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U. S. Nuclear Regulatory Commission
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SUSQUEHANNA STEAM ELECTRIC STATION
AMENDMENT REQUEST NO 305 TO UNIT 1 LICENSE NPF-14
AND AMENDMENT REQUEST NO 276 TO UNIT 2 LICENSE NPF-22:
ONE-TIME EXTENSION TO TECHNICAL
SPECIFICATION 3.8.1 ALLOWABLE COMPLETION
TIME FOR OFFSITE AC CIRCUITS **Docket Nos. 50-387**
PLA-6480 **and 50-388**

Pursuant to 10 CFR 50.90, PPL Susquehanna, LLC hereby requests an amendment to the Susquehanna Steam Electric Station (SSES) Unit 1 and Unit 2 Technical Specifications (TS). The proposed amendments would change the Technical Specifications 3.8.1 for AC Sources - Operating, to extend, on a one-time basis, the allowable Completion Time for Required Action A.3 for one offsite circuit inoperable, from 72 hours to 10 days. This change is needed to allow sufficient time for the replacement of Startup Transformer Number 20 (ST No. 20), while both units remain at power. The reason for the replacement of ST No. 20 is to ensure continued long-term reliability of the Offsite Power Systems.

The justification for this change to TS 3.8.1 Required Action A.3 Completion Times is based upon a risk-informed, deterministic evaluation presented in the Enclosure. The guidance in Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," has been followed. The incremental changes in Core Damage Probability (ICCDP) and Large Early Release Probability (ICLERP) are small.

PPL Susquehanna (PPL) requests approval of these proposed one-time changes to the SSES Technical Specifications by September 1, 2009 to support replacement of the ST No. 20 transformer, currently scheduled to begin on September 14, 2009. This one-time change would be effective from the date of issuance until midnight December 31, 2009. Similar precedent has been established for granting a one time extension of the TS Completion Time at Comanche Peak in 2001, and at PPL Susquehanna in 2002 and 2003, via a license amendment.

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PPL has concluded that the insulation capability of the H1 bushing on the ST No. 20 transformer has experienced and, potentially continues to experience physical degradation. Based on discussions with Doble Engineering, the most likely failure mechanism is moisture intrusion. Insufficient data exists to predict a time to failure for the H1 bushing. Based upon information gathered regarding the bushing's condition to date, PPL expects that the requested date of September 1, 2009 will adequately support the transformer replacement effort. Should continued monitoring indicate a different predictive outcome, PPL will notify the NRC as soon as possible.

Attachment 1 contains the proposed Unit 1 and Unit 2 Technical Specifications marked-up. Attachment 2 is a mark-up showing the changes to the Technical Specification Bases, provided for information. Attachment 3 lists the PPL commitments that would derive from NRC's approval of the proposed amendment. Attachment 4 describes the Probabilistic Risk Assessment (PRA) Peer review open B-Level Facts and Observations (F&Os) and their impact on this application. Attachment 5 describes the six remaining PRA self-assessment open items not categorized as "negligible" and their impact on this application.

The proposed changes have been reviewed by the SSES Plant Operations Review Committee and the Susquehanna Review Committee. In accordance with 10 CFR 50.91(b), PPL Susquehanna LLC is providing the Commonwealth of Pennsylvania with a copy of this proposed License Amendment request.

Should you have any questions or require additional information, please contact Ms. Brenda W. O'Rourke at (570) 542-1791.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on: 3/24/09

W. H. Spence

Enclosure:

PPL Susquehanna Evaluation of Proposed One-Time Extension to Technical Specification 3.8.1 "AC Sources – Operating"

Attachments:
Attachment 1 – Proposed Units 1 & 2 Technical Specification Changes (Mark-up)
Attachment 2 – Proposed Units 1 & 2 Technical Specifications Bases Changes (Information Only)
Attachment 3 – List of Regulatory Commitments
Attachment 4 – Open B-Level F&Os
Attachment 5 – Self-Assessment Open Items

Copy: NRC Region 1
Mr. R. Janati DEP/BRP
Mr. F. Jaxheimer, Sr. Resident Inspector
Mr. B. Vaidya, NRC Project Manager

Enclosure to PLA-6480

PPL Susquehanna Evaluation of Proposed One-Time Extension to Technical Specification 3.8.1 "AC Sources – Operating"

REQUEST FOR A ONE-TIME AMENDMENT TO TECHNICAL SPECIFICATION 3.8.1 "AC SOURCES – OPERATING" TO ALLOW AN EXTENSION OF COMPLETION TIME OF REQUIRED ACTIONS FOR OFFSITE AC CIRCUITS

1.0 DESCRIPTION

The proposal would change the Unit 1 and Unit 2 Technical Specification (TS) 3.8.1 for AC Sources – Operating, to extend the allowable Completion Time for the Required Actions associated with one offsite circuit inoperable due to the replacement of Startup Transformer Number 20 (ST No. 20). The requested changes are based upon the Susquehanna Steam Electric Station (SSES) plant specific risk-informed and deterministic evaluations performed in a manner consistent with the risk-informed approaches endorsed by Regulatory Guide 1.177 "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications" (Reference 1). The proposed changes would allow sufficient time for the planned replacement and testing of ST No. 20, while both units remain at power.

2.0 PROPOSED CHANGE

The proposed change to SSES Units 1 and 2 TS would allow for a one-time only extension of LCO 3.8.1 Action A.3 to 10 days during replacement of ST No. 20, while both units remain at power. In order to effect this one-time change, TS 3.8.1 "AC Sources – Operating" would be revised by modifying the Completion Time for Required Action A.3. The modification includes a new Completion Time, which reads "10 days for a one-time outage for replacement of Startup Transformer Number 20 to be completed by midnight on December 31, 2009." This new Completion Time will be connected with a logical connector "OR." The changes to TS 3.8.1 are marked-up on Technical Specification pages in Attachment 1.

Upon approval of the proposed change, PPL Susquehanna will revise TS Bases 3.8.1 under the Technical Specifications Bases Control program, by inserting the information below (see Attachment 2).

> A temporary Completion Time is connected to the Completion Time requirements above (72 hours AND 6 days from discovery of failure to meet LCO) with an "OR" connector. The temporary Completion Time is 10 days and applies to the replacement of Startup Transformer Number 20. The temporary Completion Time of 10 days expires at midnight on December 31, 2009. If during the conduct of the prescribed Startup Transformer Number 20 replacement, should any combination of the remaining operable AC Sources be determined inoperable (on an individual unit basis), current TS requirements would apply.

Marked-up Technical Specification pages and marked-up Technical Specification Bases pages, which incorporate the proposed changes, are provided in Attachments 1 and 2, respectively. Attachment 3 is the list of regulatory commitments. Attachment 4 describes the Peer review open B-Level F&Os and their impact on this application. Attachment 5 describes the six remaining self-assessment open items not categorized as "negligible" and their impact on this application.

3.0 BACKGROUND

On October 13, 2008, the results of insulation testing of the Startup Transformer Number 20 (ST No. 20) H1 bushing indicated that the H1-C1 power factor test results had increased from 0.47% (in 2002) to 0.77% in 2008. In addition, the H1-C2 power factor test results for the same bushing had increased from 0.48% (in 2002) to 0.90% in 2008.

For the H1 bushing, the C1 insulation is the insulation from the center (main) conductor to the tap electrode. The C2 insulation is the insulation from the tap electrode to the C2 electrode and/or the bushing flange and ground sleeve. As explained below, C1 and C2 have different pass/fail criteria.

Regarding C1 insulation, Doble Engineering indicates that any Westinghouse Type O+ bushings with an absolute power factor value approaching 1.0% should be considered in questionable condition. Additionally, input from both Doble personnel and the bushing manufacturer indicates that a bushing with an indicated power factor approaching a power factor of 1.0% should be considered for replacement at the earliest practical time. As indicated above, the last tested C1 power factor reading for the H1 bushing was 0.77%, which indicates the bushing is degraded and should be considered for replacement.

