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Exelon Nuclear

February 20, 2001

10 CFR 50.90

United States Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555

LaSalle County Station, Units 1 and 2
Facility Operating License Nos. NPF-11 and NPF-18
NRC Docket Nos. 50-373 and 50-374

Subject: Request for Amendment to Technical Specifications Extension of Allowable Completion Times for Division 1 and 2 Emergency Diesel Generators

In accordance with 10 CFR 50.90, "Application for amendment of license or construction permit," Exelon Generation Company (EGC), LLC, formerly Commonwealth Edison Company, proposes changes to Appendix A, Technical Specifications (TS), to Facility Operating License Nos. NPF-11 and NPF-18. The proposed changes to the TS will extend the allowable completion times for the Required Actions associated with restoration of an inoperable Division 1 or Division 2 Emergency Diesel Generator (EDG). These proposed changes will provide operational flexibility allowing more efficient application of plant resources to safety significant activities. The proposed changes will allow performance of periodic EDG overhauls while the associated unit is on-line, reduce plant refueling outage duration and improve EDG availability during shutdown of the associated unit.

The justification for the change to the EDG completion time is based upon a risk-informed, deterministic evaluation consisting of three main elements: 1) the availability of offsite power via the System Auxiliary Transformers (SATs) and unit cross-tie, 2) verification that the other EDGs and offsite power source are operable, and 3) reliance on an existing Configuration Risk Management Program (CRMP) while the Division 1 or Division 2 EDG is in

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an extended completion time outage. These elements provide the basis for the requested TS change by providing a high degree of assurance of the capability to provide power to the Engineered Safety Feature (ESF) buses during the EDG extended completion time outage. The NRC recently approved similar requests for several other stations including the Perry Nuclear Plant, dated February 24, 1999 and the Byron Station and Braidwood Station, dated September 1, 2000.

Implementation of these proposed changes will require use of the existing CRMP, and procedure revisions, as necessary, to manage the risk impact of performing EDG maintenance on-line.

The information supporting the proposed changes is subdivided as follows.

1. Attachment A gives a description and safety analysis of the proposed changes.
2. Attachment B includes the marked-up TS pages with the proposed changes indicated.
3. Attachment C describes our evaluation performed in accordance with 10 CFR 50.92(c), which provides information supporting a finding of no significant hazards consideration.
4. Attachment D provides information supporting an Environmental Assessment.
5. Attachment E provides a summary of the LaSalle County Station Probabilistic Risk Assessment.

The proposed changes have been reviewed by the LaSalle County Station Plant Operations Review Committee (PORC) and approved by the Nuclear Safety Review Board (NSRB) in accordance with the Quality Assurance Program.

EGC requests approval of these proposed TS changes by August 1, 2001 to support procedure changes and work planning necessary to accomplish EDG maintenance activities outside the next refueling outage.

EGC is notifying the State of Illinois of this application for amendment by transmitting a copy of this letter and its attachments to the designated State Official.

Should you have any questions concerning this letter, please contact Mr. William Riffer, Regulatory Assurance Manager, at (815) 357-6761, extension 2383.

Respectfully,

Charles G. Pardee
Site Vice President
LaSalle County Station

Attachment

cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – LaSalle County Station
Office of Nuclear Facility Safety – Illinois Department of Nuclear Safety

STATE OF ILLINOIS	)	
IN THE MATTER OF	)	
COMMONWEALTH EDISON COMPANY	)	Docket Nos.
LASALLE COUNTY STATION - UNIT 1 & UNIT 2	)	50-373 and 50-374

Subject: Request for Amendment to Technical Specifications Extension of Allowable Completion Times for Division 1 and 2 Emergency Diesel Generators

AFFIDAVIT

I affirm that the content of this transmittal is true and correct to the best of my knowledge, information and belief.

Charles G. Pardee
Site Vice President
LaSalle County Station

Subscribed and sworn to before me, a Notary Public in and for the State above named, this 20th day of February, 2001.
My Commission expires on October 1, 2004.

OFFICIAL SEAL
LAURIE J ALLEN
NOTARY PUBLIC, STATE OF ILLINOIS
MY COMMISSION EXPIRES: 10/01/04

Laurie J Allen
Notary Public

DESCRIPTION AND SAFETY ANALYSIS FOR THE PROPOSED CHANGES

A. SUMMARY OF PROPOSED CHANGES

In accordance with 10 CFR 50.90, "Application for amendment of license or construction permit," Exelon Generation Company (EGC), LLC proposes changes to Appendix A, Technical Specifications (TS), to Facility Operating License Nos. NPF-11 and NPF-18. The proposed changes to Current Technical Specifications (CTS) Section 3/4.8.1, "A.C. Sources – Operating," and the proposed Improved Technical Specifications (ITS) Section 3.8.1, "A.C. Sources – Operating," will extend the allowable completion times for the Required Actions associated with restoration of an inoperable Division 1 or Division 2 Emergency Diesel Generator (EDG) to 14 days.

Additionally, the proposed extension of the completion time to 14 days for a Division 1 or Division 2 EDG results in a corresponding extension of the proposed ITS time period associated with discovery of failure to meet TS Limiting Condition for Operation (LCO) 3.8.1 from 10 days to 17 days.

The proposed changes will provide operational flexibility allowing more efficient application of plant resources to safety significant activities. The proposed changes will allow performance of periodic EDG overhauls while the associated unit is on-line, reduce plant refueling outage duration and improve EDG availability during shutdown of the associated unit.

The proposed changes are described below. The marked-up CTS and proposed ITS pages are shown in Attachment B.

The CTS and proposed ITS requirements associated with an inoperable Division 3 EDG are not proposed to be changed by this submittal. Continued plant operation is currently allowed for 14 days with an inoperable Division 3 EDG, if its associated High Pressure Core Spray (HPCS) System is declared inoperable.

B. DESCRIPTION OF THE CURRENT REQUIREMENTS

CTS Section 3/4.8.1 and proposed ITS Section 3.8.1 address the requirements for alternating current (AC) electrical power sources including the Division 1 and 2 EDGs, when operating. Currently, the CTS and proposed ITS allow continued plant operation for 72 hours with an inoperable Division 1 or Division 2 EDG, unless Unit 1 or Unit 2 is in CTS OPERATIONAL CONDITION or proposed ITS MODE 4, "COLD SHUTDOWN," or 5, "REFUELING," in which case continued plant operation of the other operating unit is allowed for 7 days with the Division 1 EDG inoperable.

Additionally, proposed ITS Section 3.8.1 limits continued plant operation to a maximum of 10 days from discovery of a failure to meet TS LCO 3.8.1.

C. BASES FOR THE CURRENT REQUIREMENTS

The current completion times associated with inoperable Division 1 and 2 EDGs are intended to minimize the time an operating plant is exposed to a reduction in the number of available AC power sources. NRC Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources," December 1974, provides operating guidance (i.e., completion times) that the NRC considers acceptable if the number of available AC power sources are less than that required by the LCO. Specifically, "if the available AC power sources are one less than the number required by the TS LCO, power operation may continue for a period that should not exceed 72 hours if the system stability and reserves are such that a subsequent single failure (including a trip of the unit's generator, but excluding an unrelated failure of the remaining offsite circuit if this degraded state was caused by the loss of an offsite source) would not cause total loss of offsite power." RG 1.93 also states the following: "The operating time limits delineated in regulatory positions C.1 through C.5 are explicitly for corrective maintenance activities only. These operating time limits should not be construed to include preventive maintenance activities that require the incapacitation of any required electric power source." Therefore, per this guide, preventive maintenance for a Division 1 or Division 2 EDG should be scheduled for performance during cold shutdown and/or refueling periods.

