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SUSQUEHANNA STEAM ELECTRIC STATION
PROPOSED LICENSE AMENDMENT
NUMBERS 255 FOR UNIT 1 AND 220 FOR UNIT 2
FOR A ONE-TIME CHANGE TO TECHNICAL SPECIFICATIONS 3.8.1
ALLOWABLE COMPLETION TIME
FOR OFFSITE AC CIRCUITS **Docket Nos. 50-387**
PLA-5637 **and 50-388**

Pursuant to 10 CFR 50.90, PPL Susquehanna, LLC hereby requests amendments to the Susquehanna Steam Electric Station (SSES) Unit 1 and Unit 2 Technical Specifications (TS), as described in the enclosure. The proposed amendments would change the Technical Specifications for AC Sources - Operating, to extend, on a one-time basis, the allowable Completion Time for Required Actions for one offsite circuit inoperable, from 72 hours to 10 days. This change is needed to allow sufficient time for the planned replacement of Startup Transformer Number 10, while both units remain at power. The reason for the replacement of Startup Transformer Number 10 is to ensure continued long-term reliability of the Offsite Emergency Power Systems.

The justification for the change to the Startup Transformer Required Action 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 requests approval of the proposed one-time change to the SSES Technical Specifications by September 26, 2003 to support the planned replacement of the Startup Transformer Number 10, to be implemented in October 2003. This one-time change would be effective from the date of issuance until December 31, 2003. Attachments 1 and 2 are the Technical Specifications marked-up and retyped. Attachment 3 lists the PPL Susquehanna commitments that would derive from NRC's approval of the proposed amendment. For your information, Attachment 4 is a mark-up showing the changes to the Technical Specification Bases.

A001

The need for this change has been discussed with the SSES NRC Project Manager.

The proposed changes have been approved by the SSES Plant Operations Review Committee and reviewed by 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 Mr. John M. Oddo at (610) 774-7596.

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

Executed on:

B.T. James
for B. L. Shriver

Enclosures:
PPL Susquehanna Evaluation of the Proposed Changes

Attachments:
Attachment 1 – Proposed Technical Specification Changes (Mark-up)
Attachment 2 – Proposed Technical Specification Pages (Retyped)
Attachment 3 – List of Regulatory Commitments
Attachment 4 – Changes to Technical Specifications Bases Pages (Mark-up)

Copy: NRC Region 1
Mr. T. Colburn, NRC Project Manager
Mr. R. Guzman, NRC Project Manager
Mr. S. Hansell, Resident Inspector
Mr. R. Janati DEP/BRP

Enclosure to PLA-5637

PPL Susquehanna Evaluation of Proposed One-Time Change to Technical Specifications 3.8.1 Allowable Completion Time for Offsite AC Sources

SUBJECT: APPLICATION FOR A ONE-TIME AMENDMENT TO TECHNICAL SPECIFICATIONS 3.8.1 "AC SOURCES – OPERATING" TO ALLOW EXTENSION OF COMPLETION TIME OF REQUIRED ACTIONS FOR OFFSITE AC CIRCUITS

1.0 DESCRIPTION

The proposal would change Technical Specification 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 planned replacement of Startup Transformer Number 10. 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 4). The proposed changes would allow sufficient time for the planned replacement of Startup Transformer Number 10, while both units remain at power.

2.0 PROPOSED CHANGE

The proposed change to SSES Units 1 and 2 Technical Specifications (TS) would allow for a one-time only planned replacement of Startup Transformer Number 10 (ST No. 10), while both units remain at power. In order to effect this one-time change, Technical Specification (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 10 to be completed by December 31, 2003". This new Completion Time will be connected with a logical connector "<u>OR</u>." The logical connector "<u>AND</u>" in the current completion time for this required action will be moved to the right. 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 4).

> A temporary Completion Time is connected to the Completion Time requirements above (72 hours <u>AND</u> 6 days from discovery of failure to meet LCO) with an "<u>OR</u>" connector. The temporary Completion Time is 10 days and applies to the replacement of Startup Transformer Number 10. The temporary Completion Time of 10 days expires on December 31, 2003. If during the conduct of the prescribed Startup Transformer Number 10 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 and retyped Technical Specification pages and marked-up Technical Specification Bases pages, which incorporate the proposed changes, are provided in Attachments 1, 2, and 4, respectively. Attachment 3 is the list of regulatory commitments.

3.0 BACKGROUND

On October 3, 2002, a fire occurred on Startup Transformer Number 20 (ST No. 20). The fire was extinguished automatically by the deluge system. Unit 1 was in MODE 1 - Power Operation, operating at 100% power and Unit 2 was in MODE 2 - Startup. Unit 2 was manually scrammed due to a loss of both Reactor Recirculation pumps. Unit 1 continued operation at 100% power.