Regarding C2 insulation, Doble Engineering indicates that any Westinghouse Type O+ bushings with an absolute power factor value approaching 3.0% should be considered in questionable condition. The last tested C2 power factor reading for the H1 bushing was 0.90%, which indicates the bushing is slightly degraded and should be considered for replacement.

Doble testing also provides capacitance measurement data. Capacitance data provides information on the dielectric strength of the bushing insulation and can be a measure of partial discharge (i.e., insulation breakdown). PPL reviewed the capacitance measurement data for the ST No. 20 H1 bushing from 2002 and 2008, and concluded that values were acceptable. Therefore, no insulation problems for the H1 bushing were indicated by the capacitance data.

An additional measure of bushing integrity can be provided by a thermography inspection. PPL reviewed the thermography data for ST No. 20 and the H1 bushing from 2003 to present. No abnormal change in H1 bushing temperature was noted.

Based on the above data, PPL has concluded that the insulation capability of the H1 bushing has experienced and, potentially continues to experience physical degradation. Based on discussions with Doble Engineering, the most likely failure mechanism is moisture intrusion and not a partial discharge in the bushing insulation. There is insufficient data available to predict a time to failure for the bushing. What is known is that a condition caused by moisture intrusion typically takes a longer period of time to manifest itself as a failure, than a condition such as a partial discharge.

ST No. 20 is considered operable and capable of performing its design function with the noted deficiency present. Currently, no compensatory actions are in place to maintain its operability. However, in accordance with vendor recommendations, elevated power factors on the H1 bushing places the bushing in a condition that requires "additional investigation." This could be accomplished by Doble testing at an increased frequency in an effort to quantify any rate of change in the power factor. Due to the importance of ST No. 20, this approach is not considered a practical option from a risk standpoint, since its failure would results in a dual unit shutdown.

Replacement Transformer

The current ST No. 20 transformer will be replaced with the rebuilt ST No. 20 transformer that failed in 2002. Ohio Transformer re-designed the failed transformer to include a new coil and core assembly, rewound series transformer, new design Load Tap Changer, internal surge suppression, and new bushings. The new Ohio Transformer was designed utilizing the latest Institute of Electrical & Electronics Engineers (IEEE) standards.

3.1 System Description

The SSES Class 1E AC Electrical Power Distribution System sources consist of two offsite power sources, and the onsite standby diesel generator (DG) power sources, DGs A, B, C, and D. A fifth DG, E, can be used as a substitute for any one of the four DGs A, B, C or D.

As required by 10 CFR 50, Appendix A, GDC 17, the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Features (ESF) systems.

The Class 1E AC distribution system is divided into four load groups. 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 DG. A detailed description of the offsite power network and circuits to the Class 1E system can be found in the SSES FSAR Section 8.2.

3.1.1 Availability of Offsite Power Systems

The two offsite power sources each consist of a circuit between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System. The offsite power sources are independent. A 230 kV line from the Susquehanna T-10 tap 230 kV switchyard feeds Startup Transformer Number 10 (ST No. 10) and a 230 kV tap from the 500-230 kV tie line feeds ST No. 20.

ST No. 10 and ST No. 20 each provide the normal source of power to two of the four 4.16 kV Engineered Safeguards Systems (ESS) buses in each SSES 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. 20, the second offsite power source will not be available. Therefore, ST No. 10 will provide power to each of the four 4.16 kV ESS buses (A, B, C and D) in each unit (8 total buses) for both Unit 1 and Unit 2, respectively.

The Susquehanna T-10 230 kV Switchyard is supplied by two 230 kV transmission lines, the Mountain-Susquehanna and the Montour-Susquehanna lines. A total of three 230 kV circuit breakers are electrically configured in a ring bus connecting the Mountain-Susquehanna 230 kV line and Montour-Susquehanna 230 kV line to the ST No. 10 providing optimum reliability and redundancy.

3.1.2 Reliability of the Offsite Power Systems

Based on interruptions to ST No. 10, which were caused by disturbances along the 47 mile Montour-Mountain Line, the power supply for the 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, accidental bumping and to provide physical separation of ST No. 10 and ST No. 20 relaying equipment.

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 (through ST No. 10) remained operable.

3.1.3 Loss of Offsite Power (LOOP)

The only SSES LOOP event occurred in 1984 during Unit 2 pre-operational testing. It was due to the unique configuration of the preoperational testing, and only impacted Unit 2.

3.1.4 Availability of Onsite Power Systems

The onsite standby power source for 4.16 kV ESS buses A, B, C and D consists of five DGs. DGs A, B, C and D are dedicated to ESS buses 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 buses - 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 Loss of Offsite Power (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. This loading sequence prevents overloading of the DG during accident scenarios. 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 (DBA).

3.1.5 Reliability of Onsite Power Systems

SSES has a highly reliable and available Emergency Diesel Generator system. This is based on actual SSES DG reliability data and SSES Probabilistic Risk Assessment calculations. The PPL Susquehanna quarterly Mitigating Systems Performance Index (MSPI) data reported to the NRC for Emergency AC Power Sources has consistently been at the upper end of the green band.

3.1.6 Station Blackout (SBO) EDG Capacity

SSES is able to withstand and recover from a SBO event of 4 hours, as described in Section 15.9 of the Susquehanna FSAR (Reference 2). Beyond 4 hours, a portable AC generator (Blue Max) is used as a power supply for the 125 VDC battery chargers, which supply DC loads necessary to maintain core cooling and to restart the diesel generators.

The Blue Max has been specifically designed for Station Blackout and is located outside the diesel generator building. It has been designed to provide 480 Volt AC power to four of the 125 VDC battery chargers (two per unit) in order to ensure DC power endurance beyond the 4 hour Station Blackout coping requirement. Operation of the generator requires cables to be installed from the generator to motor control center cubicles in the diesel bays. Plant procedures are used for tie-in of the Blue Max. Procedures also exist for utilizing the Blue Max for non-SBO scenarios.

3.2 FSAR References

Related background in the SSES FSAR (Reference 2) is found primarily in Section 1.2 and Section 8. Compliance with NRC design criteria is described in detail in FSAR Section 8.3.2.2, "Analysis." Onsite power systems are described in FSAR Section 8.3 and Station Blackout is described in Section 15.9 of the FSAR.

3.3 Precedent

The proposed change is consistent with the following NRC approved precedent submittals:

- On October 10, 2003, the NRC issued an amendment to SSES Units 1 and 2 regarding a one-time extension of the completion time for TS 3.8.1, Action A.3, from 72 hours to 10 days. The one-time extension was needed for the planned replacement of Startup Transformer No. 10.

- On October 3, 2002, SSES experienced a catastrophic failure of ST No. 20. PPL was granted enforcement discretion from the 72-hour completion time for TS 3.8.1, Action A.3, to allow an additional 4 days to replace the affected transformer.

- On October 9, 2001, the NRC issued an amendment to the Comanche Peak Steam Electric Station Units 1 and 2 Technical Specifications regarding an Extended Outage Time for repair of a Startup Transformer. The amendment allowed 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 21 days.

4.0 TECHNICAL ANALYSIS

The proposed changes have been evaluated and it has been determined that current regulations and applicable requirements continue to be met, that adequate defense-in-depth and sufficient safety margins are maintained, and that any increases in the Incremental Conditional Core Damage Probability (ICCDP) and Incremental Conditional Large Early Release Probability (ICLERP) are small and consistent with the NRC Safety Goal Policy Statement (Reference 3), and the acceptance criteria in Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," (Reference 1).

The justification for the use of a 10-day offsite circuit extended Completion Time is based upon a combined risk-informed and deterministic evaluation consisting of four main elements: 1) the availability of the redundant offsite power source and availability of onsite sources of power, 2) the risk-reducing requirements (i.e., equipment required to be in service) which will exist during the ST No. 20 replacement, 3) the Probabilistic Risk Assessment to demonstrate that the increases in incremental core damage probability and incremental large early release probability are small, and 4) the SSES risk management process which will assess the risk impacts of planned and emergent work during the ST No. 20 replacement.

