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Exelon Nuclear

10 CFR 50.90

RS-03-065

June 11, 2003

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

Braidwood Station, Units 1 and 2
Facility Operating License Nos. NPF-72 and NPF-77
NRC Docket Nos. STN 50-456 and STN 50-457

Byron Station, Units 1 and 2
Facility Operating License Nos. NPF-37 and NPF-66
NRC Docket Nos. STN 50-454 and STN 50-455

Subject: Request for a License Amendment for a One-Time Extension of the Essential Service Water Train Completion Time

In accordance with 10 CFR 50.90, "Application for amendment of license or construction permit," Exelon Generation Company, LLC (EGC) is requesting an amendment to Appendix C, "Additional Conditions," of Facility Operating License Nos. NPF-72, NPF-77, NPF-37, and NPF-66 for Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, respectively. The proposed amendment adds a license condition that would increase the Completion Time (CT) for Required Action A.1, "Restore unit-specific SX train to OPERABLE status," associated with Technical Specifications (TS) Section 3.7.8, "Essential Service Water (SX) System," from 72 hours to 144 hours. This proposed change will only be used one time on each unit at Byron Station and on Unit 1 only at Braidwood Station.

The current TS Limiting Condition for Operation (LCO) 3.7.8.a requires that two unit-specific SX trains (i.e., the "A" and "B" trains) be operable in Modes 1, 2, 3, and 4. Condition A allows one unit-specific SX train to be inoperable with a CT of 72 hours. An extension of the CT to 144 hours is needed to replace the SX pump suction valves used for pump isolation from the SX water supply. Currently, due to long term wear, the suction isolation valves for the 1B and 2B SX pumps at Braidwood Station and all SX pump (i.e., the 1A, 2A, 1B and 2B pumps) suction isolation valves at Byron Station, are degrading such that individual pump isolation on a specific unit may not be adequate to perform pump maintenance or downstream system component maintenance. In order to replace these suction isolation valves, the common upstream suction isolation valve for the 1A and 2A SX pumps (or the common upstream suction isolation valve for the 1B and 2B SX pumps) must be closed and the suction header drained. After draining the common suction header, both the Unit 1 A(B) and Unit 2 A(B) suction isolation valves will be replaced. This evolution is time consuming and maintenance history has shown that completion

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of the needed SX suction isolation valve replacement cannot be assured within the existing 72 hour CT window.

Replacement of the SX suction isolation valves will be conducted during a refueling outage; however, due to the system configuration of the SX system, closing the common suction isolation valve for the 1A and 2A (or 1B and 2B) SX pumps, results in putting the operating unit in a 72 hour LCO. Consequently, not being able to complete the suction isolation valve replacement in the 72 hours CT would result in the operating unit also being shutdown or not completing the required work to improve the material condition of the plant.

Replacement of the SX suction isolation valves is a prudent and proactive action. Having the capability to securely isolate a single SX pump on a single unit will enable necessary system maintenance to be performed thus enhancing the reliability of the SX system and overall plant safety.

The proposed changes have been evaluated using the risk informed processes described in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated July 1998 and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998. The risk associated with the proposed change was found to be acceptable.

The attached amendment request is subdivided as shown below.

Attachment 1 provides an evaluation of the proposed changes and contains the following sections:

1.0 Description

2.0 Proposed Change

3.0 Background

4.0 Technical Analysis

5.0 Regulatory Analysis

5.1 No Significant Hazards Consideration

This section describes our evaluation performed using the criteria in 10 CFR 50.91(a), "Notice for public comment," paragraph (1), which provides information supporting a finding of no significant hazards consideration using the standards in 10 CFR 50.92, "Issuance of amendment," paragraph (c).

5.2 Applicable Regulatory Requirements/Criteria

6.0 Environmental Consideration

This section provides information supporting an Environmental Assessment. We have determined that the proposed changes meet the criteria for a categorical exclusion set forth in paragraph (c)(10) of 10 CFR 51.22, "Criterion for categorical exclusion; identification of licensing and regulatory actions eligible for categorical exclusion or otherwise not requiring environmental review."

7.0 References

Attachments 2 and 3 include the proposed changes to Appendix C, "Additional Conditions," for Braidwood Station and Byron Station, respectively.

Attachment 4 provides a summary of the internal event probabilistic risk assessment (PRA) for Byron and Braidwood Stations, including the changes made to the PRA in the recently completed routine update.

We request approval of the proposed amendment by March 1, 2004, in advance of the Byron Station, Unit 2 Spring 2004 refueling outage. Once approved, the amendment will be implemented within 30 days.

The NRC has previously approved a similar change for the Donald C. Cook Nuclear Plant in Amendment Nos. 270 and 251 for Units 1 and 2, respectively, issued September 9, 2002.

The proposed amendment has been reviewed by the Braidwood Station and the Byron Station Plant Operations Review Committees and approved by their respective Nuclear Safety Review Boards in accordance with the requirements of the Exelon Quality Assurance Program.

EGC is notifying the State of Illinois of this application for a change to the Additional Conditions by sending a copy of this letter and its attachments to the designated State Official.

Should you have any questions concerning this letter, please contact J. A. Bauer at (630) 657-2801.

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

Executed on June 11, 2003

Keith R. Jury

Keith R. Jury
Director - Licensing
Midwest Regional Operating Group

Attachments:
Attachment 1: Evaluation of Proposed Changes
Attachment 2: Proposed Additional Conditions Page Changes for Braidwood Station
Attachment 3: Proposed Additional Conditions Page Changes for Byron Station
Attachment 4: Summary of Byron and Braidwood Probabilistic Risk Assessment

cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Braidwood Station
NRC Senior Resident Inspector – Byron Station

ATTACHMENT 1

EVALUATION OF PROPOSED CHANGES

INDEX

1.0 DESCRIPTION

In accordance with 10 CFR 50.90, "Application for amendment of license or construction permit," Exelon Generation Company, LLC (EGC) is requesting an amendment to Appendix C, "Additional Conditions," of Facility Operating License Nos. NPF-72, NPF-77, NPF-37, and NPF-66 for Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, respectively. The proposed amendment adds a license condition that would increase the Completion Time (CT) for Required Action A.1, "Restore unit-specific SX train to OPERABE status," associated with TS Section 3.7.8, "Essential Service Water (SX) System," from 72 hours to 144 hours. This proposed change will only be used one time on each unit at Byron Station and on Unit 1 only at Braidwood Station.

2.0 PROPOSED CHANGE

The current CT for Required Action A.1, associated with Technical Specifications (TS) Section 3.7.8, is 72 hours.

The proposed amendment adds a license condition to TS, Appendix C, that would increase the CT for Required Action A.1, associated with TS Section 3.7.8, from 72 hours to 144 hours. The proposed license condition states the following:

Byron Station Unit 1

"During the essential service water (SX) pump suction isolation valve replacement, a one-time extension of the Completion Time (CT) for Required Action A.1, associated with Technical Specification 3.7.8, is allowed. The CT may be extended from the existing 72 hours to 144 hours. This extension is applicable only during the work window for the preplanned replacement of the SX suction isolation valves. This extension is subject to the following additional conditions:

1. The CT extension may be invoked only once for Unit 1 while Unit 2 is in Mode 5 or 6.
2. For Unit 1, this CT extension is applicable through the completion of Unit 2 Refueling 11."

Byron Station Unit 2

"During the essential service water (SX) pump suction isolation valve replacement, a one-time extension of the Completion Time (CT) for Required Action A.1, associated with Technical Specification 3.7.8, is allowed. The CT may be extended from the existing 72 hours to 144 hours. This extension is applicable only during the work window for the preplanned replacement of the SX suction isolation valves. This extension is subject to the following additional conditions:

1. The CT extension may be invoked only once for Unit 2 while Unit 1 is in Mode 5 or 6.
2. For Unit 2, this CT extension is applicable through the completion of Unit 1 Refueling 13."

Braidwood Station Unit 1

"During the essential service water (SX) pump suction isolation valve replacement, a one-time extension of the Completion Time (CT) for Required Action A.1, associated with Technical Specification 3.7.8, is allowed. The CT may be extended from the existing 72 hours to 144 hours. This extension is applicable only during the work window for the preplanned replacement of the SX suction isolation valves. This extension is subject to the following additional conditions:

1. The CT extension may be invoked only once for Unit 1 while Unit 2 is in Mode 5 or 6.

2. The CT extension is applicable through the completion of Unit 2 Refueling 11."

Note that for Braidwood Station Unit 2, an extension of the SX train CT is not required as explained in Section 3.0, "Background," below.

The current TS Limiting Condition for Operation (LCO) 3.7.8.a requires that two unit-specific SX trains (i.e., the "A" and "B" trains) be operable in Modes 1, 2, 3, and 4. Condition A allows one unit-specific SX train to be inoperable with a CT of 72 hours. An extension of the CT to 144 hours is needed to replace the SX pump suction valves used for pump isolation from the SX water supply. Currently, due to long term wear, the suction isolation valves for the 1B and 2B SX pumps at Braidwood Station; and all SX pump (i.e., the 1A, 2A, 1B and 2B pumps) suction isolation valves at Byron Station, are degrading such that individual pump isolation on a specific unit may not be adequate to perform pump maintenance or downstream system component maintenance. In order to replace these suction valves, the common upstream suction isolation valve for the 1A and 2A SX pumps (or the common upstream suction isolation valve for the 1B and 2B SX pumps) must be closed and the suction header drained. After draining the common suction header, both the Unit 1 A(B) and Unit 2 A(B) suction isolation valves will be replaced. This evolution is time consuming and maintenance history has shown that completion of the needed SX suction isolation valve replacement cannot be assured within the existing 72 hour CT window.

Replacement of the SX suction isolation valves will be conducted during a refueling outage; however, due to the system configuration of the SX system, closing the common suction isolation valve for the 1A and 2A (or 1B and 2B) SX pumps, results in putting the operating unit in a 72 hour LCO. Consequently, not being able to complete the suction isolation valve replacement in the 72 hours CT would result in the operating unit also being shutdown or not completing the required work to improve the material condition of the plant.

Replacement of the SX suction isolation valves is a prudent and proactive action. Having the capability to securely isolate a single SX pump on a single unit will enable necessary system maintenance to be performed thus enhancing the reliability of the SX system and overall plant safety.

We request approval of the proposed amendment by March 1, 2004, in advance of the Byron Station, Unit 2 Spring 2004 refueling outage. Once approved, the amendment will be implemented within 30 days.

Attachments 2 and 3 include the proposed changes to Appendix C, "Additional Conditions," for Braidwood Station and Byron Station, respectively.

3.0 BACKGROUND

System Description

The SX system is discussed in the Updated Final Safety Analysis Report (UFSAR), Section 9.2.1.2, "Essential Service Water System," (Reference 1).

The SX system provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation and a normal shutdown, the SX system also provides this function for various safety related and non-safety related components.

The unit-specific SX system consists of two separate, electrically independent, 100% capacity, safety related, cooling water trains. Each train consists of a 100% capacity pump, piping, valving, and instrumentation. The pumps and valves are remotely and manually aligned, except in the unlikely event of a Loss of Coolant Accident (LOCA). The pumps are automatically started upon receipt of a safety injection signal or an undervoltage on the Engineered Safety Features (ESF) bus, and all essential valves are aligned to their post accident positions. The SX system is also the backup water supply to the auxiliary feedwater system.

The SX system includes provisions to crosstie the trains (i.e., unit-specific crosstie), as well as provisions to crosstie the units (i.e., opposite-unit crosstie). The opposite-unit crosstie valves (i.e., 1SX005 and 2SX005) must both be open to accomplish the opposite-unit crosstie. The system is normally aligned with the unit-specific crosstie valves open and the opposite-unit crosstie valves closed.

Each full-capacity SX system loop in each unit is supplied by a single pump rated at 24,000 gpm at 180 feet ±10% total developed head. Actual system flow varies with system lineup and conditions. UFSAR Tables 9.2-1, "Essential Service Water Heat Loads," and Table 9.2-11, "Essential Service Water Component Nominal Design Flow Rates," list the components served and the nominal rated component flows. The pumps are located on the lowest level of the auxiliary building to ensure the availability of sufficient net positive suction head (NPSH). Emergency power is available to each pump from its respective ESF bus as shown in UFSAR Table 8.3-5, "Loading on 4160-Volt ESF Buses," and described in UFSAR Section 8.3.1, "Onsite AC Power Systems." At Byron Station, the suction supply is by one supply line running from each of the two redundant essential service mechanical draft cooling towers to the auxiliary building. Each supply line supplies one SX pump in each unit; each of the two pumps in a given unit takes its suction from a separate supply line. At Braidwood Station, the suction supply is by two intake lines running from the Safety Category I portion of the lake screen house essential pond to the auxiliary building. Each intake line supplies one SX pump in each unit; each of the two pumps in a given unit takes its suction from a separate intake line. The system, therefore, meets the single-failure criterion as shown in the analysis in UFSAR Table 9.2-2, "Single-Failure Analysis of the Essential Service Water System," for Braidwood Station, and UFSAR Tables 9.2-2 and 9.2-16, "Single Failure Analysis of the Ultimate Heat Sink," for Byron Station. At Byron Station, heat rejection from the SX system is to the SX cooling towers, both on a normal and on an emergency basis. The discharges from each loop in each unit are separate and fed to two separate and redundant return lines for return to the towers. The two discharges from each unit and the two return lines to the towers are arranged similar to the intakes, i.e., the two discharges from each unit run into separate return lines, and each return line is fed from one discharge from each unit. The single failure criterion is met as shown in UFSAR Tables 9.2-2 and 9.2-16. At Braidwood Station, heat rejection from the SX system is to the essential cooling pond, both on a normal and on an emergency basis. The discharges from each loop in each unit are separate and fed to two separate and redundant return lines for return to the pond. The two discharges from each unit and the two return lines to the pond are arranged similar to the intakes, i.e., the two discharges from each unit run into separate return lines, and each return line is fed from one of the two discharges from each unit. The single-failure criterion is met as shown in UFSAR Table 9.2-2. The essential cooling pond is more fully discussed in UFSAR Section 9.2.5, "Ultimate Heat Sink." At Byron Station, the SX cooling towers are designed to accommodate the heat load from both units simultaneously under both normal and accident conditions. The SX cooling towers and their auxiliary systems are more fully discussed in UFSAR Section 9.2.5.

Safety Analysis

The design basis of the SX system is for one SX train, in conjunction with the Component Cooling (CC) system and a 100% capacity containment cooling system, to remove core decay heat following a design basis LOCA as discussed in the UFSAR, Section 6.2, "Containment Systems." This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is supplied to the reactor coolant system by the emergency core cooling system pumps. The SX system is designed to perform its function with a single failure of any active component, assuming the loss of offsite power.

The SX system, in conjunction with the CC system, also cools the unit from Residual Heat Removal (RHR) entry conditions, as discussed in the UFSAR, Section 5.4.7, (i.e., Reference 2) to Mode 5 during normal and post accident operations. The time required for this evolution is a function of the number of CC and RHR System trains that are operating. One SX train is sufficient to remove decay heat during subsequent operations in Modes 5 and 6.

Note that Generic Letter 91-13, "Request For Information Related to the Resolution of Generic Issue 130, 'Essential Service Water System Failures at Multi-Unit Sites,'" included risk-based recommendations for enhancing the availability of SX systems in the case of a loss of all SX to a particular unit. Crediting the opposite-unit SX system with an opposite-unit pump and the opposite-unit crosstie valves was part of the response to this Generic Letter.

The unit-specific SX system satisfies 10 CFR 50.36, "Technical Specifications," paragraph (c)(2)(ii), Criterion 3. The opposite-unit SX system satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

System Functions

The SX system has three primary functions:

- provide cooling water to safety related equipment and equipment essential to the safe shutdown of the reactor during normal or accident conditions;
- provide backup source of water to the auxiliary feedwater pumps in the event the condensate storage tank (CST) is not available; and
- provide safety-related back-up source of water to the fire protection system.

The risk-informed technical evaluation described in Section 4.0 considered the risk impacts on each of these functions.

