Current Design Basis

The HPSW system safety design bases are set forth as follows in UFSAR 10.7:

1. The high pressure service water system is designed to seismic Class I criteria to withstand the maximum credible earthquake without impairing system function.

2. The high pressure service water system is operable during flood conditions.

3. The high pressure service water system is designed with capacity and redundancy to supply cooling water to the RHR System under post-accident conditions.

4. The high pressure service water system is operable during the loss of offsite power.

The proposed HPSW Cross-tie Modification will not change these safety design bases.

2.2.2 Current Credit for Containment Accident Pressure (CAP)

Section 3.2 of Attachment 9 (Overview of Improvement in NPSH Margin and CAP Elimination) and the description of the RHR Cross-tie Modification in Enclosure 9c provide a discussion of the credit for CAP taken in the current design bases. The DBA LOCA is the bounding event for CAP. For a DBA LOCA, one RHR pump and one heat exchanger serviced by one HPSW pump is sufficient to provide the cooling requirement. Operation of the existing HPSW cross tie is not assumed in the DBA LOCA or any other transient analysis.

2.2.3 EPU Safety Design Bases

The HPSW Cross-tie Modification in conjunction with the RHR Cross-tie Modification will enable the elimination of CAP credit. It will not, however, change the HPSW system safety design function as set forth in UFSAR 10.7. The analysis for the DBA LOCA with loss of offsite power and the single failure of a 125VDC safety related battery assumes that one RHR pump and one HPSW pump are placed in service for containment cooling at ten minutes following initiation of the event. The failure of a 125 VDC safety related battery causes the loss of the associated Emergency Diesel Generator (EDG) and 4 KV emergency auxiliary bus. One hour after the event, the Operator cross-ties a second RHR heat exchanger to the operating RHR pump and starts a second HPSW pump to provide cooling to the second RHR heat exchanger. The HPSW Cross-tie Modification enables the Control Room Operator to manually align the second HPSW pump from the opposite Division to provide cooling water to the two operating RHR heat exchangers placed in service to provide the post-LOCA suppression pool cooling that will allow the elimination of CAP credit as discussed in Enclosure 9c. A single RHR pump is also assumed to be cross-tied to two RHR heat exchangers with two HPSW pumps providing cooling water during a small steam line break (SSLB), a safety relief valve transient (SRVT) with a loss of offsite power, and when operating RHR during a Loss of RHR Normal Shutdown Cooling event with loss of offsite power.

3.0 EVENT SCENARIOS MITIGATED

The HPSW system provides cooling for the RHR heat exchangers. As such, the event scenarios mitigated parallel those of the RHR system as discussed in Enclosure 9c to Attachment 9.

4.0 SCOPE OF MODIFICATION

4.1 Physical Description

4.1.1 Overview

In order to eliminate credit for CAP and to maintain ECCS pump NPSH margin following the DBA LOCA coincident with a loss of offsite power and the single failure of a 125 VDC safety related battery, a HPSW Cross-tie Modification will be installed in conjunction with the RHR Cross-Tie Modification (Enclosure 9c) for EPU. The HPSW Cross-tie Modification will enable the Control Room Operator to manually align two HPSW pumps to provide cooling water to the two cross-tied RHR heat exchangers that will be placed in service to provide for suppression pool cooling when only one RHR pump is available and the suppression pool temperature is elevated. The HPSW Cross-tie Modification is safety related. The new and replacement piping, valves and operators, and components installed in this modification are designed and classified as Seismic Class I.

The new HPSW cross-tie valve has a safety function as an isolation valve in that it is required to remain closed to maintain HPSW pressure boundary integrity and subsystem separation except for periodic surveillance testing. It also has a safety function to open for long-term cooling following design basis accidents and events where it is required to be open ensure the availability of cooling water flow to support the RHR system safety related design basis functions.

4.1.2 Mechanical

The existing 14-inch HPSW cross-tie motor operated gate valves are not capable of stroking to the open or close position while the HPSW pumps are operating due to valve operator design limitations. To support operation of the RHR system with two heat exchangers cross-tied to one RHR pump, they will now be required to be repositioned against the full flow and differential pressure of a single HPSW pump. They will, therefore, be replaced with normally closed, 14" high-performance valves with motor operators sized to permit stroking the MOV while the HPSW pumps are in service. To facilitate maintenance on the HPSW cross-tie valves, administratively controlled, normally open, manual, 14" high-performance block valves are being added and placed on each side of the replaced HPSW cross-tie MOV for each Unit.

A hydraulic evaluation of the HPSW system confirmed that the piping and valve changes associated with the modification do not adversely affect the HPSW system in the performance of its safety and design functions and that it will:

- Provide the minimum HPSW cooling water flow rate (4,500 gpm) to the RHR System for containment cooling.
- Maintain the HPSW system pressure at the RHR heat exchanger greater than that of the RHR system when HPSW is in service to preclude potentially contaminated RHR system fluid from entering into the HPSW system.

See Figure 9d-2 for a schematic of the HPSW Cross-tie Modification.

4.1.3 Electrical

In order to ensure that the HPSW cross-tie MOVs remain functional following a design basis accident or transient with a single worse case active failure that makes the primary power supply inoperable, they are capable of being powered from a safety-related normal and safety-related alternate electrical bus backed by an Emergency Diesel Generator as shown below.

HPSW Cross-tie Valve	Normal	Alternate
Unit 2 (MO-2-32-2344)	E1	E3
Unit 3 (MO-3-32-3344)	E2	E4

Manual transfer switches allow the manual transfer between the independent power supplies from the control room. The power source and control cables associated with the normal and alternate power source for the MOVs as well as the controls and cables associated with the transfer switch shall meet the electrical and physical separation requirements of UFSAR 8.4.2.

The HPSW system is required to function for Appendix R Fire Safe Shutdown events. The new cross-tie MOVs and associated cabling, however, are not credited in the Appendix R analyses. For the Appendix R shutdown analyses, all shutdown methods are assumed to be with one RHR pump and one heat exchanger. See PUSAR 2.5.1.4.2 (10 CFR 50 Appendix R Fire Event). Since the RHR cross-tie is not assumed to open, the HPSW cross-tie valve will not be required to be opened to service a cross-tied RHR heat exchanger. Conversely, if the HPSW cross-tie valve should spuriously open during a fire, the function of the HPSW system will not be impacted

Starting a second HPSW pump (802 kw) after a loss of offsite power to service the second RHR heat exchanger adds to the total load on the operating EDG's. Even with the failure of a single EDG, individual EDG loading remains below their 2000-hour (3000 kW) rating for all time periods due to the reduction in RHR pump motor operating load resulting from the reduction in flow rate. Since the increased total EDG loading is higher, there will be an increase in EDG fuel oil consumption that requires a revision to the Technical Specification minimum required EDG fuel oil level but no physical changes to the EDG Fuel Oil and Transfer system are necessary. (see PUSAR 2.5.6.1). The new HPSW cross-tie MOVs are not considered in the EDG loading calculations since the stroke time is limited and they are an intermittent load that occurs after all the immediate actions in the first 10 minutes have been completed.