The transformer failure originated internally to the transformer. Some protective equipment on ST No. 20 did not function as designed. The combination led to significant damage to the ST No. 20 Federal Pacific transformer.

Preventive Maintenance (PM), including thermography, is performed on the transformers on a two year cycle, typically during unit outages, since this is the time that the transformers are more highly loaded. The PM had last been performed on the ST No. 20, prior to its failure, on March 08, 2001. No problems were identified at that time. Also, an oil analysis was performed shortly before the transformer failure and no problems were indicated.

Due to this failure, an onsite spare transformer (Westinghouse) was installed, replacing ST No. 20. A request for enforcement discretion was granted by NRC to extend the Technical Specification 3.8.1 Completion Time for Required Actions from 72 hours to 7 days. (References 1 and 2). This enabled continued operation of Unit 1 until the replacement transformer was installed. The actual work duration slightly exceeded 7 days. The LCO action was entered briefly. The shutdown was begun but terminated in a short period of time.

This event is described in an LER (Reference 3).

<u>Rebuilt/Spare Transformer Plan</u>

Following the October 2002 failure of ST No. 20, a contract was placed with Waukesha Electric Systems to purchase a new startup transformer. The new Waukesha Transformer has the same rating and electrical characteristics as the Federal Pacific Electric

Transformers. While electrically similar, the new Waukesha Transformer is a more robust design and was manufactured with substantially greater design margins.

Upon disassembly of the failed Federal Pacific Transformer, it was determined that the transformer could be redesigned and remanufactured at an economic cost. A decision was made to rebuild the failed ST No. 20 to provide a second spare startup transformer. Ohio Transformer redesigned the failed ST No. 20. The redesign included a new coil and core assembly, rewound series transformer, new design Load Tap Changer, internal surge suppression, and new bushings. The new Ohio Transformer design substantially increased the design margins over the Federal Pacific Electric design.

ST No. 10 is planned to be preemptively replaced with a new transformer in early October 2003, to eliminate any potential failure modes similar to the previous ST No. 20 transformer failure. The transformer is being replaced to preclude challenge to the units and operators. The new Waukesha Electric Transformer will replace the existing Federal Pacific Electric ST No. 10 Transformer. This will place in service a transformer with greater design margins and will enhance the reliability of the offsite power supply. The new Ohio Transformer will be placed on the spare transformer pad and will be used as the primary spare startup transformer. The old Federal Pacific Electric Transformer will be used as the second spare.

The following is a summary of the SSES startup transformer inventory once ST No. 10 is replaced:

ST No. 10 – Waukesha Electric
ST No. 20 – Westinghouse Electric
First Spare – Ohio Transformer
Second Spare – Federal Pacific Electric

Transformer Lifetime

The startup transformers, as opposed to, for example, main transformers, are lightly loaded during normal power operation, approximately 7 to 8 MVA. Typical outage loads usually do not exceed 25 MVA. The top rating of the startup transformers is 75 MVA. Under these operating conditions, and proper maintenance, it is expected that the design life (based on insulation life) of any of the startup transformers will exceed 40 years.

3.1 System Description

The station's Class 1E AC Electrical Power Distribution System AC sources consist of two offsite power sources, and the onsite standby power sources, Diesel Generators (DGs) A, B, C, and D. A fifth diesel generator, 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.

Additional 125 VDC Backup

A backup to the 125 VDC batteries is provided by a portable 125 kW diesel generator [termed the Station Blackout (SBO) diesel generator or the "Blue Max"]. The Blue Max has been specifically designed for Station Blackout and is stored 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. 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 non-SBO scenarios.

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. These offsite power sources are independent. A 230 kV line from the Susquehanna T-10 tap 230 kV switchyard feeds ST No. 10, and a 230 kV tap from the 500-230 kV tie line feeds ST No. 20.

ST No. 10 and No. 20 each provide the normal source of power to two of the four 4.16 kV Engineered Safeguards Systems (ESS) buses 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 (A, B, C and D) in each unit (8 total buses) for both Unit 1 and Unit 2, respectively.

The Susquehanna T-10 tap 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.

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 pre-op testing, and only impacted Unit 2.

The power supply for ST No. 20 is from a highly reliable source, the 500-230 kV tie line. The 500-230 kV tie line allows multiple sources, from both the 500 kV Switchyard through a 500/230 kV Auto Transformer (T-21) and the 230 kV Switchyard, to feed ST No. 20.

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.

3.1.2 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).

Emergency Diesel Generator Availability

As reported to the NRC, in Performance Indicator submitted data, from the 4th Quarter, 1999 to the 1st Quarter, 2003, the SSES Emergency Diesel Generator Unavailability improved from 1.2% to 0.5%.