Need for Amendment

As noted above, the current TS LCO 3.7.8.a requires that two unit-specific SX trains (i.e., the "A" and "B" trains) be operable in Modes 1, 2, 3, and 4. Condition A allows one unit-specific SX train to be inoperable with a CT of 72 hours. An extension of the CT to 144 hours is needed to replace the SX pump suction valves used for pump isolation from the SX water supply. Currently, due to long term wear, the suction isolation valves for the 1B and 2B SX pumps at Braidwood Station; and all SX pump (i.e., the 1A, 2A, 1B and 2B pumps) suction isolation valves at Byron Station, are degrading such that individual pump isolation on a specific unit may not be adequate to perform pump maintenance or downstream system component maintenance. In order to replace these suction isolation valves, the common upstream suction isolation valve for the 1A and 2A SX pumps (or the common upstream suction isolation valve for the 1B and 2B SX pumps) must be closed and the suction header drained. This evolution is time consuming and maintenance history has shown that completion of the needed SX suction isolation valve replacement cannot be assured within the existing 72 hour CT window.

Replacement of the SX suction isolation valves will be conducted during a refueling outage; however, due to the system configuration of the SX system, closing the common suction isolation valve for the 1A and 2A (or 1B and 2B) SX pumps, results in putting the operating unit in a 72 hour LCO. Consequently, not being able to complete the suction isolation valve replacement in the 72 hours CT would result in the operating unit also being shutdown or not completing the required work to improve the material condition of the plant.

Note that only the Braidwood Station 1B and 2B SX pump suction isolation valves need to be replaced as the 1A and 2A SX pump suction isolation valves were previously replaced during a Unit 1 refueling outage; however, completion of the repairs within the existing 72 hour CT was extremely difficult. Replacement of the B train valves will require a Unit 2 refueling outage due to personnel safety issues as the B train of SX takes a suction from the Unit 2 circulating water bays. A diver will be sent into the SX suction line to install isolation "balloons" for double isolation; therefore, the Unit 2 circulating water system needs to be secured.

The NRC has previously approved a similar change for the Donald C. Cook Nuclear Plant in Amendment Nos. 270 and 251 for Units 1 and 2, respectively, issued September 9, 2002.

4.0 TECHNICAL ANALYSIS

The proposed changes have been evaluated using the risk informed processes described in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated July 1998 and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998.

In implementing risk-informed decision-making under the NRC's RGs 1.174 and 1.177, Technical Specification changes are expected to meet a set of five key principles. These principles include consideration of both traditional engineering factors (e.g., defense in depth and safety margins) and risk information. This section provides a summary of the technical analysis of the proposed change in SX CT that considers each one of these principles.

- *The proposed change meets the current regulations unless it is explicitly related to a requested exemption or rule change.*

  This change is being requested as a change to the operating licenses for Byron and Braidwood Stations.

- *The proposed change is consistent with the defense-in-depth philosophy.*

  Defense in depth considerations are considered and summarized in Section 4.1.

- *The proposed change maintains sufficient safety margins.*

  Safety margin is not impacted by the proposed change as summarized in Section 4.2.

- *When proposed changes result in an increase in core damage frequency or risk, the increases should be small and consistent with the intent of the Commission's Safety Goal Policy Statement.*

  A risk evaluation is presented in Section 4.3 that considers the impact of the proposed change with respect to the risks due to:

  - internal events,
  - internal fires,
  - seismic events, and
  - other external hazards.

  The quantitative acceptance guidelines are discussed in Section 4.3.1.1.

  In addition, although not required, the risk implications of the proposed SX CT are also qualitatively evaluated for the unit that will be shutdown during the evolution, consistent with EGC's risk management practices.

- *The impact of the proposed change should be monitored using performance measurement strategies.*

  The three-tiered implementation approach consistent with RG 1.177 is used, as described in Section 4.3.

4.1 DEFENSE IN DEPTH EVALUATION

The configuration to be entered decreases the redundancy of the Essential Service Water (SX) system due to the removal of two of the four SX pumps from service simultaneously. The reduced redundancy increases the potential for the plant to lose SX cooling to plant equipment. However, the actual plant design and supporting analyses demonstrate that the plant has additional capability to prevent and mitigate a loss of SX to a unit than credited in the current plant licensing basis, (e.g., the backup fire protection system cooling to the Chemical and Volume Control (CV) centrifugal charging pumps which is not credited in the licensing basis).

The evaluation of defense in depth considerations for this proposed change considered the impact of the proposed configuration on the ability of the SX system to perform its intended functions and addresses the defense in depth considerations identified in RG 1.174.

The conclusion of this evaluation is that the one-time entrance into this configuration maintains the principles of defense-in-depth.

4.1.1 Functional Assessment

<u>Current Licensing Basis</u>

As described in Section 3.0, the current licensing basis for SX operation relies upon one SX pump providing adequate flow to important loads of that unit. In the event of loss of the operating SX pump, the second pump could be manually started to restore flow. In the event the second pump is unavailable, the opposite-unit crosstie could be opened to provide flow from the two pumps of the opposite unit. These features are controlled by plant Technical Specifications.

<u>Best Estimate Analysis</u>

A best estimate SX flow analysis was completed which demonstrates that one SX pump from either unit is capable of supporting shutdown loads of both units (with the exception of the reactor containment fan coolers (RCFC's) and emergency diesel generators (EDGs)). Thus, the first line of defense is the second pump of the unit, followed by the opposite-unit crosstie; however, only one of the two SX pumps from the opposite unit is required to operate.

In addition, Byron and Braidwood Stations have installed a modification to allow fire protection cooling to the centrifugal charging pumps (i.e., CV pumps) in order to provide a continued flow of seal injection to the reactor coolant pump (RCP) seals in the event of loss of all SX. This capability, combined with the capability of the diesel-driven auxiliary feedwater pump and the startup and motor driven main feedwater pumps to operate without SX flow, allows the plant to maintain a hot standby condition in the event of loss of all SX.

SX LCO Configuration

The proposed configuration considered in the CT extension involves having one of the SX pumps for each unit out of service simultaneously. This configuration eliminates the capability to start the second SX pump, but does not prevent the use of the opposite-unit crosstie or maintaining hot standby in the event all SX is lost.

Thus, while the level of redundancy is somewhat reduced in the proposed configuration, the plant retains a substantial defense-in-depth capability, beyond that considered in the current licensing basis.

Table 1 provides a comparison of the licensing basis related to preventing and mitigating a loss of SX and the best estimate analysis. In addition, these features are compared to the plant capability in the proposed configuration.

4.1.2 Regulatory Guide 1.174 Considerations

RG 1.174 provides additional guidance on how defense in depth should be evaluated. These elements are evaluated in Table 2 for the planned SX configuration.

Table 1
Defense In Depth Assessment of Planned SX Configuration

Basis of Evaluation	**Restore Operating Unit SX**	**Opposite-Unit Crosstie**	**Supply SX From Shutdown Unit (in order to shutdown the operating unit and maintain cooling on the shutdown unit)**	**Maintain Hot Standby With Loss of SX**
Licensing Basis	Start 2nd unit SX pump (i.e., following assumed single failure of running SX pump)	Open X-tie valves if 2nd operating unit SX pump fails	2 of 2 pumps required from shutdown unit	N/A
Best Estimate Analysis	Start 2nd unit SX pump (i.e., following assumed single failure of running SX pump)	Open X-tie valves if 2nd operating unit SX pump fails	1 of 2 pumps required from shutdown unit	• Provide FP cooling to CV pump for RCP seal cooling • Diesel driven AF pump or main feedwater provides heat removal
License Condition	Assume single failure of running SX pump, 2nd unit SX pump unavailable due to maintenance	Open X-tie valves due to unavailability of 2nd unit SX pump on operating unit	1 available pump required from shutdown unit, 2nd unit SX pump on shutdown unit also unavailable due to maintenance	• Provide FP cooling to CV pump for RCP seal cooling • Diesel driven AF pump or main feedwater provides heat removal

Table 2
Consideration of RG 1.174 Defense-In-Depth Guidelines

Guideline	Evaluation
A reasonable balance is preserved among prevention of core damage, prevention of containment failure, and consequence mitigation.	No new challenge to core damage, containment failure, or consequence mitigation is introduced by this one-time change.
Over-reliance on programmatic activities to compensate for weaknesses in plant design is avoided.	The plant design is not being changed. Some compensatory measures have been identified to maintain low risk, but these measures are consistent with normal plant practices.
System redundancy, independence, and diversity are preserved commensurate with the expected frequency, consequences of challenges to the system, and uncertainties (e.g., no risk outliers).	The risk analysis addresses this issue directly. However, Table 1 provides a summary of the redundancy and diversity of success paths. This analysis demonstrates that substantial defense-in-depth is maintained.
Defenses against potential common cause failures are preserved, and the potential for the introduction of new common cause failure mechanisms is assessed.	No new common cause mechanisms are introduced by this change. Where defenses against potential common cause failures were impacted, (i.e., fire scenarios), additional compensatory measures have been identified to mitigate the impact.
Independence of barriers is not degraded.	This change has no impact on the independence of barriers.
Defenses against human errors are preserved.	This change has no impact on the defense against human errors. The compensatory measures put in place should improve defenses against human errors.
The intent of the General Design Criteria (GDC) in Appendix A to 10 CFR Part 50 is maintained.	The current SX LCO allows an SX train to be inoperable for 72 hours which is a temporary deviation from the GDC provision to provide protection from single failures. This change only extends the 72 hour Completion Time to 144 hours; therefore, the change does not further impact the GDC.

4.2 SAFETY MARGIN EVALUATION

The proposed TS change is consistent with the principle that sufficient safety margins are maintained based on the following:

- Codes and standards (e.g., American Society of Mechanical Engineers (ASME), Institute of Electrical and Electronic Engineers (IEEE) or alternatives approved for use by the NRC) are met. The proposed change is not in conflict with approved codes and standards relevant to the SX system.

- While in the proposed configuration, safety analysis acceptance criteria in the UFSAR are met, assuming there are no additional failures.

This is consistent with the guidelines provided in RG 1.177 for permanent risk-informed changes to Technical Specifications.

4.3 RISK EVALUATION

The risk impact of the proposed changes has been evaluated and found to be acceptable. The effect on risk of the proposed increase in Completion Time for restoring an inoperable SX train has been evaluated using the NRC three-tier approach suggested in RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," August, 1998 (Reference 4). Although RG 1.177 is primarily intended for permanent changes to plant Technical Specifications, the general framework of considerations is considered applicable:

Tier 1 – Probabilistic Risk Assessment (PRA) Capability and Insights
Tier 2 - Avoidance of Risk-Significant Plant Configurations
Tier 3 - Risk-Informed Configuration Risk Management

4.3.1 Tier 1: PRA Capability and Insights

Risk-informed support for the proposed change is based on PRA calculations performed to quantify the Incremental Conditional Core Damage Probability (ICCDP) and the Incremental Conditional Large Early Release Probability (ICLERP) resulting from the increased Completion Time for the SX train. These ICCDP and ICLERP values are also equivalent to the increase in Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) as each unit will only enter the extended Completion Time once.

The Byron Station and Braidwood Station PRAs were recently updated in accordance with the Exelon PRA Maintenance Program (i.e., periodic update). Attachment 4 provides a brief summary of these PRAs as well as a description of the changes that were made to the PRA subsequent to the request to extend the EDG Completion Time (see Reference 5). The PRAs address internal events at full power, including internal flooding. Other risk sources and operating modes are discussed qualitatively below. In addition to incorporating recent advances in PRA technology across all elements of the PRA, a special effort was made to ensure that those aspects of the PRA that are potentially sensitive to changes in SX pump maintenance unavailability are adequate to evaluate the risk impacts of the increased Completion Time for the SX pumps. These elements include:

- the impact of maintenance unavailability on the loss of SX initiating event frequencies;
- treatment of the SX unit and train crosstie capability;

- use of plant specific data; and
- operator interviews to validate appropriate characterization of operator actions available to mitigate a loss of SX initiating event.

The Byron Station and Braidwood Station LERF model uses a realistic, plant-specific model that is an extension of the methodology described in NUREG/CR-6595, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events," January 1999. This model supports a realistic quantification of LERF based on:

- plant damage states that reflect the appropriate plant conditions at the time of core damage,
- containment isolation failures based on plant-specific system models,
- plant-specific analysis of containment bypass sequences (i.e., interfacing system LOCA and steam generator tube rupture (SGTR)),
- realistic, plant-specific assessment of unit-specific containment ultimate pressure capability,
- important severe accident phenomena including high pressure melt ejection and induced steam generator tube rupture, and
- plant-specific thermal hydraulic analyses reflecting the severe accident conditions expected to be present.

The scope, level of detail, and quality of the Byron Station and Braidwood Station PRAs are sufficient to support a technically defensible and realistic evaluation of the risk change from this proposed Completion Time extension. Updating and maintenance of the Byron and Braidwood Stations PRAs is controlled under Exelon Nuclear Engineering Procedure, ER-AA-600, "Risk Management."

An independent assessment of the Byron and Braidwood Stations PRAs, using the self-assessment process developed as part of the Westinghouse Owners Group (WOG) PRA Peer Review Certification Program, was conducted by a recognized industry expert. This independent review was performed from May through July of 1999 to evaluate the quality of the PRAs and completeness of the PRA documentation. Substantive comments and observations generated by this assessment, including those focused on the risk elements that are needed to evaluate the proposed Completion Time extension, have been addressed. Peer review certification of the Braidwood Station PRA using the WOG Peer Review Certification Guidelines was performed in August 1999. Certification of the Byron Station PRA was performed in July 2000. A team of independent PRA experts from U.S. nuclear utility PRA groups and PRA consultant organizations carried out these peer review certifications. The intensive peer reviews involved approximately two person-months of engineering effort by the review team and provided a comprehensive assessment of the strengths and limitations of each element of the PRA. All of the findings and observations from these assessments that the review team indicated were important and those that involved risk elements needed to evaluate the proposed Completion Time extension were dispositioned. This resulted in a number of enhancements to the PRA models prior to their use to support the proposed change. As a result of the considerable effort to incorporate the latest industry insights into the PRA upgrades, self-assessments, and certification peer reviews, EGC is confident that the results of the risk evaluation are technically sound and consistent with the expectations for PRA quality set forth in RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," July 1998 (Reference 3) and RG 1.177 (Reference 4).

Byron and Braidwood Stations evaluated the risks of external hazards as part of the Individual Plant Examination of External Events (IPEEE) process. Performed in the late 1990s, these evaluations included qualitative and conservative quantitative estimates of the plant capability to mitigate a range of potential external hazards. Since the time of the IPEEEs, the plants have made a number of plant improvements, including the addition of the capability to cool the centrifugal charging pumps using water from the fire protection system. The IPEEE analyses have not been updated to reflect the as-built, as-operated plant. As a result, for the purposes of this submittal, the risks from external hazards are considered in a qualitative manner or with bounding quantitative methods using the insights from the internal events PRA.

4.3.1.1 Quantitative Acceptance Guidelines

No specific quantitative guidelines are provided in RGs 1.174 and 1.177 for one-time risk-informed changes. The quantitative acceptance guidelines in Section 2.2.4 of RG 1.174 are expressed in terms of changes to the annual average impact on CDF and LERF. Since this is a one-time change, the risk impact would not result in an on-going change in CDF and LERF. Nevertheless, as a point of reference, the quantitative acceptance guidelines in RG 1.174 state that a long-term increase in CDF of less than 1E-6/yr and LERF of less than 1E-7/yr would be considered to be "very small."

RG 1.177 was developed specifically for TS changes. However, the acceptance guidelines provided in Section 2.4 (ICCDP < 5E-7, ICLERP < 5E-8) are clearly stated to be "applicable only to permanent (as opposed to temporary, or "one time") changes to TS requirements."

NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," (Reference 6) addresses monitoring risk during maintenance activities and provides quantitative guidelines that indicate that routine activities should generally not involve an increase in ICCDP of greater than 1E-6 or an ICLERP of greater than 1E-7. This planned one-time configuration would not be considered routine maintenance. NUMARC 93-01 also recommends that an upper limit configuration-specific CDF of 1E-3/yr be used.

Based on the available quantitative guidelines for other applications, it is judged that the quantitative criteria shown in Table 3 represent a reasonable set of acceptance guidelines. Less restrictive guidelines could also be justified, but for the purposes of this evaluation, these guidelines demonstrate that the risk impacts are acceptably low.