4.1.4 Instrumentation

The new manual transfer electromechanical transfer switch can be controlled from the control room and locally on the front of the panel. Loss of either the normal or alternate sources of power will be indicated in the control room and on the local panel.

A new non-locked selector switch and indicating lights are being provided in the control room for manually controlling the transfer of power for the HPSW cross-tie MOV from the Normal to Alternate source or vice versa. The indicating lights indicate if power is available on the Normal and Alternate sources.

4.1.5 Piping Stress Analyses and Supports

Structural evaluations and required design calculations for pipe stress evaluations associated with the HPSW Cross-tie Modification have determined that the applicable SSCs are structurally adequate to perform their intended design functions under EPU conditions with support additions and modifications. Any new supports and support modifications for the HPSW cross-tie will be designed and installed under the EGC configuration change process. Design details for individual piping support and support modifications will be performed under 10 CFR 50.59. The modification analysis including design calculations and drawings will be complete at time of application acceptance.

5.0 OPERATING WITH HPSW CROSS TIE

For EPU, a subsystem is defined as two 4,500 gpm pumps, a suction source, valves, piping and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity with one pump operating to maintain safe shutdown conditions. The HPSW cross-tie valve remains closed to maintain subsystem separation during all modes of operation, abnormal events and design basis accidents, except for periodic surveillance testing, to support the RHR System in the performance of its safety related design basis functions.

For design basis accidents or transients in which only one RHR pump is available and the suppression pool temperature is elevated above a specified limit, the operator will open the RHR cross-tie valve and balance flow between the operating two heat exchangers in that subsystem with the flow control valve. A second HPSW pump will also be started and lined up to the second RHR heat exchanger in that subsystem. In this event, the HPSW cross-tie valve will provide the flexibility to provide HPSW flow to the second operating RHR heat exchanger from the other HPSW loop.

The new manual actions required of the operator are necessary to be consistent with changes to the plant design basis and implementation of the HPSW and RHR Modifications. The analysis assumes that these actions will occur within 60 minutes of the design basis event. They have been subjected to a human engineering review and are considered consistent with the current strategy for operator actions that ensure the lineup is consistent with EDG loading requirements and adequate margin for NPSH. The Emergency Operating Procedures (EOP's) will be revised to accomplish these actions.

Surveillance Testing and Inservice Inspection

The HPSW Cross-tie Modification includes the replacement of the existing cross-tie that is a passive component that remains closed to maintain loop separation during all modes of operation, all abnormal events and DBAs with a new valve/operator design that is required to be manipulated while the HPSW pumps are running. Repositioning of

the HPSW cross-tie valve is a safety related function required by the DBA LOCA design analysis. Testing the cycling of the new valves will be incorporated into the PBAPS surveillance testing program as will testing to ensure proper functioning of the non-automatic transfer switch.

6.0 SINGLE FAILURE ANALYSIS

The HPSW cross-tie MOV is maintained closed during all normal operating conditions, abnormal operating events, and accident conditions (other than during long term cooling following a design basis accident concurrent with a single active failure and during periodic surveillance testing). The HPSW Cross-tie Modification– Failure Modes and Effects Analysis (FMEA) below looks at the effect of component failures on the ability of the HPSW System to perform its design functions.

6.1. With Single Failure of a 125 VDC Safety Related Battery
If the input condition that requires the HPSW cross-tie valve to be opened includes a single failure (e.g., single failure of an EDG), no additional failures need be considered. If the DBA initiating conditions includes the loss of an EDG, sufficient redundancy in the HPSW is still available to provide cooling water flow from two of three available HPSW pumps through the two RHR heat exchangers.

6.2. Without a Single Failure of a 125 VDC Safety Related Battery

If the accident initiating condition does not include the loss of an EDG, then a failure within the HPSW system is considered as follows.

a. HPSW Cross-tie fails closed:
With the HPSW divisional cross-tie MOV closed, two independent HPSW subsystems are maintained; adequate EDG power is available to start and operate one complete HPSW subsystem with its two pumps providing flow through its two RHR heat exchangers, thus satisfying the containment cooling analysis requirements.

b. HPSW Cross-tie fails open:
With the HPSW divisional cross-tie MOV open, the HPSW subsystem independence is lost. However, adequate EDG power is available to start and operate either one complete HPSW subsystem with its two pumps through its two RHR heat exchangers, or one pump from each HPSW subsystem providing flow through the HPSW cross-tie MOV through the two RHR heat exchangers in one RHR subsystem, thus satisfying the containment cooling analysis requirements.

c. HPSW Cross-tie fails mid-position:
With the HPSW divisional cross-tie MOV partially open, the HPSW subsystem independence is lost. However, adequate EDG power is available to start and operate one complete HPSW subsystem with two HPSW pumps providing flow through its two RHR heat exchangers, thus satisfying the containment cooling analysis requirements.

d. HPSW/RHR heat exchanger discharge fails closed:
With the HPSW divisional cross-tie MOV closed, two independent HPSW subsystems are maintained; the subsystem with the failed heat exchanger discharge MOV is failed. However, adequate EDG power is available to start and operate the other complete HPSW subsystem with its two HPSW pumps providing flow through its two RHR heat exchangers, thus satisfying the containment cooling analysis requirements.

e. HPSW/RHR heat exchanger discharge fails open:
With the HPSW divisional cross-tie MOV closed, two independent HPSW subsystems are maintained; the subsystem with the failed heat exchanger discharge MOV can be considered failed. However, adequate EDG power is available to start and operate the other complete HPSW subsystem with its two HPSW pumps providing flow through its two RHR heat exchangers, thus satisfying the containment cooling analysis requirements.

f. HPSW/RHR heat exchanger discharge fails mid-position:
With the HPSW divisional cross-tie MOV closed, two independent HPSW subsystems are maintained; the subsystem with the failed heat exchanger discharge MOV is considered failed. However, adequate EDG power is available to start and operate the other complete HPSW subsystem with two HPSW pumps providing flow through its two RHR heat exchangers, thus satisfying the containment cooling analysis requirements.

g. First HPSW pump fails to start (10 – 60 minutes):
With the HPSW divisional cross-tie MOV closed, two independent HPSW subsystems are maintained; the subsystem with the failed pump is considered failed. However, adequate EDG power is available to start and operate, within the opposite HPSW subsystem, with one HPSW pump providing flow through its RHR heat exchanger, thus satisfying the containment cooling analysis requirements.