4.1 Deterministic Considerations

The unavailability of one startup transformer is already considered in the plant design and is allowed by the current Technical Specifications. The increased outage time for a startup transformer has no effect on the capability of the other startup transformer to supply the required safety-related loads of both units if it becomes necessary to safely shut down both units simultaneously. The design basis is the ability to mitigate a LOCA in one unit, while shutting down the other unit.

SSES is designed and operated consistent with the defense-in-depth philosophy. The units have diverse power sources available (e.g., Emergency Diesel Generators and Startup Transformers to cope with a loss of the preferred AC source (i.e., offsite power)). During the ST No. 20 replacement, AC power will be supplied to the ESS buses from ST No. 10, which will not be affected by ST No. 20 replacement activities. The replacement of ST No. 20 will further ensure continued long-term reliability. It is therefore, acceptable, under certain controlled conditions, to extend the Completion Time and replace the ST No. 20 to maintain the reliability of the offsite emergency power systems.

The defense-in-depth philosophy in reactor design and operation results in multiple means to accomplish safety functions and prevent release of radioactive material. The impact of the proposed Technical Specification changes were evaluated and determined to be consistent with the defense-in-depth philosophy.

Even with the ST No. 20 out of service, there are multiple means to accomplish safety functions and prevent release of radioactive material. The Evaluation of Risk Impact (see Section 4.2 below) confirms the results of the deterministic analysis; i.e., the adequacy of defense-in-depth and that protection of the public health and safety are ensured. System redundancy, independence, and diversity are maintained commensurate with the expected frequency and consequences of challenges to the system. Implementation of the proposed changes will be done in a manner consistent with the defense-in-depth philosophy. 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. 20 is replaced. No new potential 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.

These proposed changes do not require any new operator response or introduce any new opportunities for human errors not previously considered. Experienced personnel will perform the ST No. 20 replacement within the time available, while both units remain on-line. No other new actions are necessary.

The acceptability of the extended duration is supported by the following deterministic enhancements.

- Predictive maintenance trending data will be reviewed for ST No. 10, prior to the replacement.

- Review of ST No. 10 corrective maintenance work orders will be performed prior to the replacement.

<u>Grid and Switchyard Restrictions</u>

In addition to the predictive maintenance trending and corrective maintenance work order review above, 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. 10:

- Engineering Inspections of ST No. 10 for signs of degraded conditions will be performed. These will include:

  - Daily visual inspection of the high voltage bushings and other insulators on ST No. 10.
  - Perform periodic thermography inspections of ST. No. 10.
  - Trend ST No. 10 and Bus 10 voltage levels and monitor daily.

- Perform daily engineering rounds of ST No. 10 to monitor overall performance.

- Engineering to trend Operator Rounds data for ST No. 10 on a weekly basis.

- Operator Rounds (enhanced based on the INPO SOER 02-3) will be increased to once per shift from once per day for ST No. 10, except for the bushing oil level check which will be done once per day.

- Activities within the confines of the plant that could result in a loss of ST No. 10 during the ST No. 20 replacement will be prohibited.

- Activities that could result in a loss of ST No. 10 during the ST No. 20 replacement will be prohibited.

- For the duration of the ST No. 20 replacement, the Transmission Power System Dispatcher will <u>NOT</u> grant any work requests that would jeopardize the reliability of ST No. 10. This includes, but is not limited to, canceling any requests that would cause ST No. 10 to operate in a radial manner.

<u>External Events Monitoring</u>

Per normal operating procedures, the control room will monitor weather conditions and the potential for external events such as external flood, brush or forest fire prior to and during the transformer replacement. The control room will instruct the appropriate PPL personnel to stop work on ST No. 20 if conditions warrant.

Additionally, geomagnetic activity from solar storms will be monitored via forecasts provided to the PJM Interconnection, prior to and during the replacement of ST No. 20.

<u>Contingency Planning (Work Planning Actions)</u>

The ST No. 20 replacement is scheduled for September 14, 2009, based on a planned work window during which ST No. 10 is available for service and other plant equipment will support operation with a single offsite source. September is also preferred due to generally favorable weather conditions, resource availability, and coordination with other major equipment deliveries to Susquehanna. This work will also be performed following the PJM Peak Period Maintenance Season, which is June 15 through September 11, 2009.

PPL Susquehanna has a high level of confidence in its ability to implement a pre-planned replacement of ST No. 20 within the requested Completion Time for Required Actions of 10 days. This confidence is based on a number of factors:

- PPL Susquehanna has previously replaced ST No. 10 in less than 10 days, as a pre-planned evolution in 2003.

- PPL Susquehanna replaced a similar ST No. 20 Startup Transformer, on an emergent basis, in slightly over 7 days, after the transformer experienced an in-service failure in the Fall of 2002. The nature of the 2002 ST No. 20 failure required additional work that will not be required as part of the September 2009 planned ST No. 20 replacement.

The planned evolution will be supported by the transformer manufacturer, Ohio Transformer, and a specialty rigging contractor, Aycock, in order to augment PPL's technical expertise.

Prohibitions on Preventive Maintenance

Risk analyses were performed and the higher frequency cut sets involving systems, which could potentially be in preventive maintenance, were examined to determine which systems would be required to be available during the planned work. The following systems and components are required to be available during the ST No. 20 replacement to reduce the plant risk:

DESCRIPTION
STATION PORTABLE DIESEL GEN - BLUE MAX
DIESEL GENERATOR A ESS 480V MOTOR CONTROL
DIESEL GENERATOR B ESS 480V MOTOR CONTROL
DIESEL GENERATOR 'A'
DIESEL GENERATOR 'B'
DIESEL GENERATOR 'C'
DIESEL GENERATOR 'D'
DIESEL GENERATOR 'E'
U-1 125V DC BATTERY CHARGER 1D613
U-1 125V DC BATTERY CHARGER 1D623
RHR LOOP A INJECTION OB ISO VLV, (Unit 1)
RHR LOOP A INJECTION FLOW CONTROL VLV, (Unit 1)
RHR LOOP B INJECTION FLOW CONTROL VLV, (Unit 1)
RHR LOOP B INJECTION OB ISO VLV, (Unit 1)
U-2 125V DC BATTERY CHARGER 2D613
U-2 125V DC BATTERY CHARGER 2D623
RHR LOOP A INJECTION FLOW CONTROL VLV, (Unit 2)
RHR LOOP A INJECTION OB ISO VLV, (Unit 2)
RHR LOOP B INJECTION OB ISO VLV, (Unit 2)
RHR LOOP B INJECTION FLOW CONTROL VLV, (Unit 2)
RHR/RHRSW CROSS TIE VALVES (Unit 1)
RHR/RHRSW CROSS TIE VALVES (Unit 2)
HPCI (UNIT 1)
HPCI (UNIT 2)
RCIC (UNIT 1)
RCIC (UNIT 2)

To ensure these systems and components are available, elective maintenance will not be performed and these risk significant systems will be maintained available. Any failed system/component will be returned to available status as soon as possible (The failed system/component shall be worked around the clock).

Should any of the above equipment or systems become unavailable, SSES will immediately begin and promptly complete a risk evaluation of the impact, to determine if the basis for this one-time change to LCO 3.8.1 remains valid, and within 1 hour of identification, contact the NRC Resident Inspector.

Additionally, should degradation of ST No. 10 be identified, SSES will immediately evaluate the impact and promptly complete an evaluation to determine operability of ST No. 10. If determined to be inoperable, Technical Specification requirements will be implemented.

4.2 Evaluation of Risk Impact

This section describes the Probabilistic Risk Assessment performed to support the proposed one-time increase in the allowable outage time for ST No. 20. The Probabilistic Risk Assessment supplements the deterministic evaluation presented in Section 4.1.

4.2.1 PRA Capability and Insights

This section contains information consistent with the guidance of Regulatory Guide 1.177, Section 2.3, Tier 1.

