October 10, 2003

Mr. Bryce L. Shriver
Senior Vice President
 and Chief Nuclear Officer
PPL Susquehanna, LLC
769 Salem Boulevard
Berwick, PA 18603-0467

SUBJECT: SUSQUEHANNA STEAM ELECTRIC STATION, UNITS 1 AND 2 - ISSUANCE OF AMENDMENTS RE: EXTENDED OUTAGE TIME FOR OFFSITE POWER - SINGLE OCCURRENCE (TAC NOS. MB9903 AND MB9904)

Dear Mr. Shriver:

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 214 to Facility Operating License No. NPF-14 and Amendment No. 189 to Facility Operating License No. NPF-22 for the Susquehanna Steam Electric Station, Units 1 and 2. These amendments are in response to your application dated July 3, as supplemented by letters dated September 9 and 23, 2003.

The amendments change the Technical Specification (TS) to allow a one-time only change to TS 3.8.1, “AC [Alternating Current] Sources - Operating,” Action A.3, by extending the required Completion Time for restoration of an inoperable offsite circuit from 72 hours to 10 days.

A copy of our safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's Biweekly *Federal Register* Notice.

Sincerely,

/RA/

Richard V. Guzman, Project Manager, Section 1
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-387 and 50-388

Enclosures: 1. Amendment No. 214 to License No. NPF-14
2. Amendment No. 189 to License No. NPF-22
3. Safety Evaluation

cc w/encls: See next page

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<u>DISTRIBUTION</u>:

PDI-1 R/F	MRubin	BPlatchek, RGN-1
ACRS	RGuzman	OGC
PUBLIC	M'OBrien	GHill (4)
APal	RLaufer	CDoutt
RJenkins	TBoyce	

cc w/encls: See next page
*Provided SE input by memo. No substantive changes made.

Accession No.: ML032830347 Package No.: ML TSs: ML

OFFICE	PDI-1/PM	PDI-2/LA	EEIB*	IROB	SPLB*	OGC	PDI-1/SC
NAME	RGuzman	SLittle for MO'Brien	RJenkins	TBoyce	MRubin	RWeisman	RLaufer
DATE	09/30/03	10/1/03	09/23/03	10/6/03	09/26/03	10/10/03	10/10/03

OFFICIAL RECORD COPY

Susquehanna Steam Electric Station,
Units 1 &2

cc:

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Units 1 &2

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PPL SUSQUEHANNA, LLC

ALLEGHENY ELECTRIC COOPERATIVE, INC.

DOCKET NO. 50-387

SUSQUEHANNA STEAM ELECTRIC STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 214
License No. NPF-14

1. The Nuclear Regulatory Commission (the Commission or the NRC) having found that:

   A. The application for the amendment filed by PPL Susquehanna, LLC, dated July 3, as supplemented by letters dated September 9 and 23, 2003, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the regulations of the Commission;

   C. There is reasonable assurance: (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 2.C.(2) of the Facility Operating License No. NPF-14 is hereby amended to read as follows:

    (2) Technical Specifications and Environmental Protection Plan

    The Technical Specifications contained in Appendix A, as revised through Amendment No. 214 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. PPL Susquehanna, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance. In implementing this amendment, PPL Susquehanna, LLC, shall not change the commitments set forth in the July 3, 2003, application, and described as commitments 1 through 7 in the NRC Safety Evaluation dated October 10, 2003, associated with this amendment, without first evaluating any such change in accordance with the criteria set forth in 10 CFR 50.59(c)(2), and obtaining a license amendment for any change meeting one of those criteria. The license amendment shall be implemented by October 31, 2003.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Richard J. Laufer, Chief, Section 1
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Date of Issuance: October 10, 2003

ATTACHMENT TO LICENSE AMENDMENT NO. 214

FACILITY OPERATING LICENSE NO. NPF-14

DOCKET NO. 50-387

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contains marginal lines indicating the areas of change.

REMOVE	INSERT
3.8-2	3.8-2
3.8-3	3.8-3
3.8-4	3.8-4

PPL SUSQUEHANNA, LLC

ALLEGHENY ELECTRIC COOPERATIVE, INC.

DOCKET NO. 50-388

SUSQUEHANNA STEAM ELECTRIC STATION, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 189
License No. NPF-22

1. The Nuclear Regulatory Commission (the Commission or the NRC) having found that:

    A. The application for the amendment filed by PPL Susquehanna, LLC, dated July 3, as supplemented by letters dated September 9 and 23, 2003, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

    B. The facility will operate in conformity with the application, the provisions of the Act, and the regulations of the Commission;

    C. There is reasonable assurance: (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I;

    D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

    E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 2.C.(2) of the Facility Operating License No. NPF-22 is hereby amended to read as follows:

   (2) Technical Specifications and Environmental Protection Plan

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 189 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. PPL Susquehanna, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance. In implementing this amendment, PPL Susquehanna, LLC, shall not change the commitments set forth in the July 3, 2003, application, and described as commitments 1 through 7 in the NRC Safety Evaluation dated October 10, 2003, associated with this amendment, without first evaluating any such change in accordance with the criteria set forth in 10 CFR 50.59(c)(2), and obtaining a license amendment for any change meeting one of those criteria. The license amendment shall be implemented by October 31, 2003.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Richard J. Laufer, Chief, Section 1
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Date of Issuance: October 10, 2003

ATTACHMENT TO LICENSE AMENDMENT NO. 189

FACILITY OPERATING LICENSE NO. NPF-22

DOCKET NO. 50-388

Replace the following page of the Appendix A Technical Specifications with the attached revised page. The revised page is identified by amendment number and contains marginal lines indicating the areas of change.

REMOVE	INSERT
3.8-2	3.8-2

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 214 TO FACILITY OPERATING LICENSE NO. NPF-14

AND AMENDMENT NO. 189 TO FACILITY OPERATING LICENSE NO. NPF-22

PPL SUSQUEHANNA, LLC

ALLEGHENY ELECTRIC COOPERATIVE, INC.