The 72 hour completion time for a Division 1 or Division 2 EDG takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a Design Basis Accident (DBA) occurring during this period.

The 10 day completion time establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the TS LCO (e.g., the addition of an inoperable Division 1 EDG due to pre-planned maintenance (7 days) and an inoperable offsite circuit (72 hours or 3 days).

D. NEED FOR REVISION OF THE REQUIREMENTS

The proposed changes are consistent with NRC policy and will continue to provide adequate protection of public health and safety as described below. The changes advance the objectives of the NRC's Safety Goal Policy Statement, "Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," Federal Register, Volume 60, p. 42622, August 16, 1995, for enhanced decision making and result in a more efficient use of resources and reduction of unnecessary burden. Implementation of this proposed completion time extension will provide the following benefits.

- Allow increased flexibility in the scheduling and performance of EDG preventive maintenance.
- Allow better control and allocation of resources. Allowing on line preventive maintenance, including overhauls, provides the flexibility to focus more quality resources on any required or elected EDG maintenance.
- Avert unplanned plant shutdowns and minimize the potential need for requests for a Notice of Enforcement Discretion (NOED). Risks incurred by unexpected plant shutdowns can be comparable to and often exceed those associated with continued power operation.

- Improve EDG availability during shutdown Modes or Conditions. This will reduce the risk associated with EDG maintenance and the synergistic effects on risk due to EDG unavailability occurring at the same time as other various activities and equipment outages that occur during a refueling outage.
- Permit scheduling of EDG overhauls within the requested 14 day completion time extension period.

The proposed completion time of 14 days for a Division 1 or Division 2 EDG is adequate to perform normal preventive EDG inspections and maintenance requiring disassembly of the EDG and to perform post-maintenance and operability tests required to return the EDG to operable status. LaSalle County Station intends to use the proposed 14 day completion time extension for performing a planned major overhaul of a Division 1 or Division 2 EDG at a frequency of no more than once per EDG per operating cycle. In addition to the planned major overhaul of a Division 1 or Division 2 EDG, LaSalle County Station shall continue to minimize the time periods to complete other unplanned EDG maintenance that may occur during the operating cycle. Plant configuration changes for planned and unplanned maintenance of the Division 1 and Division 2 EDGs as well as the maintenance of other equipment having risk significance is managed by the Configuration Risk Management Program (CRMP). The CRMP helps ensure that these maintenance activities are carried out with no significant increase in the consequences of a severe accident.

E. DESCRIPTION OF THE PROPOSED CHANGES

The proposed ITS changes are as follows.

1. Delete proposed ITS Section 3.8.1, Action B and all references to it.
2. Modify proposed ITS Section 3.8.1, Actions B and C completion time to incorporate the proposed 14 day inoperability period for a Division 1 or Division 2 EDG.
3. Modify proposed ITS Section 3.8.1, Actions A, B and C to increase the time period associated with discovery of failure to meet TS LCO 3.8.1 from 10 to 17 days.
4. Modify proposed ITS Section 3.8.1, Action G to address the changes to Action B.
5. Modify proposed ITS Bases Section 3.8.1.

The proposed changes delete CTS Section 3/4.8.1 footnote * and references to it; and incorporate the proposed 14 day inoperability period for a Division 1 or Division 2 EDG in Actions b, d, g, h, I, j, k, and l.

EGC requests approval of these proposed TS changes by August 1, 2001 to support procedure changes and work planning necessary to accomplish EDG maintenance activities outside the next refueling outage. Based on the current schedule for converting LaSalle County Station to ITS, the implementation of these proposed changes is currently scheduled to occur at the time of or after we have converted to ITS, therefore, the enclosed proposed changes to CTS are only provided for consistency.

F. SAFETY ANALYSIS OF THE PROPOSED CHANGES

LaSalle County Station, Units 1 and 2, has five EDGs providing power to the Division 1, 2 and 3 emergency power busses. Division 1 for each unit is powered by one swing EDG (i.e., EDG 0). Division 2 for each unit is powered by its specific Division 2 EDGs (i.e., EDGs 1A and 2A). Division 2 powers equipment that is common between both units therefore, both Division 2 EDGs are required to be operable to satisfy Division 2 TS operability requirements. Division 3 is powered by two independent EDGs (EDGs 1B and 2B). Therefore, the continued operation of each unit is based on the operability of its associated Division 1, 2 and 3 EDGs and the opposite unit Division 2 EDG. The ESF systems powered by any of two of the three divisions provide the minimum safety functions necessary to shutdown the unit and maintain it in a safe shutdown condition.

The proposed changes have been evaluated to determine that applicable regulations and requirements continue to be met, that adequate defense-in-depth and sufficient safety margins are maintained, and that any increase in core damage frequency (CDF) and large early release frequency (LERF) is small and consistent with the NRC Safety Goal Policy Statement, 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 Decision Making: Technical Specifications," dated August, 1998.

The justification for the use of a Division 1 or Division 2 EDG extended completion time is based upon a risk-informed and deterministic evaluation consisting of three main elements: 1) the availability of the "preferred" and "reserve" offsite power sources via the system auxiliary transformers (SATs) and unit cross-tie, 2) verification that the other EDGs and offsite power source are operable, and 3) implementation of the CRMP while a Division 1 or Division 2 EDG is in an extended completion time. The CRMP is used for EDG as well as other work and helps ensure that there is no significant increase in the risk of a severe accident while any EDG maintenance is performed. These elements provide the bases for a high degree of assurance that power can be provided to the Engineered Safety Feature (ESF) buses during all DBAs (i.e., Single Unit Loss of Offsite Power (LOOP)/ Loss of Coolant Accident (LOCA)), Station Black-out (SBO) and a fire during the EDG extended completion time outage.

The proposed changes differ from the proposed ITS in that the proposed ITS provide a completion time of 72 hours and the proposed changes are for a completion time of 14 days to perform required maintenance and testing.

<u>Defense in Depth</u>

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

LaSalle County Station is designed and operated consistent with the defense in depth philosophy. The Station has diverse power sources available (e.g., EDGs and opposite unit EDGs and SATs) to cope with a loss of the preferred AC power source (i.e., offsite power). In addition, the opposite unit EDG can be temporarily used to compensate for a unit's onsite emergency power source that is not available. The overall availability of the AC power sources to the ESF buses will not be reduced significantly as a result of increased on line preventive maintenance activities. It is therefore, acceptable, under controlled conditions, to extend the completion time and perform on-line maintenance intended to maintain the reliability of the onsite emergency power systems. A summary of defense-in-depth relative to station AC power sources is provided in the following table.

Summary of Defense In Depth for LaSalle County Station, Unit 2. Unit 2 is chosen for illustration.

Configuration	Station AC Power Available Sources		
	Division 1	Division 2	Division 3 (HPCS)
Normal	Unit 2 SAT feed Unit 1 Cross-Tie EDG 0	Unit 2 SAT feed Unit 1 Cross-Tie (incl. EDG 1A) EDG 2A	Unit 2 SAT feed EDG 2B
EDG 0 OOS	Unit 2 SAT feed Unit 1 Cross-Tie	See normal	See normal
EDG 2A OOS	See normal	Unit 2 SAT feed Unit 1 Cross-Tie (incl. EDG 1A)	See normal
EDG 1A OOS	See normal	Unit 2 SAT feed Unit 1 Cross-Tie (excl. EDG 1A) EDG 2A	See normal

While the proposed changes do increase the length of time a Division 1 or Division 2 EDG can be out of service during unit operation, it will also increase the availability of the EDGs while either unit is shutdown. Even with one EDG out-of-service during operation, the system is designed with adequate defense in depth. The increased availability of the EDG while shutdown will increase the systems defense in depth during outages. The LaSalle County Station Probabilistic Risk Assessment (PRA) confirms the results of the deterministic analysis (i.e., the adequacy of defense-in-depth) and that protection of the public health and safety is ensured.