Table 3
Proposed Risk Acceptance Guidelines

RISK ACCEPTANCE GUIDELINE	BASIS
ICCDP < 1E-6	• ICCDP appropriate metric for assessing risk impacts of out of service equipment per RG 1.177 and NUMARC 93-01 • 1E-6 consistent with NUMARC 93-01 guidance for routine maintenance and RG 1.174 increases assessed as "very small" • Greater than RG 1.177 guideline (5E-7) for permanent TS changes which are allowed to be entered repeatedly over the life of the plant.
ICLERP < 1E-7	• ICLERP appropriate metric for assessing risk impacts of out of service equipment per RG 1.177 and NUMARC 93-01 • 1E-7 consistent with NUMARC 93-01 guidance for routine maintenance and RG 1.174 increases assessed as "very small" • Greater than RG 1.177 guideline (5E-8) for permanent TS changes which are allowed to be entered repeatedly over the life of the plant.
Configuration-specific CDF < 1E-3/yr	• NUMARC 93-01 recommends configurations exceeding this guideline be avoided.

4.3.1.2 Risk from Internal Events

The Byron and Braidwood Stations internal events PRA was used as a tool to evaluate the quantitative risk impacts due to internal events during the planned SX configuration. To determine the effect of the proposed 144-hour Completion Time for restoration of an inoperable SX train, the guidance suggested in RG 1.177 was used. Thus, the following risk metrics were used to evaluate the risk impacts of extending the SX train Completion Time from 72 hours to 144 hours.

ICCDP{xY} = incremental conditional core damage probability with SX train Y on Unit x out-of-service for an interval of time equal to the proposed new Completion Time (i.e.,144 hours).

ICLERP{xY} = incremental conditional large early release probability with SX train Y on Unit x out-of-service for an interval of time equal to the proposed new Completion Time (i.e., 144 hours).

The ICCDP and ICLERP are computed using definitions in RG 1.177. In terms of the above defined parameters, the definition of ICCDP is as follows.

$$ICCDP_{xY} = (CDF_{xYOOS} - CDF_{xBASE}) * T_{CT}$$
$$ICCDP_{xY} = (CDF_{xYOOS} - CDF_{xBASE}) * (6days) * (365days / year)^{-1}$$
$$ICCDP_{xY} = (CDF_{xYOOS} - CDF_{xBASE}) * 1.64x10^{-2}$$

Where the following definitions were applied:

T_{CT} = the requested Completion Time.

Note that in the above formula, 365 days/year is merely a conversion factor to get the Completion Time units consistent with the CDF frequency units. The ICCDP values are dimensionless probabilities to evaluate the incremental probability of a core damage event over a period of time equal to the extended Completion Time.

Similarly, ICLERP is defined as follows.

$$ICLERP_{xY} = (LERF_{xYOOS} - LERF_{xBASE}) * 1.64x10^{-2}$$

The intermediate results of the risk evaluation are presented in Table 4, "Intermediate Results of Risk Evaluation for Braidwood Station," and Table 5, "Intermediate Results of Risk Evaluation for Byron Station." These tables show the results for each train dependent calculation of risk metrics. The base CDF values for each unit are 6E-05/year based on the average unavailability of the SX pumps using plant specific data.

The risk evaluation of internal events incorporates a number of compensatory measures that the plant will take to assure the risk impacts are acceptably low. These measures include the following.

- Restrict maintenance on CC heat exchangers including the opposite-unit SX cross-tie valves.
- Restrict maintenance on AFW.
- Restrict maintenance on the station auxiliary transformers (SATs).
- Restrict maintenance on appropriate electrical power equipment, including key 4KV buses, EDGs and battery chargers.
- Isolate appropriate RCFCs.
- Provide "dedicated" operators to monitor SX and respond to any SX-related problems (e.g., cross-connect SX).

Tables 12-1 through 12-3 provide details on how these compensatory measures are applied during the maintenance evolutions at each unit.

Credit for the dedicated operator to maintain and respond to SX-related problems is recognized as a key compensatory measure. Implementation of the dedicated operator will include:

- training emphasis on establishing the SX unit crosstie and alternate cooling for the CV pumps for control room operators and equipment operators;

- assignment of dedicated operators inside and outside the control room to back up the nominal staff for these actions. These personnel represent additional operators (i.e., one senior reactor operator (SRO) in the control room, one reactor operator (RO), and one equipment operator) assigned to monitor SX performance and take these actions as a back up to the nominal shift staff;
- conducting training to walk through the alignment actions with designated operators prior to entering the SX LCO;
- briefings on the SX alignment and the conditions that could require performance of these operator actions at each shift change;
- providing copies of the procedures for the action to align fire protection cooling to the designated equipment operators prior to each shift change to minimize the need to locate the procedures during loss of SX conditions; and
- placing ladders/stepping stools in locations where the fire protection hose hookup is above the height that an operator can reach it without assistance (such as the B charging pump rooms at Byron Station).

Table 4
Intermediate Results of Risk Evaluation for Braidwood Station

Risk Metric	Unit 1
	1SX01PB and 2SX01PB
CDF_{xBASE}	6E-5
CDF_{xYOOS}	8E-5
$LERF_{xBASE}$	5E-6
$LERF_{xYOOS}$	5E-6

Table 5
Intermediate Results of Risk Evaluation for Byron Station

Risk Metric	Unit 1	Unit 2
	1SX01PB and 2SX01PB	1SX01PA and 2SX01PA
CDF_{xBASE}	6E-5	6E-5
CDF_{xYOOS}	8E-5	8E-5
$LERF_{xBASE}$	5E-6	6E-6
$LERF_{xYOOS}$	5E-6	7E-6

NOTE: The difference in LERF values between Unit 1 and Unit 2 are due to a lower ultimate containment failure pressure resulting from differences in electrical penetrations.

Comparison of Risk Acceptance Guidelines

The results of the risk evaluation are compared in Table 6 with the risk acceptance guidelines from Table 3. The values for the ICCDP and the ICLERP demonstrate that the proposed SX train Completion Time change has a very small quantitative impact on plant risk.

Table 6
Results of Risk Evaluation for Braidwood and Byron Stations

Risk Metric	Risk Acceptance Guideline	Risk Metric Results		
		Braidwood	Byron	
		Unit 1	Unit 1	Unit 2
ICCDP	< 1E-6	3E-7	3E-7	3E-7
ICLERP	< 1E-7	7E-9	5E-9	1E-8
CDF	< 1E-3/yr	8E-5	8E-5	8E-5

Conclusions Related to Internal Event Risks

The evaluation of the quantitative impacts of internal event risks due to the planned configuration demonstrate that the impact on the likelihood of core damage and large early release is well below the risk acceptance guidelines.

4.3.1.3 Risk from Internal Fires

A quantitative analysis of internal fire vulnerabilities was conducted as part of the Byron and Braidwood Stations IPEEE. The Byron Station IPEEE was submitted to the NRC on December 23, 1996, and the Braidwood Station IPEEE was submitted to the NRC on June 27, 1997. Requests for additional information (RAIs) were issued by the NRC on July 23, 1998, and July 9, 1998, for the Byron and Braidwood Stations, respectively. Responses to most of the station-specific questions in the RAIs were provided on January 29, 1999. Plant-specific responses to the generic fire issues were provided on July 15, 1999, after the Electric Power Research Institute (EPRI) and Nuclear Electric Institute (NEI) final generic responses were issued.

The IPEEE fire analysis results were not combined with the internal events PRA results since the fire analysis was based on a screening process using the EPRI Fire Induced Vulnerability Evaluation (FIVE) Programs in contrast with the realistic assessment of risk contributors in the internal events PRA. The majority of fire zones were screened out due to lack of PRA targets or based on combustible material, fire detection, fire mitigation, and spatial separation.

The IPEEE fire analyses at the Byron and Braidwood Stations resulted in a low fire CDF and did not identify any vulnerabilities. As discussed above, due to the nature of the fire IPEEE analysis and the safety improvements made at the plants subsequent to the submittal of the IPEEEs, a quantitative fire evaluation is not within the current capability of the Byron Station and Braidwood Station PRAs.

Therefore, a qualitative assessment was performed to identify the areas of the plant where the configuration to be entered could lead to increased fire risks. The following process was used.

- Plant equipment and cable location data were reviewed to identify fire scenarios where the SX LCO configuration could result in an increase in fire risk.
- For each of those areas, the internal events PRA was used to identify whether a success path for achieving safe shutdown could be identified for that area.
- Compensatory measures, including those considered in the internal events analysis, were identified to reduce the likelihood of a fire in those areas and increase the mitigation capability.

The compensatory measures identified through the assessment of internal events included establishing restrictions on concurrent maintenance activities on several plant components and trains. These compensatory actions are summarized in Table 7. It should be noted that Table 7 is an index of all fire related compensatory measures. The applicability of each action to any specific unit is provided in Tables 9-1 through 9-3.

Table 7
Table of Compensatory Measures

Code	Compensatory Measure	Fire Specific
CC-0	Restrict maintenance on CC HX 0, to include 1SX005 and 2SX005	
AF-1A	Restrict maintenance on AFW Train 1A	
AF-1B	Restrict maintenance on AFW Train 1B	X
AF-2A	Restrict maintenance on AFW Train 2A	
AF-2B	Restrict maintenance on AFW Train 2B	X
SAT-1	Restrict maintenance on Unit 1 station auxiliary transformers (SATs)	
SAT-2	Restrict maintenance on Unit 2 SATs	
AP-141	Restrict maintenance on Unit 1 Train A electrical power, to include 4KV Bus 141, Diesel Generators (DG) 1A and Battery Charger 111	
AP-241	Restrict maintenance on Unit 2 Train A electrical power, to include 4KV Bus 241, DG 2A and Battery Charger 211	
DG-1A	Restrict maintenance on DG 1A	
DG-2A	Restrict maintenance on DG 2A	
DG-1B	Restrict maintenance on DG 1B	
DG-2B	Restrict maintenance on DG 2B	
OP-SX	"Dedicated" operators to monitor SX and respond to any SX-related problems (e.g., cross-connect SX)	
CV-1B	Restrict maintenance on CV-1B	X
CV-2A	Restrict maintenance on CV-2A	X
1SX-004	De-energize 1SX004 to prevent spurious closure	X
1SX-007	De-energize 1SX007 to prevent spurious closure	X
RH-1B	Restrict maintenance on Residual Heat Removal (RH) Train 1B	X
RH-2A	Restrict maintenance on RH Train 2A	X
RW	Establish roving fire watch for applicable zones	X
PW	Establish a full time fire watch for applicable zones	X
TR-CMB	Transient combustible control	X
OP-FIRE	Special instructions or precautions provided to operations for specific scenarios	X

Fire-specific compensatory measures are noted in Table 7 and are summarized below.

1. Remove power from the SX007 and SX004 valves to preclude spurious closure of these valves (due to so-called "smart shorts"), which would result in loss of cooling to the applicable CC heat exchanger.

2. Restrict maintenance on the following additional trains:
   - AF 1B and 2B
   - RH 1B and 2A
   - CV 1B and 2A

3. Establish fire watches

4. Establish transient combustible free zones

5. Establish a permanent fire watch to provide early detection of a fire in motor control center (MCC) 232X1. If indications of a fire are identified, the control room will be contacted to de-energize the MCC followed by actions to locally suppress the fire. (Note: This item is for Byron Station, Unit 2 only).

Tables 8-1 and 8-2 list the fire scenarios that comprise the majority of the risk due to fire while the SX pumps are in maintenance. The table is sorted from most risk significant to least, after the recommended compensatory measures discussed above have been considered.

Table 8-1
List of Important Fire Scenarios
for Unit 1 with SX Trains 1B/2B in Maintenance

No.	Fire Zone	Scenario ID - Description
1	11.1A-0	A - Unit 1 Auxiliary Building Basement
2	11.4C-0	B - Remote Shutdown Panel Area
3	11.5-0	B - MCC 133X3 Fire
4	11.6-0	D/E - Riser Fire at Q-14 (El 346')
5	5.2-2	A - Division 21 4kV Switchgear Room
6	11.6-0	B - MCC 131X5 Fire
7	18.2-1	A - DG 1A/Switchfear Room Air Shaft
8	11.6C-0	B - Auxiliary Building Laundry Room (Braidwood only)
9	11.3-1	B - MCC 131X1 Severe Fire
10	11.3-0	C - MCC 133V1 Severe Fire
11	5.2-1	B - 4kV Bus 141 Small Fire

Table 8-2
List of Important Fire Scenarios
for Unit 2 with SX Trains 1A/2A in Maintenance

No.	Fire Zone	Scenario ID - Description
1	11.1B-0	A - Unit 2 Auxiliary Building Basement
2	11.4-0	D - MCC 232X1 Severe Fire
3	5.1-2	C - Large 4KV Bus Fire in Div 22 Swgr Rm
4	11.4-0	E - MCC 232X3 Severe Fire
5	3.1-2	B/D - Unit 2 Cable Tunnel
6	3.2B-2	B/C - Unit 2 Lower Cable Spreading Room
7	3.2A-2	E - Unit 2 LCSR, Riser Fire at Q-26
8	3.2-0	B/C - Riser Fire at P-19 (Elev 439')
9	11.6-0	Q/S - Riser Fire at P-19 (Elev 426')
10	3.2C-2	B/C - Unit 2 Lower Cable Spreading Room
11	11.4-0	M/T - Riser Fire at P-19 (Elev 383')
12	11.4C-0	C - Remote Shutdown Control Room
13	11.6-2	C - MCC 232X4 Severe Fire
14	3.1-1	A - Unit 1 Cable Tunnel
15	11.6-0	C - MCC 132X5 Fire
16	3.2A-2	B - Unit 2 LCSR, Riser Fire at L-28.5
17	2.1-0	I -Panel 2PM01J
18	11.5-0	R/S - Riser Fire at M-24/25 and P/Q-19
19	11.3-2	C/D/E - Riser Fires at Y-24, W-23 and X-23

Tables 9-1 through 9-3 provide a synopsis of these scenarios, the success paths available and the significant compensatory actions that are applicable for each scenario.

Conclusions Related to Fire Risk

A success path to prevent core damage has been identified for every fire scenario that has a significant increase in risk due to the planned SX system configuration. In addition, compensatory measures have been identified that further reduce the risk of these fire scenarios.