SUSQUEHANNA STEAM ELECTRIC STATION, UNITS 1 AND 2

DOCKET NOS. 50-387 AND 388

1.0 INTRODUCTION

By application dated July 3, 2003, as supplemented by letters dated September 9 and 23, 2003, PPL Susquehanna, LLC (PPL, the licensee), requested changes to the Technical Specifications (TSs) for Susquehanna Steam Electric Station, Units 1 and 2 (SSES 1 and 2).

The proposed changes would revise TS 3.8.1 for Alternating Current (AC) Sources - Operating, to extend the allowable Completion Time for Required Actions for one offsite circuit inoperable, from 72 hours to 10 days on a one-time basis. The supplemental letters dated September 9 and 23, 2003, provided clarifying information that did not change the scope of the amendment as described in the initial notice of the proposed action published in the *Federal Register* (68 FR 43392, July 22, 2003), or the U.S. Nuclear Regulatory Commission (NRC) staff's proposed no significant hazards consideration determination.

2.0 REGULATORY EVALUATION

The NRC finds that PPL in its July 3, 2003, submittal identified the applicable regulatory requirements. The regulatory requirements and guidance which the NRC staff considered in its review of the application are as follows:

1. Title 10 of the *Code of Federal Regulations* (10 CFR) establishes the fundamental regulatory requirements with respect to the electric power distribution systems. Specifically, General Design Criterion (GDC) 17, "Electrical power systems," in Appendix A to Part 50, "General Design Criteria for Nuclear Power Plants," states, in part, that electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions.

2. GDC 18, "Inspection and Testing of Electric Power Systems," requires that electric power systems that are important to safety be designed to permit appropriate inspection and testing.

3. Section 50.63, “Loss of All Alternating Current Power,” requires that all nuclear power plants must have the capability to withstand a loss of all AC power (not including AC power fed by station batteries through invertors or by alternate AC sources, as defined in section 50.63) for an established period of time.

4. Section 50.36 requires that all operating licenses for nuclear reactors must include limiting conditions for operation (LCO), along with required Completion Times in the TSs.

5. The Maintenance Rule, 10 CFR 50.65(a)(4), requires licensees to assess and manage any increase in risk that may result from maintenance activities on structures, systems, and components (SSCs) covered by the Maintenance Rule, before performing the proposed activities. Regulatory Guide (RG) 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants,” dated May 2000, provides guidance on implementing the provisions of 10 CFR 50.65(a)(4).

6. RG 1.93, “Availability of Electric Power Sources,” provides operating procedures and restrictions acceptable to the NRC staff which should be implemented if the number of available AC power sources are less than the number specified in the LCO.

7. RG 1.174, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,” dated November 2002, and RG 1.177, “An Approach for Plant-Specific, Risk-Informed Decision Making: Technical Specifications,” dated August 1998, provide specific guidance and acceptance criteria for assessing the nature and impact of licensing-basis changes, including proposed TS changes in Completion Times by considering engineering issues and applying risk insights. In addition, Chapter 16.1, “Risk-Informed Decision Making: Technical Specifications,” of the NRC Standard Review Plan (SRP), NUREG-0800, describes acceptable approaches and guidelines for reviewing proposed TS modifications including Completion Time changes as part of risk-informed decision making.

3.0 <u>TECHNICAL EVALUATION</u>

In reviewing PPL’s proposed changes to TS 3.8.1, the NRC staff has reviewed the proposed changes from a probabilistic risk assessment (PRA), as well as a deterministic perspective. Section 3.1 of this evaluation addresses the deterministic aspects of the proposed changes. The probabilistic aspects of the amendment are addressed in Section 3.2.

3.1 Deterministic Evaluation

LCO 3.8.1, Required Action A.3, currently requires, in part, that if one required offsite power circuit (in this case, a startup transformer (ST)) is inoperable, the required offsite circuit be restored to Operable status within 72 hours. The LCO requires further that if the offsite power circuit cannot be restored to Operable status within 72 hours, both units should be placed in Mode 3 within 12 hours and in Mode 4 within 36 hours. PPL has proposed to extend the Completion Time for restoration of an inoperable offsite circuit from 72 hours to 10 days on a one-time basis. This change would allow sufficient time for the planned replacement of ST No. 10 to be completed by December 31, 2003. Accordingly to PPL, this change is needed to ensure the continued long-term reliability of ST No. 10.

Under the current TS requirements, SSES 1 and 2 would need to be in a Mode 4 state simultaneously for an extended period of time in order to replace ST No. 10. This action is required because ST No. 10 provides one of the two TS-required offsite power sources to SSES 1 and 2, and both units are required to maintain two offsite power sources when above cold shutdown. Based on PPL's experience, the proposed transformer replacement could not be completed within the current outage time limit of 72 hours. PPL intends to use the proposed completion time to replace existing ST No. 10 manufactured by Federal Pacific with new ST No. 10 manufactured by Waukesha Electric. PPL states that the proposed outage time of 10 days is adequate to replace the ST based on the past experience of replacing ST No. 20 which took slightly over 7 days. ST No. 10 will be returned to service and, upon successful completion of the operability tests required to return the offsite circuit to operable status, declared operable.

PPL stated that implementation of the proposed changes will be done in a manner consistent with the defense-in-depth philosophy. Specifically, PPL stated as follows: station procedures will ensure consideration of prevailing conditions, including other equipment out of service, and implementation of compensatory actions to assure adequate defense-in-depth while ST No. 10 is replaced. No new common cause failure modes are introduced by these proposed changes and protection against common cause failure modes previously considered is not compromised. Independence of physical barriers to radionuclide release is not affected by these proposed changes.