Fast/Slow Bus Transfer

In addition to supplying Class 1E 4.16 kV busses, ST No. 10 and ST No. 20 also supply the startup busses 10 and 20. SSES is designed with a bus fast transfer of the auxiliary bus loads at the 13.8 kV level, through a 13.8 kV startup/auxiliary bus tie-breaker. Following a unit trip, the Unit Auxiliary Buses (11A, 11B, 12A, and 12B) will fast transfer to Startup Bus 10 or 20 to restore 13.8 kV power to these busses. During a fast transfer, the startup busses and their Class 1E safety related loads remain continuously energized.

The plant is designed with a slow bus transfer of the ST No. 10 and ST No. 20 startup bus loads at the 13.8 kV level, through a 13.8 kV startup bus tie-breaker. Following a loss of offsite power to one of the startup transformers, the startup bus will transfer to the other startup bus through the tie bus. During a slow transfer, the startup bus and its Class 1E loads will momentarily lose power.

3.1.3 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 4). Beyond 4 hours, the Blue Max portable AC generator is used to supply DC loads necessary to maintain core cooling and to restart the diesel generators.

3.2 FSAR References

Related background in the SSES FSAR (Reference 4) 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 an NRC approved precedent submittal. 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 Offsite Power for a Single Occurrence. 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 5), and the acceptance criteria in Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," (Reference 6).

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 during a Loss of Offsite Power, 2) the risk-reducing requirements (i.e., equipment required to be in service) which will exist during the ST No. 10 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 Susquehanna Steam Electric Station risk management process which will assess the risk impacts of planned and emergent work during the ST No. 10 outage.

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 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)). The availability of the AC power sources to the ESS buses will not be reduced since ST No. 20 will not be affected by the ST No. 10 replacement activities, and the replacement of ST No. 10 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. 10 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. 10 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. 10 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. 10 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. 20, prior to the replacement.

- Review of ST No. 20 corrective maintenance work orders will be performed prior to the replacement.

<u>Grid and Switchyard Restrictions</u>

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:

- Engineering Inspections of ST No. 20 for obvious signs of degraded conditions will be performed. These will include:

  - Visually inspect the high voltage bushings and other insulators on ST No. 20 daily.
  - Perform daily thermography inspections of ST No. 20.
  - Trend ST No. 20 and Bus 20 voltage levels and monitor daily.
  - Perform daily engineering rounds of ST No. 20 to monitor overall performance.

- Operator Rounds (enhanced based on the INPO SOER 02-3) 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.

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

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

- 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.

External Events Monitoring

Per normal operating procedures, the control room will monitor weather conditions and the potential for external events such as external flood or forest fire prior to and during the transformer replacement. The control room will instruct Field Services to stop work 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. 10.

Contingency Planning (Work Planning Actions)

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. 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 Susquehanna has a high level of confidence in its ability to implement a pre-planned replacement of ST No. 10 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.

PPL Susquehanna replaced a similar ST No. 20 Startup Transformer, on an emergent basis, in slightly over 7 days, after this transformer suffered an in-service failure in the Fall of 2002. The nature of the ST No. 20 failure required additional work that will not be required as part of the planned ST No. 10 replacement.

SSES's recent experience with replacing ST No. 20, in the Fall of 2002, highlighted the need for enhanced engineering and production contingencies that are being addressed in the development of work plans for the planned ST No. 20 replacement. After the Fall 2002 replacement, SSES 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.

Design Change Packages, which are already developed, and Work Packages that are being developed, contain a finer level of detail than the packages used to implement the ST No. 20 replacement. This level of detail is beneficial in preventing work challenges during the evolution.

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

PPL Susquehanna will also implement contingency actions to have a second spare startup transformer available for use in either the ST No. 10 or ST No. 20 location. 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. Having a second spare further strengthens our contingency plans.

<u>Prohibitions on Preventive Maintenance</u>

The following systems and components are required to be available during the ST No. 10 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 0B516073
U-1 125V DC BATTERY CHARGER 0B526073
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 0B516071
U-2 125V DC BATTERY CHARGER 0B526071
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 operable. Any failed system/component will be returned to operable 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 or inoperable, SSES will immediately begin and promptly complete a risk evaluation of the impact, to determine if the basis for this onetime change to LCO 3.8.1 remains valid, and within 1 hour of identification, contact the NRC Resident Inspector. The risk evaluation will be performed using the model described in Section 4.2.1.