4.2.1.1 PRA Capability

This section provides a discussion of the capability of the Susquehanna Steam Electric Station (SSES) Probabilistic Risk Assessment model to evaluate the proposed extension of the Completion Time for ST No. 20. This section, along with Section 4.2.1.2, addresses information required by Tier 1 in NRC Regulatory Guide 1.177.

The SSES PRA is fully capable of assessing the risk effects of the proposed change. The change being considered is an extension of the Completion Time for Startup Transformer ST No. 20. The PRA explicitly models the AC and DC systems. The two offsite power lines (230kV), Startup Transformers (230kV to 13kV), the 13kV, the 1E 4kV, the 1E and non-1E 480V, the 120V instrument power, and 250 and 125VDC systems together with their dependencies on each other are modeled. The onsite power sources (emergency diesel generators) are also individually modeled. Susquehanna has four diesels (4000kW- A, B, C, D) supplying power to the 4 ESS busses in each unit. There is also a fifth diesel (5000kW - E) that can be manually switched into service if one of the onsite diesels fails. The switch can be accomplished in approximately ninety minutes, but is not credited in the model before four hours. In addition, there is a 480V portable diesel generator the "Blue Max," which can be used to supply power to the A and/or B 125VDC battery chargers via a manual connection. The four diesel generators and the fifth diesel along with the 480V portable diesel are all modeled.

The model uses a LOOP initiation fault tree that explicitly calculates the LOOP initiation frequency based on the equipment in service. Hence, the Susquehanna model is capable of assessing the risk effects of removing ST No. 20 from service.

Further discussion of the Susquehanna Steam Electric Station PRA capability and quality is given in Section 4.3.

4.2.1.2 Risk Evaluation & PRA Insights

This section provides the results of the Probabilistic Risk Assessment and details the risk insights pertaining to the proposed Completion Time for ST No. 20 outage. This section, along with Section 4.2.1.1, addresses information required by Tier 1 in NRC Regulatory Guide 1.177.

The SSES Station PRA model described in Section 4.2.1.1 was used to evaluate the risk impact of the increased Completion Time for the transformer ST No. 20 outage. The analyses were performed with the CAFTA/PRAQUANT computer programs. The analyses calculated various risk measures. The definitions of the risk measures are based on guidance from NRC Regulatory Guides 1.174 (Reference 4) and 1.177:

ΔCDF = Change in Core Damage Frequency (CDF)
ΔCDF = Difference in calculated CDF between the ST No. 20 Out-of-Service (OOS) case and the base case (ST No. 20 OPERABLE)

ICCDP = Incremental Conditional Core Damage probability
ICCDP = ΔCDF (years $^{-1}$) * requested Completion Time (years)

ΔLERF = Change in Large Early Release Frequency
ΔLERF = Difference in calculated LERF between the ST No. 20 OOS case and the base case (ST No. 20 OPERABLE)

ICLERP = Incremental Conditional Large Early Release Probability
ICLERP = ΔLERF (years $^{-1}$) * (requested Completion Time (years))

The following cases were analyzed with the SSES internal events PRA model for both Unit 1 and Unit 2:

	Case
Base	ST No. 20 OPERABLE / Random maintenance allowed except for systems listed in "Prohibitions on Preventive Maintenance" section
ST No. 20 Out of Service	ST No. 20 INOPERABLE / Random maintenance allowed except for systems listed in "Prohibitions on Preventive Maintenance" section

As noted previously, SSES has 5 diesel generators. Four diesel generators are normally aligned to their corresponding ESS buses (A, B, C, and D). The E-Emergency Diesel Generator is not required to be operable per the SSES Unit 1 and Unit 2 Technical Specifications, however, it can be used as a spare should one of the other diesel generators be in maintenance or otherwise unavailable.

The quantitative calculations of the at-power risk measures associated with the increased Completion Time for the planned ST No. 20 replacement use an aggregate of our internal events model and a fire input based on an approach originally developed for the SSES License Renewal Application and Extended Power Update Application.

The fire analysis is based on Unit 1 and does not credit automatic fire suppression. The fire analysis only credits manual fire suppression. The fire analysis performed assumes all fires, if not suppressed manually, progress to a large fire and it is assumed that all cables and equipment in the zone are damaged (i.e., not credited in the analysis).

To evaluate the impact of ST No. 20 replacement on the fire input, all fire zones where a fire was predicted to cause a LOOP (with ST No. 20 in service) had their core damage frequencies doubled. The doubling is to account for the situation that only one of the two off site sources needs to be damaged during the ST No. 20 replacement to produce a LOOP. In addition, a fire in one specific fire zone which did not cause a LOOP with ST No. 20 in-service, was found to cause a LOOP with ST No. 20 OOS. The impact of the LOOP in this fire zone, along with the other equipment failed due to the fire, was included in the analysis of the fire related CDF and LERF with ST No. 20 OOS. It should be noted that the fire input did not credit balance of plant equipment. Not crediting the BOP equipment is conservative since some of it may be functional after a fire. The internal events results and fire results are listed separately but the results are aggregated for comparison to the Regulatory Guide 1.177 criteria.

In addition to the quantitative calculations of the at-power risk measures associated with the increased Completion Time for the planned ST No. 20 replacement, the impacts of the proposed Completion Time increase for external events (external flooding and seismic events) were qualitatively evaluated.

Compensatory Measures for Probabilistic Risk Assessment

The "protected equipment program" will be invoked for the equipment which will not be electively removed from service, as listed in section 4.1, subsection Prohibitions on Preventive Maintenance.

At Power Risk Assessment

The quantitative results of the analysis for the internal events PRA are given in Table 4-1 for both Unit 1 and Unit 2. The results shown below for Unit 1 and Unit 2 are slightly different due to electrical design asymmetries between the units.

TABLE 4-1: Risk Results – Internal Events (includes flooding)

Risk Measure	Internal Events Only	
	Base	ST No. 20 OOS
Unit 1 CDF	1.31E-06	1.55E-06
Unit 1 LERF	6.41E-07	9.81E-07
Unit 2 CDF	1.28E-06	1.44E-06
Unit 2 LERF	6.09E-07	9.28E-07

The quantitative fire analysis results are given in Table 4-2 for Unit 1.

TABLE 4-2: Risk Results – Fire Analysis

Risk Measure	External Events – Fire Only	
	Base	ST No. 20 OOS
Unit 1 CDF	2.65E-06	5.24E-06
Unit 1 LERF	2.19E-07	4.40E-07

The aggregate quantitative fire analysis results are given in Tables 4-3 through 4-5 for Unit 1. The results for Unit 2 are expected to be similar.

TABLE 4-3: Aggregated Risk Results

Risk Measure	Internal Events Only		External Events – Fire Only		Aggregate	
	Base	ST No. 20 OOS	Base	ST No. 20 OOS	Base	ST No. 20 OOS
Unit 1 CDF	1.31E-06	1.55E-06	2.65E-06	5.24E-06	3.96E-06	6.79E-06
Unit 1 LERF	6.41E-07	9.81E-07	2.19E-07	4.40E-07	8.60E-07	1.42E-06

TABLE 4-4: Aggregated Risk Increase
10 day Completion Time on ST No. 20

Risk Increase	
Unit 1 Aggregate Delta CDF	2.83E-06
Unit 1 Aggregate Delta LERF	5.61E-07

TABLE 4-5: Incremental Conditional Increase in Probability
10 Day Completion Time on ST No. 20

Incremental Conditional Increase	
Unit 1 ICCDP (Aggregate)	7.76E-08
Unit 1 ICLERP (Aggregate)	1.54E-08

Comparison with Regulatory Guide 1.177 Criteria

The criteria given in RG 1.177, Section 2.4, for a "small change" in risk relating to the proposed Completion Time are:

a) ICCDP is less than or equal to 5.0E-7
b) ICLERP is less than or equal to 5.0E-8

As it can be seen from Table 4-5, the ICCDP and ICLERP are within the RG 1.177 criteria for the proposed 10 day Completion Time. The ICCDP is a factor of over 6 times lower than the RG 1.177 criterion and the ICLERP is a factor of over 3 times lower than the RG 1.177 criterion.