PPL stated that the Class 1E AC distribution system is divided into four load groups. PPL explained as follows: loss of any one load group does not prevent the minimum safety functions from being performed. Each load group can be supplied from either offsite power supply or a single diesel generator (DG). ST No. 10 (fed from a 230-kilovolt (kV) switchyard) and ST No. 20 (fed from a 500-230-kV tie line) each provide the normal source of power to two of the four 4.16 kV engineered safety systems (ESS) busses in each unit and they each provide the alternate source of power to the remaining two 4.16 kV ESS buses in each unit. If any 4.16 kV ESS bus loses power, an automatic transfer from the normal to the alternate source occurs after the normal supply breaker trips. During the replacement of ST No. 10, the second offsite power source will not be available. Therefore, ST No. 20 will provide power to each of the four 4.16 kV ESS buses in each unit.

PPL stated that only one loss of offsite power (LOOP) event has occurred at SSES 1 and 2 (in 1984 during Unit 2 pre-operational testing). PPL indicated that: the LOOP event was due to the unique configuration of the pre-operational testing and impacted Unit 2 only. The October 2002 fire in ST No. 20 resulted in losing one source of offsite power; all ESS busses remained energized because one offsite source (ST No. 10) remained operable. PPL stated that the power supply for ST No. 10 was modified in 1995 to improve its reliability. The modifications included segmenting the Montour-Mountain line into two new lines, by installing a Susquehanna T-10 Tap 230 kV switchyard, with a three-breaker ring bus arrangement. In addition, the relaying and control circuits for both ST No. 10 and ST No. 20 were physically separated, to eliminate exposure to common-cause loss due to periodic testing or accidental bumping and to provide physical separation of ST No. 10 and ST No. 20 relaying equipment.

PPL described the DGs and their operation as follows: the onsite standby power source for 4.16 kV ESS busses A, B, C, and D consists of five DGs. DGs A, B, C, and D are dedicated to ESS busses A, B, C, and D, respectively. DG E is available to be used as a substitute for any

one of the four DGs (A, B, C, or D) to supply the associated ESS bus. Each DG provides standby power to two 4.16 kV ESS busses - one associated with Unit 1 and one associated with Unit 2. The four required DGs provide onsite standby power for both Unit 1 and Unit 2.

Any DG, when aligned to an ESS bus, starts automatically on a loss-of-coolant accident (LOCA) signal (i.e., low reactor water level signal or high drywell pressure signal) or on a LOOP which could be the result of an undervoltage or sustained degraded grid voltage.

When a DG is connected to its respective ESS bus, LOCA mitigating loads are sequentially connected to the ESS bus by individual load timers, which control the permissive and starting signals to large motor circuit breakers. The ESS electrical loads are automatically loaded on the 4.16 kV busses connected to each DG in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a design basis accident. Based on performance indicator data submitted to the NRC, ESS DG unavailability at SSES 1 and 2 improved from 1.2 percent to 0.5 percent from the 4th Quarter 1999 to the 1st Quarter 2003.

PPL also indicated that a backup to the 125 V direct current (DC) batteries is provided by a portable 125 kilowatt (kW) DG (termed the “Blue Max”). Specifically, PPL stated as follows: the Blue Max has been specifically designed for station blackout (SBO) and is stored outside the DG building. It has been designed to provide 480 V AC power to four of the 125 V DC battery chargers (two per unit) in order to ensure DC power endurance beyond the 4-hour SBO coping requirement. Operation of the generator requires cables to be installed from the generator to motor control center cubicles in the diesel bays. A procedure is used to instruct tie-in of the portable diesel. Procedures are also being revised which support tie-in of the portable diesel for scenarios other than SBO.

PPL stated that the ST No. 10 replacement is scheduled for October 2003, based on a planned work window during which ST No. 20 is available for service and other plant equipment will support operation with a single offsite source. In this regard, PPL indicated as follows: October is also preferred due to generally favorable weather conditions, resource availability, and coordination with other major equipment deliveries to Susquehanna. The request for approval of a period from October to December 31, 2003, is a contingency action based on the possibility that required equipment may not be available during the planned work window in October, but may become available subsequently. The termination date of December 31, 2003, is based on the higher potential for unfavorable weather conditions in the winter versus the fall to support the ST No. 10 replacement.

PPL stated that the proposed changes do not require any new operator response or introduce any new opportunities for human errors not previously considered. PPL explained as follows: experienced personnel will perform the ST No. 10 replacement. After the fall 2002 replacement of the ST No. 20 transformer, PPL conducted extensive root cause evaluation and self assessments of the change-out itself and have incorporated lessons learned into the engineering and work planning efforts of ST No. 10 replacement.

PPL will also implement contingency actions to have a second spare ST available for use in either the ST No. 10 or ST No. 20 location. According to PPL, this spare is at the plant site, and design change and work packages are being developed to support its use as a spare in either the ST No. 10 or ST No. 20 location.

In addition, PPL identified the following actions as regulatory commitments:

1. To minimize the transformer replacement time, experienced personnel will perform the transformer replacement.

2. The following mitigating measures will be taken, prior to and/or during the transformer replacement, to increase the ability to identify and take appropriate actions before a problem arises with ST No. 20:

   (a) Predictive maintenance trending data will be reviewed for ST No. 20.

   (b) ST No. 20 corrective maintenance work orders will be reviewed.

   (c) Engineering inspections of ST No. 20 for obvious signs of degraded conditions will be performed. These include (1) visual inspection of the high voltage bushings and other insulators daily, (2) daily thermography inspections, (3) daily monitoring of ST No. 20 and Bus 20 voltage levels, (4) daily engineering rounds of ST No. 20 to monitor overall performance.

   (d) Operator rounds will be increased to once-per-shift from once-per-day for ST No. 20 except for the bushing oil level check which will be done once-per-day.

   (e) High-risk activities within the confines of the plant that may result in a loss of ST No. 20 during ST No. 10 replacement will be prohibited.

   (f) High-risk grid activities that may result in a loss of ST No. 20 during ST No. 10 replacement will be prohibited.