System redundancy, independence, and diversity are maintained commensurate with the expected frequency and consequences of challenges to the system. As demonstrated below there are no risk outliers. Implementation of the proposed changes will be done in a manner consistent with the defense-in-depth philosophy. Station procedures will ensure consideration of prevailing conditions, including other equipment out of service, and implementation of compensatory actions to assure adequate defense in depth whenever the EDGs are out of service. In addition, appropriate personnel are trained on the operation and maintenance of the

EDGs and the Unit 1 and Unit 2 cross-tie breakers. The use of the cross-tie breakers are governed by procedure.

No new potential common cause failure modes are introduced by these proposed changes and protection against common cause failure modes previously considered is not compromised.

Independence of physical barriers to radionuclide release is not affected by these proposed changes.

Adequate defenses against human errors are maintained. These proposed changes do not require any new operator response or introduce any new opportunities for human errors not previously considered. Qualified personnel will continue to perform EDG maintenance and overhauls whether they are performed on-line or during shutdown. The maintenance activities are not affected by this change. No other new actions are necessary because the EDG overhaul will be performed on-line.

Availability of the Off-Site Power System

Offsite power is supplied to the switchyard from four 345 kV transmission lines. Two of the transmission lines are in service for Unit 1 and the other two lines service Unit 2. From the switchyard, two electrically and physically separate circuits provide AC power for each unit via the unit's assigned SAT and the other from the SAT of the other unit by cross-tie between the two units. The unit SAT provides the normal source of power to the respective unit's Division 1, 2 and 3 emergency buses. In the event of a loss of a unit SAT, the Division 1 and 2 emergency buses fast transfer to the Unit Auxiliary Transformer (UAT) which is connected to the main generator output. The UAT is rated to carry all onsite power to the unit, but is not considered an offsite source unless it is backfed from the switchyard with the main generator disconnect links removed. The Division 3 emergency bus has no second offsite power source, and will automatically be supplied by the Division 3 EDG after the bus is de-energized. The Division 1 and 2 emergency buses can be manually transferred to the UAT through the unit ties on a dead bus transfer or a live bus transfer if the EDG is supplying power to the bus. A detailed description of the offsite power network and circuits to the onsite Class 1E 4.16 kV emergency buses is found in Updated Final Safety Analysis Report (UFSAR) Chapter 8, "Electric Power."

In summary, the offsite power system consists of independent transmission lines into the switchyard and two independent circuits into each unit. A single loss of an incoming transmission line, switchyard breaker, transmission tower, SAT or circuit into the plant will not result in unavailability of offsite power.

Availability of the On-Site Power System

LaSalle County Station, Units 1 and 2, has five EDGs providing power to the Division 1, 2 and 3 emergency power busses. Division 1 for each unit is powered by one swing EDG (i.e., EDG 0). Division 2 for each unit is powered by its specific Division 2 EDGs (i.e., EDGs 1A and 2A). Division 2 powers equipment that is common between both units therefore, both Division 2 EDGs are required to be operable to satisfy Division 2 TS operability requirements. Division 3 is powered by two independent EDGs (EDGs 1B and 2B). Therefore, the continued operation of each unit is based on the operability of its associated Division 1, 2 and 3 EDGs and the opposite

unit Division 2 EDG. The ESF systems powered by any of two of the three divisions provide the minimum safety functions necessary to shutdown the unit and maintain it in a safe shutdown condition.

Each EDG will start on emergency bus degraded voltage or under voltage from its associated 4.16kV emergency bus. The Division 1 EDG will start on an Emergency Core Cooling System (ECCS) actuation signal (i.e., reactor vessel low water level or high drywell pressure) from either unit. The Division 2 and 3 EDG will start on an ECCS actuation signal (i.e., reactor vessel low water level or high drywell pressure) from the respective unit.

Cross-tie breakers between each Division 1 and Division 2 ESF buses and its associated 4.16kV non-safety-related bus may be manually closed, by operator action, in the event of the loss of both UAT and SAT, the normal feeds to the non-safety-related bus. The ESF bus can be used to power certain non-safety-related, but essential loads that are within the capability of the EDG. The operator may manually synchronize the reserve offsite power source to the ESF bus. Load limits on the cross-tie are controlled in both normal and Emergency Operating Procedures (EOPs).

Due to the redundancy of the unit's ESF divisions and EDGs, the loss of any one of the EDGs, (i.e., the unit's associated Division 1, 2 and 3 EDGs or the opposite unit Division 2 EDG) will not prevent the safe shutdown of the unit. The total standby power system, including EDGs and electrical power distribution equipment, satisfies the single failure criterion.

Station Blackout EDG Capacity

LaSalle County Station is able to withstand and recover from an SBO event of 4 hours in accordance with 10 CFR 50.63, "Loss of all alternating current power." For each unit, an SBO occurs as a result of a LOOP in conjunction with a loss of onsite AC power from the unit Division 1 and 2 EDGs, and failure of the cross-tie breaker to the other unit. The Division 3 EDGs are assumed to be available to support the operation of the HPCS system during an SBO, but are not classified as "Alternate AC" power sources, because Division 3 EDGs do not supply power to safe shutdown loads. Therefore, even though Division 3 EDGs are available, LaSalle County Station coping analysis uses the AC independent approach. The proposed changes do not effect the LaSalle County Station SBO analysis.

Other Considerations

As discussed in the previous section, conformance with relevant regulatory guidance is not affected by this proposed change, with the exception of RG 1.93. The proposed changes do not affect any assumptions or inputs to the safety analyses. Unavailability of a single EDG due to maintenance does not reduce the number of EDGs below the minimum required to mitigate DBAs. In addition, the proposed changes have no impact on the availability of the two off-site sources of power. The effect on UFSAR acceptance criteria has been assessed assuming that one EDG is out-of-service and no additional failures on the maintenance unit occur. All safety functions continue to be available and acceptance criteria are met.

Evaluation of Risk Impact

Risk informed input for these proposed changes is based on a LaSalle County Station PRA. The PRA is used to quantify the change in the CDF and the LERF produced by the increased completion time for the EDGs. Other deterministic techniques are being implemented to minimize any risk impact. These deterministic techniques include: (1) implementation of a CRMP to control performance of other high risk tasks during the EDG outage; and, (2) consideration of specific compensatory measures to minimize risk.

The risk impact of the proposed EDG completion time changes has been evaluated and found to be acceptable. The calculated risk increases are within acceptable limits. The effect on risk of the requested increase in completion time for restoration of an inoperable EDG has been evaluated using NRC's three-tier approach suggested in RG 1.177.

Tier 1: PRA Capability and Insights
Tier 2: Avoidance of Risk-Significant Plant Configurations
Tier 3: Risk-Informed Configuration Risk Management

Tier 1: PRA Capability and Insights

The risk impact associated with the extension of the EDG completion time has been evaluated for changes in CDF, LERF, Incremental Conditional Core Damage Probability (ICCDP), and Incremental Conditional Large Early Release Probability (ICLERP). The results have been compared to guidelines for acceptable changes in these parameters set forth in RGs 1.174 and 1.177. This evaluation examined the following conditions from a number of different view points.