- or -

With the HPSW divisional cross-tie MOV open, the HPSW subsystem independence is lost. However adequate power is available to start and operate a HPSW pump from the other HPSW subsystem providing flow through the RHR heat exchanger, thus satisfying the containment cooling analysis requirements.

h. Second HPSW pump failure to start (> 60 minutes):
With the divisional cross-tie MOV closed, two independent HPSW subsystems are maintained; adequate EDG power is available to start and operate, within the opposite HPSW subsystem, two HPSW pumps providing flow through its RHR heat exchangers, thus satisfying the containment cooling analysis requirements.

- or –

With the HPSW divisional cross-tie MOV open, the HPSW subsystem independence is lost; however, adequate power is available to start and operate one HPSW pump from each HPSW subsystem to provide flow through two RHR heat exchangers in one RHR subsystem, thus satisfying the containment cooling analysis requirements.

i. HPSW pump failure after being in service (> 60 minute):
With the HPSW divisional cross-tie MOV closed, two independent HPSW subsystems are maintained. Failure of one operating HPSW pump may induce the failure of the second running HPSW pump due to exceeding pump runout and lack of suction head (NPSHa) as it supplies two RHR heat exchangers. However, adequate EDG power is available to start and operate, within the opposite HPSW subsystem, two HPSW pumps to provide flow through its RHR heat exchangers, thus satisfying the containment cooling analysis requirements.

– or –

With the HPSW divisional cross-tie MOV open, the HPSW subsystem independence is lost. Failure of one operating HPSW pump may induce the failure of the second running HPSW pump due to exceeding pump runout and lack of suction head (NPSHa as it supplies two RHR heat exchangers. However, two additional HPSW pumps are available due to the open HPSW cross-tie MOV. Adequate power is available to start and operate one HPSW pump from each HPSW subsystem providing flow through two RHR heat exchangers in one RHR subsystem, thus satisfying the containment cooling analysis requirements.

Note that the failure of a plant Operator to properly position the HPSW cross-tie MOV or the HPSW/RHR heat exchanger discharge MOV has a similar effect as the spuriously opening of the valve. The HPSW System is designed with sufficient redundancy to accommodate a single active failure and perform its design functions.

7.0 POST-MODIFICATION FUNCTIONAL TESTING

Post modification testing for the RHR Cross-tie Modification will be conducted in accordance with the PBAPS modification program and the surveillance test program.

8.0 SUMMARY

As discussed in Enclosure 9c to Attachment 9 to this EPU license amendment request, RHR cross-tie valves are to be installed so that for events in which only one RHR pump is available, it can be cross tied to two RHR heat exchangers. The additional heat capacity provided by the RHR Cross-tie Modification will reduce peak suppression pool temperature and eliminate the need to rely on CAP to ensure adequate NPSH margin for the ECCS pumps. Implementation of the HPSW Cross-tie Modification will ensure that a second HPSW pump on the other loop is available as needed to supply cooling water to the second operating RHR heat exchanger. The HPSW cross-tie motor operated valves will be powered from normal and alternate safety related power supplies to assure that no single component failure can prevent the HPSW system from performing its design function.

A human engineering review has determined that the new manual actions required of the operators are consistent with the current strategy for operator actions and will not significantly impact operator actions and mitigation strategies.

As described in Attachment 12, the PBAPS PRA model was updated to determine the impacts of EPU and the CAP elimination modifications. Specific representation of the RHR Cross-tie Modification including throttling the RHR system flow and the HPSW modification was included in the PRA model for EPU conditions. The analysis concluded that overall Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) increases were very small: a 2.8% increase in CDF and 3.5% increase in LERF. A separate sensitivity study indicated that without the CAP modifications, the CDF increase would have been 3.3% and the LERF increase would have been 7.9%. The results of the sensitivity cases demonstrate the PRA benefits of the CAP elimination modifications in addition to the enhancements to the defense-in-depth achieved by removing dependence on containment accident pressure in the determining adequate NPSH.

FIGURE 9d-1

HPSW SYSTEM (CLTP CONFIGURATION)