   (g) For the duration of the ST No. 10 replacement, transmission and distribution operations will not grant any work requests that would jeopardize the reliability of ST No. 20. This includes, but is not limited to, canceling any requests that would cause ST No. 20 to operate in a radial manner.

   (h) Geomagnetic activity from solar storms will be monitored via forecasts prior to and during the replacement of ST No. 10.

   (i) Weather conditions and potential for external events will be monitored such as external fire or forest fire prior to and during the transformer replacement. The licensee will instruct field services to stop work if conditions warrant.

3. The PPL risk management process will assess the risk impacts of planned and emergent work during the ST No. 10 outage using the PRA model on which the amendment is based.

4. PPL will ensure consideration of prevailing conditions, including other equipment out of service, and implementation of compensatory actions to assure adequate defense-in-depth while ST No. 10 is replaced.

5. The following systems and components will be maintained available during ST No. 10 replacement to reduce the plant risk. Elective maintenance will not be performed on these systems and components. Any failed system or component will be returned to operable status as soon as possible. (Failed system/component shall be worked around the clock.) If one of these systems or components become unavailable or inoperable, PPL will immediately begin and promptly complete a risk evaluation to determine if the basis for the proposed one-time change to LCO 3.8.1 remains valid, and within 1 hour, contact the NRC resident inspector.

   (a) Station portable DG - “Blue Max”
   (b) DG A ESS 480 V motor control
   (c) DG B ESS 480 V motor control
   (d) DG A
   (e) DG B
   (f) DG C
   (g) DG D
   (h) DG E
   (i) U-1 125 V DC battery charger 0B516073
   (j) U-1 125 V DC battery charger 0B526073
   (k) U-1 residual heat removal (RHR) LOOP A injection OB isolation valve
   (l) U-1 RHR LOOP A injection flow control valve
   (m) U-1 RHR LOOP B injection flow control valve
   (n) U-1 RHR LOOP B injection OB isolation valve
   (o) U-2 125 V DC battery charger 0B516071
   (p) U-2 125 V DC battery charger 0B526071
   (q) U-2 RHR LOOP A injection OB isolation valve
   (r) U-2 RHR LOOP A injection flow control valve
   (s) U-2 RHR LOOP B injection flow control valve
   (t) U-2 RHR LOOP B injection OB isolation valve
   (u) U-1 RHR/RHRSW cross tie valves
   (v) U-2 RHR/RHRSW cross tie valves
   (w) U-1 high-pressure coolant injection (HPCI)
   (x) U-2 HPCI
   (y) U-1 reactor core isolation cooling (RCIC)
   (z) U-2 RCIC

6. Procedures will be strengthened to reflect PRA insights to ensure that model assumptions are valid. Procedure change requests have been initiated and were credited in the analysis. The procedures will be revised before October 2003.

7. If ST No. 20 degrades, PPL will immediately evaluate the impact to determine operability of ST No. 20.

On the basis of its review and the above, the NRC staff has determined that:

1. The redundant offsite power source and onsite sources of power will be available during the extended AOT for the planned replacement of ST No. 10.

2. PPL will establish risk-reducing provisions (i.e., for equipment in service) which will exist during the ST No. 10 replacement.

3. PPL's risk management process will assess the risk impacts of planned and emergent work during the ST No. 10 outage.

4. Regulatory commitments to implement other restrictions and compensatory measures during the extended AOT ensure the availability of the remaining sources of power and minimize the occurrence of an SBO.

In order to assure that these determinations remain valid during ST No. 10 replacement, implementation of the amendment has been conditioned on evaluation of any proposed change to PPL commitments 1-7, listed above, in accordance with the criteria set forth in 10 CFR 50.59(c)(2). Should the evaluation of such a proposed change show that one of the criteria is met, PPL will not make the change unless the NRC grants a license amendment authorizing the change. Based on the above, the NRC staff concludes from the deterministic perspective that the proposed TS changes do not affect PPL's compliance with GDC 17. Accordingly, the NRC staff concludes that PPL's proposed one-time change to SSES 1 and 2 TSs to replace the ST No. 10 by December 31, 2003, is acceptable.

3.2 Probabilistic Risk Assessment Evaluation

The NRC staff reviewed PPL's July 3, 2003, submittal using the three-tiered approach referenced in RG 1.174, RG 1.177, and Standard Review Plan (SRP) Chapter 16.1. The first tier of the three-tiered approach includes assessing the risk impact of the proposed change in accordance with acceptance guidelines consistent with the Commission's Safety Goal Policy Statement, as documented in RG 1.174 and RG 1.177. Under the first tier, the staff assesses the impact on operational plant risk based on the change in core damage frequency (ΔCDF) and the change in large early release frequency (ΔLERF). In addition, under the first tier, the staff evaluates plant risk while equipment covered by the proposed Completion Time is out of service, as represented by the incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP). In addition, the licensee should establish that the quality of the PRA is compatible with the safety implications of the proposed TS change and that the scope and level of the PRA are adequate to fully support the evaluation of the TS change. The staff also considered cumulative risk of the present TS change in light of past applications or additional applications under review along with uncertainty and sensitivity analyses with respect to the assumptions related to the proposed TS change.

The second tier involves identifying potential high-risk configurations that may exist if other equipment or systems (in addition to the equipment associated with the proposed change) were also taken out of service simultaneously, or subjected to concurrent testing. The purpose of the Tier 2 evaluation is to ensure that appropriate restrictions will be in place to prevent the occurrence of such high-risk configurations.

The third tier establishes a risk management program for the overall configuration and confirms that risk insights are incorporated into the decision making process before taking equipment out of service prior to or during the Completion Time. The third tier provides additional assurance over the second tier by identifying risk-significant configurations that may be encountered over

extended periods of plant operation. Licensees can implement the overall configuration risk management program (as referenced in RG 1.177) through the Maintenance Rule (10 CFR 50.65(a)(4)). Specifically, the Rule requires that, before performing any maintenance activity, PPL must assess and manage the potential risk increase that may result from a proposed maintenance activity.