Sensitivity Studies

The SSES LOOP fault tree model addresses five LOOP initiators, extremely severe weather, severe weather, grid, plant center and switchyard. Since the work being performed on ST No. 20 will affect the plant centered LOOP initiator, a sensitivity study was performed by doubling the plant centered initiator frequency. The result of doubling the initiator frequency is a very small increase, less than 1 percent, in the Unit 1 internal events CDF with ST No. 20 out of service. Since the results of the Unit 1 sensitivity assessment on CDF showed little increase in CDF, sensitivities were not performed for Unit 2 CDF or LERF. Unit 2 is expected to have a similarly small increase in CDF, and the LERF for both units is even less sensitive than CDF to LOOP initiators.

Dual Unit Shutdown Issues

Extended Power Uprate (EPU) related modifications have been installed on Unit 1 which eliminate the need to swap suppression pool cooling between the units for certain scenarios. These modifications allow both divisions of ESW to supply cooling water to both Unit 1 C and D RHR pump motors.

Potential dual unit concerns were also examined which relate to common systems that may be needed by both units for a shutdown. The common systems credited in the PRA are the diesel driven fire pump, Emergency Service Water (ESW) and the Refueling Water Storage Tank (RWST). To account for the commonality of the diesel driven fire pump and the RWST, the PRA thermal-hydraulic analysis only credited one half the flow capacity of the diesel driven fire pump and one half the RWST water volume for each unit. ESW is designed to cool all of its loads in both units simultaneously.

Thus, with the existing Unit 1 modification to the RHR pump motor cooling, swapping pumps between units for certain scenarios is no longer required. In addition, only crediting one half the flow rate and one half the total capacity for each unit for common systems in the thermal-hydraulic calculations, and the fact that ESW is designed for simultaneous cooling of both units; there are no adverse dual unit shutdown concerns.

Evaluation of External Events

This section provides a qualitative evaluation of the impact of the external events on the proposed one-time increase in Completion Time for the ST No. 20 Transformer.
A specific evaluation was performed for seismic events, external fires, and external floods. Other external events are considered addressed by the PRA model because their effect is limited to a transient already included, e.g. Loss of Offsite Power.

Seismic

During the planned replacement of the ST No. 20 Transformer, only the ST No. 10 Transformer will be available to supply offsite power to the station. There is an insignificant plant risk associated with having a seismic event while the ST No. 20 Transformer is being replaced, due to the short duration of the replacement.

Based on lessons learned from earthquake events, transformers and substations in general have low to modest levels of seismic ruggedness. Thus, it is expected that the source of offsite power would be lost for a significant seismic event. Since the ST No. 10 and ST No. 20 Transformers are similar in their geometry and construction, it is likely that if one of them is lost during a seismic event, the other one would be lost as well. Therefore, having only one startup transformer available during the planned ST No. 20 replacement does not significantly increase the probability of a loss of offsite power (LOOP) due to a seismic event.

The SSES Seismic Margins Assessment (SMA) performed for the IPEEE explicitly assumed a Loss of Offsite Power. The two safe shutdown paths considered in the SMA are ones that are the most likely to be used following an earthquake. These two paths use the EDGs for AC power. For this reason, the Emergency Diesel Generators are the major source of AC power considered in the SMA.

The SMA showed that SSES is capable of safely shutting down for a 0.3G earthquake. The SSES design earthquake is 0.1G. The seismic hazard at the SSES site is very low. Therefore, the extended Completion Time for the planned ST No. 20 replacement does not significantly increase the probability of core damage or a large early release due to a seismic event.

Fires External to the Plant

During the planned replacement of the ST No. 20 Transformer, only the ST No. 10 Transformer will be available to supply offsite power to the station. There is an insignificant incremental risk to plant risk associated with having an external fire causing a loss of power to ST No. 10.

A potential vulnerability exists from brush or forest fires causing a loss of the 230 kV line supplying ST No. 10. The 230kV supply line only has one span (from the T-10 switchyard to the first transmission pole) that is outside the plant's security fence. The majority of the line is inside the security fence where the vegetation is minimal. The risk of fire outside the security fence affecting the 230kV supply line is also minimal since the routine process of clearing the trees from the transmission right-of-ways controls this vulnerability. Hence, any fires that do occur are not expected to produce enough heat, due to the amount of combustibles, to cause a power disruption. Therefore, an external fire does not significantly affect the probability of a LOOP and, hence, core damage or a large early release.

External Flooding

During the planned replacement of the ST No. 20 Transformer, only the ST No. 10 Transformer will be available to supply offsite power to the station. There is an insignificant incremental increase to plant risk associated with having an external flooding event while the ST No. 20 Transformer is being replaced.

Based on FSAR Section 2.4 which provides information regarding flooding due to the Probable Maximum Flood (PMF) of the Susquehanna River or the probable maximum precipitation on the area surrounding the plant, SSES is classified as a "dry" site with regard to external flooding events.

The PMF water elevation, coincident with wind-generated waves, for the Susquehanna River is defined as 548.0 feet MSL which is more than 120 feet below the site grade elevation of 670.0 feet MSL. The Susquehanna River is the only water system adjacent to SSES that could have an impact on onsite flooding and therefore is the only consideration, except for local runoff, in deriving the PMF-generated water elevation. Taking into consideration seismically induced dam failures upstream of the SSES plant and ice-jam related events, flood stages are comparable to the normal precipitation flood stages and appreciably lower than the PMF-related water level which is itself over 120 feet below the plant grade. Also, an onsite confirmatory walkdown during the IPEEE Project concluded there was no evidence to indicate any potential flooding vulnerabilities to safety-related facilities/structures due to local stormwater runoff.

Since the governing flood design level is significantly below the plant grade level, safety-related structures and facilities at SSES are considered to be secure from flooding and the incremental risk to plant risk while the ST No. 20 Transformer is being replaced is insignificant.

4.2.2 Avoidance of Risk Significant Plant Configurations

This section contains information consistent with the guidance of Regulatory Guide 1.177, Section 2.3, Tier 2.

Analyses using CAFTA/PRAQUANT were performed and the higher frequency cut sets involving systems which could potentially be in preventive maintenance were examined to determine which systems would be required to be available during the planned work. The list of items generated by this analysis is given in Section 4.1.

Other restrictions are imposed to further reduce the risk during performance of the ST No. 20 replacement. These grid and switchyard restrictions and external event monitoring are discussed in Section 4.1. It should be noted that these additional restrictions were not credited in the Probabilistic Risk Assessment in Section 4.2.1 and, thus, represent additional conservatisms.

4.2.3 Risk-Informed Configuration Management

This section contains information consistent with the guidance of Regulatory Guide 1.177, Section 2.3, Tier 3.

The Susquehanna Steam Electric Station performs at-power risk management in compliance with 10 CFR 50.65 (a)(4), the Maintenance Rule, which meets the intent of the Configuration Risk Management Program described in Regulatory Guide 1.177. The program provides a proceduralized risk-informed assessment to manage the risk associated with equipment unavailability. The program provides for the control and implementation of a Level 1 and Level 2 PRA-informed methodology. The program also has provisions for performing an assessment prior to entering an LCO for preplanned and unplanned activities. The program is capable of risk assessment of equipment-out-of-service whether the equipment is in the Technical Specifications or not. The risk assessment is performed using the EOOS software. This software quantifies the CDF and LERF tops to generate the risk results and re-quantifies the results whenever a configuration change is made (it does not use pre-generated cut sets).

In the event a risk threshold is exceeded, existing procedural requirements will be implemented, which can include protection of risk significant equipment and/or expedited equipment restoration.

During the ST No. 20 replacement, the model described in Section 4.2.1, which includes the detailed LOOP initiating event frequency fault tree and the effect of the 'E' Emergency Diesel Generator, will be used to evaluate the at-power risk profile for Unit 1 and Unit 2, in accordance with 10 CFR 50.65(a)(4).