Table 9-1
Summary of Dominant Fire Risk Scenarios
Braidwood Unit 1 with SX Train B Maintenance

No.	Fire Zone	Scenario ID / Scenario Description	Success Paths	Compensatory Measures
1	11.1A-0	A - Unit 1 Auxiliary Building Basement	A. Align FP cooling to CV pump to preclude RCP seal LOCA and remove decay heat with B AF.	AF-1B, OP-SX, SAT-1, RW
2	11.4C-0	B - Remote Shutdown Panel Area	A. Align FP cooling to CV pump to preclude RCP seal LOCA and remove decay heat with B AF.	AF-1B, OP-SX, CV-1B, SAT-1, RW
3	11.5-0	B - MCC 133X3 Fire	A. Cross-connect SX and remove decay heat with A/B AF or B train feed and bleed. B. Align FP cooling to CV pump and remove decay heat with B AF.	CC-0,AF-1B,RH-1B,OP-SX, RW
4	11.6-0	D/E - Riser Fire @ Q-14 (El 346')	A. Align FP cooling to CV pump to preclude RCP seal LOCA and remove decay heat with B AF.	AF-1B, OP-SX, CV-1B, TR-CMB, RW
5	5.2-2	A - Division 21 4kV Switchgear Room	A. Energize Bus 141 (recovers SX pump 1A) and remove decay heat with A/B AF or Train A feed and bleed.	AF-1A, AF-1B, AP-141
6	11.6-0	B - MCC 131X5 Fire	A. Re-energize Bus 241 (recovers SX pump 2A), cross-connect SX and remove decay heat with B AF or B train feed and bleed. B. Align FP to CV pump and remove decay heat with B AF.	CC-0, AF-1B, DG-2A, RH-1B, OP-SX, RW
7	18.2-1	A - DG1A Switchgear Room/Air Shaft	A. Cross-connect SX and remove decay heat with either train of AF or feed and bleed. B. Align FP cooling to CV pump and remove decay heat with B AF.	CC-0,AF-1B,OP-SX, SAT-1, TR-CMB, RW
8	11.6C-0	B - Aux Building Laundry Room	A. Cross-connect SX and remove decay heat with B AF or B train feed and bleed. B. Align FP cooling to CV pump and remove decay heat with B AF.	CC-0, AF-1B, RH-1B, OP-SX, DG-2A, RW, TR-CMB
9	11.3-1	B - MCC 131X1 Severe Fire	A. Cross-connect SX, mitigate LOCA with B ECCS and remove decay heat via B AF or B train feed and bleed.	CC-0, AF-1B, RH-1B, 1SX-004, OP-SX. RW
10	11.3-0	C - MCC 133V1 Severe Fire	A. Cross-connect SX, mitigate seal LOCA with B ECCS, and remove decay heat via B AF or B train feed and bleed.	CC-0, AF-1B, AF-B-SX, RH-1B, OP-SX, 1SX-004, RW
11	5.2-1	B - 4kV Bus 141 Small Fire	A. Cross-connect SX and remove decay heat with B AF or B train feed and bleed. B. Align FP cooling to CV pump and remove decay heat with B AF or FW (requires cross-connecting DC prior to battery depletion).	CC-0, AF-1B, RH-1B, OP-SX

Table 9-2
Summary of Dominant Fire Risk Scenarios
Byron Unit 1 with SX Train B Maintenance

No.	Fire Zone	Scenario ID / Scenario Description	Success Paths	Compensatory Measures
1	11.1A-0	A - Unit 1 Auxiliary Building Basement	A. Align FP cooling to CV pump to preclude RCP seal LOCA and remove decay heat with B AF.	AF-1B, OP-SX, SAT-1, RW
2	11.4C-0	B - Remote Shutdown Panel Area	A. Align FP cooling to CV pump to preclude RCP seal LOCA and remove decay heat with B AF.	AF-1B, OP-SX, CV-1B, SAT-1, RW
3	11.5-0	B - MCC 133X3 Fire	A. Cross-connect SX and remove decay heat with A/B AF or B train feed and bleed. B. Align FP cooling to CV pump and remove decay heat with B AF.	CC-0,AF-1B,RH-1B,OP-SX, RW
4	11.6-0	D/E - Riser Fire @ Q-14 (El 346')	A. Align FP cooling to CV pump to preclude RCP seal LOCA and remove decay heat with B AF.	AF-1B, OP-SX, CV-1B, TR-CMB, RW
5	5.2-2	A - Division 21 4kV Switchgear Room	A. Energize Bus 141 (recovers SX pump 1A) and remove decay heat with A/B AF or Train A feed and bleed.	AF-1A, AF-1B, AP-141
6	11.6-0	B - MCC 131X5 Fire	A. Re-energize Bus 241 (recovers SX pump 2A), cross-connect SX and remove decay heat with B AF or B train feed and bleed. B. Align FP to CV pump and remove decay heat with B AF.	CC-0, AF-1B, DG-2A, RH-1B, OP-SX, RW
7	18.2-1	A - DG1A Switchgear Room/Air Shaft	A. Cross-connect SX and remove decay heat with either train of AF or feed and bleed. B. Align FP cooling to CV pump and remove decay heat with B AF.	CC-0,AF-1B,OP-SX, SAT-1, TR-CMB, RW
8	11.3-1	B - MCC 131X1 Severe Fire	A. Cross-connect SX, mitigate LOCA with B ECCS and remove decay heat via B AF or B train feed and bleed.	CC-0, AF-1B, RH-1B, 1SX-004, OP-SX. RW
9	11.3-0	C - MCC 133V1 Severe Fire	A. Cross-connect SX, mitigate seal LOCA with B ECCS, and remove decay heat via B AF or B train feed and bleed.	CC-0, AF-1B, AF-B-SX, RH-1B, OP-SX, 1SX-004, RW
10	5.2-1	B - 4kV Bus 141 Small Fire	A. Cross-connect SX and remove decay heat with B AF or B train feed and bleed. B. Align FP cooling to CV pump and remove decay heat with B AF or FW (requires cross-connecting DC prior to battery depletion).	CC-0, AF-1B, RH-1B, OP-SX

Table 9-3
Summary of Dominant Fire Risk Scenarios – Byron Unit 2

No.	Fire Zone	Scenario ID / Scenario Description	Success Paths	Compensatory Measures
1	11.1B-0	A - Unit 2 Auxiliary Building Basement	A. Align FP cooling to CV pump to preclude RCP seal LOCA and remove decay heat with B AF.	AF-2B, OP-SX, SAT-2, RW
2	11.4-0	D - MCC 232X1 Severe Fire	A. Align FP cooling to CV pump to preclude RCP seal LOCA and remove decay heat with B AF.	AFW-2B, CV-2A, PW, OP-SX
3	5.1-2	C- Bus 242 Large Fire	A. Locally cross-connect SX and remove decay heat with A AF or A train feed and bleed.	CC-0, DG-1B, OP-SX, AF-2A, RH-2A, OP-FIRE[1]
4	11.4-0	E - MCC 232X3 Severe Fire	A. Locally cross -connect SX and remove decay heat with A AF or A train feed and bleed.	CC-0, AF-2A, RH-2A, OP-SX, RW
5	3.1-2	B/D - Unit 2 Cable Tunnel	A. Locally cross-connect SX and remove decay heat with A AFW or A train feed and bleed.	CC-0, AF-2A, RH-2A, OP-SX, TR-CMB
6	3.2B-2	B/C - Unit 2 Lower Cable Spreading Room (LCSR)	A. Locally cross-connect SX and remove decay heat with A AF or A train feed and bleed.	CC-0, AF-2A, RH-2A, OP-SX, SAT-2, TR-CMB, RW
7	3.2A-2	E - Unit 2 LCSR – Riser at Q-26	A. Locally cross-connect SX and remove decay heat with A AF or A train feed and bleed.	CC-0, AF-2A, RH-2A, OP-SX, TR-CMB, RW
8	3.2-0	B/C - Riser Fire at P-19 (Elevation 439')	- There is no degradation of success paths by precluding transient combustible fires in this area.	TR-CMB, RW
9	11.6-0	Q/S - Riser Fire at P-19 (Elevation 426')	- There is no degradation of success paths by precluding transient combustible fires in this area.	TR-CMB, RW
10	3.2C-2	B/C - Unit 2 LCSR – Bounding fire in rooms 3.2C-2	- There is no degradation of success paths by precluding transient combustible fires in this area.	TR-CMB, RW
11	11.4-0	M/T - Riser Fire at P-19 (Elevation 383')	- There is no degradation of success paths by precluding transient combustible fires in this area.	TR-CMB, RW
12	11.4C-0	C - Radwaste Panel Area - West	A. Cross-connect SX and remove decay heat with A AF or A train feed and bleed.	CC-0, AF-2A, RH-2A, OP-SX, RW
13	11.6-2	C - MCC 232X4 - Severe Fire	A. Cross-connect SX and remove decay heat with A AF or A train feed and bleed.	CC-0, AF-2A, RH-2A, OP-SX, RW

[1] Manage plant operations to minimize, or preclude, breaker switching operations on Switchgear Bus 242. This is especially applicable to the offsite power supply breakers.

Table 9-3 Summary of Dominant Fire Risk Scenarios – Byron Unit 2				
No.	**Fire Zone**	**Scenario ID / Scenario Description**	**Success Paths**	**Compensatory Measures**
14	3.1-1	A - Unit 1 Cable Tunnel	A. Energize Bus 242 (recovers SX Pump 2B) and remove decay heat with either train of AF or feed and bleed. B. Align FP cooling to CV pump to preclude RCP seal LOCA and remove decay heat with B AF.	**AF-2B, DG-2B, OP-SX, TR-CMB**
15	11.6-0	C - MCC 132X5 Fire	A. Energize Bus 242 (recovers SX pump 2B) and remove decay heat with either train of AF or feed and bleed. B. Align FP cooling to CV pump to preclude RCP seal LOCA and remove decay heat with B AF.	AF-2B, DG-2B, OP-SX, RW
16	3.2A-2	B - Unit 2 LCSR - Riser L-28.5 in Non-segregated Bus Duct Area	A. Locally cross-tie SX and remove decay heat with either train of AF or A train feed and bleed. B. Align FP cooling to CV pump to preclude RCP seal LOCA and remove decay heat with B AF.	AF-2B, OP-SX, CV-2A, TR-CMB, RW
17	2.1-0	I - Main Control Room - Panel 2PM01J	A. Locally cross-tie SX and remove decay heat with either train of AF or feed and bleed. B. Align FP cooling to CV pump to preclude RCP seal LOCA and remove decay heat with B AF.	AF-2B, OP-SX, CV-2A, OP-FIRE[2]
18	11.5-0	R/S - Riser Fire at M-24/25 and P/Q-19	- There is no degradation of success paths by precluding transient combustible fires in this area.	TR-CMB, RW
19	11.3-2	C/D/E - Riser Fires at Y-24, W-23 and X-23	A. Locally cross-tie SX and remove decay heat with either train of AF or A train feed and bleed. B. Align FP cooling to CV pump to preclude RCP seal LOCA and remove decay heat with B AF.	AF-2B, RH-2A, OP-SX, TR-CMB, RW

[2] Heightened operator awareness of significance of fire internal to 2PM01J, and perform periodic visual inspection of panel interior focusing on fire precursors – smoke, odor.

4.3.1.4 Risk from Seismic Events

The seismic analyses in the Byron and Braidwood Stations' IPEEEs were based on the seismic margin assessment. No significant seismic concerns were identified and it was concluded that the plants possess significant seismic margin. The IPEEEs did identify some seismic outliers (i.e., control room lighting diffuser panels and electrical cabinet interactions). These seismic outliers will be resolved either by additional analysis or completion of design modifications prior to implementing this extended Completion Time. These issues are currently being tracked in the station's corrective action program.

The impact of removing two same train SX pumps from service is evaluated to ensure that the seismic risk impact is not significantly increased (e.g., the results of the seismic IPEEE are essentially unchanged). The interaction between seismic events and the SX systems are dominated by seismically-induced loss of offsite power and station blackout events, as well as the function of the SX system to provide a suction source to the auxiliary feedwater (AF) pumps following a seismic event.

The configuration during the extended Completion Time will involve both units' same train SX pumps unavailable concurrently (i.e., 1A and 2A, or 1B and 2B). Since the configuration of the SX system does not change the seismic capacity of the system, and two available SX pumps are sufficient to support the SX success criteria required by the Success Path Equipment List (SPEL), then the results of the Seismic Margins Analysis (SMA) are unchanged.

No other issues unique to the configurations required during the SX out of service were identified during a review of the IPEEE information that would result in the plant High Confidence of Low Probability of Failure (HCLPF) dropping below 0.3g.

Therefore, with the exception of the potential seismic interaction issues listed above, Byron Station and Braidwood Station will continue to possess a HCLPF of 0.3g, and the risk from seismic initiators is considered small.

Recent Plant Modification Review

Since the completion of the IPEEE, modifications have been made to the plant to include the erection of a security tower at Byron Station. This security tower is attached to the SX towers. These towers are designed to all design basis seismic, high wind and tornado loads. However, the IPEEE seismic event is a 0.3 g earthquake compared to the 0.2 g design basis earthquake. The seismic loading from a 0.3g earthquake has been analyzed and determined to be enveloped by the tornado loading for the structure; therefore, this HCLPF of 0.3g is maintained.

Seismic Screening Analysis

The SX system performs several functions that might have an increased significance following a seismic event. These functions include:

- provide cooling to emergency diesel generators following a seismically induced loss of offsite power (LOOP);
- provide a backup supply of water to the auxiliary feedwater pumps in the event of seismically induced failure of the CST; and

- provide a backup supply of water to the fire protection system in the event of seismically-induced failure of the fire protection pumps.

The deterministic evaluation presented in Section 4.1 describes the basis for SX system defense in depth. The following evaluation demonstrates that likelihood of these functions being demanded are very low and, therefore, any risk impacts to the configuration would be expected to be very small.

Seismic-Induced LOOP

Past seismic PRAs have shown that seismic-induced loss of offsite power can be an important contributor to seismic risk due to the unrecoverable loss of offsite power. SX performs an important function following a LOOP. Thus, a screening analysis was performed to evaluate the potential risk impacts of the planned configuration on seismic induced LOOP.

The non-recoverable internal events dual-unit LOOP (i.e., DLOOP) frequency is ~1E-3/yr. The seismically induced DLOOP is estimated to be on the order of 4E-05/yr for Byron Station and 3E-05/yr for Braidwood Station based on seismic hazard curves from NUREG/CR-1488 [Reference 7] and the generic offsite power fragilities from the supporting analyses to NUREG-1150 [Reference 8].

There are no issues regarding this configuration that negatively impact the seismically induced LOOP frequency. Hence, since the seismically induced LOOP frequency is small compared to the internal events DLOOP frequency, and the LAR will not increase the seismically induced LOOP frequency, seismically induced LOOP represents a negligible risk source for this configuration.

Seismically induced station blackout (SBO) is estimated to be on the order of 1E-06 for Byron and Braidwood Stations based on seismic hazard curves from NUREG/CR-1488 and generic EDG fragilities from NUREG-1150. Seismically induced LOOP with random SX pump failure would result in an SBO on the unit with the failed SX pump.

Note that SX crosstie is not credited in this case as it is assumed that the diesel fails due to lack of cooling before the SX crosstie is made. Furthermore, the 4kV bus crosstie is not credited when only 1 EDG is available on both units. Thus, the planned configuration causes some increase in the potential for seismic-induced station blackout due to the reduced redundancy of the SX system.

Based on the internal events PRA, the probability of SX pump failure to start and run after a demand is about 2E-03. Given a seismic-induced LOOP frequency of roughly 4E-5/yr, the probability of seismically induced LOOP with the random failure of an SX pump is less than 1E-07/yr. Since this is about an order of magnitude less than seismically induced SBO, and there are known conservatisms regarding this scenario, the configuration specific SBO is not a significant contributor to seismic risk. Further more, this risk contribution would only last for a maximum of 144 hours. This would translate to an ICCDP of less than 2E-9.

SX as Backup for CST

The CST is not considered in the SPEL in the Byron and Braidwood Stations IPEEE SMA. The CST is not seismically qualified in the station design basis, and SX is used to supply secondary heat removal via the steam generators. SX is supplied at the suction of the AF pumps via the

1(2)AF006A(B) and 1(2)AF017A(B) motor operated valves (MOVs). These MOVs open automatically on low suction pressure, or can be remote manually operated from the control room, or locally manually opened. The MOVs were determined to have a HCLPF of at least 0.3g, and no interaction issues were identified.

In the SX maintenance configuration, a flow path will remain from the available SX pump to the suction of the AF pumps. This flow path could be lost following a seismically induced SX pipe break that would require isolation of the SX033/SX034 MOVs on the operating unit. However, this would not only effectively isolate suction to one of the two AF pumps, it would also result in loss of cooling to the respective AF pump. The AF pump would be lost regardless of the suction source, and therefore, relying on the SX as the AF pump suction source does not result in an increase in risk.

Finally, since the SX piping has a HCLPF of at least 0.3g, it is unlikely that a seismic event less than the plant HCLPF would result in an SX pipe break.

SX as Backup to Fire Protection

The SX system can provide a backup supply of water to the fire protection system in the event of seismically-induced failure of the fire protection pumps. This function would only be necessary if the seismic event caused a fire and failure of the fire protection pumps. The Byron and Braidwood Stations' IPEEEs specifically investigated the potential for seismic-induced fires. The conclusion of the IPEEE analysis was that there was no significant risk from seismic-induced fires at Byron and Braidwood Stations. Given this finding, it is concluded that the impact of the planned configuration on this function of SX is not risk significant.

4.3.1.5 Risk From Other External Events

Evaluation of high winds, external floods, and other external events in the Byron and Braidwood Stations' IPEEEs, which are in accordance with NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," June 1991, indicated that the sites conform to NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," June 1987, criteria and revealed no potential vulnerabilities. The impact of the extended SX train Completion Time on the risk profile associated with these external events is discussed below.

The potential impact of other external events occurring during the SX extended Completion Time (CT) was considered based on the results of the Braidwood Station and Byron Station IPEEE (References 9 and 10). The IPEEE considered a broad spectrum of other potential external event hazards including:

- Rail Transportation Accidents
- Barge Transportation Accidents
- Pipeline Transportation Accidents
- Military Facilities
- On-site Hazardous Material Accidents
- Severe Temperature Transients
- Severe Weather Storms
- Lightning Strikes
- External Fires

- Extraterrestrial Activity
- Volcanic Activity
- Abrasive Windstorms

All of these hazards were evaluated in the IPEEE against the criteria provided in NUREG-1407 (Reference 11) and found to pose no risk significance.