- Internal Events.
- Low Power / Shutdown Risk.
- Internal Flooding Events.
- Seismic Events.
- Internal Fires.
- Other External Event Hazards.

The quantitative evaluation of the risk impact on LaSalle County Station, Unit 2, associated with on-line diesel generator maintenance is calculated using the current LaSalle County Station PRA model. Unit 2 is chosen to represent both units for generalized results because the PRA model is a Unit 2 model, and there are no significant differences between the units with respect to the EDGs.

The LaSalle County Station PRA is built upon initial Individual Plant Examination (IPE) and Individual Plant Examination for External Events (IPEEE) results based on the work that Sandia National Lab performed for the NRC in NUREG/CR-4832, "Risk Methods Integration and Evaluation Program Study." The current LaSalle County Station PRA model is a third generation update from the original PRA constructed by Sandia National Lab for the station. The latest and most current model used for this analysis has also undergone the scrutiny of an external peer review via the Nuclear Energy Institute (NEI) Probabilistic Safety Assessment

(PSA) Peer Certification Process. (See Attachment E for details regarding the LaSalle County Station PRA Model.)

The LaSalle County Station PRA used for the risk determinations is a recent upgrade to the "Modified Individual Plant Examination (IPE)," submitted to the NRC by letters dated April 28, 1994 and December 12, 1994. This modified IPE had been accepted by the NRC by Safety Evaluation Report (SER) letter dated March 14, 1996. The NRC letter noted that the modified IPE submittal met the intent of Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities – 10 CFR 50.54(f)," dated November 23, 1988.

Attachment E provides a brief summary of the recently upgraded LaSalle County Station PRA with additional information related to EDG modeling. This PRA addresses internal events at full power. Other risk sources and operating modes are discussed 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 EDG maintenance unavailability are adequate to evaluate the risk impacts of the increased completion times for the EDGs. These elements include the proper characterization of initiating events involving LOOP, treatment of operator actions to implement bus cross-ties and other EOPs, and data analysis of key parameters such as EDG failure rates, maintenance unavailabilities, and common cause failure probabilities.

For the Level 2 analysis (i.e., the containment analysis), LERF was estimated using the methology in NUREG/CR-6595, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events," dated January 1999. This approach to LERF evaluation, while somewhat simplified, supports a realistic quantification of systemic contributions to containment isolation failures and bypass sequences that are actually derived from the Level 1 event sequence model.

The scope, level of detail, and quality of the LaSalle County Station PRA is sufficient to support a technically defensible and realistic evaluation of the risk change from this proposed completion time extension.

Updating and maintenance of the LaSalle County Station PRA is controlled under a set of programmatic procedures for all aspects of the model and documentation. This process includes mechanisms for screening plant configuration changes and a means of updating the model where judged necessary to maintain model fidelity.

An independent assessment of the LaSalle County Station PRA was conducted for the current PRA model using the NEI PSA Certification Peer Review Process, using a team of industry PRA experts. This independent review was performed to evaluate the quality of the PRA and completeness of the PRA documentation. The Certification Team found that the LaSalle County Station PRA exhibited grades consistent with a very solid PSA program, with no major weaknesses. The element and sub-element grades demonstrate that it is adequate for use in regulatory submittals.

As a result of the considerable effort to incorporate the latest industry insights into the PRA upgrade, self-assessments, and certification peer review, the results of the risk evaluation are considered to be technically sound and consistent with the expectations for PRA quality set forth in RGs 1.174 and 1.177.

EVALUATION APPROACH

To determine the effect of the proposed 14 day completion time for restoration of an inoperable EDG, the guidance of RGs 1.174 and 1.177 was used. Thus, the following risk metrics were used to evaluate the risk impacts of extending the EDG completion time from 3 days to 14 days.

ΔCDF_{AVE} = change in the annual average CDF due to any increased on-line maintenance unavailability of EDGs that could result from the increased completion time. This risk metric is used to compare against the criteria of RG 1.174 to determine whether a change in CDF is regarded as risk significant. These criteria are a function of the baseline annual average core damage frequency, CDF_{BASE}. Therefore, $\Delta CDF_{AVE} = CDF_{AVE} - CDF_{BASE}$.

$\Delta LERF_{AVE}$ = change in the annual average LERF due to any increased on-line maintenance unavailability of EDGs that could result from the increased completion time. RG 1.174 criteria were also applied to judge the significance of changes in this risk metric.

ICCDP{EDG Y} = incremental conditional core damage probability with EDG Y out-of-service for an interval of time equal to the proposed new completion time (i.e., 14 days). This risk metric is used as suggested in RG 1.177 to determine whether a proposed increase in completion time has an acceptable risk impact.

ICLERP{EDG Y} = incremental conditional large early release probability with EDG Y out-of-service for an interval of time equal to the proposed new completion time (i.e., 14 days). RG 1.177 criteria were also applied to judge the significance of changes in this risk metric.

The evaluation of the above risk metrics was performed as follows.

The change in the annual average CDF at each reactor Unit due to the change in the EDG completion time, ΔCDF_{AVE} ,was evaluated by computing the following.

$$CDF_{AVE} = \left(\frac{T_{1A}}{T_{CYCLE}}\right) CDF_{1A\text{-}OOS} + \left(\frac{T_{2A}}{T_{CYCLE}}\right) CDF_{2A\text{-}OOS} + \left(\frac{T_{O}}{T_{CYCLE}}\right) CDF_{0\text{-}OOS} + \left(1 - \frac{T_{1A} + T_{2A} + T_{O}}{T_{CYCLE}}\right) CDF_{base} \qquad [Eq.1]$$

CDF_{BASE} = baseline annual average CDF with average unavailability of EDGs consistent with the current EDG completion time. This is the CDF result of the current baseline PRAs for each Unit.

$CDF_{1A\text{-}OOS}$ = CDF evaluated from the PRA model with the EDG 1A out-of-service and compensating measures for EDG 1A implemented. These compensating measures include prohibiting concurrent maintenance or inoperable status of any of the remaining three EDGs at the site as well as other compensating measures identified in this evaluation.

$CDF_{2A\text{-}OOS}$ = CDF evaluated for the PRA model with the EDG 2A out-of-service and compensating measures for EDG 2A implemented. These compensating measures include prohibiting concurrent maintenance or inoperable status of any of the remaining three EDGs at the site as well as other compensating measures identified in this evaluation.

$CDF_{0\text{-}OOS}$ = CDF evaluated for the PRA model with the EDG 0 out-of-service and compensating measures for EDG 0 implemented. These compensating measures include prohibiting concurrent maintenance or inoperable status of any of the remaining three EDGs at the site as well as other compensating measures identified in this evaluation.

T_{1A} = Total time per fuel cycle (i.e., T_{CYCLE}) that EDG 1A is out-of service for the extended completion time

T_{2A} = Total time per fuel cycle (i.e., T_{CYCLE}) that EDG 2A is out-of-service for the extended completion time

T_0 = Total time per fuel cycle (i.e., T_{CYCLE}) that EDG 0 is out-of service for the extended completion time.

$$CDF_{AVE} = CDF_{1A-OOS} \times \frac{14\,days}{517.5\,days} + CDF_{2A-OOS} \times \frac{14\,days}{517.5\,days} +$$

$$CDF_{0-OOS} \times \frac{14\,days}{517.5\,days} + CDF_{base} \times \frac{475.5\,days}{517.5\,days} \qquad [Eq.2]$$

$$\Delta CDF_{AVE} = CDF_{AVE} - CDF_{BASE} \qquad [Eq.3]$$

CDF_{AVE} = Average CDF over a "typical" fuel cycle with the EDG completion time extended to 14 days.