4.2.4 Summary of Probabilistic Risk Assessment Results

The Probabilistic Risk Assessment evaluations and insights discussed above justify this one-time extension of the allowable outage time for the ST No. 20 Transformer (Unit 1 and Unit 2 Technical Specification 3.8.1 Action A.3 Completion Time). The calculated increase in risk as measured by ICCDP and ICLERP is within the guidelines of Regulatory Guide 1.177. Also, the calculated CDF and LERF values are within the range of values normally encountered for planned routine tests and maintenance activities. Restrictions on equipment availability and switchyard activities limit the increase in risk during the planned work.

4.3 PRA Quality

The SSES PRA is of sufficient quality and scope to measure the potential changes in plant risk related to ST No. 20 replacement. The SSES PRA modeling is highly detailed, including a wide variety of initiating events (e.g., transients, internal floods, LOCAs inside and outside containment, support system failure initiators), modeled systems, extensive level of detail, operator actions, and common cause events.

PPL had a BWROG Peer Review PRA in 2003. The major findings of this review are summarized below. The BWROG peer review provided PPL Susquehanna with Level B, C, D and S Facts and Observations (F&Os). PPL Susquehanna did not receive any A Level F&Os.

PPL has closed all but 7 of the 59 original Peer review B-Level F&Os. Attachment 4 describes the open B-Level F&Os and their impact on this application.

PPL also performed a self-assessment with ERIN Engineering in 2004 using the ASME PRA standard, ASME-RA-S-2002 and ASME RA-Sa-2003 and the NRC guidance included in Regulatory Guide 1.200 (Reference 5). The majority of the remaining open items were identified in the assessment as "the impact of this item on the ability to use the PRA in any application is considered negligible." Attachment 5 describes the six remaining self assessment open items not categorized as "negligible" and their impact on this application.

The open B-Level F&Os and Self Assessment Gaps fall into the general categories of pre-initiators, data update, documentation, operator actions, and uncertainties and key assumptions. The effect of model changes to address these open items would principally be to influence the base CDF and LERF values. However, considering the margin our base CDF and LERF values have to the guidance thresholds, the result of incorporating these open issues would not be expected to cause any of the guidance thresholds to be exceeded. The changes in delta CDF and delta LERF between the base case and ST No. 20 out of service case are not expected to be significantly affected as a result of incorporating the open items. This is expected since the changes would perturb the base case and the out of service case equally; i.e. there is no synergism expected between ST No. 20 being out of service and the open F&Os and Self – Assessment Gaps.

Model Structure

The fault tree model encompasses at-power internal events (including internal floods). The model utilizes a "single top" type linked fault tree model. It has separate tops for Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) for both Units 1 and 2.

Fidelity with the supporting event trees is preserved for both the failure branch and success branch in the single top model. The successes are the "not" of the failures. For a given event sequence, both the failures and the successes (characterized as "NOT" gates) are combined via an "AND" gate.

Assumptions

The truncation limit used was 1E-11. Note the base case random maintenance CDF is 1.96E-6 and with the current truncation limit all significant cut sets are included.

The fault tree model also includes common cause failures. The diesel generators are included in the common cause failures considered.

The model used to support this Completion Time change is based on a random maintenance model with the exception of the components listed in Section 4.2.1.2, for which no elective maintenance will be allowed during the Completion Time.

The component failure rates used in all cases presented are the same from case to case. The model includes the probability that the operator fails to align the 'E' Emergency Diesel Generator for a failed diesel given a LOOP in less than 4 hours.

4.4 Conclusion

The Susquehanna Steam Electric Station PRA model is an accurate representation of the Unit 1, Unit 2, and Common dependencies, failure probabilities, and event sequences. The model explicitly calculates the LOOP frequencies based on equipment out of service. The deterministic evaluation and the results of the risk evaluation demonstrate that the proposed extension to the allowable outage time for ST No. 20 represents only a small increase in risk, per NRC Regulatory Guide 1.177 guidelines.

From the above it is concluded that the four main elements of the risk informed deterministic evaluation introduced in Section 4.0 have been met, namely: 1) One source of offsite power will be available and if it is lost, the five on-site power sources including the spare source, E DG, will be available, 2) Risk reduction requirements of both availability of equipment and restriction of work activities will be in place, 3) These actions have resulted in small increases in ICCDP and ICLERP, within the guidance of RG 1.177, and 4) The plant risk during the ST No. 20 replacement will be monitored via our risk management procedures.

5.0 REGULATORY SAFETY ANALYSIS

5.1 No Significant Hazards Consideration

PPL Susquehanna, LLC (PPL) proposes a one-time change to the Susquehanna Steam Electric Station (SSES) Units 1 and 2 Technical Specification (TS) 3.8.1 "AC Sources – Operating," Action A.3 Completion Time from 72 hours to 10 days. This change is requested to allow the necessary time for replacement and testing of Startup Transformer Number 20 (ST No. 20). PPL has evaluated whether or not a significant hazards consideration is involved with the proposed change by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The proposal would change the Technical Specifications 3.8.1, "AC Sources - Operating," to extend, on a one-time basis, the allowable Completion Time for Required Action A.3, from 72 hours to 10 days.

   The consequence of a loss of offsite power (LOOP) event has been evaluated in the FSAR and the Station Blackout evaluation. Increasing the completion time for one offsite power source from 72 hours to 10 days does not increase the consequences of a LOOP event nor change the evaluation of LOOP events as stated in the FSAR or Station Blackout evaluation.

The proposed one-time only change to the TS 3.8.1 Required Action A.3 Completion does not, of itself, result in an increase in the risk of plant operation. The incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) do not exceed the regulatory guidance thresholds for these values.

Therefore, this proposal does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   The proposed change does not result in a change in the manner in which the electrical distribution subsystems provide plant protection. The change does not alter assumptions made in the safety analysis. Allowing the completion time for Action A.3 to increase from 72 hours to 10 days is a one-time change that will allow continued operation of Unit 1 and 2 while replacing ST No. 20.

   The accident analyses affected by this proposed change are the LOOP events discussed in the FSAR. The proposed change is consistent with the safety analysis assumptions and current plant operating practice. The potential for the loss of other plant systems or equipment to mitigate the effects of an accident is not altered.

   Thus, this change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

   Response: No.

   The proposed change does not affect the acceptance criteria for any analyzed event nor is there a change to any Safety Limit. There will be no effect on the manner in which safety limits, limiting safety system settings, or limiting conditions for operation are determined nor any effect on those plant systems necessary to assure the accomplishment of protection functions. There will be no impact on the Safety Limits or any other margin of safety. The radiological dose consequence acceptance criteria will continue to be met.

Therefore, the proposed changes do not involve a significant reduction in the margin of safety.

5.2 Applicable Regulatory Requirements / Criteria

5.2.1 Analysis

SSES FSAR Sections 3.1 and 3.13 provide detailed discussion of SSES compliance with the applicable regulatory requirements and guidance. The proposed TS amendment:

(a) Does not alter the design or function of any reactivity control system;
(b) Does not result in any change in the qualifications of any component; and
(c) Does not result in the reclassification of any component's status in the areas of shared, safety related, independent, redundant, and physically or electrically separated.

Regulatory Guide 1.93

The current Completion Times associated with inoperable AC power source(s) are intended to minimize the time an operating plant is exposed to a reduction in the number of available AC power sources. NRC Regulatory Guide 1.93, "Availability of Electric Power Sources" (Reference 6) is referenced in the TS Bases for Actions associated with TS Section 3.8.1. Regulatory Guide 1.93 provides operating restrictions (i.e., Completion Times) that the NRC considers acceptable if the number of available AC power sources are less than the Limiting Conditions for Operation (LCO). Specifically, "if the available AC power sources are one less than the number required by the TS LCO, power operation may continue for a period that should not exceed 72 hours if the system stability and reserves are such that a subsequent single failure (including a trip of the unit's generator, but excluding an unrelated failure of the remaining offsite circuit if this degraded state was caused by the loss of an offsite source) would not cause total loss of offsite power."