Additionally, should degradation of ST No. 20 be identified, SSES will immediately begin to evaluate the impact and promptly complete an evaluation to determine operability of ST No. 20. 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 Startup Transformer No. 10 (ST No. 10). 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 (CT) for ST No. 10. 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. 10. 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. 10 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 CT for ST No. 10 repair. 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 CT for the transformer ST No. 10 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 (Reference7) and 1.177:

ΔCDF = Change in Core Damage Frequency (CDF)
ΔCDF = Difference in calculated CDF between the ST No. 10 Out-of-Service (OOS) case and the base case (ST No. 10 OPERABLE)

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

ΔLERF = Change in Large Early Release Frequency
ΔLERF = Difference in calculated LERF between the ST No. 10 OOS case and the base case (ST No. 10 OPERABLE)

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

The following cases were analyzed:

#	Case
1	ST No. 10 OPERABLE / E-Emergency Diesel Generator <u>not</u> available (other 4 Emergency Diesel Generators operable)
2	ST No. 10 OPERABLE / E-Emergency Diesel Generator available (other 4 Emergency Diesel Generators operable)
3	ST No. 10 INOPERABLE / E-Emergency Diesel Generator available with Compensatory Actions (other 4 Emergency Diesel Generators operable)

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. Thus, Cases 1 and 2 were run to demonstrate the benefit of having the E-Emergency Diesel Generator available to backup one of the other diesel generators. Since PPL will require the E-Emergency Diesel Generator to be available and capable of being substituted for any of the DGs during the replacement evolution, the "base case" for calculating ΔCDF, ΔLERF, ICCDP and ICLERP was case #2.

In addition to the quantitative calculations of the at-power risk measures associated with the increased CT for the planned ST No. 10 replacement, the impacts of the proposed CT increase for external events (fire, external flooding and seismic events) were qualitatively evaluated.

Compensatory Measures for Probabilistic Risk Assessment

Analyses using CAFTA/PRAQUANT were performed and the higher frequency cut sets, involving systems in preventive maintenance, were examined to determine which systems would be required to be available during the planned work. Other compensatory measures will be taken as described in Section 4.1; however, the following equipment, identified as risk significant, was explicitly credited in the Probabilistic Risk Assessment to support the ST No. 10 replacement. The following systems will be required to be operable (and were credited in the quantitative at-power evaluation):

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 0B516073
U-1 125V DC BATTERY CHARGER 0B526073
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 0B516071
U-2 125V DC BATTERY CHARGER 0B526071
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)

Note that this list differs from the list of risk significant equipment in the NOED. The differences exist because of recent model changes and because the maintenance on the systems omitted from the NOED did not appear in the higher frequency cut sets in this evaluation.

Since Unit 1 and Unit 2 Technical Specification 3.8.1 effectively prohibit performing the ST No. 10 replacement without four emergency diesel generators OPERABLE, preventive maintenance for the emergency diesel generators was removed from the fault tree. This is not a compensatory action, but rather is the required configuration for performing the replacement.

At Power Risk Assessment

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

TABLE 4-1: Results for a 10 Day CT on Offsite Transformer (ST No. 10)

Case #	Description	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	For Information Case - ST No. 10 OPERABLE / E-Emergency Diesel Generator not available	5.32E-6 (5.33E-6)	---	---	2.59E-6 (2.56E-6)	---	---
2	Base Case - ST No. 10 OPERABLE / E-Emergency Diesel Generator available	2.46E-6 (2.48E-6)	---	---	1.00E-6 (9.74E-7)	---	---
3	ST No. 10 INOPERABLE / E-Emergency Diesel Generator available with Compensatory Actions	2.52E-6 (2.57E-6)	6.00E-8 (9.00E-8)	**1.64E-9 (2.47E-9)**	2.06E-6 (1.96E-6)	1.06E-6 (9.86E-7)	**2.90E-8 (2.70E-8)**

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 change in CT are:

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

In Table 4-1, the ICCDP and ICLERP (assuming the E-Emergency Diesel Generator is available for both the base case and the increased CT case with compensatory actions credited) are within the RG 1.177 criteria for the proposed 10 day CT.

The CDF and LERF changes from case 2 to case 3 are well within the normal operating background of the plant i.e., normal maintenance activities can cause larger changes in CDF and LERF.

Sensitivity Studies

One additional result is worthy of note. Specifically, the CDF and LERF for ST No. 10 INOPERABLE and the E-Emergency Diesel Generator available (with compensatory actions), Case #3, is actually less than the Case #1 with ST No. 10 OPERABLE and only four diesel generators available – which is allowed by Technical Specifications. The E DG has more of an influence to reduce risk than the ST No. 10 outage has to increase risk since the loss of offsite power initiating event is the highest contribution to CDF and LERF of all the initiators. Since a LOOP can be caused by equipment failures (ST No. 10 and ST No. 20), weather, grid problems and other plant related problems, a reduction in redundancy in offsite power sources does not add as much to the plant risk as having a spare onsite power source reduces the plant risk. See Section 4.3, PRA Quality, for additional discussion of LOOP frequency evaluation.