ΔCDF_{AVE} = Difference between CDF with CTS on EDGs and the CDF for an average fuel cycle with the EDG completion time extended to 14 days.

A similar approach was used to evaluate the change in the average LERF for each Unit due to the requested completion time, $\Delta LERF_{AVE}$ as follows.

$$LERF_{AVE} = \left(\frac{T_{1A}}{T_{CYCLE}}\right) LERF_{1A\text{-}OOS} + \left(\frac{T_{2A}}{T_{CYCLE}}\right) LERF_{2A\text{-}OOS} + \left(\frac{T_0}{T_{CYCLE}}\right) LERF_{0\text{-}OOS}$$

$$+ \left(1 - \frac{T_{1A} + T_{2A} + T_0}{T_{CYCLE}}\right) LERF_{BASE} \qquad [Eq.4]$$

$LERF_{BASE}$ = baseline annual average LERF with average unavailability of EDGs consistent with the current EDG completion time. This is the LERF result of the current baseline PRAs for each unit. (See discussion under CDF_0 and above.)

$LERF_{1A\text{-}OOS}$ = LERF evaluated from the PRA model with the EDG 1A out-of-service and compensating measures for EDG 1A implemented. These compensating measures include prohibiting concurrent maintenance or inoperable status of any of the remaining three EDGs at the site as well as other compensating measures identified in this evaluation.

$LERF_{2A\text{-}OOS}$ = LERF evaluated for the PRA model with the EDG 2A out-of-service and compensating measures for EDG 2A implemented. These compensating measures include prohibiting concurrent maintenance or inoperable status of any of the remaining three EDGs at the site as well as other compensating measures identified in this evaluation.

$LERF_{0\text{-}OOS}$ = LERF evaluated from the PRA model with the EDG 0 out-of-service and compensating measures for EDG 0 implemented. These compensating measures include prohibiting concurrent maintenance or inoperable status of any of the remaining three EDGs at the site as well as other compensating measures identified in this evaluation.

$$\Delta LERF = LERF_{AVE} - LERF_{BASE} \qquad [Eq.\ 5]$$

The evaluation was performed based on the assumption that the extended completion time would be applied to only one major overhaul per EDG per refueling cycle, hence $T_{0\text{-}OOS} = T_{1A\text{-}OOS} = T_{2\text{-}AOOS}$ = 14 days. The cycle time is based on an 18 month fuel cycle and an assumed total planned and unplanned outage duration of 30 days, which yields T_{CYCLE} = 517.5 days. Note that the above formula for ΔCDF_{AVE} conservatively neglects the decrease in CDF contributions from accidents initiated during shutdown that will be associated with increased EDG availability of the EDGs during shutdown periods. Additionally, all risk calculations are expected to reduce as a result of extending the operating cycles from 18 months to 24 months. The existing risk analysis, based on an 18-month operating cycle, bounds the results of a 24-month operating cycle. Therefore, there are no risk calculations needed for extending the operating cycle to 24 months.

It is also recognized that these estimates are obtained using a PRA model that does not include quantitative risk contributions from internal fires, but does include internal flooding and seismic events. However, fire was evaluated for applicability to the proposed changes regarding the

EDG completion times, and this contribution was evaluated to be negligible to the overall results presented here.

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

$$ICCDP_{1A} = (CDF_{1A\text{-}OOS} - CDF_{BASE})T_{CT} \qquad [Eq.6]$$

$$ICCDP_{1A} = (CDF_{1A\text{-}OOS} - CDF_{BASE}) \bullet (14\ days)/(365\ days/year) \qquad [Eq.7]$$

$$ICCDP_{1A} = (CDF_{1A\text{-}OOS} - CDF_{BASE}) \bullet 3.84 \times 10^{-2} \qquad [Eq.8]$$

Note that in the above formula 365 days/year is merely a conversion factor to provide 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. This should not be confused with the evaluation of ΔCDF_{AVE} in which the CDF is averaged over an 18 month refueling cycle.

Similarly, ICLERP is defined as follows.

$$ICLERP_{1A} = (LERF_{1A\text{-}00S} - LERF_{BASE}) \bullet 3.84 \times 10^{-2} \qquad [Eq.9]$$

CALCULATION RESULTS

Table 1 summarizes input unavailabilities for key components and how they are to be treated for each of the "cases."

Table 2 summarizes the calculated CDF and LERF values from the LaSalle County Station, Unit 2, PRA model.

Table 3 presents the calculations of the change in CDF for use in comparison with the RG 1.174 guidelines.

Table 4 presents the calculations of the change in LERF for use in comparison with the RG 1.174 guidelines.

Table 5 presents the calculations for ICCDP for each of the EDG completion times for use in comparison with the RG 1.177 guidelines.

Table 6 presents the calculations for ICLERP for each of the EDG completion times for use in comparison with the RG 1.177 guidelines.

Table 1

EDG MAINTENANCE UNAVAILABILITIES FOR CALCULATIONS

Case	Planned Maintenance Unavailabilities to be Imposed			
	EDG 2A Unavailable	EDG 0 Unavailable	EDG 1A Unavailable	All Other Unavailable
1: $CDF_{2A\text{-}OOS}$	2.7E-02[1]	0	0	0
2: $CDF_{0\text{-}OOS}$	0	2.7E-02[1]	0	0
3: $CDF_{1A\text{-}OOS}$	0	0	2.7E-02[1]	0
4: CDF_{BASE}	Random[2]	Random[2]	Random[2]	Random[2]

(1) $\frac{14 \text{ days}}{17 \text{ months}} = \frac{14 \text{ days}}{517.5 \text{ days}} = 2.7E\text{-}02$

(2) This case is considered representative of current plant operation, using historical average unavailability for the EDGs.

Table 2

PRA MODEL RESULTS FOR THE RISK METRIC CALCULATIONS

CDF	Frequency (Per Rx Yr.)(1)	LERF	Frequency (Per Rx Yr.)(7)
$CDF_{2A\text{-}OOS}$	7.22E-06	$LERF_{2A\text{-}OOS}$	1.33E-06/yr(3)
$CDF_{0\text{-}OOS}$	1.66E-05(6)	$LERF_{0\text{-}OOS}$	1.33E-06/yr
$CDF_{1A\text{-}OOS}$	7.22E-06(2)	$LERF_{1A\text{-}OOS}$	1.33E-06/yr(4)
CDF_{BASE}	6.92E-06(5)	$LERF_{BASE}$	1.03E-06/yr

(1) All quantified risk estimates based on a truncation of 1E-011/yr.

(2) Risk values are based on the results obtained from the Unit 2 PRA model. Unit 1 EDG unavailability actually has a lower impact on Unit 2 than depicted. Unit 1 and Unit 2 Division 2 EDGs are assumed to be equivalent for purposes of this evaluation. Likewise, Unit 2 EDG unavailability actually has a lower impact on Unit 1 than depicted.

(3) Conservatively estimated to be same as $LERF_{0\text{-}OOS}$.

(4) Estimated to be same as $LERF_{0\text{-}OOS}$.

(5) Base CDF case assumes that an augmented piping inspection program for service water piping located in the turbine building basement is in place.