Conformance with Regulatory Guide 1.93 is affected by these proposed changes. According to Regulatory Guide 1.93, operation may continue with one offsite circuit inoperable for a period that should not exceed 72 hours. If the proposed change is approved, the station will continue to conform to Regulatory Guide 1.93 with the exception that, for the proposed SSES replacement of ST No. 20, the allowed Completion Time for restoration of an offsite circuit will be increased to 10 days.

The proposed extended Completion Times do not change the compliance with the above general design criteria and regulatory requirement, other than the deviations from Regulatory Guide 1.93.

As discussed above, conformance with regulatory guidance is not affected by this proposed change, with the exception of Regulatory Guide 1.93.

5.2.2 Conclusion

Based on the analyses provided in Section 4.0 Technical Analysis, the proposed change is consistent with all applicable regulatory requirements and criteria. In conclusion, there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, such activities will be conducted in compliance with the Commission's regulations, and the approval of the proposed license amendments will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

10 CFR 51.22(c)(9) identifies certain licensing and regulatory actions that are eligible for categorical exclusion from the requirement to perform an environmental assessment. A proposed amendment to an operating license for a facility does not require an environmental assessment if operation of the facility in accordance with the proposed amendment would not (1) involve a significant hazards consideration; (2) result in a significant change in the types or significant increase in the amounts of any effluents that may be released offsite; or (3) result in a significant increase in individual or cumulative occupational radiation exposure. PPL Susquehanna has evaluated the proposed change and has determined that the proposed change meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Accordingly, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment needs to be prepared in connection with issuance of the amendment. The basis for this determination, using the above criteria, follows:

1. As demonstrated in the No Significant Consideration Evaluation, the proposed amendment does not involve a significant hazards consideration.

2. There is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite. The proposed change does not involve any physical modification or alteration of plant equipment (no new or different type of equipment will be installed) or change in methods governing normal plant operation.

3. There is no significant increase in individual or cumulative occupational radiation exposure. The proposed change does not involve any physical modification or alteration of plant equipment (no new or different type of equipment will be installed) or change in methods governing normal plant operation.

7.0 SUMMARY

The deterministic and risk-informed evaluations of the proposed one-time Technical Specification change meets the set of five key principles, delineated as expected by Regulatory Guide 1.177. Specifically;

1. The proposed change meets the current regulation as discussed in Section 5.0, Regulatory Safety Analysis, under Applicable Regulatory Requirements/Criteria.

2. The proposed change is consistent with the defense-in-depth philosophy as discussed in Section 4.1, Deterministic Considerations.

3. Safety Margins are adequately maintained as discussed in Section 5.0, Regulatory Safety Analysis, under the No Significant Hazards Consideration.

4. The proposed increases in risk are small and are consistent with the Commission's Safety Goal Policy as discussed in the Technical Analysis, under Section 4.2.1.2, Risk Evaluation and PRA Insights.

5. Performance measurement strategies will be used to monitor the change as discussed in the Technical Analysis under Section 4.2.3 Risk-Informed Configuration Management.

Therefore, PPL Susquehanna has concluded that (1) there is reasonable assurance that the health and safety of the public will not be endangered by operating 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.

8.0 REFERENCES

1. NRC Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decision Making: Technical Specifications," August 1998.

2. Susquehanna Steam Electric Station Final Safety Analysis Report, Docket Numbers 50-387 and 50-388.

3. NRC's Probabilistic Safety Assessment Policy Statement, "Use of Probabilistic Risk Assessment Methods in Nuclear Regulatory Activities: Final Policy Statement," Federal Register, Volume 60, p. # 42622, August 16, 1995.

4. NRC Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 1, November 2002.

5. U. S. Nuclear Regulatory Commission, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Regulatory Guide 1.200 For Trial Use, December 2003.

6. NRC Regulatory Guide 1.93, "Availability of Electric Power Sources," December, 1974.

ATTACHMENT 1 to PLA-6480

Proposed Units 1 & 2 Technical Specification Changes (Mark Up)

3.8 Electrical Power Systems

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 Restore offsite circuit to OPERABLE status.	72 hours <u>AND</u> 6 days from discovery of failure to meet LCO <u>OR</u> 10 days for a one-time outage for replacement of Startup Transformer Number 20 to be completed by midnight on December 31, 2009.
B. One required DG inoperable.	B.1 Perform SR 3.8.1.1 for OPERABLE offsite circuits. <u>AND</u> B.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable. <u>AND</u>	1 hour <u>AND</u> Once per 8 hours thereafter 4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s) (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one 4.16 kV ESS bus concurrent with inoperability of redundant required feature(s).
	AND	
	A.3 Restore offsite circuit to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO <u>OR</u> 10 days for a one-time outage for replacement of Startup Transformer Number 20 to be completed by midnight on December 31, 2009.

(continued)

ATTACHMENT 2 to PLA-6480

Proposed Units 1 & 2 Technical Specification Bases Changes (Information Only)

ACTIONS

A.3 (continued)

Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered. A temporary Completion Time is connected to the Completion Time requirements above (72 hours AND six days from discovery of failure to meet LCO) with an "OR" connector. The temporary Completion Time is 10 days and applies to the replacement of the Startup Transformer Number 20. The temporary Completion Time of 10 days expires at midnight on December 31, 2009. If during the conduct of the prescribed Startup Transformer Number 20 Replacement, should any combination of the remaining operable AC sources be determined inoperable (on an individual unit basis), current TS requirements would apply.

B.1

To ensure a highly reliable power source remains with one required DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion

BASES

ACTIONS

A.3 (continued)

and B are entered concurrently. The "AND" connector between the 72 hours and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered. A temporary Completion Time is connected to the Completion Time requirements above (72 hours AND six days from discovery of failure to meet LCO) with an "OR" connector. The temporary Completion Time is 10 days and applies to the replacement of the Startup Transformer Number 20. The temporary Completion Time of 10 days expires at midnight on December 31, 2009. If during the conduct of the prescribed Startup Transformer Number 20 Replacement, should any combination of the remaining operable AC sources be determined inoperable (on an individual unit basis), current TS requirements would apply

B.1

To ensure a highly reliable power source remains with one required DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

(continued)

ATTACHMENT 3 to PLA-6480

List of Regulatory Commitments

LIST OF REGULATORY COMMITMENTS

The following table identifies those actions committed to by PPL Susquehanna in this document. Any other statements in this submittal are provided for information purposes and are not considered to be regulatory commitments. Please direct questions regarding these commitments to Ms. Brenda W. O'Rourke.

REGULATORY COMMITMENTS	Due Date/Event
	All commitments will be applicable prior to and/or during the transformer replacement, as indicated below:
1. Grid and Switchyard Restrictions: The following mitigating measures will be taken to increase the ability to identify and take appropriate actions before a problem arises with ST No. 10 during the transformer replacement:	
• Predictive maintenance trending data will be reviewed for ST No. 10.	Before transformer replacement
• Review of ST No. 10 corrective maintenance work order.	Before transformer replacement
• Engineering to trend Operator Rounds data for ST No. 10 on a weekly basis.	One month prior to the scheduled T-20 replacement work window.
• Engineering Inspections of ST No. 10 for obvious signs of degraded conditions will be performed. These will include: ➢ Visually inspect the high voltage bushings and other insulators on ST No. 10 daily. ➢ Perform periodic thermography inspections of ST No. 10. ➢ Trend ST No. 10 and Bus 10 voltage levels and monitor daily. ➢ Perform daily engineering rounds of ST No. 10 to monitor overall performance.	During transformer replacement