Considering the above mentioned result and that the ICCDP was more than two orders of magnitude below the RG 1.177 threshold, and that ICLERP is about a factor of two lower than the threshold listed in RG 1.177, no further sensitivity cases were required.

Evaluation of External Events

This section provides a qualitative evaluation of the impact of the external events on the proposed one-time increase in CT for the ST No. 10 Transformer. A specific evaluation was performed for seismic events, internal and 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. 10 Transformer, only the ST No. 20 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. 10 Transformer is being replaced.

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. 10 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 CT for the planned ST No. 10 replacement does not significantly increase the probability of core damage or a large early release due to a seismic event.

Fires

During the planned replacement of the ST No. 10 Transformer, only the ST No. 20 Transformer will be available to supply offsite power to the station. There is an insignificant incremental risk associated with having a fire event because the time during which the ST No. 10 Transformer is being replaced, is so short.

Fires Internal to the Plant

The potential for increased risk of core damage or a large early release considering internal fires was examined. It was concluded that the probability of a LOOP during the 10 day proposed CT for ST No. 10 combined with a fire that would damage other key equipment is extremely low. For a LOOP event, the Emergency Diesel Generators are critical components in preventing core damage. Thus, the potential to cause a fire upon starting was considered. Note that Diesel Generator failure probabilities (from all causes, including diesel fires) are included in the Susquehanna Steam Electric Station

Probabilistic Risk Assessment model. Thus, the effect on ICCDP and ICLERP for the proposed 10 day CT from internal fires is considered small.

Fires External to the Plant

During the planned replacement of the ST No. 10 Transformer, only the ST No. 20 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. 20.

A potential vulnerability exists from brush or forest fires causing a loss to the 500 kV to 230 kV tie line supplying ST No. 20. 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. 10 Transformer, only the ST No. 20 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. 10 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 probable maximum flood (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 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. 10 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 4.2.1.2.

Other restrictions are imposed to further reduce the risk during performance of the ST No. 10 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 inoperability. 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 requantifies the results whenever a configuration change is made (it does not use pregenerated 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. 10 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 and Conclusions 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. 10 Transformer (Unit 1 and Unit 2 Technical Specification 3.8.1). 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 Susquehanna IPE was internally and externally reviewed, and the NRC issued the SER on August 11, 1998. PPL has since upgraded the software for the risk model to the CAFTA/EOOS format. A Peer Review (Certification) is scheduled for October 6, 2003. PPL has not been previously certified. The original CAFTA model was based on the IPE model and was used to support a Technical Specification change involving elimination of the HPCI automatic transfer to the suppression pool. The NRC approved the Technical Specification change (Reference 8) on August 5, 2002.

In August 2002, the NRC performed an SDP benchmark visit at Susquehanna. During the visit, the modeling techniques, success criteria and mitigating systems employed were discussed. The NRC commented on the following:

- the use of Reactor Water Clean-Up (RWCU) in blowdown mode as a means of removing decay heat,
- success of Control Rod Drive (CRD) flow as a high pressure makeup source,
- a fuel damage success criterion based on generated hydrogen,
- terminating the containment failure and containment venting sequences without accounting for long term reactor makeup and the potential for core damage.

As a result of these comments, PPL re-evaluated these issues as part of a PRA Upgrade Project and has determined that the following permanent changes to the model were appropriate:

- eliminated the use of RWCU as a means of removing decay heat
- eliminated CRD as a high pressure makeup source
- changed the fuel temperature success criterion to 1800°F,
- revised the model based on the assumption that active components in the reactor building would not function following containment venting or containment failure (note that SSES does not have a "hardened" containment vent),

- extended the containment failure and containment venting sequences to include late injection (sources of makeup from outside the Reactor Building), and
- revised the Event Trees and Fault Trees to address inventory and cooling concerns.

Prior to PPL implementing all of the above listed changes, Startup Transformer ST No. 20 failed, and PPL requested a Notice of Enforcement Discretion (NOED). The NOED was approved by the NRC, extending the CT from 3 days to 7 days. The model changes that were implemented at the time of the request were the elimination of RWCU and the elimination of CRD as a high pressure makeup source. Also, the Plant Damage states for venting or containment failure with no prior core damage were added to the CDF calculation without any late injection. The NOED was approved on October 5, 2002. Subsequently, the balance of the above described changes have been made to the model.