(6) Note that the impact on CDF for the EDG 0 unavailability is significantly greater than the impact of either unit-specific EDG. This difference is due to the fact that the EDG 0 is common between the units, while the other EDG can be used to supply the opposite unit Division 2 if required. The EDG 0 has no backup EDG for Division 1.

(7) LERF results shown above are for the cases in which an augmented piping inspection process is not credited. This is conservative because the EDGs and their supports are treated as being vulnerable to turbine building flooding scenarios.

Table 3

CDF CALCULATIONS FOR LASALLE COUNTY STATION UNIT 2

Average CDF after Completion Time Extension Included [Use Eq. 2]

$$CDF_{AVE} = 7.22E\text{-}06/yr \bullet 2.7E\text{-}02 + 7.22E\text{-}06/yr \bullet 2.7E\text{-}02 + 1.66E\text{-}05/yr \bullet 2.7E\text{-}02 + 6.92E\text{-}06/yr \bullet 0.919$$

$$CDF_{AVE} = 1.95E\text{-}07/yr + 1.95E\text{-}07/yr + 4.48E\text{-}07/yr + 6.36E\text{-}06$$

$$CDF_{AVE} = 7.20E\text{-}06/yr$$

Change in CDF [Use Eq. 3]

$$\Delta CDF = CDF_{AVE} - CDF_{BASE}$$

$$\Delta CDF = 7.20E\text{-}06/yr - 6.92E\text{-}06/yr$$

$$\Delta CDF = 2.8E\text{-}07/yr$$

Table 4

LERF CALCULATIONS FOR LASALLE COUNTY STATION UNIT 2

Average LERF after Completion Time Extension Included [Use Eq. 4]

$$LERF_{AVE} = 1.33E\text{-}06/yr \bullet 2.7E\text{-}02 + 1.33E\text{-}06/yr \bullet 2.7E\text{-}02 + 1.33E\text{-}06/yr \bullet 2.7E\text{-}02 + 1.03E\text{-}06/yr \bullet 0.919$$

$$LERF_{AVE} = 3.59E\text{-}08/yr + 3.59E\text{-}08/yr + 3.59E\text{-}08/yr + 9.47E\text{-}07/yr$$

$$LERF_{AVE} = 1.05E\text{-}06/yr$$

Change in LERF [Use Eq. 5]

$$\Delta LERF = 1.05E\text{-}06/yr - 1.03E\text{-}06/yr$$

$$\Delta LERF = 2.0E\text{-}08/yr$$

Table 5

ICCDP CALCULATION [Use Eq. 6]

$$1A:\ ICCDP = (CDF_{1A\text{-}OOS} - CDF_{BASE}) \bullet 3.84E\text{-}02/yr$$
$$= (7.22E\text{-}06/yr - 6.92E\text{-}06/yr) \bullet 3.84E\text{-}02$$
$$= 1.2E\text{-}08$$

$$2A:\ ICCDP = (CDF_{2A\text{-}OOS} - CDF_{BASE}) \bullet 3.84E\text{-}02/yr$$
$$= (7.22E\text{-}06/yr - 6.92E\text{-}06/yr) \bullet 3.84E\text{-}02/yr$$
$$= 1.2E\text{-}08$$

$$0:\ ICCDP = (CDF_{0\text{-}OOS} - CDF_{BASE}) \bullet 3.84E\text{-}2/yr$$
$$= (1.66E\text{-}5/yr - 6.92E\text{-}6/yr) \bullet 3.84E\text{-}2$$
$$= 3.7E\text{-}7$$

Table 6

ICLERP CALCULATION [Use Eq. 9]

$$1A:\ ICLERP = (LERF_{1A\text{-}OOS} - LERF_{BASE}) \bullet 3.84E\text{-}02/yr$$
$$= (1.33E\text{-}06/yr - 1.03E\text{-}06/yr) \bullet 3.84E\text{-}02$$
$$= 1.2E\text{-}08$$

$$2A:\ ICLERP = (LERF_{2A\text{-}OOS} - LERF_{BASE}) \bullet 3.84E\text{-}2/yr$$
$$= (1.33E\text{-}6/yr - 1.03E\text{-}6/yr) \bullet 3.84E\text{-}2/yr$$
$$= 1.2E\text{-}8$$

$$0:\ ICLERP = (LERF_{0\text{-}OOS} - LERF_{BASE}) \bullet 3.84E\text{-}2/yr$$
$$= (1.33E\text{-}6/yr - 1.03E\text{-}6/yr) \bullet 3.84E\text{-}2$$
$$= 1.2E\text{-}8$$

Note that Unit 2 is chosen to represent both units for generalized results. For specific applications, when appropriate, a Unit 1 model is developed to account for known differences between the units. For example, the online risk monitor PRA tool accounts

for differences between the two units explicitly. In these cases, no appreciable numerical differences are evident in the overall CDF and LERF totals.

Summary of Calculated Risk Values compared to Regulatory Guide Acceptance Criteria

Risk Metric	Risk Significance Guideline	Risk Metric Results Unit 2 (1)
Δ CDF_{ave}	< 1.0E-06/yr	2.8E-07/yr
Δ $LERF_{ave}$	< 1.0E-07/yr	2.0E-08/yr
$ICCDP_{EDG\ 0}$	< 5.0E-07	3.7E-07
$ICLERP_{EDG\ 0}$	< 5.0E-08	1.2E-08
$ICCDP_{EDG\ 2A}$	< 5.0E-07	1.2E-08
$ICLERP_{EDG\ 2A}$	< 5.0E-08	1.2E-08
$ICCDP_{EDG\ 1A}$	< 5.0E-07	Same as 2A for Unit 1(1)
$ICLERP_{EDG\ 1A}$	< 5.0E-08	Same as 2A for Unit 1(1)

(1) The risk calculations have been performed for LaSalle Unit 2. The two units are essentially symmetrical, and they have no significant differences with regard to the EDGs. Therefore, the calculated values apply to Unit 1 also.

FLOODING RESULTS

Flooding was evaluated in the internal flooding analysis and flooding initiators are included. In particular, the turbine building flood results in the following scenario.

- Failure of BOP equipment due to flood.
- Disabling SATs per procedure, resulting in a dual unit loss of offsite power (DLOOP).
- Failure of EDGs 1A and 2A due to flooding of the Division 2 Core Standby Cooling System (CSCS) rooms.
- Failure of HPCS due to flooding of the Division 3 CSCS and the Division 3 switchgear room.

Given this scenario the Division 1 EDG is the only available AC power source to supply the remaining mitigation equipment. An unmitigated turbine building flood, which drains the cooling lake to the Turbine Building, with failure of Division 1 EDG leads to core damage. This postulated low frequency scenario increases in frequency with the proposed increase of the Division 1 EDG completion time from 72 hours to 14 days. In the base PRA model, Turbine Building floods account for 13% of the 6.92E-06/yr CDF. The increase in Turbine Building flood contribution is directly tied to the unavailability of Division 1 EDG.

LaSalle County Station will assess an unmitigated turbine building flood scenario as part of the CRMP. Preventive actions, such as regular walkdowns, as well as cyclic inspections of potentially vulnerable piping, will be implemented as needed by the CRMP. These

preventive actions will help assure there is no precursor degradation in the structural integrity of turbine building basement piping.