FOR INFORMATION ONLY

NOT A CONTROLLED DRAWING

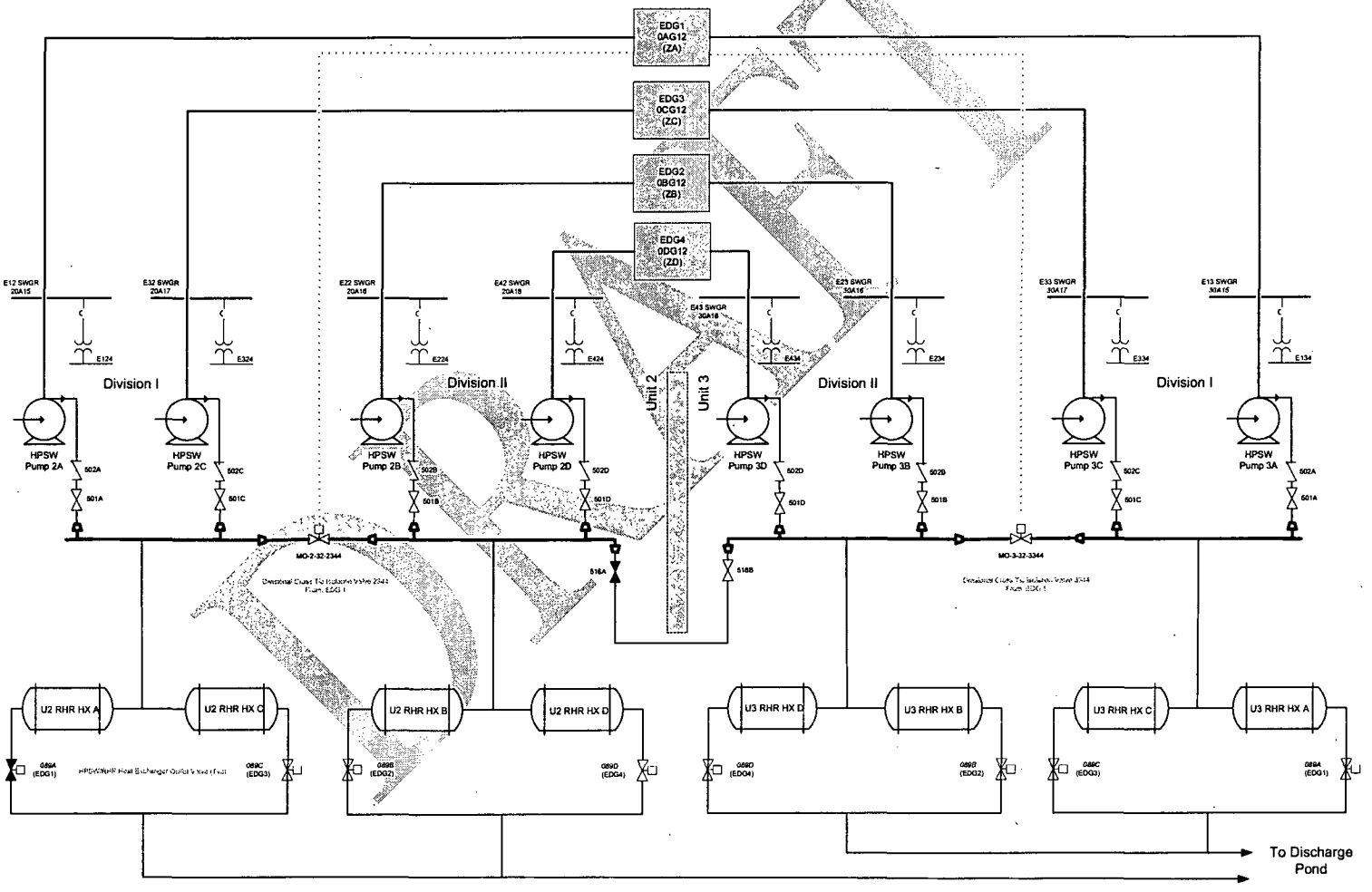
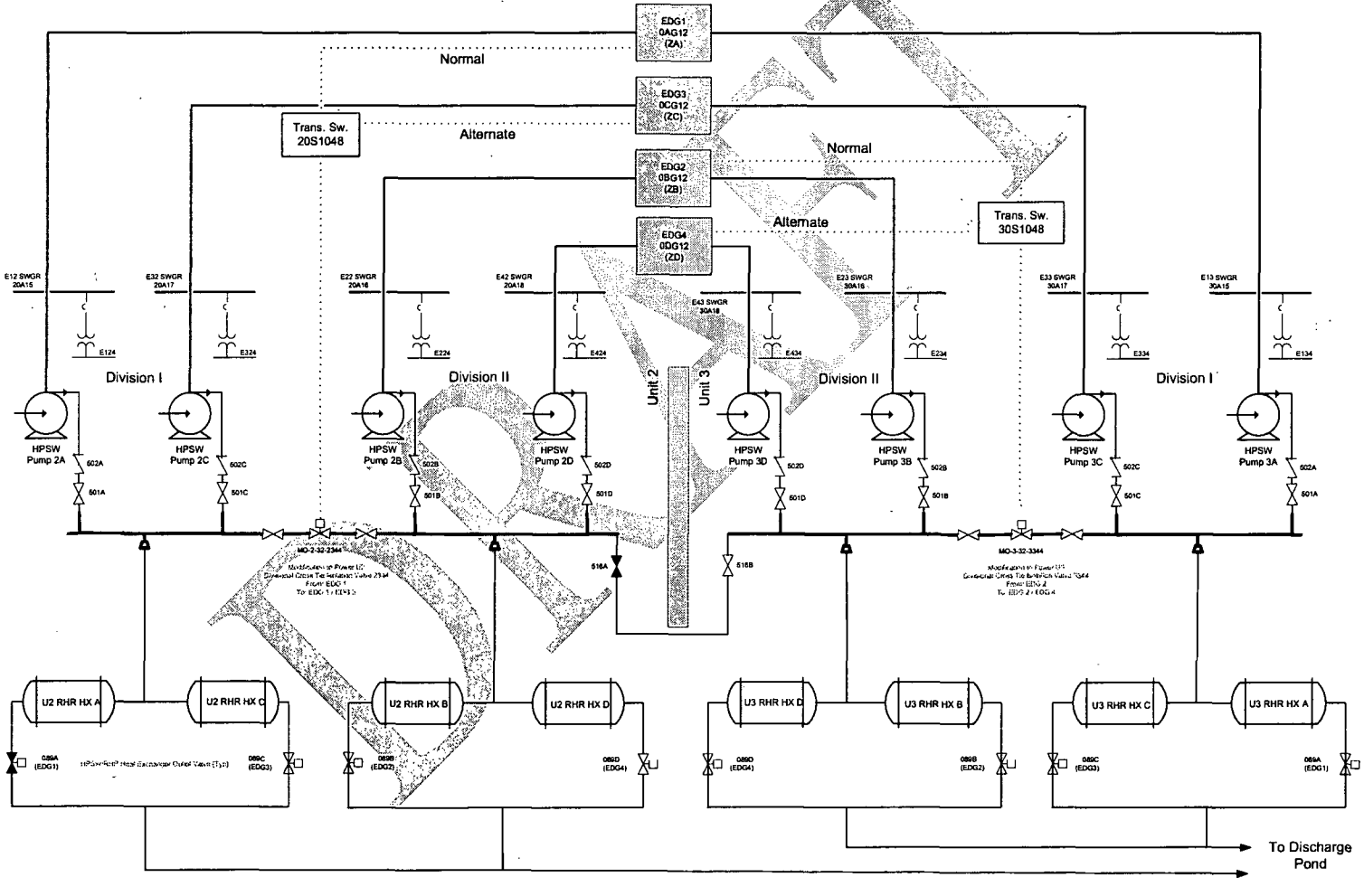


FIGURE 9d-2

HPSW SYSTEM (EPU CONFIGURATION)

FOR INFORMATION ONLY

NOT A CONTROLLED DRAWING



Enclosure 9e to Attachment 9

Peach Bottom Atomic Power Station Units 2 and 3

NRC Docket Nos. 50-277 and 50-278

Condensate Storage Tank (CST) Modifications

1.0 Purpose

Exelon Generation Company (EGC) is pursuing an Extended Power Uprate (EPU) of approximately 12.4 percent at the Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3. As part of the EPU, Exelon Generation Company (EGC) has decided to voluntarily eliminate the reliance on containment accident pressure (CAP) credit assumptions in the accident analysis. PBAPS proposes modifications to the Condensate Storage and Transfer System that support the elimination of reliance on CAP credit. A summary of the CAP credit elimination is contained in Attachment 9, Section 3.2.

This enclosure discusses modifications and operational (procedure) changes being made to the Condensate Storage and Transfer System and primary containment suppression pool system instrumentation for suppression pool level. The described modifications and operational changes ensure that the only suction source for High pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) during the entire Anticipated Transient Without SCRAM (ATWS) and Appendix R events is the Condensate Storage Tank (CST). For Station Blackout (SBO), the CST will be the primary suction source for HPCI and RCIC; however, the suppression pool can be used if necessary. The CST has adequate inventory for the mitigating an SBO. However, the Refueling Water Storage Tank (RWST) will be relied upon to provide the additional adequate condensate supply to the CST for the duration of the Anticipated Transient Without Scram (ATWS) and Appendix R event scenarios.