Many of these hazards are totally unrelated to risk associated with the SX extended CT. Table 10 summarizes the relationship of these hazards to the SX extended CT configuration. Only three of the IPEEE hazards were identified as having any potential to impact risk during the SX extended CT. The three hazards identified are:

- Severe Temperature Transients - Severe temperature transients could challenge SX makeup (i.e., during very low temperatures) or heat removal capability (i.e., during very high temperatures). However, the one-time CT extensions will be entered during a scheduled refueling outage. Refueling outages are scheduled at times in the year (i.e., Fall and Spring) when severe temperature transients would be extremely unlikely. The IPEEE states that the impact of severe temperature transients is to cause a loss of offsite power. This is included in the ICCDP/ICLERP calculations.

- Severe Weather Storms - Severe weather storms include high winds and tornadoes. The SX pumps and all associated support and mitigation systems are located in buildings that are designed for tornadoes and high winds. Thus, they are protected from the effects of these events. High winds and tornadoes can cause loss of offsite power. These events are considered in the loss of offsite power and recovery analysis in the Internal Events PRA and are, therefore, included in the computed ICCDP/ICLERP.

- Lightning Strikes - Lightning strikes can cause loss of offsite power or reactor trips. These events are considered in the Internal Events PRA and are, therefore, included in the computed ICCDP/ICLERP.

Based on this evaluation, it is concluded that other external events have a negligible impact on the risk associated with the SX CT extension.

Table 10
Summary of Impact of Other External Hazards on SX Extended CT Risks

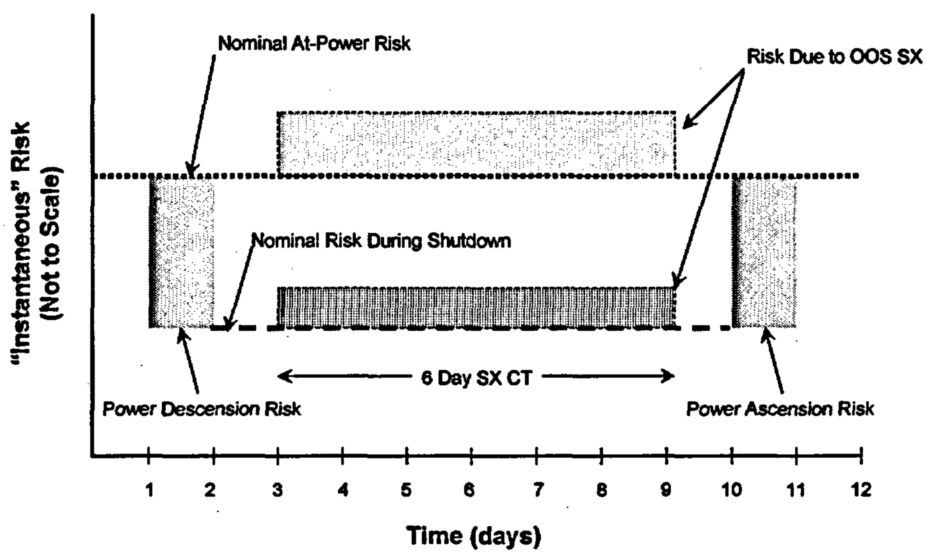
Other External Event Hazard	Impact on SX Extended CT	Basis
Rail Transportation Accidents	None	The threat to SX and associated mitigation is unchanged by the SX configuration.
Barge Transportation Accidents	None	The threat to SX and associated mitigation is unchanged by the SX configuration.
Pipeline Transportation Accidents	None	The threat to SX and associated mitigation is unchanged by the SX configuration.
Military Facilities	None	The threat to SX and associated mitigation is unchanged by the SX configuration.
On-site Hazardous Material Accidents	None	The threat to SX and associated mitigation is unchanged by the SX configuration.
External Floods	None	The threat to SX and associated mitigation is unchanged by the SX configuration.
Severe Temperature Transients	Negligible/Already Addressed	One-time outages scheduled during Spring and Fall.
Severe Weather Storms	Negligible/Already Addressed	Likelihood of damage to operating SX intake is negligible.
Lightning Strikes	Already Addressed	Already considered in the Internal Events PRA.
External Fires	None	The threat to SX and associated mitigation is unchanged by the SX configuration.
Extraterrestrial Activity	None	The threat to SX and associated mitigation is unchanged by the SX configuration.
Volcanic Activity	None	The threat to SX and associated mitigation is unchanged by the SX configuration.
Abrasive Windstorms	None	The threat to SX and associated mitigation is unchanged by the SX configuration.

4.3.1.6 Averted Risk from Incremental Transition Risk

Performing the SX valve replacement with one unit on-line avoids the incremental risk associated with a shutdown and subsequent restart of the unit as well as the risk associated with performing the SX valve replacement with that unit shutdown. The risk associated with this evolution is qualitatively displayed in Figure 1.

Figure 1

Comparison of Risk Profiles



Though a Shutdown PRA model is not available for Byron and Braidwood Stations, as discussed previously, there is a risk associated with performing this evolution during an outage as it would place both units in a condition where shutdown cooling, which is dependent on SX, would be relied on to provide decay heat removal. This risk would be avoided for one unit by performing the valve replacement with that unit on-line.

The incremental transition risk is estimated as follows.

<u>Calculation of the Risk Associated With a Normal Shutdown</u>

During a normal reactor shutdown, the startup feed-water (SUFW) pump is started prior to securing the running turbine-driven pump. This is performed after power is reduced to less than 15% (Braidwood Station) or less than 10% (Byron Station). Once the plant can achieve this configuration, it is judged that risk is relatively low as the SUFW pump is available to provide cooling and is backed up by a reliable AF system (i.e., automatic actuation available), and there is an ability to revert to bleed and feed if required. The risk in this configuration can be estimated as 1E-9/day. This relatively small risk may be further reduced if the plant proceeds to cold shutdown. Therefore, it was concluded that the shutdown risk is negligible provided that a normal shutdown can be properly executed.

Calculation of the Reactor Trip Risk From a Normal Shutdown

If the reactor is shutdown to support the SX work, there is a possibility that a plant upset will occur. Numerous industry studies have shown that the probability of a reactor trip is significantly increased when major perturbations are introduced, such as are introduced by the power descension procedure. If a non-intended reactor trip occurs during the power descension process, a demand on plant emergency systems is generated that is similar to the demand generated from a trip from full power.

The probability of a reactor trip occurring during a shutdown is estimated as 0.023 based on plant specific experience.

The probability of core damage given a shutdown induced reactor trip was estimated using the PRA Revision 5A results, and the process outlined below.

- Zero out all initiators other than the general transient initiator in the base case results.
- Set the general transient initiating event to a value of 1.00 (intended result is the conditional core damage probability).
- Zero out all maintenance events as concurrent maintenance of risk important equipment during the SX outage is not expected\planned. Note that this may be conservative as the possibility exists for equipment on the outage unit, which can support the unit being shutdown, to be unavailable (e.g., EDG, SX pump).
- Since many shutdown induced reactor trips occur at low power, it is judged that there is a significantly reduced potential for the pressurizer PORVs to be challenged by a pressure transient following the trip.

Using this process the core damage probability, given that a shutdown induced reactor trip has occurred, was estimated as 7E-8 to 9E-8.

The conditional probability of core damage given a normal shutdown (due to unplanned reactor trips) is then estimated as follows:

- 9E-8 (Braidwood)
- 7E-8 (Byron)

The conditional probability of a LERF given a normal shutdown (due to unplanned reactor trips) is similarly estimated as follows:

- 5E-9 (Braidwood)
- 4E-9 (Byron)

4.3.1.7 Summary of Risk Insights

The above evaluation assesses the risk from the following sources:

- Internal Events
- Internal Fire
- Seismic Events
- Other External Hazards

Table 11 provides a summary of the approach and results of the evaluation of each of these potential risk contributors. These analyses demonstrate that the risk impact of the proposed one-time extension of the SX Completion Time is very small and below the acceptance guidelines.

This risk-informed evaluation identified a number of compensatory measures that will be implemented during the planned SX configuration. These are discussed in more detail in Section 4.3.2.

Table 11
Summary of Risk Insights for SX CT Extension

RISK CONTRIBUTOR	APPROACH	INSIGHTS
Internal Events	• Quantify ICCDP & ICLERP for Planned Configuration, Including Compensatory Measures: ▪ ICCDP < 1E-6 ▪ ICLERP < 1E-7 ▪ CDF < 1E-3	• Compensatory Measures Keep Risk Well Within Acceptance Guidelines
Internal Fire	• Qualitatively Evaluated: ▪ Identify Fire Scenarios Impacted By Configuration ▪ Confirm Availability of Success Path for Every Scenario ▪ Identify Compensatory Measures	• Every Fire Scenario Has At Least One Success Path • Internal Events Compensatory Measures Apply to Fire Scenarios • New Fire-Related Compensatory Measures Identified
Seismic	• Qualitatively Identify Key Seismic Risk Impacts for Planned Configuration • Evaluate Impact on Seismic-related Key Functions of SX	• Seismic Risk Impacts Negligible
Other External Hazards	• Qualitatively Evaluate Each Hazard to Identify Unique Challenges	• No Unique Challenges Identified
Overall At-Power Risks	• No Evidence Quantitative Guidelines Will Be Challenged	• Key Compensatory Measures Identified to Minimize Risk
Transition Risk	• Quantitatively Evaluate Risk Associated With Unplanned Plant Shutdown ▪ CCDP ~1E-7	• Transition Risk Offsets Some of Calculated Risk Increase Due to Extended CT
Risk at Unit in Shutdown	• Qualitatively Evaluate Impact of SX Configuration on Unit in Shutdown • Identify Compensatory Measures Consistent With Shutdown Safety Management Program	• Reduction in SX Redundancy Leads to Some Increase in Risk at Shutdown Unit Since SX Transfers Heat to the Ultimate Heat Sink • Compensatory Actions At Unit in Shutdown Consistent With Shutdown Safety Management Program

4.3.2 TIER 2: Avoidance of Risk-Significant Plant Configurations

The evaluation of the risk significance of plant configurations considers the impact on both the at-power unit for which the license amendment is being requested and on the opposite unit which will be shutdown during the planned configuration. While evaluation of the shutdown unit is not required, it is included here as part of EGC's overall configuration risk management program.

At-Power Unit

In order to avoid risk-significant plant equipment outage configurations during the extended Completion Time, the impact of having other equipment unavailable was evaluated. This resulted in a list of protected equipment that will not be allowed to be unavailable for maintenance during the extended Completion Time. Tables 12-1, 12-2 and 12-3 provide the results of this evaluation as well as additional compensatory measures that will be established to reduce the risk associated with the configuration.

Opposite (Shutdown) Unit

Having a train of SX unavailable will have an impact on the shutdown unit as well as the on-line unit for which the license condition is being requested. As such, a qualitative evaluation of the impact on the shutdown unit was performed.

The key safety functions that are included and evaluated for Byron and Braidwood Stations outage risk evaluations include the following.

- Reactivity Control
- Shutdown Cooling
- Inventory Control
- Fuel Pool Cooling
- Electric Power Control
- Containment
- Vital Support Systems

The impact of the SX outage on each of the key shutdown safety functions is discussed in turn.

Reactivity Control

The equipment that is potentially impacted from the SX outage that supports reactivity control includes the safety injection system (SI) and chemical and volume control system (CV) pumps. Each provides a potential pathway for boron addition to the RCS. In general, requirements include one SI and one CV pump during Mode 4 and one SI or one CV pump at all other times. Given the planned evolution with the available SX pump supplying both SX trains, the SX outage will not hinder the capability to meet these requirements.

Shutdown Cooling

The shutdown cooling requirements consist of optimizing the RH train availability along with feed and bleed capabilities from at least one SI or CV pump, and/or with two or more steam generators available with AF or MFW as appropriate depending on the outage configuration.

Although both SX trains would be supplied by the available SX pump for the planned evolution, it would be prudent to protect the SX-supported trains of RH, SI, and CV components at any point during the SX outage to minimize the failure set that could render the safety function unsatisfied. That is, if only one train of the RH, SI, or CV systems is to be maintained available during the outage, then best efforts will be made to maintain the B train available during the A train SX outage and the A train available during the B train SX outage. This is illustrated in the example below.

SX Configuration	"A" Train Failure Set	"B" Train Failure Set
"A" Out of Service "B" Running	"A" Power Supplies "B" Power Supplies[3] "A" Train Component Failures	"B" Power Supplies "B" Train Component Failures
"A" Running "B" Out of Service	"A" Power Supplies "A" Train Component Failures	"A" Power Supplies [3] "B" Power Supplies "B" Train Component Failures

In summary, when the "A" SX outage occurs and the "B" SX pump is running, the "B" RH and either the "B" SI or CV trains will be maintained available to the extent possible. However, as a minimum, at least one train of RH and one train of either SI or CV will be maintained available. Similar configuration control will be maintained during the "B" SX train outage.

Inventory Control

The inventory control requirements consist of optimizing the RH, SI, and CV train availability at all times during the outage except when the core is completely offloaded. At reduced inventory and high decay heat levels, more than one train of each system may be required to be maintained. As such, the impact from the SX outage is similar to the impact on the shutdown cooling safety function.

Fuel Pool Cooling

The fuel pool cooling safety function is only impacted by the need to maintain the spent fuel pool heat exchangers available with CC cooling which in turn requires SX cooling. As such, the shutdown cooling requirements and limitations are considered to dominate the potential impacts from the SX outage as long as CC cooling and sufficient fuel pool cooling trains are maintained.

Electric Power Control

The electric power safety function examines the availability of offsite sources, emergency diesel generators, AC divisions, and instrument buses. Only the diesel generators are of direct concern (as long as minimum requirements are met for the other components) since SX cooling

[3] Failure of this train's power supplies would result in loss of SX cooling, thus disabling the train.

is required to support the diesel generators. Given the proposed outage evolution with the available SX pump supplying both SX trains, both diesel generators could be maintained available. However, to ensure that power would be available during a LOOP event to the operable SX pump, best efforts will be made to ensure the opposite train diesel generator is maintained available during the SX outage. That is, the B diesel generator should be available during the A train SX outage and the A diesel generator should be available during the B train SX outage.

Containment

Generally, containment cooling consists of maintaining two or more (out of four total) containment fan coolers when the reactor cavity is not flooded. Lesser requirements exist when the cavity is flooded or when the core is offloaded. SX cooling is utilized to support the containment fan coolers, but given the planned evolution with the available SX pump supplying both SX trains, the SX outage should not hinder the capability to provide cooling.

Vital Support Systems

The vital support system safety function includes the availability of the SX and CC trains. The planned evolution restricts the availability of SX. To improve the reliability of the CC system, the CC train associated with the available SX pump will be maintained available to the extent possible.

Configuration Considerations

No specific quantitative evaluation has been performed at this time. However, it is well known that pressurized water reactor (PWR) outage risk is dominated during time frames at reduced inventory and high decay heat conditions. This is generally reflected with more stringent requirements during these time frames. As such, best efforts will be made to ensure that the SX outage will not to coincide with these known higher risk time frames.

Based on a preliminary assessment of the risk impact of the planned SX outages for Byron and Braidwood Stations, the following will be established to avoid unnecessary risk levels associated with the SX outage on the shutdown unit.

- During the SX outage, the opposite train EDG components will be protected. This is a necessity since the available SX pump will require the same train EDG to be available to maintain SX cooling given a LOOP event.

- Opposite train RH, SI or CV, and CC components will also be protected during the SX outage. That is, best efforts will be made to ensure the B trains remain available during the A train SX outage and the A trains remain available during the B train SX outage. Protecting the opposite train equipment reduces the number of failures that could render safety function requirements unsatisfied.

- The SX outage will be planned so as not to coincide with the known time frames of higher outage risk (e.g., at reduced inventory and high decay heat conditions) when two RH trains and a full complement of support systems are desired to be maintained available.