As part of a PRA upgrade, PPL reviewed the EOPs and only credited operator actions that can be reasonably assumed to occur and for which a procedure exists. Procedures will be strengthened to reflect PRA insights to ensure that model assumptions are valid. The procedures will be revised before October 2003, and thus have been credited in this analysis. The Event Trees were reviewed to assure consistency with the EOPs. The revised Event Trees are documented, reviewed and approved per PPL's calculation procedure. The translation of the event trees into the fault tree has also been reviewed as part of the event tree calculation. It can be seen from the previous discussion that the emphasis of the upgrade project was to model the as-built/as-operated plant.

Since the ST No. 10 Technical Specification change being requested involves an offsite power source, the Loss of Offsite Power (LOOP) initiation frequency was updated along with the LOOP recovery probabilities. The LOOP initiating event frequency was determined from a collection of nuclear plants in the Pennsylvania-New Jersey-Maryland (PJM) grid area. The LOOP initiator frequency was calculated using a Bayesian approach with the prior distribution based on 1986-1995 PJM area operating experience and updated with PJM area specific operating experience for the dates January 1, 1996 to December 31, 2001. The result of the updating is that the LOOP initiating event frequency has been reduced but the recovery of offsite power is of a longer duration. These results are consistent with "Operating Experience Assessment-Effects of Grid Events on Nuclear Power Plant Performance" (Reference 9). The model was revised to replace the previously used LOOP initiating events with the new LOOP initiating event fault tree. The LOOP initiating event fault tree dynamically changes the LOOP initiation frequency when one source of offsite power is removed from service.

Model Structure

The fault tree model encompasses at-power internal events (excluding 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. All sequences that involve core damage (core damage only, core damage with vessel failure, and core damage with containment failure) are included in the CDF top. The quantifier then deletes all non-minimal cut sets. Similarly, the LERF top is a collection of all sequences, which are predicted to have a large early release.

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. To demonstrate the validity of this approach, this method of developing a single top model was compared to quantifying the failures in a sequence (combined via an "AND" gate) and then deleting the successes in the sequence (combined via an "OR" gate). The successes in this second case do not involve using "NOT" gates. The comparison was made for one arbitrary sequence involving 4 failures and 3 successes, with the same truncation level used throughout. The CDF results of the two approaches were identical, and the same number of cut sets are produced.

Assumptions

The truncation limit used was 1E-9. Note the base case total CDF is 2.5E-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 among others, are included in the common cause failures considered.

The model used to support this CT change is based on our random maintenance model with the exception of the components listed in Section 4.2.1.2, for which no elective maintenance is allowed.

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. 10 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. 4) The plant risk during the ST No. 10 replacement will be monitored via our risk management procedures.

5.0 REGULATORY SAFETY ANALYSIS

5.1 No Significant Hazards Consideration

PPL Susquehanna, LLC has evaluated whether or not a significant hazards consideration is involved with the proposed generic 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 for AC Sources - Operating, to extend, on a one-time basis, the allowable Completion Times for Required Actions for one offsite circuit inoperable, from 72 hours to 10 days. The proposed change does not involve a significant increase in the probability of an accident previously evaluated because the probability increases are within the guidance provided in Regulatory Guide 1.177.

The consequence of losing offsite power have 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.

Therefore, this change 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 involve a physical alteration of the plant (no new or different type of equipment will be installed nor will there be changes in methods governing normal plant operation).

Allowing the completion time for ST No. 10 to increase from 72 hours to 10 days is a one-time change that will allow continued operation of Unit 1 while replacing Startup Transformer Number 10. The accident analyses affected by this extension are the LOOP events that are discussed in the FSAR. 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 involve a significant reduction in margin of safety.

The proposed change allows, on a one-time basis, ST No. 10 to be out of service for 7 days more than is allowed by Technical Specifications. This increase in completion time for ST No. 10 results in a slight decrease in the margin of safety. Implementation of the compensatory measures described in Section 4.0 mitigates the increase in the core damage frequency and large early release frequency during this time, such that the potential impact of extending the completion time is small. Therefore, this one-time exemption will not involve a significant reduction in safety margin.

Based on the above, the PPL Susquehanna concludes that the proposed change presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and accordingly, a finding of "no significant hazards consideration" is justified.

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 10) is referenced in the Technical Specification (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. Aside from the exception discussed above, the station currently conforms to the RG. If the proposed change is approved, the station will continue to conform to RG 1.93 with the exception that, for the proposed SSES replacement of ST No. 10, 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 change 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. PPL Susquehanna Letter PLA-5533 to NRC, "Susquehanna Steam Electric Station Request for Regional Enforcement Discretion: Inoperable Power Source," October 5, 2002.

2. NRC letter to Bryce L. Shriver, "Susquehanna Steam Electric Station, Units 1 and 2 - Issuance of Amendment RE: High Pressure Coolant Injection Pump Automatic Transfer to Suppression Pool Logic Elimination (TAC Nos. MB2190 and MB2191)," August 5, 2002.