By enabling the HPCI and RCIC pumps to maintain suction from the CST during the SBO, ATWS, and Appendix R scenarios, the CST modifications provide the ability to add water volume to the reactor pressure vessel (RPV) for makeup. This additional water volume provides for additional heat removal capacity and additional water height in the suppression pool. The additional water volume and heat removal capacity add to the available NPSH for the RHR pump in suppression pool cooling operation without reliance on CAP.

The modifications are as follows:

- Installing a standpipe within the CST for hotwell reject/makeup.
- Raising the "Suppression Pool Water Level – High" Technical Specification (TS) allowable value and the plant high suppression pool level swap over setpoint.

The operational change is as follows:

- Maintaining CST level above the low level trip set point by gravity draining condensate supply from the RWST. Additionally, RWST level will be maintained to ensure the CST level can be maintained above the low level trip for the entire ATWS and Appendix R events. These operational changes ensure a CST supply to HPCI and RCIC pumps for the duration of the SBO, ATWS, and Appendix R events.

2.0 Background and Current Licensing and Design Basis

2.1 Existing Plant Configuration

<u>Condensate Storage and Transfer System</u>

The Condensate Storage and Transfer System is a non-safety related auxiliary system at PBAPS that includes the CST and the RWST. The Condensate Storage and Transfer system

provides the non-safety function of providing both water supply and storage capacity to various plant systems. The CSTs provide the preferred source of water to the HPCI and RCIC Pumps.

Standpipes are installed within the CST for other systems that draw water off the tank. The standpipes allow the remaining CST water volume to be dedicated for the HPCI and RCIC systems. The system piping is configured in such a way as to permit the water of either tank to supply either unit. The CSTs and RWST are protected against cold weather conditions by freeze protection, which consists of steam fed heaters inside the tanks and heat tracing of external piping. Both CST and RWST are Seismic Class II design and are not protected from external events.

Reactor Core Isolation Cooling (RCIC)

The RCIC system is described in UFSAR Section 4.7. Its safety objective is to provide makeup water to the reactor vessel during shutdown and reactor isolation in order to prevent the release of radioactive materials to the environs as a result of inadequate core cooling. The RCIC system consists of a steam-driven turbine-pump unit and associated valves and piping capable of delivering makeup water to the reactor vessel.

The RCIC system pumps water either from the CST (normal supply) or the suppression pool (safety related alternate supply) into the reactor vessel. The RCIC system supplies the design flow rate within a specified initiation time over a range of reactor pressures. The RCIC system is started automatically upon a Reactor Low Water Level (Level 2) signal. The system may also be manually started.

A low water level alarm from the CST provided in the control room is energized when the level in the CST falls to a predetermined point. This is to ensure the NPSH requirement of the RCIC pump is met. Should the CST be unavailable, pump suction is automatically transferred from the CST to the suppression pool.

The electrical power required for system startup, operation, and control is provided by a DC bus. The RCIC system is designed to be capable of startup and operation without auxiliary AC power.

The RCIC system supports Fire Safe Shutdown by providing a source of makeup water to the reactor vessel for Shutdown Method A. The operation of the RCIC turbine also removes steam from the reactor vessel which limits the rate of core temperature rise for Shutdown Method A. Shutdown Method A is one of the four methods designed to bring the plant to a cold shutdown condition for a postulated fire event. Descriptions of the Shutdown Methods are provided in Attachment 6, PUSAR Section 2.11.1.2.2.

Additionally, RCIC is used to support operation during an SBO event.

The RCIC safety design basis is described in UFSAR Section 4.7 as follows:

1. The system operates automatically to maintain sufficient coolant in the reactor vessel so that the integrity of the radioactive material barrier is not compromised.

2. The functional components of RCIC satisfy seismic Class I criteria.

High Pressure Coolant Injection (HPCI)

The HPCI system is provided to assure that the reactor is adequately cooled to limit fuel-clad temperature in the event of a small break in the nuclear system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCI system permits the nuclear plant to be shut down while maintaining sufficient reactor vessel water inventory until the reactor vessel is depressurized. The HPCI system continues to operate until reactor vessel pressure is below the pressure at which Low Pressure Coolant Injection (LPCI) operation or CS system operation maintains core cooling. In addition, HPCI fulfills the function of the RCIC system in the event that the RCIC system fails. The HPCI system consists of a steam turbine driving a constant-flow pump, system piping, valves, controls, and instrumentation.

The HPCI system pumps water either from the CST or the suppression pool into the reactor vessel via one of the feedwater lines. Suction piping for the system is provided from the CST and suppression pool. Pump suction for HPCI is normally aligned to the CST. Initially, the CST is used and, upon being drawn down to a low level, automatic transfer to the suppression pool occurs.

Steam exhausted from the HPCI turbine is directed to the suppression pool. The HPCI system is started automatically upon a reactor low water level signal (Level 2) or a primary containment high pressure signal.

A high suppression pool water level condition causes an automatic transfer of the HPCI pump suction source from the CST to suppression pool. The basis for the CST transfer on high suppression pool level is to prevent the HPCI system from contributing to any further increase in the suppression pool level. The maximum suppression pool water level is dictated by the need to maintain air space to accommodate the non-condensable gases that are blown down to the suppression pool during an accident and to limit steam discharge hydrodynamic loads in the suppression pool.

The HPCI system supports Fire Safe Shutdown by providing a source of makeup water to the reactor vessel for Shutdown Methods B and D. The operation of the HPCI turbine also removes steam from the reactor vessel which limits the rate of core temperature rise for Shutdown Methods B and D. Shutdown Methods B and D are two of the four methods designed to bring the plant to a cold shutdown condition for a postulated fire event. Descriptions of the Shutdown Methods are provided in Attachment 6, PUSAR Section 2.11.1.2.2.

Primary Containment Pressure Suppression System

The Primary Containment Pressure Suppression (PCPS) system consists primarily of the drywell air space, suppression chamber air space, suppression pool water, suppression chamber-to-drywell vacuum relief valve assemblies, and safety relief valve (SRV) discharge line assemblies.

The HPCI system supports Technical Specification (TS) operability of the PCPS system by transferring HPCI pump suction from the CST to the suppression pool prior to the suppression pool water level exceeding its high level setpoint during normal operation and following plant transients and design basis accidents (DBAs). This transfer of suction minimizes the steam discharge hydrodynamic loads on the pool boundary and submerged structures including the SRV discharge lines.

The system has the following functions:

- Provides sufficient water volume within the suppression pool and air volume within the suppression pool to absorb the total amount of air, steam, and water discharged from the drywell following a DBA to limit primary containment post-Loss of Coolant Accident (LOCA) peak pressures and temperatures to below design values to maintain primary containment integrity.