REGULATORY COMMITMENTS	Due Date/Event
• Operator Rounds (enhanced based on the INPO SOER 02-3) will be increased to once per shift from once per day for ST No. 10, except for the bushing oil level check which will be done once per day.	During transformer replacement
• Activities within the confines of the plant that may result in a loss of ST No. 10 during the ST No. 20 replacement will be prohibited.	During transformer replacement
• Activities that may result in a loss of ST No. 10 during the ST No. 20 replacement will be prohibited.	During transformer replacement
• For the duration of the ST No. 20 replacement, Transmission and Distribution Operations will NOT grant any work requests that would jeopardize the reliability of ST No. 10. This includes, but is not limited to, canceling any requests that would cause ST No. 10 to operate in a radial manner.	During transformer replacement
• Geomagnetic activity from solar storms will be monitored.	Before and during transformer replacement
2. The SSES risk management process will assess the risk impacts of planned and emergent work during the ST No. 20 replacement.	During transformer replacement
3. PPL will take into consideration plant conditions, including other equipment out of service, and implementation of compensatory actions to assure adequate defense-in-depth while ST No. 20 is replaced.	Before and during transformer replacement
4. The following systems and components will be required to be available during the ST No. 20 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 available status as soon as possible. (The failed system/component shall be worked around the clock.) If one of these systems or components becomes unavailable, SSES will	Prior to beginning and during transformer replacement

REGULATORY COMMITMENTS	Due Date/Event
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 one hour, contact the NRC Resident Inspector. • Station Portable Diesel Gen - Blue Max • Diesel Generator A ESS 480V Motor Control • Diesel Generator B ESS 480V Motor Control • Diesel Generator 'A' • Diesel Generator 'B' • Diesel Generator 'C' • Diesel Generator 'D' • Diesel Generator 'E' • U-1 125V DC Battery Charger 1D613 • U-1 125V DC Battery Charger 1D623 • RHR LOOP A Injection OB ISO VLV, (Unit 1) • RHR LOOP A Injection Flow Control VLV, (Unit 1) • RHR LOOP B Injection Flow Control VLV, (Unit 1) • RHR LOOP B Injection OB ISO VLV, (Unit 1) • U-2 125V DC Battery Charger 2D613 • U-2 125V DC Battery Charger 2D623 • RHR LOOP A Injection Flow Control VLV, (Unit 2) • RHR LOOP A Injection OB ISO VLV, (Unit 2) • RHR LOOP B Injection OB ISO VLV, (Unit 2) • RHR LOOP B Injection Flow Control VLV, (Unit 2) • RHR/RHRSW Cross Tie Valves, (Unit 1) • RHR/RHRSW Cross Tie Valves, (Unit 2) • HPCI (UNIT 1) • HPCI (UNIT 2) • RCIC (UNIT 1) • RCIC (UNIT 2)	
5. If ST No. 10 degrades, SSES will immediately evaluate the impact to determine operability of ST No. 10.	During transformer replacement

ATTACHMENT 4 to PLA-6480

Open B-Level F&Os

Open B-Level F&Os – Impact on ST No. 20
Technical Specifications Submittal

Description of Open B Level F&Os	Impact on ST No. 20 TS Submittal
The human interactions that can cut across system trains and can cause failure of multiple trains due to pre-initiator should be identified and documented.	The model includes pre-initiators for the Diesel generators, RHR injection, Core Spray injection, Standby Liquid injection and the standby Control Rod Drive Pump. The highest F-V of these pre-initiators is about 1 % which is for the A and B diesel generators. All the other F-Vs are less than 1%. The LOOP contribution to Core Damage in the base model is about 55%. Therefore, it is reasonable that the pre-initiators for the diesel generators have the highest F-V. Including additional pre-initiators would have little impact on the requested Technical Specification change, since the proposed TS is for an extension of the Allowed Completion Time for one source of off-site power which increases the likelihood of a loss of off-site power. This situation elevates the importance of the diesel generators and diesel generator pre-initiators are included. Any new pre-initiators would have the effect of slightly raising both the base case and the ST No. 20 case by approximately the same amount; therefore the calculated changes in CDF or LERF would not be affected.
Only a limited number of pre- initiator human errors are included in the fault trees. "The pre-initiators included in the model are considered to be adequate except for possible common cause events. However, further consideration of plant specific procedures could identify other pre-initiators for inclusion."	See above

Description of Open B Level F&Os	Impact on ST No. 20 TS Submittal
Selected pre- initiator human errors are included in the system model. PPL should ensure that the pre-initiators are examined relative to plant design and procedures and are incorporated and quantified.	See above
The quality and content of system notebooks are good. Several other system notebooks are in various stages of development. All modeled systems should have these books completed and reviewed.	This F&O only affects the documentation. Creating system notebooks for all modeled systems will not change the quantified results.
A limited set of failure data was updated with plant-specific data prior to 1999. The majority of the failure data is based on generic values. Develop program to periodically update failure data using accumulated plant data.	A procedure has been developed which specifies the periodicity for data updates. The diesel generators which are of principal importance with ST No. 20 OOS did use plant specific data in the development of their modeled failure rate.
The plant-specific components receiving a data update do not include the HPCI pump which has a relatively high Fuessell-Vesely importance. Include the HPCI pump in the component population for periodic plant-specific data update. Consider whether any other components merit plant-specific data update.	It is planned to update the HPCI failure rate with plant specific data at the next data update. However, for this application, the risk metric results are relatively insensitive to changes in HPCI failure rates. The HPCI F-V for the base case is about 1% and for ST No. 20 OOS it is about 2%. Thus, changes in the HPCI failure rate would not significantly alter the overall risk results.

Dual Unit Effects
Dual unit effects and insights with a single diesel operating should be included in the summary notebook discussion (as sensitivities if desired) to address:
- Effects of switching RHR high AMP loads
  - On RHR Motors
  - On D/G
 	
- RWST adequacy to support
	This F&O was written when a failure of the A or B diesel generator, given a LOOP, would cause the operators to cool the suppression pool on one unit then shut down suppression pool cooling and initiate it on the other unit. A modification to the RHR pump cooling has since resolved this issue. A failure of the A or B diesel no longer requires "swapping" suppression pool cooling.
	
	Dual unit concerns are further discussed in Section 4.2 of the submittal.

Description of Open B Level F&Os	Impact on ST No. 20 TS Submittal
- Loss of SW on Unit 1 - Loss of Instrument Air on Unit 1 should be discussed Ensure Dual Unit impacts are adequately understood.	

ATTACHMENT 5 to PLA-6480

PRA Self-Assessment Open Items

Self-Assessment Open Items – Impact on ST No. 20 Technical Specifications Submittal

Description of Self Assessment Open Items	Impact on ST No. 20 TS Submittal
Include a discussion of dual unit effects in the event tree /success criteria notebook.	Dual unit concerns are discussed in Section 4.2 of the submittal.
Conduct interviews and walkdowns to verify that the model reflects the as-built, as-operated plant.	The systems modeled use design capacities. If there is a deviation from design it has been justified. Interviews and walkdowns would help to refine the operating aspects of the systems modeled but would not appreciably impact the risk metric results.
Provide HEPs for flood isolation capability in model or provide rationale for their exclusion.	A Human Error probability (HEP) for flood isolation has conservatively not been included in the model. However, the highest F-V for a flood initiator in the base model is about one half of one percent. Adding HEPs for flood isolation would reduce the flood F-V and will not significantly impact the risk metric results.
Add common cause mis-calibration for low pressure permissive for RHR and CS injection valves	A common cause mis-calibration for the low pressure permissive for RHR and CS injection valves is not currently modeled. This is not predicted to be impacting for the application for two reasons. First, the pressure switches being out of the calibration range but not failed will still allow the injection valves to open. Second, both core spray loops have a low pressure permissive bypass switch that can be manually activated from the control room if the core spray valves do not open at the correct pressure.
Update the component data notebook to incorporate more plant-specific data evaluations, especially for high FV components.	The diesel generators have the highest F-V of any modeled component. The failure rate for diesel generators was based on plant specific data. HPCI is another relatively high F-V system. However, for this application, the risk metric results are relatively insensitive to changes in HPCI failure rates. The HPCI F-V for the base case is about 1% and for ST No. 20 OOS it is

	about 2%. Thus, changes in the HPCI failure rate would not significantly alter the overall risk results.
The HRA notebook should provide an assessment of the uncertainty in HEPs.	Adding HEP uncertainties will enhance the uncertainty analysis. The risk metrics for this application are "best estimate". Therefore, the uncertainties would not alter the risk metric results.