The following subsections describe each tier and the associated reviews.

3.2.1 Tier 1: PRA Capability and Insights

3.2.1.1 PRA Quality

To determine whether the SSES 1 and 2 PRA used in the evaluation of the proposed ST replacement is of sufficient scope and detail, the NRC staff reviewed the information provided in the proposed amendment request and the findings of the SSES 1 and 2 individual plant examination (IPE) and individual plant examination of external events (IPEEE). In addition, the NRC staff reviewed the significance determination process (SDP) benchmark summary report for Susquehanna, which compared the SDP Phase 2 notebook to PPL's risk model results.

The SSES 1 and 2 IPE was submitted to the NRC on December 13, 1991. The NRC issued a safety evaluation (SE) for the SSES 1 and 2 IPE by letter dated October 27, 1997, stating that the NRC staff could not conclude that the SSES 1 and 2 IPE met the intent of Generic Letter (GL) 88-20. PPL responded with additional information and on August 11, 1998, the NRC staff issued a supplemental SE on the SSES 1 and 2 IPE. The supplement concluded that improvements identified in the original IPE had been implemented and that the PPL IPE was complete with respect to the information requested by GL 88-20 and met the objectives of the IPE program.

The NRC staff reviewed the SSES 1 and 2 IPEEE with a particular focus on the proposed extended Completion Time for ST No. 10. PPL submitted the IPEEE for SSES 1 and 2 on June 27, 1994. The NRC accepted the IPEEE by letter dated April 27, 1999, and found that PPL's IPEEE was complete regarding the information requested by GL 88-20, Supplement 4, and the IPEEE results were reasonable given the SSES 1 and 2 design, operation, and history.

PPL's PRA has subsequently been converted to the cutset and fault tree analysis (CAFTA) software. In addition, the equipment out of service (EOOS) plant configuration risk management tool has also been adopted by SSES 1 and 2. PPL stated that an electronic conversion to the EOOS/CAFTA format was made with the EOOS/CAFTA model results compared to the previous IPE model. To ensure consistency with the IPE model, PPL compared the results for CDF, LERF and the dominant cutsets. PPL stated the results for the EOOS/CAFTA model were comparable. PPL considers changes to the SSES 1 and 2 PRA as a calculation with changes documented through a PPL calculation procedure that complies with 10 CFR Part 50, Appendix B.

During August of 2002, the NRC staff and contractors compared the SSES 1 and 2 SDP Phase 2 notebook and PPL's risk model results to ensure that the SDP notebooks were generally conservative. The NRC staff noted that there was poor correlation between the Phase 2 SDP notebook and PPL's PRA.

The benchmarking team noted the following differences between the SSES 1 and 2 PRA and the SDP notebooks:

- The PRA definition of core damage was based on hydrogen generation from the cladding. Other PSAs assume core damage occurs when reactor water level is not maintained above the top of active fuel or 2/3 core height. This assumption affects success criteria for mitigating systems. For example, as a result of this definition, the SSES 1 and 2 PRA credited the control rod drive pumps as being capable of fulfilling the high pressure injection function and credited the RCIC pump following a stuck or open relief valve.

- The PRA did not carry containment failure prior to core damage forward to core damage. PPL classified this as a containment failure end state that was only an input to the level 2 PRA. Traditionally, containment failure is carried forward to core damage because the location of the failure is unknown; and, the containment atmosphere is dumped into the reactor building, which is likely to fail substantial core damage prevention equipment.

- Accident sequences that involved successful containment venting were considered a success and not carried forward to core damage. Traditionally, plants with “soft” containment vent paths do not necessarily consider these sequences as a success because the containment atmosphere is dumped into the reactor building at the point where the vent path ruptures, which is likely to fail substantial equipment necessary for reactor inventory makeup.

- The PRA assumed that the reactor water cleanup (RWCU) system was capable of removing decay heat from containment following an accident. This assumption is atypical for other BWR 4 PSAs reviewed during the benchmarking visits.

- The PRA modeled several operator actions with essentially zero failure probability.

On October 3, 2002, ST No. 20 was damaged by fire necessitating the replacement of ST No. 20. On October 8, 2002, the NRC staff issued a notice of enforcement discretion (NOED) that stated that the NRC would exercise discretion to not enforce compliance with the actions required by TS 3.8.1, AC Sources - Operating, for SSES Unit 1 and allow ST No. 20 to be replaced at power. In granting the NOED, the NRC staff considered improvements made to the SSES 1 and 2 PRA that considered some of the observations noted during the NRC staff’s benchmarking visit. At the time, model changes included the elimination of the RWCU and the control rod drive system (CRD) as high-pressure makeup sources.

The NRC staff also considered the following in granting the NOED: (1) the availability and satisfactory testing of ST No. 10, main transformer, and emergency safety system transformers; (2) the operable status of the four emergency diesel generators (EDGs) and the availability of a fifth EDG that could be substituted for any of the four; (3) the operability of the remaining offsite electrical source; (4) weather, generation supply, and solar magnetic

disturbance forecasts and the potential impact on the reliability of the remaining offsite power sources for the additional 4-day period; (5) improvements made to the SSES 1 and 2 PRA model; (6) the status of risk important systems; (7) the comprehensive number of compensatory actions undertaken to ensure the 4-day LCO extension did not result in a net increase in radiological risk; (8) that PPL indicated that ST No. 20 could be successfully replaced during the extended LCO; (9) and that the most likely cause of the failure of ST No. 20 had been identified and that no failure mechanisms common to ST No. 10 had been identified.

PPL stated that the staff benchmark findings were evaluated and the following permanent changes were subsequently made to the SSES 1 and 2 PRA.