External Events Review

A rigorous risk assessment for external events at LaSalle County Station was conducted as part of the Risk Methods Integration and Evaluation Program (RMIEP). We submitted the results of the RMIEP study (i.e., NUREG/CR-4832) to the NRC in letters dated April 28, 1994 and December 12, 1994, as the basis for the LaSalle County Station IPE/IPEEE submittal. Each of the RMIEP external event evaluations were reviewed as part of the submittal and compared to the guidance contained in NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities - Final Report." The NRC transmitted to EGC in a letter dated March 14, 1996, "Review of Individual Plant Examination Submittal – Internal Events – Lasalle County Station, Units 1 and 2," its SER for LaSalle County Station.

FIRE RESULTS

A fire analysis was conducted as part of the IPEEE, based on the original fire PRA modeling performed and documented in the NRC-sponsored RMIEP Study (i.e., NUREG/CR-4832). The IPEEE Fire PRA results were not combined with the internal events PRA results since the fire analysis was based on conservative assumptions used during the RMIEP Study.

The key elements of the LaSalle County Station RMIEP internal fire assessment are consistent with current approaches and include the following.

1. Fire hazard analysis.
2. Fire growth and propagation.
3. Fire suppression.
4. Accident sequence development and quantification.

The conclusions of the RMIEP internal fire study applicable to the EDG completion time assessment are the following.

- Consistent with other Boiling Water Reactor (BWR) internal fire PRAs, the dominant fire areas are the Control Room and Essential Switchgear Rooms.
- Consistent with other BWR internal fire PRAs, the majority of the internal fire-induced CDF is comprised of long-term decay heat removal sequences.
- Fire-induced loss of offsite power events represent a negligible fraction of the RMIEP internal fire CDF. As such, the internal fire CDF is not sensitive to EDG reliability and availability.

These conclusions were verified with the base LaSalle County Station model by re-quantifying the dominant RMIEP fire scenarios with the current Transient Initiator event structure and associated system fault trees. The key conclusion remains the same (i.e., internal fire CDF is not sensitive to EDG performance). Therefore the proposed EDG completion time extension has a negligible effect on the risk profile at LaSalle County

Station from fire. In addition, explicit modeling of such sequences would complicate the quantification process for no benefit as it would not impact the decision making process.

SEISMIC RESULTS

The seismic analyses was conducted as part of the IPEEE, based on the original seismic PRA modeling performed and documented in the NRC-sponsored RMIEP Study (i.e., NUREG/CR-4832). The RMIEP study analyzed LaSalle County Station seismic risk employing the methodology sponsored by the NRC under Seismic Safety Margin Research Program (SSMRP) and developed by Lawrence Livermore National Laboratory (LLNL). The key elements used in the evaluations for this submittal are as follows.

1. Development of the seismic hazard at the LaSalle County Station site including the effect of local site conditions.
2. Comparisons of the best estimate seismic response of structures, components, and piping systems with design values for the purposes of specifying median responses in the seismic risk calculations.
3. Investigation of the effects of hydrodynamic loads on seismic risk.
4. Development of building and component fragilities for important structures and components.
5. Estimation of the seismically induced core damage frequency.

This approach to seismic risk assessment is consistent with the requirements of the NRC IPEEE Program and current seismic risk assessment technology. The conclusions of the RMIEP seismic study applicable to the EDG completion time risk assessment are as follows.

- "The LaSalle plant is very well designed from a seismic view-point...If a LOSP was not likely to occur as a result of the seismic event, there would be no dominant seismic sequences at LaSalle." (Note: LOSP is defined as a Loss of Off Site Power)
- The dominant seismic sequences at LaSalle County Station (i.e., 99% of the RMIEP seismic CDF) are seismically induced loss of offsite power events.
- The seismic risk is sensitive to EDG reliability and availability.

Given the above conclusions, seismic-induced core damage sequences are included in the accident sequence quantification in support of this EDG completion time risk assessment. These sequences are developed based on the extensive work provided in the RMIEP study and are quantified using the current LaSalle County Station base DLOOP accident sequence structure. The conclusion resulting from these sequences is that seismic-initiated accident sequences involving EDG failures and/or unavailabilities are not significant contributors (i.e., <1%) to overall plant risk. Therefore, the proposed EDG completion time extension has a negligible effect on the risk profile at LaSalle County Station from seismic events.

Other External Hazards

Extreme winds, external floods, and other external events (e.g., aircraft impact, turbine missiles, transportation accidents, etc.) were also discussed in the RMIEP study and

included in the LaSalle County Station IPE/IPEEE Submittal. These hazards were determined to be not significant contributors to total plant risk and no potential vulnerabilities were identified. Therefore, the proposed EDG completion time extension has a negligible effect on risk profile at LaSalle County Station from these other external events. Quantification of such accident sequences is not explicitly included in the accident sequence quantification of this EDG completion time risk assessment.

Low Power and Shutdown Risk

Because this assessment is being performed to evaluate the risks associated with extending EDG completion times for an at-power unit, an explicit quantification of the risk impact for low-power and shutdown conditions is not warranted.

The guidance contained in NUREG-1449, "Shutdown and Low-Power Operation at Commercial Nuclear Power Plants in the United States," dated September 1993, identified that an outage typically represents times when equipment unavailability is high, unusual electrical lineups exist and the likelihood of an electrical perturbation is increased by maintenance activities. Increasing the flexibility to perform more EDG work on-line will result in less unavailability during plant shutdown conditions. This will reduce shutdown risk by improving the availability of standby AC power sources for shutdown cooling equipment and other equipment needed to mitigate the events postulated to occur during shutdown. It will also increase the availability of the shutdown unit EDGs in support of the other unit through the cross-tie breakers if the need arose. Therefore, a risk benefit with regard to shutdown is expected as the result of increasing their availability during the low-power/shutdown conditions.

The effect of the proposed EDG completion time extension on low-power operations is expected to be negligible. This is because only a small fraction of the operating cycle is spent in a low-power configuration. The majority of the operating cycle consists largely of the near full-power operation which is addressed by the at-power PRA and the forced or planned shutdown periods. The risk of completing a forced shutdown or planned shutdown is treated in the at-power PRA model by the manual shutdown initiating event sequences. Furthermore, most "down-power" events are expected to be brief and infrequent. Therefore, the risk of low-power operations is considered to be negligible.

Applicability of the Risk Results to an Extended Operating Cycle

The proposed EDG completion time extension will be administered on the basis of an operating cycle, as opposed to a calendar year. The risk calculations for changes in annual average CDF and LERF will decrease because the operating cycle is increased. See equations 1 and 4 as examples, and note that the duration of the operating cycle is in the denominator of the risk calculations. All risk calculations are expected to reduce as a result of extending the operating cycles from 18 months to 24 months. The existing risk analysis, based on an 18-month operating cycle, bounds the results of a 24-month operating cycle. Therefore, there are no risk calculations needed for extending the operating cycle to 24 months.

Tier 2: Avoidance of Risk-Significant Plant Configurations

There is reasonable assurance that risk-significant plant equipment configurations will not occur when specific plant equipment is out-of-service consistent with the proposed TS changes. CTS and proposed ITS require the SATs, offsite power and cross-tie breakers to be operable.

Tier 3: Risk-Informed Configuration Risk Management Program

LaSalle County Station has developed a CRMP that ensures that the risk impact of equipment out-of-service is appropriately evaluated prior to performing any maintenance activity. This program involves an integrated review (i.e., both probabilistic and deterministic) 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.

LaSalle County Station currently has 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 equipment failure/malfunction or emergent condition produce a plant configuration that has not been previously assessed.

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 is 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 allowed outage time, compensatory measures and contingency plans are required to minimize SSC unavailability and maximize SSC reliability.