- Provides the safety related source of cooling water to support the ECCS and RCIC system functions following transients and DBAs.

- Provides sufficient water volume within the suppression pool and air volume within the suppression chamber to condense steam discharges from the Nuclear Boiler System SRVs to ensure that the Reactor Coolant Pressure Boundary (RCPB) is maintained while containing SRV steam discharges within containment.

- Provides sufficient water volume within the suppression pool to condense steam discharges from the RCIC and HPCI systems turbine exhaust lines to ensure that the release of potentially radioactive materials are contained within containment.

- Provides sufficient water level within the suppression pool to adequately support the NPSH requirements of the ECCS and RCIC system while minimizing the hydrodynamic loads on the pool boundary and submerged structures to maintain primary containment integrity.

- Provides the suppression pool-to-drywell vacuum relief valves which, in conjunction with the reactor building-to-suppression pool vacuum relief valves, maintain the negative pressure requirements of primary containment to maintain its integrity.

Design Basis of High Suppression Pool Water Level

Excessively high suppression pool water could affect pressure suppression capability and SRV tail pipe limits. The Maximum Pressure Suppression Primary Containment Water Level (MPSPCWL) is the highest containment water level at which the pressure suppression capability of the containment can be maintained. Above this level, the pressure suppression capability of the Primary Containment may be insufficient to accommodate the energy released to containment from either a RPV blowdown or an RPV breach by core debris. Current procedures define the SRV tail pipe level limit to be the highest suppression pool water level at which opening an SRV will not result in exceeding the capability of the SRV tail pipe, tail pipe supports, quencher, or quencher supports. Damage to these components can lead to inability to use the SRVs or can lead to direct pressurization of the primary containment without pressure suppression. The SRV tail pipe level limit is a curve that is truncated at the suppression pool level that corresponds to the MPSPCWL. The MPSPCWL and tail pipe limit is 17.1 feet. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of HPCI from the CST to the suppression pool to eliminate the possibility of HPCI continuing to provide additional water from a source outside containment. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CST suction valve automatically closes.

The high suppression pool water level signals are initiated from two level switches. The logic is arranged such that either switch can cause the suppression pool suction valves to open and the CST suction valve to close. The Allowable Value (AV) for the TS "Suppression Pool Water Level — High" Function is chosen to ensure that HPCI will be aligned for suction from the suppression pool to prevent HPCI from contributing to any further increase in the suppression pool level.

3.0 Scope of Modification/Design

Two modifications and one operational change are designed to mitigate SBO, ATWS, and Appendix R scenarios with no reliance on CAP credit:

3.1 CST Standpipe Addition

Purpose/Justification:

This modification installs a standpipe to limit the drain down volume of the CST to the condenser. The purpose of this modification is to prevent a fire induced failure of the makeup or let down valves from draining the CST inventory to the hotwell. The addition of this standpipe will ensure a CST dedicated usable volume for the HPCI and RCIC pumps for SBO, ATWS, and Appendix R events.

Modification Scope:

This modification will limit the volume of water in the tank available to the condenser hotwell makeup line and assure availability of the water volume for the ECCS systems. Besides the standpipe, there is no additional equipment added and no operator actions are necessary to operate the standpipe. Following installation of the standpipe, the CST dedicated usable volume will be approximately 101,109 gallons. Addition of a standpipe to the makeup line does not have a negative impact on the operability of other equipment downstream of the makeup/letdown line.

Events Mitigated:

Station Blackout was analyzed for EPU. The analysis is discussed in Attachment 6, PUSAR, Section 2.3.5, "Station Blackout". The EPU SBO analysis demonstrates that the CST dedicated usable volume for RCIC and HPCI suction ensures adequate water volume is available to remove decay heat, depressurize the reactor, and maintain the reactor vessel level above the top of the active fuel during the coping period. The CST volume needed for SBO at EPU conditions is approximately 94,570 gallons.

The ATWS event was analyzed for EPU and is discussed in Attachment 6, PUSAR Section 2.8.5.7, "Anticipated Transient Without Scram." The EPU analysis demonstrates that a condensate volume of approximately 120,000 gallons is necessary for RCIC and HPCI suction to mitigate the event. This exceeds the CST dedicated usable volume of approximately 101,109 gallons. Therefore, additional capacity is provided by gravity draining the RWST to the CST as explained in Section 3.2 below. The CST and RWST combined have sufficient capacity to meet requirements for the duration of the ATWS event.

The limiting Appendix R fire events were analyzed for EPU and are discussed in Attachment 6, PUSAR Section 2.5.1.4.2, "10 CFR 50 Appendix R Fire Event." The Appendix R maximum CST

usage volume is from Shutdown Method A1 and is 154,000 gallons. This exceeds the CST dedicated usable volume of approximately 101,109 gallons. Therefore, additional capacity is provided by gravity draining the RWST to the CST as explained in Section 3.2 below. The CST and RWST combined have sufficient capacity to meet requirements for the duration of the Appendix R event.

Design Requirements:

The CST is a non-safety related tank classified as Seismic Class II. Therefore, the CST standpipe shall be designed to Seismic Class II criteria. ATWS, Appendix R and SBO scenarios do not require these tanks to be seismically qualified or protected from external events. There will be no changes to these classifications for the CST.

3.2 Operational Change - Maintain RWST Inventory to Supplement the CST Inventory

Purpose/Justification:

For EPU, the CST is credited as the primary HPCI and RCIC makeup water source to the RPV for the EPU SBO, ATWS, and Appendix R scenarios. Therefore, HPCI or RCIC pump suction swap over from the CST to the suppression pool must be controlled. The swap over occurs at the low CST level limit setpoint, which is 5.63 feet above the tank bottom. The setpoint provides margin to the TS low level of 5.25 feet above the tank bottom. To prevent swap over, the RWST will be used to supply additional inventory to the CST. This will be accomplished by gravity draining the RWST supply to the CST through lineups of existing valves. Procedure changes are required to ensure the RWST inventory is transferred to the CST in a timely manner to prevent HPCI and RCIC swap over from CST to the suppression pool.

The dedicated usable volume for the CST is approximately 101,109 gallons. For SBO at EPU conditions, the maximum CST usage is 94,570 gallons. This usage volume is well within the dedicated usable volume of the CST and use of RWST volume is not necessary for the SBO event. Therefore, the CST volume required for SBO is bounded by the CST volume required for ATWS and Appendix R events.