- Eliminated the use of the RWCU as a means of removing decay heat.
- Eliminated the control rod drives (CRD) as a high-pressure makeup source.
- Revised the fuel temperature success criterion to 1800 degrees F.
- Revised the PRA model with the assumption that active components in the reactor building would not function following containment failure or containment venting.
- Extended the containment failure and containment venting sequences to include late injection.
- Revised the event trees and fault trees to address inventory and cooling concerns.
- Reviewed the emergency operating procedures (EOPs) and only credited operator actions that can reasonably be assumed to occur and where procedures exist.

In addition, PPL updated the LOOP initiation event frequency and LOOP recovery probabilities for the requested TS change to offsite power sources. The update resulted in a reduction of LOOP event frequency but the recovery of offsite power increased in duration. (This is consistent with recent NRC staff's observations with respect to LOOP frequency and recovery times). In addition to the updated LOOP event frequency, the SSES 1 and 2 PRA model LOOP frequency is now adjusted when one source of offsite power is unavailable.

PPL further stated that the SSES 1 and 2 PRA models the AC and DC systems, offsite power lines, startup transformers, 13 kV, 4 kV, 480 V, 120V instrument power, 250 and 125 V DC systems, EDGs A, B, C, D, and E and the 480 V portable Blue Max. Blue Max provides backup 480 V AC power to the 125 V DC battery chargers and was specifically designed for station blackout. The model used to support the proposed one-time Completion Time extension is based on a random maintenance model.

The SSES 1 and 2 PRA have not been peer-reviewed or previously certified by industry. The SSES 1 and 2 peer review is currently scheduled for October 6, 2003, which is prior to ST No. 10 replacement scheduled to start October 13, 2003. Because potential peer-review findings might impact the conclusions of the proposed amendment request and safety analysis, PPL provided the following regulatory commitment:

- Any potential findings which are substantive issues with respect to the proposed 10-day ST No. 10 replacement Completion Time will be assessed immediately by PPL with appropriate actions taken to ensure that the one-time 10-day Completion Time for the on-line replacement of ST No. 10 remains valid. If a

substantive issue related to the 10-day ST No. 10 replacement Completion Time is identified by the peer review, the NRC shall be informed of the issue and of the corrective action taken by PPL.

Based on the above information, the NRC staff considers the quality of the SSES 1 and 2 PRA analysis to be adequate when considered in conjunction with the licensee's stated compensatory measures and regulatory commitments. Therefore, the staff finds the proposed one-time licensee amendment to extend the offsite sources Completion Time to 10-days in support of ST No. 10 replacement to be acceptable.

3.2.1.2 Cumulative Risk

PPL indicated that there were no current risk significant amendments pending (or recently approved) for SSES 1 and 2. An earlier risk-informed review by the NRC staff involving the elimination of the HPCI automatic transfer to the suppression pool does not adversely affect this amendment request nor does the proposed one-time 10-day Completion Time impact the staff's earlier HPCI review.

3.2.1.3 PRA Results

One approach to demonstrate that the risk impact of the proposed change is acceptable is to show that the licensing basis meets the key principles set forth in RG 1.174 for the proposed change. One of these principles is to show that when the proposed change results in an increase in CDF or risk, the increased risk should be small. In addition, the impact of the proposed change should be monitored using performance measurement strategies. RG 1.174 and RG 1.177 provide acceptance guidelines for meeting the above principles. Specifically, those guidelines include values of ΔCDF, ΔLERF, ICCDP, and ICLERP. The risk metrics ICCDP and ICLERP suggested by RG 1.177 are used in addition to the metrics outlined in RG 1.174 for the evaluation of Completion Times which are entered infrequently and are temporary in nature.

With SSES 1 and 2 having five EDGs, three cases were analyzed:

(1) ST No. 10 operable/EDG E not available (DGs A, B, C, and D operable)

(2) ST No. 10 operable/EDG E available (DGs A, B, C, and D operable)

(3) ST No. 10 inoperable/EDG E available with compensatory measures (EDGs A, B, C, and D operable)

The first two cases provide risk insights into the benefit of having the EDG E available during ST replacement. The third case was designated as the preferred configuration during ST replacement. PPL's results for all three cases are reproduced below.

Case	CDF Unit 1 Unit 2	ΔCDF Unit 1 Unit 2	ICCDP Unit 1 Unit 2	LERF Unit 1 Unit 2	ΔLERF Unit 1 Unit 2	ICLERP Unit 1 Unit 2
(1)	5.32E-6 5.33E-6	—	—	2.59E-6 2.56E-6	—	—
(2) Base Case	2.46E-6 2.48E-6	—	—	1.00E-6 9.47E-7	—	—
(3)	2.52E-6 2.57E-6	6.00E-8 9.0E-8	1.64E-9 2.47E-9	2.06E-6 1.96E-6	1.06E-6 9.86E-7	2.90E-8 2.07E-8

Case (1) assumes ST No. 10 is operable and that EDG E is not available with EDGs A, B, C, and D operable. Case (2) requires the EDG E be available with ST No. 10 operable and EDGs A, B, C, and D operable. PPL used Case (2) as the base case for estimating the risk impact of replacing ST No. 10. The evaluation indicates a benefit of EDG E being available and capable of substituting for the EDGs A, B, C, or D (EDGs A, B, C, and D considered operable) during ST No. 10 replacement. Case (3) represents the configuration to be implemented by PPL during ST replacement. In Case (3), EDGs A, B, C, and D are operable, with EDG E also available and capable of replacing EDGs A, B, C, or D. Case (3) also includes compensatory measures to manage risk significant equipment identified by PPL's PRA analysis. Additional compensatory measures identified by PPL's deterministic analysis were not credited in PPL's PRA analysis.

PPL's results for ΔCDF, ΔLERF, ICCDP, and ICLERP show a small change in risk for the proposed 10-day ST replacement Completion Time. Previous startup transformer maintenance (including replacement) has been completed in less than 10 days. Therefore, a 10-day Completion Time should bound expected transformer replacement activities.