3. PPL Susquehanna Letter PLA 5534, "Licensee Event Report 50-387/2002-006-00," October 15, 2002.

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

5. 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.

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

7. 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.

8. NRC letter to Bryce L. Shriver, "Susquehanna Steam Electric Station, Units 1 and 2 - Issuance of Amendment RE: High Pressure Coolant Injection Pump Automatic Transfer to Suppression Pool Logic Elimination (TAC Nos. MB2190 and MB2191)," August 5, 2002.

9. NRC Final Report, "Operating Experience Assessment-Effects of Grid Events on Nuclear Power Plant Performance," April 29, 2003. (ADAMS Accession Number ML031220116)

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

ATTACHMENT 1 to PLA-5637

Proposed Technical Specification Change (Mark-Up)

No change ON this page – INFORMATION ONLY

3.8 Electrical Power Systems

3.8.1 AC Sources—Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System; and

b. Four diesel generators (DGs).

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

-----NOTE-----
When an OPERABLE diesel generator is placed in an inoperable status solely for the purpose of alignment of DG E to or from the Class 1E distribution system, entry into associated Conditions and Required Actions may be delayed for up to 8 hours, provided both offsite circuits are OPERABLE and capable of supplying the affected 4.16 kV ESS Bus.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 for OPERABLE offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND		
	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		

(continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 Restore offsite circuit to OPERABLE status. OR 10 DAYS FOR A ONE-TIME OUTAGE FOR REPLACEMENT OF STARTUP TRANSFORMER NUMBER 10 TO BE COMPLETED BY DECEMBER 31, 2003.	72 hours ~~AND~~ AND 6 days from discovery of failure to meet LCO
B. One required DG inoperable.	B.1 Perform SR 3.8.1.1 for OPERABLE offsite circuits.	1 hour AND Once per 8 hours thereafter
	AND	
	B.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND	
	B.3.1 Determine OPERABLE DGs are not inoperable due to common cause failure.	24 hours
	OR	
	B.3.2 Perform SR 3.8.1.7 for OPERABLE DGs.	24 hours OR 24 hours prior to entering Condition B
	AND	
		(continued)

No change on this page — Information Only

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources—Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System; and

b. Four diesel generators (DGs).

c. Two qualified circuits between the offsite transmission network and the Unit 1 onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.7, Distribution Systems — Operating; and

d. The DG(s) capable of supplying the Unit 1 onsite Class 1E electrical power distribution subsystem(s) required by LCO 3.8.7.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

-----------------------------------NOTE-----------------------------------
When an OPERABLE diesel generator is placed in an inoperable status solely for the purpose of alignment of DG E to or from the Class 1E distribution system, entry into associated Conditions and Required Actions may be delayed for up to 8 hours, provided both offsite circuits are OPERABLE and capable of supplying the affected 4.16 kV ESS Bus.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for OPERABLE offsite circuit. AND	1 hour AND Once per 8 hours thereafter

(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~~ AND 6 days from discovery of failure to meet LCO OR 10 DAYS FOR A ONE-TIME outage FOR Replacement OF StartUp TRANSFORMER Number 10 to be Completed by December 31, 2003.

(continued)

ATTACHMENT 2 to PLA-5637

Proposed Technical Specification Pages (Retyped)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 Restore offsite circuit to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO OR 10 days for a one-time outage for replacement of Startup Transformer Number 10 to be completed by December 31, 2003
B. One required DG inoperable.	B.1 Perform SR 3.8.1.1 for OPERABLE offsite circuits.	1 hour AND Once per 8 hours thereafter
	AND	
	B.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND	

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.3.1 Determine OPERABLE DGs are not inoperable due to common cause failure. OR B.3.2 Perform SR 3.8.1.7 for OPERABLE DGs.	24 hours 24 hours OR 24 hours prior to entering Condition B
	B.4 Restore required DG to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO
C. Two offsite circuits inoperable.	C.1 Restore one offsite circuit to OPERABLE status.	24 hours
D. One offsite circuit inoperable. AND One required DG inoperable.	----------------------NOTE---------------------- Enter applicable Conditions and Required Actions of LCO 3.8.7, "Distribution Systems-Operating," when Condition D is entered with no AC power source to any 4.16 kV ESS bus. --	
	D.1 Restore offsite circuit to OPERABLE status. OR D.2 Restore required DG to OPERABLE status.	12 hours 12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Two or more required DGs inoperable.	E.1 Restore at least three required DGs to OPERABLE status.	2 hours
F. Required Action and Associated Completion Time of Condition A, B, C, D, or E not met.	F.1 Be in MODE 3. AND F.2 Be in MODE 4.	12 hours 36 hours
G. One or more offsite circuits and two or more required DGs inoperable. OR One required DG and two offsite circuits inoperable.	G.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

-----NOTE-----

Four DGs are required and a DG is only considered OPERABLE when the DG is aligned to the Class 1E distribution system. DG Surveillance Requirements have been modified to integrate the necessary testing to demonstrate the availability of DG E and ensure its OPERABILITY when substituted for any other DG. If the DG Surveillance Requirements, as modified by the associated Notes, are met and performed, DG E can be considered available and OPERABLE when substituted for any other DG after performance of SR 3.8.1.3 and SR 3.8.1.7.