Table 12-1
Braidwood SX B Train Outage Summary of Compensatory Measures

Compensatory Measure		Risk Source			Comments
		Internal Events	Fire	Shutdown	
Protected Equipment	Unit 0 CC Heat Exchanger	X	X		
	Unit 1 CC Heat Exchanger	X			
	Unit 2 CC Heat Exchanger	X		X	
	1SX005 (crosstie MOV)	X	X		
	2SX005 (crosstie MOV)	X	X		
	1A AF Pump	X	X		
	1B AF Pump	X	X		
	Unit 1 SATs	X	X		
	Unit 2 SATs	X			
	4KV Bus 141	X	X		
	4KV Bus 241	X			
	1A EDG	X	X		
	2A EDG	X	X	X	
	Battery Charger 111	X	X		
	Battery Charger 211	X			
	1B CV Pump		X		
	2A CV Pump or 2A SI Pump			X	
	1B RH Pump		X		
	2A or 2B RH Pump			X	
	2A CC Pump			X	
	1SX033/1SX034	X	X		
	2SX033/2SX034	X	X		
	120 VAC Inst Inverters 111 and 114	X			
Equipment Alignment Changes	2 of 4 Unit 2 RCFC Flow Paths Isolated	X			Improves reliability of SX crosstie
	Unit 1 CST Filled to 350,000 gallons	X			
	1SX007 De-energized		X		
	1SX004 De-energized		X		
Fire Watch	Zone 11.1A-0		X		
	Zone 11.4C-0		X		
	Zone 11.3-1		X		
	Zone 11.4-0		X		
	Zone 11.5-0		X		
	Zone 11.6-0		X		
	Zone 11.6C-0		X		
	Zone 18.2-1		X		
Transient Combustible Free Zone	Zone 11.6C-0		X		
	Zone 11.6-0		X		
	Zone 3.4A-1		X		
	Zone 3.2E-1		X		
Dedicated SX Operators		X	X		Improve response to loss of one or both remaining SX Pumps
Not Performed During Reduced Inventory or High Decay Heat Levels				X	

Table 12-2
Byron SX B Train Outage Summary of Compensatory Measures

Compensatory Measure		Risk Source: Internal Events	Risk Source: Fire	Risk Source: Shutdown	Comments
Protected Equipment	Unit 0 CC Heat Exchanger	X	X		
	Unit 1 CC Heat Exchanger	X			
	Unit 2 CC Heat Exchanger	X		X	
	1SX005 (crosstie MOV)	X	X		
	2SX005 (crosstie MOV)	X	X		
	1A AF Pump	X	X		
	1B AF Pump	X	X		
	Unit 1 SATs	X	X		
	Unit 2 SATs	X			
	4KV Bus 141	X	X		
	4KV Bus 241	X			
	1A EDG	X	X		
	2A EDG	X	X	X	
	Battery Charger 111	X	X		
	Battery Charger 211	X			
	1B CV Pump		X		
	2A CV Pump or 2A SI Pump			X	
	1B RH Pump		X		
	2A or 2B RH Pump			X	
	2A CC Pump			X	
	1SX033/1SX034	X	X		
	2SX033/2SX034	X	X		
	120 VAC Inst Inverters 111 and 114	X			
Equipment Alignment Changes	2 of 4 Unit 2 RCFC Flow Paths Isolated	X			Improves reliability of SX crosstie
	Unit 1 CST Filled to 350,000 gallons	X			
	1SX007 De-energized		X		
	1SX004 De-energized		X		
Fire Watch	Zone 11.1A-0		X		
	Zone 11.4C-0		X		
	Zone 11.3-1		X		
	Zone 11.4-0		X		
	Zone 11.4-5		X		
	Zone 11.6-0		X		
	Zone 11.6C-0		X		
	Zone 18.2-1		X		
Transient Combustible Free Zone	Zone 11.6C-0		X		
	Zone 11.6-0		X		
	Zone 3.4A-1		X		
	Zone 3.2E-1		X		
Dedicated SX Operators		X	X		Improve response to loss of one or both remaining SX pumps
Not Performed During Reduced Inventory or High Decay Heat Levels				X	

Table 12-3
Byron SX A Train Outage Summary of Compensatory Measures

Compensatory Measure		Risk Source: Internal Events	Risk Source: Fire	Risk Source: Shutdown	Comments
Protected Equipment	Unit 0 CC Heat Exchanger	X	X		
	Unit 2 CC Heat Exchanger	X			
	Unit 1 CC Heat Exchanger	X		X	
	1SX005 (crosstie MOV)	X			
	2SX005 (crosstie MOV)	X			
	2A AF Pump	X	X		
	2B AF Pump	X	X		
	Unit 1 SATs	X			
	Unit 2 SATs	X	X		
	4KV Bus 142	X			
	4KV Bus 242	X			
	1B EDG	X	X		
	2B EDG	X	X	X	
	Battery Charger 112	X			
	Battery Charger 212	X			
	2A RH Pump		X		
	1B CV or 1B SI Pump			X	
	2A CV Pump		X		
	1A or 1B RH Pump			X	
	1B CC Pump			X	
	1SX033/1SX034	X	X		
	2SX033/2SX034	X	X		
	120 VAC Inst Inverters 211 and 214	X			
Equipment Alignment Changes	2 of 4 Unit 1 RCFC Flow Paths Isolated	X			Improves reliability of SX crosstie
	Unit 2 CST Filled to 350,000 gallons	X			
Fire Watch	Zone 11.1B-0		X		
	Zone 11.4-0				Permanent fire watch
	Zone 5.1-2				See Table 9-3 for additional restrictions
	Zone 11.4-0		X		
	Zone 3.2B-2		X		
	Zone 3.2A-2		X		
	Zone 3.2-0		X		
	Zone 11.6-0		X		
	Zone 3.2C-2		X		
	Zone 11.4-0		X		
	Zone 11.4C-0		X		
	Zone 11.6-2		X		
	Zone 2.1-0				See Table 9-3 for additional restrictions
	Zone 11.5-0		X		
	Zone 11.3-2		X		

Compensatory Measure		Risk Source: Internal Events	Risk Source: Fire	Risk Source: Shutdown	Comments
Transient Combustible Free Zone	Zone 3.1-2		X		
	Zone 3.2B-2		X		
	Zone 3.2A-2		X		
	Zone 3.2-0		X		
	Zone 11.6-0		X		
	Zone 3.2C-2		X		
	Zone 11.4-0		X		
	Zone 3.1-1		X		
	Zone 11.3-2		X		
Dedicated SX Operator		X	X		Improve response to loss of one or both remaining SX Pumps
Not performed during reduced inventory or high decay heat levels				X	

4.3.3 Tier 3: Risk-Informed Configuration Risk Management Program

Byron and Braidwood Stations have developed a Configuration Risk Management Program (CRMP) governed by station procedures that ensures the risk impact of equipment out of service is appropriately evaluated prior to performing any maintenance activity. This program requires an integrated review to uncover risk-significant plant equipment outage configurations in a timely manner both during the work management process and for emergent conditions during normal plant operation. Appropriate consideration is given to equipment unavailability, operational activities like testing or load dispatching, and weather conditions. Byron and Braidwood Stations currently have the capability to perform a configuration dependent assessment of the overall impact on risk of proposed plant configurations prior to, and during, the performance of maintenance activities that remove equipment from service. Risk is re-assessed if an equipment failure/malfunction or emergent condition produces a plant configuration that has not been previously assessed.

For planned maintenance activities, an assessment of the overall risk of the activity on plant safety, including benefits to system reliability and performance, is currently performed prior to scheduled work. The assessment includes the following considerations.

- Maintenance activities that affect redundant and diverse structures, systems, and components (SSCs) that provide backup for the same function are minimized.

- The potential for planned activities to cause a plant transient are reviewed and work on SSCs that would be required to mitigate the transient are avoided.

- Work is not scheduled that is highly likely to exceed a TS or Technical Requirements Manual (TRM) Completion Time requiring a plant shutdown. For activities that are expected to exceed 50% of a TS Completion Time, compensatory measures and contingency plans are considered to minimize SSC unavailability and maximize SSC reliability.

- For Maintenance Rule (MR) high risk significant SSCs, the impact of the planned activity on the unavailability performance criteria is evaluated.

- As a final check, a quantitative risk assessment is performed to ensure that the activity does not pose any unacceptable risk. This evaluation is performed using the impact on both CDF and LERF. The results of the risk assessment are classified by a color code based on the increased risk of the activity as shown below.

Color	Meaning	Plant Impact and Required Action
Green	Non-risk significant	Small impact on plant risk. Requires no specific actions.
Yellow	Non-risk significant with non-quantitative factors applied	Impact on plant risk. Limit unavailability time or take compensatory actions to reduce plant risk.
Orange	Potentially risk-significant	Significant impact on plant risk. Requires senior management review and approval prior to entering this condition. Requires compensatory measures to reduce risk including contingency plans. All entries will be of short duration.
Red	Risk-significant	Not entered voluntarily. If this condition occurs, immediate and significant actions taken to alleviate the problem.

Emergent work is reviewed by shift operations to ensure that the work does not invalidate the assumptions made during the work management process. EGC's PRA risk management procedure has been implemented at Byron and Braidwood Stations. This procedure defines the requirements for ensuring that the PRA model used to evaluate on-line maintenance activities is an accurate model of the current plant design and operational characteristics. Plant modifications and procedure changes are monitored, assessed, and dispositioned. Evaluation of changes in plant configuration or PRA model features are dispositioned by implementing PRA model changes or by the qualitative assessment of the impact of the change on the PRA assessment tool. Changes that have potential risk impact are recorded in an update requirements evaluations (URE) log for consideration in the next periodic PRA model update.

Maintenance Rule Program

The reliability and availability of the SX pumps are monitored under the MR Program. If the pre-established reliability or availability performance criteria are exceeded for the SX pumps, they are considered for 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," paragraph (a)(1) actions, requiring increased management attention and goal setting in order to restore their performance (i.e., reliability and availability) to an acceptable level. The performance criteria are risk-based and, therefore, are a means to manage the overall risk profile of the plant. An accumulation of large core damage probabilities over time is precluded by the performance criteria.

The SX pumps are all currently in the 10 CFR 50.65 a(2) MR category (i.e., the SX pumps are meeting established performance goals). Performance of the SX pump maintenance is not anticipated to result in exceeding the current established MR criteria for SX pumps.

Plant modifications and procedure changes are monitored, assessed and dispositioned. Evaluation of changes in plant configuration or PRA model features are dispositioned by implementing PRA model changes or by qualitatively assessing the impact of the changes on the CRMP assessment tool. Procedures exist for the control and application of CRMP assessment tools, and include a description of the process when the plant configuration of concern is outside the scope of the CRMP assessment tool.

Change Control

The CRMP is referenced and maintained as an administrative program in the Byron and Braidwood Stations TRMs. Changes to the TRM are subject to the requirements of 10 CFR 50.59, "Changes, Tests, and Experiments." The goals of a CRMP are to ensure that risk-significant plant configurations will not be inadvertently entered for planned maintenance activities, and appropriate actions will be taken should unforeseen events place the plant in a risk-significant configuration during the proposed extended SX train Completion Time.

Overall Conclusion

This request has been evaluated consistent with the key principles identified in RG 1.174 for risk informed changes to the licensing basis and demonstrates that the risk from the proposed change is acceptably small. The evaluation with respect to these principles is summarized below.

- *The proposed change meets the current regulations unless it is explicitly related to a requested exemption or rule change.*

  This change is being requested as a change to the operating licenses for Byron and Braidwood Stations.

- *The proposed change is consistent with the defense-in-depth philosophy.*

  The configuration to be entered decreases the redundancy of the SX system due to the removal of two of the four SX pumps from service simultaneously. The reduced redundancy increases the potential for the plant to lose SX cooling to plant equipment; however, the actual plant design and supporting analyses demonstrate that the plant has additional capability to prevent and mitigate a loss of SX to a unit than credited in the current plant licensing basis, (e.g., the backup fire protection system cooling to the CV pumps which is not credited in the licensing basis).

  Defense-in-depth is maintained during the configuration. Compensatory measures are identified to strengthen the level of defense-in-depth and reduce overall risk.

- *The proposed change maintains sufficient safety margins.*

  The proposed TS change is consistent with the principle that sufficient safety margins are maintained based on the following.

  - Codes and standards (e.g., American Society of Mechanical Engineers (ASME), Institute of Electrical and Electronic Engineers (IEEE) or alternatives approved for use by the NRC). The proposed change is not in conflict with approved codes and standards relevant to the SX system.

- While in the proposed configuration, safety analysis acceptance criteria in the UFSAR are met, assuming there are no additional failures.

- *When proposed changes result in an increase in core damage frequency or risk, the increases should be small and consistent with the intent of the Commission's Safety Goal Policy Statement.*

  A risk evaluation was performed that considers the impact of the proposed change with respect to the risks due to internal events, internal fires, seismic events and other external hazards. The evaluation of the quantitative impacts of internal event risks due to the planned configuration demonstrate that the impact on the likelihood of core damage and large early release is well below the risk acceptance guideline. The fire evaluation determined that at least one success path to prevent core damage is available for every fire scenario that has a significant increase in risk due to the planned SX system configuration. In addition, compensatory measures have been identified that further reduce the risk of these fire scenarios. The risk associated with seismic events and other external hazards are either not impacted by the change or are bounded by the risk from internal events. In addition, although not required, the risk implications of the proposed change were qualitatively evaluated for the unit that will be shutdown during the evolution, consistent with EGC's risk management practices.

- *The impact of the proposed change should be monitored using performance measurement strategies.*

  EGC's configuration risk management program will effectively monitor the risk of emergent conditions during the period of time that the proposed change is in effect. This will ensure that any additional risk increase due to emergent conditions is appropriately managed.

5.0 REGULATORY ANALYSIS

5.1 NO SIGNIFICANT HAZARDS CONSIDERATION

According to 10 CFR 50.92, "Issuance of amendment," paragraph (c), a proposed amendment to an operating license involves no significant hazards consideration if operation of the facility in accordance with the proposed amendment would not:

(1) Involve a significant increase in the probability or consequences of an accident previously evaluated; or

(2) Create the possibility of a new or different kind of accident from any accident previously evaluated; or

(3) Involve a significant reduction in a margin of safety.

In support of this determination, an evaluation of each of the three criteria set forth in 10 CFR 50.92 is provided below regarding the proposed license amendment.

Overview

In accordance with 10 CFR 50.90, "Application for amendment of license or construction permit," Exelon Generation Company, LLC (EGC) is requesting an amendment to Appendix C, "Additional Conditions," of Facility Operating License Nos. NPF-72, NPF-77, NPF-37, and NPF-66 for Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, respectively. The proposed amendment adds a license condition that would increase the Completion Time (CT) for Required Action A.1, "Restore unit-specific SX train to OPERABE status," associated with TS Section 3.7.8, "Essential Service Water (SX) System," from 72 hours to 144 hours. This proposed change will only be used one time on each unit at Byron Station and on Unit 1 only at Braidwood Station.

The current TS Limiting Condition for Operation (LCO) 3.7.8.a requires that two unit-specific SX trains (i.e., the "A" and "B" trains) be operable in Modes 1, 2, 3, and 4. Condition A allows one unit-specific SX train to be inoperable with a CT of 72 hours. An extension of the CT to 144 hours is needed to replace the SX pump suction valves used for pump isolation from the SX water supply. Currently, due to long term wear, the suction isolation valves for the 1B and 2B SX pumps at Braidwood Station and all SX pump (i.e., the 1A, 2A, 1B and 2B pumps) suction isolation valves at Byron Station, are degrading such that individual pump isolation on a specific unit may not be adequate to perform pump maintenance or downstream system component maintenance. In order to replace these suction isolation valves, the common upstream suction isolation valve for the 1A and 2A SX pumps (or the common upstream suction isolation valve for the 1B and 2B SX pumps) must be closed and the suction header drained. After draining the common suction header, both the Unit 1 A(B) and Unit 2 A(B) suction isolation valves will be replaced. This evolution is time consuming and maintenance history has shown that completion of the needed SX suction isolation valve replacement cannot be assured within the existing 72 hour CT window.

Replacement of the SX suction isolation valves will be conducted during a refueling outage; however, due to the system configuration of the SX system, closing the common suction isolation valve for the 1A and 2A (or 1B and 2B) SX pumps results in putting the operating unit in a 72 hour LCO. Consequently, not being able to complete the suction isolation valve replacement in the 72 hours CT would result in the operating unit also being shutdown or not completing the required work to improve the material condition of the plant.