In the current licensee's base case analysis, CDF was estimated to be 2.46E-6/year for Unit 1 and 2.48E-6/year for Unit 2. LERF was estimated at 1.00E-6/year for Unit 1 and 9.47E-7/year for Unit 2. A comparison of the risk impacts for SSES 1 and 2 shows that the increase in ΔCDF is comparable with the RG 1.174 acceptance guideline of less than 1.0E-6/year (very small changes in CDF) with the values for ΔLERF approximately equal to the RG 1.174 (small changes in CDF) guideline of 1.0E-6/year.

PPL stated that several valve recoveries that impact LERF were not incorporated into the ST No. 10 Completion Time analysis. This resulted in more conservative values for LERF and ΔLERF. However, with additional recovery actions considered in the analysis, the estimated ΔLERF would be within the RG 1.174 acceptance guideline range of 1.0E-7 to 1.0E-6 with an estimated total LERF value significantly less than the RG 1.174 total LERF guideline of 1.0E-5/year.

In addition, deterministic compensatory measures are to be implemented by PPL that were not considered in PPL's risk analysis. These additional measures include the review of maintenance data for ST No. 20 prior to replacement activities, additional mitigating measure on grid and switchyard activities, external events monitoring (weather, flood, fire), and the

availability of a second spare ST that can be used in either the ST No. 10 or 20 locations. These additional compensatory measures would be expected to provide a further qualitative improvement in plant risk. In addition, once installed, the ST No. 10 replacement transformer should eliminate any potential failure modes similar to the previous failed ST No. 20, provide greater design margins, and enhance offsite power supply reliability.

Based on the above, the staff considers the ΔLERF values for SSES 1 and 2 to be within the guidelines of RG 1.174 and are therefore acceptable. The estimated values for ICCDP and ICLERP are also comparable with the RG 1.177 ICCDP and ICLERP guidelines of less than 1.0E-7 and 5.0E-8, respectively, and are also acceptable.

3.2.1.4 PRA Uncertainty

As discussed in RG 1.174 and NUREG/CR-6141, "Handbook of Methods for Risk-Based Analyses of Technical Specifications," PPL can perform sensitivity studies to provide additional insights into the uncertainties related to the proposed Completion Time extension and demonstrate conformance with the guidelines and evaluate uncertainties related to modeling and completeness issues.

A comparison of Case (3) with the results of Case (1) show that the CDF and LERF are less for Case (3) (the configuration proposed for transformer replacement). Based on PPL's analysis, the EDG has more impact to reduce risk than the ST has to increase risk (a LOOP having the largest contribution to CDF and LERF). Generally, reducing the redundancy of the ST has less impact than ensuring onsite power sources are available (defined plant configuration with additional compensatory measures), and therefore, no additional sensitivity analysis was performed by PPL. Based on the above, the NRC staff finds that PPL's analysis to assess uncertainties related to the proposed Completion Time extension is acceptable.

3.2.1.5 External Events

PPL qualitatively evaluated the impact of external events on the proposed one-time ST Completion Time. The evaluation considered seismic events, internal and external fires, and external floods.

For a seismic event, PPL assumed that offsite power would be lost for a significant seismic event and that ST No. 10 and 20 would be lost due to the similar construction of both transformers. Therefore, the inoperability of ST No. 10 due to replacement would have a negligible impact on a LOOP due to a seismic event. In addition, the seismic hazard for SSES 1 and 2 is very low and does not significantly impact the risk for a one-time Completion Time extension for ST No. 10.

As stated in the NRC technical evaluation report (TER), dated December 1998, included with the NRC staff's IPEEE SE, dated April 27, 1999, a significant weak point in the fire analysis involved PPL's assumption that the severity of a fire and the probability of suppression failure are independent, which led to the calculation of a small CDF for all fire scenarios. The NRC staff's SE also stated that the ranking of fire scenarios was based on the relative values of CDF and not the absolute values. The NRC staff's SE concluded that since the same treatment was applied consistently across all significant fire scenarios, the impact on the relative ranking of fire

scenarios may be minimal. As set forth in the SE, the NRC staff therefore concluded that despite the improper assumption, PPL had, in fact, identified the significant fire scenarios and dominant accident sequences and had not missed any potential fire vulnerabilities at the plant.

The NRC staff's IPEEE SE stated that PPL originally estimated a fire CDF of 1.0 E-9 per refueling cycle (up to18 months), which was significantly smaller than CDF values reported by other comparable studies of similar plants. The reason for this smaller CDF, as stated in PPL's response to a request for additional information (RAI), dated February 27, 1998, was that the small human-error probabilities used in the original IPE internal events analysis led to the small overall CDF estimate for fire events. During the IPEEE review, PPL performed additional analyses of the dominant fire scenarios using new screening criteria and revised human-error probabilities. The methodology and results were reviewed during a staff site audit during the IPEEE review. As a result of the concerns that were raised with regard to assumptions about independence among events, PPL subsequently performed a sensitivity analysis on the upper cable spreading rooms, which resulted in an estimated fire CDF of 2.4E-7 per reactor year for this area. This CDF was found to be three orders of magnitude greater than the CDF originally reported for this area. The NRC staff's SE of April 27, 1999, noted that although PPL did not perform additional sensitivity analyses to revise the results for all other scenarios, similar results could be anticipated for those scenarios. The NRC staff concluded that there was an indication that the fire CDF estimate at SSES 1 and 2 could be three orders of magnitude higher than the originally reported CDF.

PPL stated that SSES 1 and 2 did not have a current fire PRA analysis. Because of this, PPL did not calculate the fire contribution to a LOOP but proposed additional compensatory measures to minimize the probability of a combination of an internal fire and a LOOP, to control fire risk during ST No. 10 replacement. PPL identified the following fire zones that have the potential to initiate a LOOP or other postulated transients. PPL stated that the identified areas were chosen to bound postulated fire-induced LOOP locations.

- Reactor building
- Control structure
- Turbine building
- EDG building
- Emergency service water pumphouse
- Circulating water pumphouse

PPL stated that during the proposed 10-day Completion Time to replace ST No. 10, the following regulatory commitments will be implemented with regard to the above areas.