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each offsite circuit.	7 days

(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).
	<u>AND</u>	
	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 from a one-time outage for replacement of Startup Transformer Number 10 to be completed by December 31, 2003

(continued)

ATTACHMENT 3 to PLA-5637

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 Mr. John M. Oddo.

REGULATORY COMMITMENTS	Due Date/Event
	All commitments will be applicable prior to and/or during the transformer replacement, as indicated below:
1. To minimize the transformer replacement time:	
- Experienced personnel will perform the transformer replacement.	Before and during transformer replacement
2. 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. 20 during the transformer replacement:	
• Predictive maintenance trending data will be reviewed for ST No. 20.	Before transformer replacement
• Review of ST No. 20 corrective maintenance work order.	Before transformer replacement
• Engineering Inspections of ST No. 20 for obvious signs of degraded conditions will be performed. These will include:	Before and during transformer replacement
➢ Visually inspect the high voltage bushings and other insulators on ST No. 20 daily. ➢ Perform daily thermography inspections of ST. No. 20. ➢ Trend ST No. 20 and Bus 20 voltage levels and monitor daily.	

REGULATORY COMMITMENTS	Due Date/Event
➢ Perform daily engineering rounds of ST No. 20 to monitor overall performance.	
• Operator Rounds (enhanced based on the INPO SOER 02-3) 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.	During transformer replacement
• High-risk activities within the confines of the plant that may result in a loss of ST No. 20 during the ST No. 10 replacement will be prohibited.	During transformer replacement
• High-risk grid activities that may result in a loss of ST No. 20 during the ST No. 10 replacement will be prohibited.	During transformer replacement
• 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.	During transformer replacement
• Geomagnetic activity from solar storms will be monitored.	Before and during transformer replacement
3. The Susquehanna Steam Electric Station 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.	During transformer replacement
4. Station 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.	Before and during transformer replacement
5. The following systems and components will be required to be available during the ST No. 10 replacement to reduce the plant risk. Elective maintenance will not be performed on these systems	During transformer replacement

REGULATORY COMMITMENTS	Due Date/Event
and components. Any failed system or component will be returned to operable status as soon as possible. (The failed system/component shall be worked around the clock.) If one of these systems or components become unavailable or inoperable, SSES 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 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 0B516073 • U-1 125V DC Battery Charger 0B526073 • 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 0B516071 • U-2 125V DC Battery Charger 0B526071 • 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)	

REGULATORY COMMITMENTS	Due Date/Event
6. Procedures will be strengthened to reflect PRA insights to ensure that model assumptions are valid Procedure change requests have been initiated and the procedures will be revised before October 2003, and were credited in the analysis.	Before transformer replacement
7. If ST No. 20 degrades, SSES will immediately evaluate the impact to determine operability of ST No. 20.	During transformer replacement

ATTACHMENT 4 to PLA-5637

Changes to Technical Specification Bases

No change on this page — Information Only

ACTIONS

A.2 (continued)

hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hours and 6 day Completion Times means that both

(continued)

BASES

ACTIONS

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 10. The temporary completion Time of 10 days expires on December 31, 2003. If during the conduct of the prescribed Startup Transformer Number 10 Replacement, should any combination of the Remaining Operable AC Sources be determined Inoperable (on an individual unit basis), current TS Requirements would apply.

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.

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 Time only begins on discovery that both:

a. An inoperable DG exists; and

(continued)

No change on this page – Information Only

ACTIONS

A.2 (continued)

hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.2 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable, and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A

(continued)

BASES

ACTIONS

A temporary Completion Time is connected to the Completion Time Requirements above (72 hours and 6 days from Discovery of the Failure to meet LCO) with an "OR" connector, the temporary Completion Time is 10 Days and Applies to the Replacement of Startup Transformer Number 10. The Temporary Completion Time of 10 days expires on December 31, 2003. If during the Conduct of the prescribed Startup Transformer Number 10 Replacement, should Any Combination of the Remaining operable AC Sources be determined inoperable (on an individual unit basis), current TS Requirements would apply.

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.

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 Time only begins on discovery that both:

(continued)