Replacement of the SX suction isolation valves is a prudent and proactive action. Having the capability to securely isolate a single SX pump on a single unit will enable necessary system maintenance to be performed thus enhancing the reliability of the SX system and overall plant safety.

The risk associate with the proposed increase in the time a SX pump is allowed to be inoperable was evaluated using the risk informed processes described in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated July 1998 and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998. The risk was shown to be acceptable. Based on this evaluation, the proposed change does not involve a significant reduction in a margin of safety.

Criteria

1. **The proposed TS change does not involve a significant increase in the probability or consequences of an accident previously evaluated.**

The proposed changes have been evaluated using the risk informed processes described in RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated July 1998 and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998. The risk associated with the proposed change was found to be acceptable.

The previously analyzed accidents are initiated by the failure of plant structures, systems, or components. The SX system is not considered an initiator for any of these previously analyzed events. The proposed change does not have a detrimental impact on the integrity of any plant structure, system, or component that initiates an analyzed event. No active or passive failure mechanisms that could lead to an accident are affected. The proposed change will not alter the operation of, or otherwise increase the failure probability of any plant equipment that initiates an analyzed accident. Therefore, the proposed change does not involve a significant increase in the probability of an accident previously evaluated.

The unit-specific SX system consists of two separate, electrically independent, 100% capacity, safety related, cooling water trains. Each train consists of a 100% capacity pump, piping, valving, and instrumentation. The pumps and valves are remote and manually aligned, except in the unlikely event of a loss of coolant accident (LOCA). The pumps are automatically started upon receipt of a safety injection signal or an undervoltage on the engineered safety features (ESF) bus, and all essential valves are aligned to their post accident positions. The SX system is also the backup water supply to the auxiliary feedwater system and fire protection system.

The design basis of the SX system is for one SX train, in conjunction with the component cooling water (CC) system and a 100% capacity containment cooling system, to remove core decay heat following a design basis LOCA as discussed in the UFSAR, Section 6.2, "Containment Systems." This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is supplied to the reactor coolant system by the emergency core cooling system pumps. The SX system is designed to perform its function with a single failure of any active component, assuming the loss of offsite power. The proposed one-time increase in the CT of the operating unit's SX pump is consistent with the philosophy of the current Technical Specification LCO which allows one train of SX to be inoperable for 72 hours. This change only extends the 72 hour Completion Time to 144 hours which has been shown to be acceptable from a risk perspective; therefore, the proposed change does not involve a significant increase in the consequences of an accident previously evaluated.

2. **The proposed TS change does not create the possibility of a new or different kind of accident from any accident previously evaluated.**

   The proposed changes do not involve the use or installation of new equipment and the currently installed equipment will not be operated in a new or different manner. No new or different system interactions are created and no new processes are introduced. The proposed changes will not introduce any new failure mechanisms, malfunctions, or accident initiators not already considered in the design and licensing bases. Based on this evaluation, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. **The proposed TS change does not involve a significant reduction in a margin of safety.**

   The proposed change does not alter any existing setpoints at which protective actions are initiated and no new setpoints or protective actions are introduced. The design and operation of the SX system remains unchanged. The risk associated with the proposed increase in the time an SX pump is allowed to be inoperable was evaluated using the risk informed processes described in RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated July 1998 and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998. The risk was shown to be acceptable. Based on this evaluation, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above evaluation, EGC concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c).

5.2 APPLICABLE REGULATORY REQUIREMENTS/CRITERIA

The design of the unit-specific SX system must satisfy the requirements of 10 CFR 50.36, "Technical Specifications," paragraph (c)(2)(ii), Criterion 3; and the design of the opposite-unit SX system must satisfy the requirements of 10 CFR 50.36, paragraph (c)(2)(ii), Criterion 4. These requirements state the following:

> (ii) A technical specification limiting condition for operation of a nuclear reactor must be established for each item meeting one or more of the following criteria:
>
> Criterion 3. A structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.
>
> Criterion 4. A structure, system, or component which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

The design basis of the SX system is described in the UFSAR, Section 9.2.1.2, "Essential Service Water System."

Impact on Previous Submittals/Precedent

The impact on previous risk informed submittals is summarized below.

Emergency Diesel Generator (EDG) Extended Completion Time
Reference 5 approved an extension of the EDG Completion Time from 72 hours to 14 days. A significant compensatory measure required to enter the extended CT is to verify that all four SX pumps are operable. Therefore, planned entry into the extended EDG CT will be precluded during the SX pump outage so as not to impact the conclusions of the analysis supporting the EDG CT.

Risk Informed Inservice Inspection (ISI)
References 12 and 13 approved a Risk Informed ISI program for Braidwood Station and Byron Station, respectively. Operating with an SX train in maintenance for six days has no impact on the insights or conclusions from those analyses.

120 VAC Inverter Completion Time
As documented in Reference 14, as a compensatory measure, no planned maintenance will be allowed on the operating unit 120 VAC inverters (specifically 111/211 and 114/214) during the SX pump extended CT; therefore, there will be no impact on the inverter license amendment request.

The NRC has previously approved a similar change for the Donald C. Cook Nuclear Plant in Amendment Nos. 270 and 251 for Units 1 and 2, respectively, issued September 9, 2002.

6.0 ENVIRONMENTAL CONSIDERATION

Overview

In accordance with 10 CFR 50.90, "Application for amendment of license or construction permit," Exelon Generation Company, LLC (EGC) is requesting an amendment to Appendix C, "Additional Conditions," of Facility Operating License Nos. NPF-72, NPF-77, NPF-37, and NPF-66 for Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2, respectively. The proposed amendment adds a license condition that would increase the Completion Time (CT) for Required Action A.1, "Restore unit-specific SX train to OPERABE status," associated with Technical Specification (TS) Section 3.7.8, "Essential Service Water (SX) System," from 72 hours to 144 hours. This proposed change will only be used one time on each unit at Byron Station and on Unit 1 only at Braidwood Station.

The current TS Limiting Condition for Operation (LCO) 3.7.8.a requires that two unit-specific SX trains (i.e., the "A" and "B" trains) be operable in Modes 1, 2, 3, and 4. Condition A allows one unit-specific SX train to be inoperable with a CT of 72 hours. An extension of the CT to 144 hours is needed to replace the SX pump suction valves used for pump isolation from the SX water supply. Currently, due to long term wear, the suction isolation valves for the 1B and 2B SX pumps at Braidwood Station; and all SX pump (i.e., the 1A, 2A, 1B and 2B pumps) suction isolation valves at Byron Station, are degrading such that individual pump isolation on a specific unit may not be adequate to perform pump maintenance or downstream system component maintenance. In order to replace these suction isolation valves, the common upstream suction isolation valve for the 1A and 2A SX pumps (or the common upstream suction isolation valve for the 1B and 2B SX pumps) must be closed and the suction header drained. This evolution is time consuming and maintenance history has shown that completion of the needed SX suction isolation valve replacement cannot be assured within the existing 72 hour CT window.

Replacement of the SX suction isolation valves will be conducted during a refueling outage; however, due to the system configuration of the SX system, closing the common suction isolation valve for the 1A and 2A (or 1B and 2B) SX pumps, results in putting the operating unit in a 72 hour LCO. Consequently, not being able to complete the suction isolation valve replacement in the 72 hours CT would result in the operating unit also being shutdown or not completing the required work to improve the material condition of the plant.

Replacement of the SX suction isolation valves is a prudent and proactive action. Having the capability to securely isolate a single SX pump on a single unit will enable necessary system maintenance to be performed thus enhancing the reliability of the SX system and overall plant safety.

The risk associated with the proposed increase in the time a SX pump is allowed to be inoperable was evaluated using the risk informed processes described in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated July 1998 and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998. The risk was shown to be acceptable. Based on this evaluation, the proposed change does not involve a significant reduction in a margin of safety.

Criteria

EGC has evaluated this proposed operating license amendment consistent with the criteria for identification of licensing and regulatory actions requiring environmental assessment in accordance with 10 CFR 51.21, "Criteria for and identification of licensing and regulatory actions requiring environmental assessments." EGC has determined that these proposed changes meet the criteria for a categorical exclusion set forth in paragraph (c)(9) of 10 CFR 51.22, "Criterion for categorical exclusion; identification of licensing and regulatory actions eligible for categorical exclusion or otherwise not requiring environmental review," and as such, has determined that no irreversible consequences exist in accordance with paragraph (b) of 10 CFR 50.92, "Issuance of amendment." This determination is based on the fact that this change is being proposed as an amendment to a license issued pursuant to 10 CFR 50, "Domestic Licensing of Production and Utilization Facilities," which changes a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, "Standards for Protection Against Radiation," or which changes an inspection or a surveillance requirement, and the amendment meets the following specific criteria:

(i) The amendment involves no significant hazards consideration.

As demonstrated in Section 5.1, "No Significant Hazards Consideration," the proposed changes do not involve any significant hazards consideration.

(ii) **There is no significant change in the types or significant increase in the amounts of any effluent that may be released offsite.**

The proposed changes to increase the time a unit-specific SX pump may be inoperable does not result in an increase in power level, do not increase the production nor alter the flow path or method of disposal, of radioactive waste or byproducts; thus, there will be no change in the amounts of radiological effluents released offsite.

Based on the above evaluation, the proposed change will not result in a significant change in the types or significant increase in the amounts of any effluent released offsite.

(iii) **There is no significant increase in individual or cumulative occupational radiation exposure.**

The proposed change to increase the time a unit-specific SX train may be inoperable will not result in any changes to the previously analyzed configuration of the facility. There will be no change in the level of controls or methodology used for the processing of radioactive effluents or handling of solid radioactive waste, nor will the proposal result in any change in the normal radiation levels in the plant. Therefore, there will be no increase in individual or cumulative occupational radiation exposure resulting from this change.

7.0 REFERENCES

1. Byron/Braidwood Stations Updated Final Safety Analysis Report, Section 9.2.1.2, "Essential Service Water System."
2. Byron/Braidwood Stations Updated Final Safety Analysis Report, Section 5.4.7, "Essential Service Water System."
3. Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," July 1998.
4. Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," August 1998.
5. Letter from G. F. Dick (NRC) to O. D. Kingsley (EGC), Issuance of Amendments," dated September 1, 2000; issuing Amendments 114 and 108 for Byron and Braidwood Stations respectively, approving an EDG Completion Time of 14 days.
6. NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness Maintenance at Nuclear Power Plants."
7. NUREG-1488, "Revised Livermore Seismic Hazard Estimates for Sixty-Nine Nuclear Power Plant Sites East of the Rocky Mountains," April 1994.
8. NUREG/CR-4550, Vol. 3, Revision 1, Part 3, "Analysis of Core Damage Frequency: Surry Power Station, Unit 1 External Events," December 1990.

9. Braidwood Station IPEEE Report, June 1997.

10. Byron Station IPEEE Report, December 1996.

11. NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities."

12. Letter from NRC to O. D. Kingsley, "Braidwood Station, Units 1 and 2 – Interval 2 Inservice Inspection Program – Relief Request I2R-39, Alternative to the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI Requirements for Class 1 and Class 2 Piping Welds," dated February 20, 2002

13. Letter from NRC to O. D. Kingsley, "Approval of Relief Request I2R-40 for Application of Risk-Informed Inservice Inspection Program as an Alternative to the Alternative to the ASME Boiler and Pressure Vessel Code Section XI Requirements for Class 1 and Class 2 Piping Welds for Byron Station, Units 1 and 2," dated February 5, 2002

14. Letter from Keith R. Jury (EGC) to the NRC, "Request for Technical Specification Change, Extension of Completion Time for Instrument Bus Inverters."

ATTACHMENT 2

Proposed Additional Conditions Page Changes

BRAIDWOOD STATION

<u>REVISED PAGE</u>

Appendix C, Page 3 (for NPF-72)

ADDITIONAL CONDITIONS

FACILITY OPERATING LICENSE NO. NPF-72

The licensee shall comply with the following conditions on the schedules noted below:

Amendment Number	Additional Condition	Implementation Date
xxx	During the essential service water (SX) pump suction isolation valve replacement, a one-time extension of the Completion Time (CT) for Required Action A.1, associated with Technical Specification 3.7.8, is allowed. The CT may be extended from the existing 72 hours to 144 hours. This extension is applicable only during the work window for the preplanned replacement of the SX suction isolation valves. This extension is subject to the following additional conditions: 1. The CT extension may be invoked only once for Unit 1 while Unit 2 is in Mode 5 or 6. 2. The CT extension is applicable through the completion of Unit 2 Refueling 11.	With implementation of the amendment

ATTACHMENT 3

Proposed Additional Conditions Page Changes

BYRON STATION

<u>REVISED PAGES</u>

Appendix C, Page 3 (for NPF-37)
Appendix C, Page 3 (for NPF-66)

ADDITIONAL CONDITIONS

FACILITY OPERATING LICENSE NO. NPF-37

The licensee shall comply with the following conditions on the schedules noted below:

Amendment Number	Additional Condition	Implementation Date
xxx	During the essential service water (SX) pump suction isolation valve replacement, a one-time extension of the Completion Time (CT) for Required Action A.1, associated with Technical Specification 3.7.8, is allowed. The CT may be extended from the existing 72 hours to 144 hours. This extension is applicable only during the work window for the preplanned replacement of the SX suction isolation valves. This extension is subject to the following additional conditions: 1. The CT extension may be invoked only once for Unit 1 while Unit 2 is in Mode 5 or 6. 2. For Unit 1, this CT extension is applicable through the completion of Unit 2 Refueling 11.	With implementation of the amendment

ADDITIONAL CONDITIONS

FACILITY OPERATING LICENSE NO. NPF-66

The licensee shall comply with the following conditions on the schedules noted below:

Amendment Number	Additional Condition	Implementation Date
xxx	During the essential service water (SX) pump suction isolation valve replacement, a one-time extension of the Completion Time (CT) for Required Action A.1, associated with Technical Specification 3.7.8, is allowed. The CT may be extended from the existing 72 hours to 144 hours. This extension is applicable only during the work window for the preplanned replacement of the SX suction isolation valves. This extension is subject to the following additional conditions: 1. The CT extension may be invoked only once for Unit 2 while Unit 1 is in Mode 5 or 6. 2. For Unit 2, this CT extension is applicable through the completion of Unit 1 Refueling 13.	With implementation of the amendment

ATTACHMENT 4

SUMMARY OF THE BYRON AND BRAIDWOOD STATION PROBABILISTIC RISK ASSESSMENT

1.0 Background

The Byron and Braidwood Stations Individual Plant Examinations (IPEs) were submitted to the NRC by letters dated April 28,1994 and June 30, 1994, respectively, in response to Generic Letter (GL) 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities – 10 CFR 50.54(f)." The NRC issued Requests for Additional Information (RAIs) to Exelon Generation Company (EGC), LLC (formerly Commonwealth Edison (ComEd) Company) on January 26, 1996, for Braidwood Station and February 1, 1996, for Byron Station. The requests identified concerns that were similar to those raised previously by the NRC for the Zion Nuclear Power Station IPE. As a result of the RAIs, Modified IPEs were developed for the Byron and Braidwood Stations and submitted to the NRC on March 27,1997. The Modified IPEs included the 4 KV ESF bus crosstie procedure enhancements discussed in the original IPEs. The NRC approved the Modified IPEs by letters dated December 3, 1997, for Byron Station and October 27, 1997, for Braidwood Station. The NRC letters noted that the Modified IPE submittals met the intent of Generic Letter 88-20. The current Byron and Braidwood Stations PRAs were prepared by major upgrades of the previous updates. The following section highlights changes to the Modified IPEs made during the development of the Probabilistic Risk Assessment (PRA) upgrades.

2.0 Changes To the PRA Model

An overview of the upgrades that have been made to the Braidwood and Byron Stations' PRAs since the EDG Completion Time extension request was submitted is provided in Table 2-1 (Summary of Major Changes in Current PRA Models for Braidwood and Byron Stations). Some of the more significant enhancements are discussed below.

2.1 Event Trees

The following event trees are represented in the Byron and Braidwood Stations PRAs.

General Transient
Loss of a Direct Current (DC) Bus Transient Event Tree
Anticipated Transient Without Scram (ATWS)
Secondary Line Break Inside Containment
Secondary Line Break Outside Containment
Single Unit and Dual Unit Loss of Offsite Power (LOOP, DLOOP)
Steam Generator Tube Rupture (SGTR)
Excessive LOCA (i.e., vessel rupture) (XLOCA)
Large Break LOCA (LLOCA)
Medium Break LOCA (MLOCA)
Small Break LOCA, Isolable and Non-Isolable (SLOCA)
Interfacing Systems LOCA Outside Containment (ISLOCA)

The XLOCA and ISLOCA event trees are mapped directly to core damage.