- No planned "Hot Work" (grinding, welding, or open flame) will be performed.
- No planned maintenance on fire detection and/or suppression equipment, that would cause the fire detection and/or suppression equipment to be inoperable, will be performed during ST No. 10 replacement activities.
- For any emergent "Hot Work", consistent with SSES 1 and 2 standard practice in accordance with the "Hot Work" program, a continuous, independent fire watch will be stationed.
- Testing of fire detection and/or suppression equipment that would cause the equipment to be inoperable during testing, will be performed with a continuous independent fire watch.

For fires external to the plant, PPL's evaluation limited the vulnerability to the 500 kV-230 kV tie line to ST No. 20 as this is the source for offsite power during ST No. 10 replacement. PPL stated that routine clearing of the transmission right-of-way helps control this vulnerability; and, therefore, an external fire should have a minimal impact on LOOP CDF within the proposed one-time 10-day Completion Time for ST No. 10. PPL also stated that the 500 kV-230 kV tie line right-of-way is included in PPL's vegetation maintenance program that is intended to minimize the loss of the line due to vegetation or fire. The line was last inspected in May 2003 with tree trimming performed on July 5, 2003.

In addition, PPL provided the following as a regulatory commitment:

- For the duration of ST No. 10 replacement, transmission and distribution operations will not grant any work requests that would jeopardize the reliability of ST No. 20. This includes, but is not limited to, canceling any requests that would cause ST No. 20 to operate in a radial manner.

Based on the above, including PPL's additional compensatory measures and regulatory commitments, there is minimal impact on plant risk during the proposed Completion Time for ST No. 10 replacement due to fire.

PPL evaluated the impact of external events including flooding on the proposed ST No. 10 one-time Completion Time. PPL stated that the flood levels are significantly below plant grade level. Safety-related structures and facilities are considered secure from flooding; therefore, the risk impact on ST No. 10 replacement is insignificant. This is consistent with the finding of the IPEEE which considered external floods and high winds to be insignificant contributors to severe accidents.

3.2.2 Tier 2: Avoidance of Risk-Significant Plant Configuration

PPL's PRA analyses identified systems that could be in maintenance while ST No. 10 is being replaced. Based on PPL's evaluation, the following systems and components will be available (no preventive maintenance) during transformer replacement and are credited in PPL's PRA analysis.

- Portable station EDG - "Blue Max"
- EDG A ESS 480 V motor control
- EDG B ESS 480 V motor control
- EDG A
- EDG B
- EDG C
- EDG D
- EDG E
- Unit 1 125 V DC battery charger 0B516073
- Unit 1 125 V DC battery charger 0B526073
- RHR LOOP A injection OB isolation valve, (Unit 1)
- RHR LOOP A injection flow control valve, (Unit 1)
- RHR LOOP B injection flow control valve, (Unit 1)
- RHR LOOP B injection OB isolation valve, (Unit 1)

- Unit 2 125 V DC battery charger 0B516071
- Unit 2 125 V DC battery charger 0B526071
- RHR LOOP A injection flow control valve (Unit 2)
- RHR LOOP A injection OB isolation valve (Unit 2)
- RHR LOOP B injection OB isolation valve (Unit 2)
- RHR LOOP B injection flow control valve (Unit 2)

3.2.3 Tier 3: Risk-Informed Configuration Risk Management

RG 1.177 states that a licensee should develop a program to ensure that the risk impact of out-of-service equipment is appropriately evaluated before a maintenance activity is performed. Scheduling of maintenance and surveillance testing with ST No. 10 out of service will be evaluated and controlled according to the Maintenance Rule (10 CFR 50.65(a)(4)).

PPL has implemented online work control procedures which provide for an integrated review to identify risk-significant plant configurations prior to entering maintenance activities. PPL's work control procedure is applicable to both planned maintenance activities and emergent conditions during plant operations. PPL stated that during ST No. 10 replacement, the PRA model as modified for transformer replacement (including the availability of the EDG E, and compensatory measures) will be used to assess the at-power risk in accordance with the Maintenance Rule (10 CFR 50.65(a)(4)).

The NRC staff finds that PPL's program to control risk is capable of adequately assessing the activities being performed to ensure that high-risk plant configurations do not occur and/or compensatory actions are implemented if a high-risk plant configuration or condition should occur (including existing procedure implementation, equipment protection, or expedited equipment restoration). As such, PPL's program addresses Tier 1, 2 and 3 in RG 1.177.

3.3 Conclusions Regarding the Evaluation of Deterministic and PRA Aspects

The risk impact of the proposed one-time 10-day Completion Time for the replacement of ST No. 10, as reflected in ΔCDF, ΔLERF, ICCDP, and ICLERP, is consistent with the acceptance guidelines specified in RG 1.174, RG 1.17, and staff guidance outlined in Chapter 16.1, "Risk-Informed Decisionmaking: Technical Specifications," of NUREG-0800. The Tier 2 evaluation identified the applicable risk-significant plant equipment outage configurations needing compensatory measures that will be implemented by the licensee prior to and during ST No. 10 replacement. In addition, the deterministic evaluation identified additional equipment limitations while ST No. 10 is being replaced. PPL has also committed to implement additional compensatory measures to address the deterministic equipment limitations. Therefore, the NRC staff finds that the risk analysis methodology and approach used by the licensee (in conjunction with additional compensatory measures and regulatory commitments), to estimate the risk impacts are reasonable and of sufficient quality.

Based on the above, the NRC staff finds the proposed one-time change to revise the Completion Time of required actions of TS 3.8.1, "AC Sources Operating," associated with one offsite circuit inoperable to support the replacement of ST No. 10 to be acceptable.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Pennsylvania State official was notified of the proposed issuance of the amendments. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding (68 FR 43392). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

6.0 CONCLUSION

The Commission has concluded based on the considerations discussed above that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

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