For ATWS at EPU conditions, the maximum CST usage is approximately 120,000 gallons. Therefore, the ATWS requires a water volume that exceeds the CST dedicated usable volume of 101,109 gallons. Following EPU implementation, a minimum volume of water is required to be maintained in both the CST and the RWST for ATWS. The Appendix R scenario discussed below requires an even greater volume of condensate transferred from the RWST, and therefore, bounds the condensate required from the RWST for the ATWS event. Required tank volumes and levels will be administratively controlled based on Appendix R event analysis.

Appendix R Shutdown Method A1 provides the bounding CST usage of 154,000 gallons. Therefore, the Appendix R event requires a condensate volume that exceeds the CST inventory. Following EPU implementation, a minimum volume of condensate is required to be maintained in both the CST and the RWST for Appendix R.

The CST dedicated usable volume following EPU is approximately 101,109 gallons. The 24.83 foot level in the CST is associated with the 101,109 gallon dedicated usable volume. The existing CST low level alarm point at 27.25 feet provides approximately 113,886 gallons of usable volume and provides a margin of approximately 12,777 gallons to the dedicated usable

volume. Therefore, the existing low level alarm point will be used as the initial action point for Operators to ensure the volume in the CST does not decrease below the dedicated usable volume of 101,109 gallons.

The remainder of the needed condensate supply for mitigating the Appendix R event is provided from the RWST. The RWST volume required to complete the Appendix R event mitigation is approximately 52,891 gallons, which is approximately 4.65 feet of level in the RWST. The usable RWST volume is that volume above the 5.63 foot level associated with the CST low level swap over setpoint. Therefore, the required RWST volume corresponds to a RWST level of approximately 10.28 feet. In order to ensure appropriate driving head for the gravity drain to the CST, the RWST minimum level is conservatively set at 12 feet. The 12 foot level will be the RWST low level alarm point. Therefore, the RWST dedicated usable volume will be 72,450 gallons.

The minimum volume required by the Appendix R analysis is assured by maintaining a combined inventory in the CST and RWST that is greater than the usable CST and RWST volumes added to the CST and RWST unusable tank volumes. The unusable CST volume is the volume below the 5.63 foot low level switchover setpoint. This unusable CST volume is approximately 29,768 gallons. The unusable RWST volume is that volume below the elevation of the 5.63 foot CST low level switchover setpoint. The unusable RWST volume is approximately 64,033 gallons. The combined unusable tank volume, when added to the volumes associated with the minimum CST and RWST tank levels of 24.83 feet and 12 feet, equates to a minimum required volume for the combined CST and RWST. This minimum required combined volume is approximately 267,360 gallons. Controlling the combined volume in the CST and RWST above 270,000 gallons ensures the Appendix R required volume is available and is conservative. The minimum combined volume in the CST and RWST will be administratively controlled.

Scope of Operational Change:

This operational change (procedural changes) makes available the condensate inventory of the RWST to supplement CST during the ATWS and Appendix R event scenarios. This operational change will use the existing piping and manual isolation valves currently used to transfer condensate from the RWST to CST during normal or outage conditions

Procedures will be updated to require the specific inventory within the RWST to ensure the gravity drain is functional and to ensure capability to mitigate the events. Procedures will also provide steps (valve lineup) to increase CST capacity by gravity draining the RWST to the CST through the currently installed cross connect piping between these two tanks. The operator will open the existing cross connect valves to meet the demand flow requirements prior to reaching CST low level swap over setpoint of 5.63 feet above the tank bottom. This prevents the CST low level setpoint from actuating and the resulting transfer of HPCI or RCIC suction from the CST to the suppression pool.

Design Requirements:

The pre-EPU Appendix R scenarios assumed transfer of HPCI and RCIC CST suction to the suppression pool on low level. Additionally, pre-EPU FSSD analysis did not include the RWST and its associated equipment because the suppression pool was the credited inventory source during Appendix R. However, post-EPU Appendix R scenarios rely on the greater decay heat

removal capability of the cooler CST and RWST source over the duration of the event. Therefore, the post-EPU configuration will be evaluated to identify any potential circuits or equipment that are required to perform a safe shutdown function and could be affected by a design basis fire. Any identified scenarios that require modification for continued compliance with Appendix R events following EPU will be performed in accordance with PBAPS Appendix R Program requirements and will be developed through the EGC Configuration Change Process.

3.3 High Suppression Pool Water Level Setpoint Change

Purpose/Justification:

The ATWS and Appendix R events for EPU rely upon HPCI and RCIC pump suctions aligned only to the CST for the entire event. For SBO, the CST is the primary suction source, but the suppression pool can be used if necessary. In the case of ATWS and Appendix R, the CST volume will be supplemented by the RWST volume, which will be transferred by gravity draining the RWST as described in Section 3.2. Appendix R Shutdown Method A1 provides the bounding (largest) water volume to consider maximum volume, while Shutdown Method B1 provides the bounding water volume while operating with HPCI. Shutdown Method B1 is the basis of the suppression pool water high setpoint. The CST supplemented volume will permit operation of the HPCI pump during the entire event, the supplemented volume will cause the plant high suppression pool water level swap over setpoint and the current allowable value of TS Table 3.3.5.1-1, Function 3.e, "Suppression Pool Water Level – High," to be exceeded.

The plant has a setpoint for swap over of the HPCI pump suction from the CST to the suppression pool prior to the TS allowable value for "Suppression Pool Water Level – High" being reached. When the high level swap over setpoint is reached, HPCI suction automatically transfers from the CST to the suppression pool. Both the plant swap over setpoint and the TS allowable value must be changed to prevent swap over from the CST to the suppression pool suction prior to the required Appendix R CST volume being transferred by HPCI and to prevent exceeding the TS value. This modification raises the suppression pool high level swap over setpoint that initiates transfer of the HPCI pump suction from the CST to the suppression pool. The new setpoint is selected to prevent prematurely switching the suction source of HPCI to the suppression pool, yet remain below the TS "Suppression Pool Water Level – High" allowable value.

Appendix R Shutdown Method B1 analysis for EPU assumes no reliance on CAP credit and results in a maximum suppression pool level of 16.5 feet (16 feet, 6 inches). The current TS allowable value for "Suppression Pool Water Level – High" is 5 inches above the suppression pool mid-point of 15 feet, 6 inches, which is a level of 15 feet, 11 inches. To prevent premature swap over of the HPCI suction, the new TS level allowable value will be raised to ≤ 16 feet, 7 inches. The plant instrument setpoint will be set below the new TS allowable value but above 16.5 foot level from the Appendix R Shutdown Method B1 analysis. The setpoint change will be implemented in accordance with the EGC Configuration Change process.

Excessively high suppression pool water could affect pressure suppression capability and SRV tail pipe limits. As described in Section 2.1, the MPSPCWL and SRV tail pipe limit is 17.1 feet. The new "Suppression Pool Water Level – High" TS allowable value is 16 feet, 7 inches, which is below the MPSPCWL and the tail pipe limit. Therefore, the new "Suppression Pool Water Level – High" TS allowable value and the plant high level swap over setpoint support Appendix R Shutdown Method B1 and protect the suppression pool design limits.