Table 2-1
Summary of Major Changes in Current PRA Models for Braidwood and Byron Stations

PRA Elements	Summary of Major Changes
Initiating Events Analysis	Added three internal flooding initiating events to model. Deleted loss of 120V bus initiators based on plant experience. Revised CC (i.e., component cooling water) initiating event treatment.
Event Sequence Modeling	Expanded LOOP/DLOOP event tree. Removed credit for condensate/feedwater as a means of secondary heat removal. Revised the event tree modeling to credit startup feedwater (using MFW pumps) as a means of secondary cooling when no high head ECCS injection is available.
Success Criteria and Thermal Hydraulic Analysis	Modified SX (i.e., essential service water) pump success criteria to credit one of four pumps supporting both units, under specific conditions.
Systems Analysis	Incorporated plant modification to allow CV (i.e., centrifugal charging) cooling via FP (i.e., fire protection). Incorporated detailed RPS (i.e., reactor protection system) and ESFAS (i.e., engineered safety feature actuation system) models. Revised CC model to reflect operational modes. Miscellaneous enhancements.
Common Cause Analysis	Added inverter common cause and included some additional MOV common cause events (8804A\B, CC 9412A\B).
Human Reliability Analysis	Updated selected human error probabilities (HEPs) based on operator interviews, and added internal flood human actions.
Data Analysis	Updated plant-specific failure rates up to 2002 for significant components.
Internal Flooding Analysis	Developed plant-specific pipe break frequencies for SX, WS (non-essential service water), and FP. Detailed assessment of auxiliary building impacts. Human reliability analysis (HRA) updated.
Level 2 LERF	Updated evaluation of high pressure melt ejection (HPME) impacts.

3.0 PRA Baseline Results for Core Damage Frequency (CDF)

The current baseline PRA results for each unit at the Braidwood and Byron Stations are compared with the previous results for each station in Table 3-1, "Summary of Mean CDF Baseline PRA Results for Braidwood and Byron Stations." The results show a moderate increase both at the Byron Station and Braidwood Station units. As a result of the incorporation of the plant modification made to provide alternate cooling to the centrifugal charging pumps lube oil heat exchanger via the FP system, the CDF sequences related to loss of essential service water at both stations decreased. However, this decrease in loss of essential service water CDF sequences was offset by increased CDF from other scenarios (primarily due to inclusion of internal flooding initiators) and refinement of recovery factors previously credited on loss of essential service water system initiators. The CDF related to flooding is somewhat larger at Byron Station than it is at Braidwood Station such that the inclusion of flooding had a greater impact on Byron Station.

Table 3-1
Summary of Mean CDF Baseline PRA Results for Braidwood and Byron Stations

Station	Reactor Unit	Previous Result (Note 1)	Current PRA Update
Braidwood Station	Unit 1	5E-05	6E-05
	Unit 2	5E-05	6E-05
Byron Station	Unit 1	5E-05	6E-05
	Unit 2	5E-05	6E-05

Note 1: This is the Revision 0 result, which does not include the changes summarized in Table 2-1 (of which the inclusion of flooding scenarios and incorporation of an alternate cooling supply to the charging pumps are of primary importance).

Figure 3-1, "Contributors to Braidwood Unit 1 CDF," shows that a significant portion of CDF is caused by the transients resulting from loss of support systems, which dominates the core damage profile. Various support system failures contribute to this category, including loss of SX, loss of a DC bus and loss of CC. This is similar to the risk profile from the Revision 0 analysis where core damage was dominated by loss of essential service water scenarios. However, when refinement was made to the recovery factor applied to loss of essential service water initiators, the importance of the support system scenarios increased again.

Transients are the next largest individual category. Most of the transient core damage contribution comes from loss of secondary heat removal with failure of bleed and feed cooling. LOCAs, predominantly small LOCAs, are the next largest contributor. The internal flooding contribution is dominated by auxiliary building flood scenarios, which lead to loss of SX and failure of the FP cooling to the charging pumps. Loss of offsite power is the next set of scenarios. These include both loss of secondary heat removal and station blackout scenarios. The last category includes containment bypass scenarios initiated by steam generator tube rupture (SGTR) and interfacing systems LOCA (ISLOCA).

The largest contribution to CDF by initiating event are single and dual unit loss of essential service water. The dominant scenarios are failure to establish alternate cooling source to CV pumps upon loss of essential service water, and this eventually leads to RCP seal LOCA. The next largest is a general transient initiator, which is dominated by scenarios leading to failure of both auxiliary feedwater (AFW) pumps and failure to restore main feedwater, and then various failures of bleed and feed cooling after a reactor trip.

The contribution from LOCA sequences are mainly from the small LOCA initiator, where failure of RH system leads to loss of high-pressure recirculation. Loss of offsite power (LOSP) events have been delineated to distinguish between events that impact both units concurrently and each unit separately. Rounding out the top contributors are two other transient events, the loss of condenser heat sink and loss of main feedwater. The dominant core damage scenarios for loss of condenser and main feedwater are due to the initiator leading to loss of main feedwater, followed by failure of both auxiliary feedwater (AFW) pumps and various failures of bleed and feed cooling.

Table 3-2, "CDF Contribution by Initiating Event," provides a tabulation of the CDF contribution by initiating event for Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2, in the updated PRA. This table shows that, while there are differences between the respective risk profiles, the general character of the profiles illustrated in Figures 3-1 and 3-2 is similar at both stations, except the internal flood contribution at Byron Station is higher due to higher flood initiating event frequencies and differences in plant operating procedures.

FIGURE 3-1
CONTRIBUTORS TO BRAIDWOOD UNIT 1 CDF
TOTAL CDF = 6E-5/YR

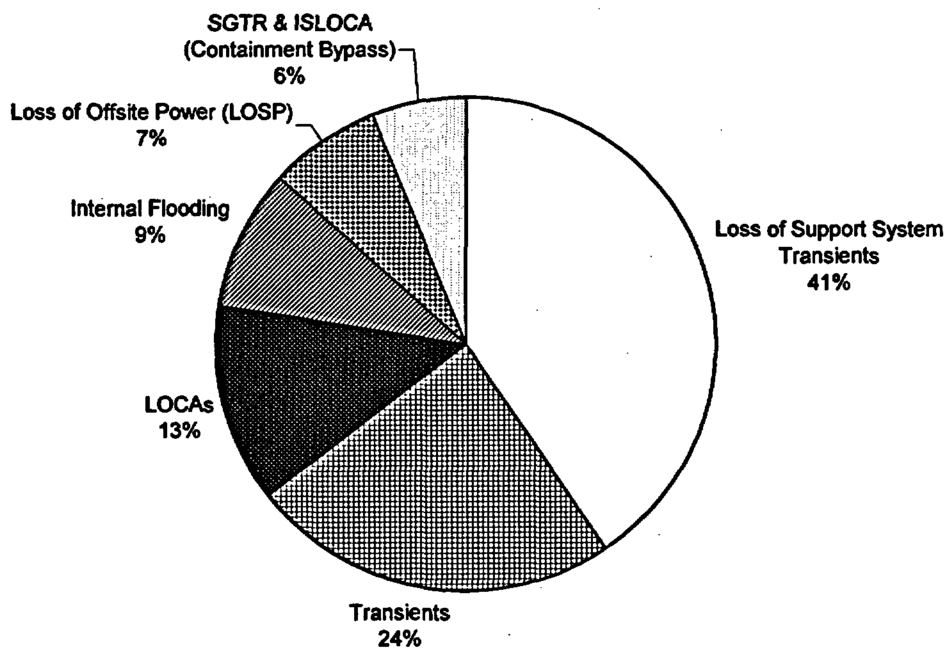


FIGURE 3-2
CONTRIBUTORS TO BYRON UNIT 1 CDF
TOTAL CDF = 6E-5/YR

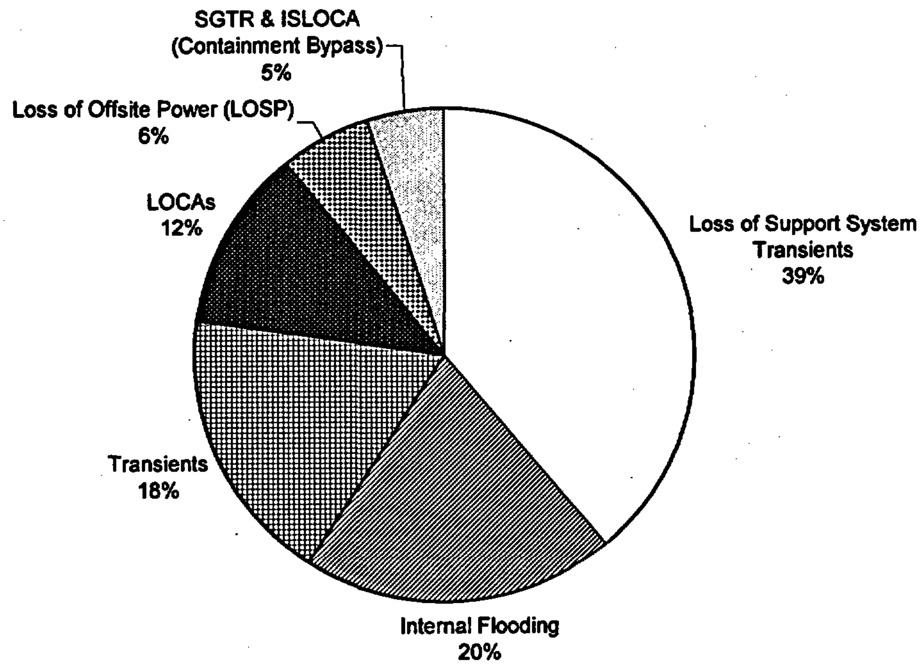


Table 3-2
CDF Contribution by Initiating Event

Initiating Event	Core Damage Frequency (/year)			
	Braidwood Unit 1	Braidwood Unit 2	Byron Unit 1	Byron Unit 2
Transients	**24%**	**24%**	**18%**	**18%**
Loss Of Condenser Heat Sink	3E-06	3E-06	2E-06	2E-06
General Transient Initiating Event	9E-06	9E-06	8E-06	7E-06
Loss Of Main Feedwater	1E-06	1E-06	2E-06	2E-06
Feedline Break Inside Containment	2E-07	2E-07	2E-07	2E-07
Steamline Break Inside Containment	1E-07	1E-07	2E-07	2E-07
Steamline Break Outside Containment	2E-08	2E-08	2E-08	2E-08
Loss of Offsite Power (LOOP)	**7%**	**7%**	**6%**	**5%**
Dual Unit LOOP (Sustained)	3E-06	3E-06	2E-06	2E-06
Dual Unit LOOP (Momentary)	2E-07	2E-07	3E-07	3E-07
Single Unit LOOP (Sustained)	1E-06	8E-07	1E-06	4E-07
Single Unit LOOP (Momentary)	4E-08	4E-08	4E-08	3E-08
Internal Flooding	**9%**	**9%**	**20%**	**21%**
FP Flood	2E-06	2E-06	5E-06	5E-06
SX Flood	2E-06	2E-06	3E-06	3E-06
WS Flood	1E-06	1E-06	5E-06	5E-06
Loss of Support System	**41%**	**41%**	**39%**	**39%**
Dual Unit Loss Of SX (Non Recoverable Failures)	8E-06	8E-06	8E-06	8E-06
Dual Unit Loss Of SX (Recoverable Failures)	1E-09	1E-09	6E-10	6E-10
Single Unit Loss Of SX (Non-Recoverable)	8E-06	8E-06	8E-06	8E-06
Single Unit Loss Of SX (Recoverable)	8E-09	8E-09	4E-09	4E-09
Single Unit Loss Of SX (One Pump in OOS)	3E-06	3E-06	6E-06	6E-06
Loss Of DC Bus 111/211	1E-06	1E-06	8E-07	8E-07
Loss Of DC Bus 112 /212	8E-09	8E-09	9E-09	7E-09
Loss Of CC	3E-07	3E-07	6E-07	6E-07
Dual Unit Loss Of CC	3E-08	3E-08	3E-08	3E-08
Loss Of CC To RCPs	3E-07	3E-07	3E-07	3E-07
Loss Of Instrument Air	2E-07	2E-07	2E-07	2E-07
Loss Of Non-ESW System	2E-06	2E-06	2E-06	2E-06
LOCAs	**13%**	**13%**	**12%**	**12%**
Small LOCA (Non-Isolable)	7E-06	7E-06	7E-06	7E-06
Small LOCA (Isolable)	2E-07	2E-07	2E-07	2E-07
Medium LOCA	4E-08	4E-08	4E-08	4E-08
Large LOCA	6E-09	6E-09	6E-09	6E-09
Excessive LOCA (Reactor Vessel Rupture)	3E-07	3E-07	3E-07	3E-07
SGTR & ISLOCA (Containment Bypass)	**6%**	**6%**	**5%**	**5%**
SGTR	3E-06	3E-06	3E-06	3E-06
Interfacing Systems LOCA	3E-07	3E-07	3E-07	3E-07
Total	**6E-05**	**6E-05**	**6E-05**	**6E-05**

Note: Percentages shown are calculated with respect to total CDF for each unit.

4.0 Evaluation of Large Early Release Frequency (LERF)

The Byron and Braidwood LERF model uses a realistic, plant-specific model that is an extension of the methodology described in NUREG/CR-6595, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events," January 1999. This model supports a realistic quantification of LERF based on:

- Plant damage states that reflect the appropriate plant conditions at the time of core damage,
- Containment isolation failures based on plant-specific system models,
- Plant-specific analysis of containment bypass sequences (i.e., interfacing system LOCA and SGTR)
- Realistic, plant-specific assessment of unit-specific containment ultimate pressure capability,
- Important severe accident phenomena including high pressure melt ejection and induced steam generator tube rupture, and
- Plant-specific thermal hydraulic analyses reflecting the severe accident conditions expected to be present.

The results of the LERF quantification for each unit at Byron and Braidwood Stations are shown in Table 4-1 (LERF Results for Byron and Braidwood Stations) and Figure 4-1 (Contributors to LERF).

Table 4-1
LERF Results for Byron and Braidwood Stations

LERF Contribution	Braidwood Station		Byron Station	
	Unit 1	**Unit 2**	**Unit 1**	**Unit 2**
SGTR	3E-06	3E-06	3E-06	3E-06
ISLOCA	3E-07	3E-07	3E-07	3E-07
Containment Overpressurization	8E-07	2E-06	1E-06	2E-06
Induced SGTR	2E-07	2E-07	1E-07	1E-07
Containment Isolation Failure	5E-07	5E-07	5E-07	5E-07
Total LERF	**5E-06**	**6E-06**	**5E-06**	**6E-06**

These results are all within the criteria for risk significance in Section 2.2.4 of RG 1.174 and are consistent with results from other PWRs with large, dry containments.

The relative contribution to LERF from the various containment failure modes/bypasses is illustrated in Figure 4-1. The majority (approximately two-thirds) of LERF occurs as the result of accident sequences that involve containment bypass (i.e., SGTR and ISLOCA). The largest phenomenological contributor is containment overpressurization, contributing roughly 16-35%. The containment overpressurization contributes more for Unit 2 at each site due to some electrical penetrations that have a lower ultimate pressure capability. This was identified in the IPE, but had not shown up in the previous LERF analysis because the NUREG/CR-6595 screening values for containment overpressurization were used. When a plant-specific analysis was developed as part of the recent update, it was determined that the conditional probability of a high pressure vessel rupture failing the Unit 2 containment was roughly twice the Unit 1 value (i.e., 0.05 vs. 0.025). Overall, the Byron Station containment overpressurization contribution is higher than for Braidwood Station. This is due to the higher core damage contribution from internal flooding that produces high pressure vessel failure scenarios. Containment isolation failures contribute roughly 9-10%. Induced SGTR that occur during the core melt progression contribute about 2-3%.

In summary, the LERF results for Byron and Braidwood Stations represent a realistic treatment of severe accident phenomena that is comparable with the results from other plants with large dry containments.

FIGURE 4-1
CONTRIBUTORS TO LERF