Events Mitigated:

Both the ATWS and the Appendix R events rely upon supplementary condensate volume from the RWST. Of these events, the Appendix R scenario Shutdown Method B1 analysis results in the largest required condensate volume while operating with HPCI. Shutdown Method B1 is the basis for the suppression pool high level swap over setpoint as discussed above. Additional inventory is provided during the event by gravity draining the RWST to the CST. The CST and RWST combined have sufficient capacity to meet requirements for the duration of the Appendix R Shutdown Method B1 scenario. The additional condensate volume from the RWST does result in a higher suppression pool level. The level is 16 feet, 6 inches. The larger volume results in the current high suppression pool water level HPCI swap over setpoint and current TS allowable value being exceeded. Therefore, the plant swap over setpoint and the TS allowable value will be raised for EPU.

The NPSH analyses for the ECCS pumps at EPU conditions do not take credit for CAP. This is based on improving ECCS pump NPSH through changed methodologies and modifications that are contained in the SBO, ATWS, and Appendix R analyses. This results in a lower peak suppression pool temperature and additional volume in the suppression pool and a resulting increase in suppression pool level.

Modification Scope:

CST modification will require the relocation of the installed safety related level switches to a higher elevation to span the level of the new setpoint. There is sufficient piping in the vertical direction to permit relocation of the level switches to span the new setpoint. The associated cables will require minor modification of the associated conduits in the area of the level switches to accommodate the relocation of the switches. All associated equipment will remain installed and will operate as it did prior to the raising the level switches. Existing instrumentation will provide adequate indication for the event scenarios. Switch operation logic will not be altered for any of the applications. All existing design requirements remain the same. The modification will be performed in accordance with the EGC Configuration Change Process.

The HPCI system is a safety related system. Therefore, the CST modification will be classified as safety related. The HPCI system equipment, piping, and support structures are designed to Seismic Class I Criteria. Relocated instrumentation and hardware will continue to meet the current design requirements (remains safety related and Seismic Class I). Instrumentation and hardware will continue to meet current environmental qualification requirements. Basic design and functions of the instrumentation and the HPCI suction valve will not be affected.

Design Requirements:

The pre-EPU Appendix R analysis scenarios assumed transfer of HPCI to the suppression pool on high suppression pool water level setpoint. However, post-EPU Appendix R scenarios rely on the greater decay heat removal capability of the cooler CST and RWST source over the duration of the event, and as such, spurious operation can no longer be tolerated. Therefore, the post-EPU configuration will be evaluated to identify any potential circuits or equipment that are required to perform a safe shutdown function and could be affected by a design basis fire. Any identified scenarios that require modification for continued compliance with Appendix R events following EPU will be performed prior to EPU implementation in accordance with PBAPS

Appendix R Program requirements and will be developed through the EGC Configuration Change Process

Post-Modification Testing:

All affected circuits shall pass a post-modification Acceptance Test(s) to verify proper operability and verify no unanticipated operability changes prior to returning to operation. Development of post-modification testing is part of the EGC Configuration Change Process.

Structural Impacts:

The maximum water level limit is to ensure that the hydrodynamic loads which impinge on the submerged structures and pool boundary induced by steam discharges to the pool will not jeopardize primary containment integrity. Existing procedures indicate that the suppression pool should not exceed a maximum water level of 17.1 feet. The maximum credible water level is 16.5 feet for the Appendix R Shutdown Method B1 scenario. Therefore, there is no structural impact on the suppression pool and its support structures.

Operational Requirements:

The current high suppression pool water level setpoint that causes the HPCI suction to swap over from the CST to the suppression pool will be changed. This also requires a TS change to the allowable value for TS Table 3.3.5.1-1, Function 3.e, "Suppression Pool Water Level – High," which is discussed in Attachment 1 with Markups TS provided in Attachment 2. This change will be incorporated into plant procedures and training for the modified condition as required by the EGC Configuration Change Process.

Technical Specification Changes:

As stated above, this modification will change TS Table 3.3.5.1-1, Function 3.e, "Suppression Pool Water Level – High." The TS change is described and justified in Attachment 1. Markups of the TS are provided in Attachment 2. Supporting TS Bases changes are provided in Attachment 3 for information only.

3.4 New Licensing Basis Summary

The current Appendix R and SBO evaluations rely on CAP credit in the analyses to ensure that adequate NPSH exists for the ECCS pumps. The CST inventory is credited as the primary HPCI and RCIC makeup water source to the RPV for the EPU SBO, ATWS, and Appendix R events analyses. The above modifications will allow for a lower peak suppression pool temperature. The increase in the NPSH available for the ECCS pumps eliminates the need for CAP credit in the EPU analysis.

A standpipe will be installed in the CST to ensure that a spurious actuation of makeup or let down valves will not drain the CST to the hot well. This modification reserves condensate inventory for HPCI and RCIC suction during Appendix R events.

The CST contains an acceptable usable volume for the SBO event. Additional CST capacity will be provided by gravity draining the RWST to the CST through use of the cross connect between these two tanks for the ATWS and Appendix R events. With the addition of the RWST

inventory, the CST condensate level can be maintained above the low CST level setpoint, thus preventing HPCI or RCIC swap over from the cooler CST to the warmer suppression pool source.

Appendix R Shutdown Method B1, which assumes operation with the HPCI pumps, results in the maximum suppression pool water level of 16.5 feet. This exceeds the current high suppression pool water level swap over setpoint that initiates transfer of the HPCI pump suction from the CST to the suppression pool. The high suppression pool water level swap over setpoint will be raised to accommodate the increased level. The Allowable Value for TS Table 3.3.5.1-1, Function 3.e, "Suppression Pool Water Level – High," will increase to ≤ 16 feet, 7 inches. Both changes ensure that adequate CST and RWST condensate volume is supplied during an ATWS or Appendix R event eliminating the need to have the HPCI suction source switch to the suppression pool. The suppression pool is not credited in ATWS, or Appendix R scenarios for HPCI and RCIC water sources for EPU.

4.0 Summary

Implementation of the CST modifications eliminates the reliance on CAP credit for the duration of an ATWS event, the 8 hour coping period for the SBO event, and for the duration of the Appendix R event. Using the cooler CST supply ensures that both the HPCI and RCIC pumps have adequate NPSH available and reduces the peak suppression pool temperature, which increases the NPSH available for the ECCS pumps. The increased height of water in the suppression pool, which is the result of the change in setpoint for the suppression pool high level, also provides additional means of improving NPSH.