- For Maintenance Rule High Risk Significant SSCs, the impact of the planned activity on the unavailability performance criteria is monitored and trended.

- As a final check, a risk assessment is performed to ensure that the activity does not pose any unacceptable risk. The results of the risk assessment are classified by a color code based on the increased risk of the activity as follows.

Color	Meaning	Plant Impact and Required Action
Green	Non-Risk Significant	➢ Small impact on plant risk ➢ No specific actions are required
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. ➢ Compensatory measures are required 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 shall be 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. If an offsite power source becomes unavailable or degraded, or the risk of losing offsite power significantly increases due to inclement weather (e.g., high wind, severe thunderstorm forecast, tornado watch/warning, or freezing rain), then systems required to mitigate the LOOP shall be made available as soon as possible in accordance with contingency plans.

Increases in risk posed by potential combinations of equipment out-of-service will be managed under the CRMP. Examples of the CRMP include the following.

- The proposed EDG extended completion time will be scheduled at times of the year with the least potential to have severe weather induced LOOP events (i.e., the dominant contributor to risk). This represents a real risk benefit that is not yet explicitly quantified.

- The availability of the dual unit power supplies will be verified prior to entering the completion time.

- No elective maintenance will be scheduled within the switchyard that would challenge the SAT connection or offsite power availability during the proposed EDG extended completion time.
- The condition of the offsite power supply and switchyard will be evaluated.
- The appropriate Operations personnel will be trained in the use of the cross-tie breaker procedures, and the procedures will be available to the appropriate Operations personnel during an proposed EDG extended completion time.
- Voluntary entry into the proposed EDG extended completion time will not be abused by repeated entry into and exit from the TS LCO.
- The opposite unit EDGs and cross-tie breaker will be verified to be operable prior to voluntarily entering into proposed EDG extended completion time.
- While in the extended EDG completion time, additional elective equipment maintenance or testing, or equipment failure will be evaluated using the CRMP. The CRMP is a program used to assess the integrated capability of the plant. The goals of the CRMP are to ensure that risk-significant plant configurations will not be entered for planned maintenance activities, and appropriate actions will be taken should unforeseen events place the plant in a risk significant configuration during the extended EDG completion time. Activities that yield unacceptable results via the CRMP will be avoided.
- The system load dispatcher will be notified in advance that the station is performing onsite emergency AC power source maintenance and be advised of the increased risk of an SBO during this time.
- No work will be performed on the Division 3 HPCS system or its associated EDG on either unit during the proposed EDG extended completion time.
- LaSalle County Station will have procedures in place to implement the above compensatory actions prior to entering an extended EDG completion time.

The CRMP will be referenced and maintained as an administrative program in the LaSalle County Station TRM. RG 1.177 recommends that the CRMP be described in the TS Administrative Controls Section. We will describe the CRMP in the TRM. The TRM contains various plant conditions, actions, and testing similar to the TS, which are required to support appropriate operation in accordance with commitments. Changes to the TRM are subject to the requirements of 10 CFR 50.59, "Changes, Tests, and Experiments."

SAFETY BENEFITS

There are two safety benefits to be obtained from the proposed EDG extended completion time that have not been quantitatively assessed. These important benefits are identified here qualitatively for consideration in the assessment and sufficient decisions regarding any perceived risk profile changes.

1. There would be a reduction in entry into TS 3.0.3 which would require a forced shutdown of the plant and its attendant risks. Transition risk

associated with unneeded reactor shutdown for EDG maintenance is avoided. This is generally considered a relatively small safety benefit.

2. One of the principal safety benefits is associated with the ability to remove the EDG maintenance and overhauls from the refueling outages and to perform them during power operation. This safety benefit can be quite significant especially given the improved performance of utilities in completing refueling outages in relatively short times.

   However, as part of this submittal, no quantitative benefit is included in any of the calculations associated with the risk reduction during refuel outages.

Performing EDG overhauls with the reactor at power results in beneficial conditions such that with only EDG work on-going, the maintenance planning, work, and inspection efforts can be focused on this single task. Planning the performance of EDG overhauls at power is judged to result in an improved process compared with attempting the EDG outage during a refueling outage with its many competing demands for resources.

Industry and Plant Operating Experience

Industry and plant operating experience were reviewed to assess the proposed change. A number of plants have been performing EDG maintenance on-line for several years and no events or adverse consequences have been experienced to date.

CONCLUSION

The proposed 14 day EDG completion time is based upon both a deterministic evaluation and a risk-informed assessment. The risk assessment concluded that the increase in plant risk is small and consistent with the NRC Safety Goals Policy Statement and guidance contained in RGs 1.174 and 1.177. The deterministic evaluation concluded that the proposed changes are consistent with the defense-in-depth philosophy and that sufficient safety margins are maintained. Together these analyses provide high assurance of the capability to provide power to the ESF buses during the proposed 14 day EDG completion time.

IMPACT ON PREVIOUS SUBMITTALS

We have reviewed the proposed changes regarding impact on any previous submittals, and have determined that our ITS submittal of March 3, 2000 is impacted. Based on the current schedule for converting LaSalle County Station to ITS formatted TS, the implementation of these proposed changes is currently scheduled to occur at the time of or after we have converted to ITS.

SCHEDULE REQUIREMENTS

EGC requests approval of these proposed TS changes by August 1, 2001 to support procedure changes and work planning necessary to accomplish EDG maintenance activities outside the next refueling outage.

ATTACHMENT B
MARKED-UP PAGES FOR PROPOSED CHANGES
LASALLE COUNTY STATION

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for OPERABLE required offsite circuit.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>	
	A.2 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one division concurrent with inoperability of redundant required feature(s)
	<u>AND</u>	
	A.3 Restore required offsite circuit to OPERABLE status.	72 hours <u>AND</u> ~~10~~ 17 days from discovery of failure to meet LCO 3.8.1.a or b

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
~~B. --------NOTE-------- Not applicable when the opposite unit is in MODE 1, 2, or 3. -------------------- Division 1 DG inoperable for the purposes of completing preplanned maintenance, modifications, or Surveillance Requirements on the Division 1 DG or its associated support systems.~~	~~B.1~~	~~Verify the unit crosstie breakers between the unit and opposite unit Division 2 emergency buses are capable of being closed with a DG powering one of the buses.~~	~~Immediately~~
	~~AND~~		
	~~B.2~~	~~Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).~~	~~1 hour~~ ~~AND~~ ~~Once per 24 hours thereafter~~
	~~AND~~		
	~~B.3~~	~~Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.~~	~~4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)~~
	~~AND~~		
	~~B.4~~	~~Restore inoperable DG to OPERABLE status.~~	~~7 days~~ ~~AND~~ ~~10 days from discovery of failure to meet LCO 3.8.1.a or b~~

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B ~~C~~. ~~Required Action B.1 and associated Completion Time not met.~~ ~~OR~~ One required Division 1, ~~2~~ or ~~3~~ 2 DG inoperable ~~for reasons other than Condition B~~. OR Required opposite unit Division 2 DG inoperable. ~~OR~~ ~~One required Division 1, 2, or 3 DG inoperable and the required opposite unit Division 2 DG inoperable.~~	B ~~C~~.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND ~~C~~.2 B	Declare required feature(s), supported by the inoperable DG(s), inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition ~~C~~ B concurrent with inoperability of redundant required feature(s)
	AND B ~~C~~.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR B ~~C~~.3.2	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	AND ~~C~~.4 B	Restore required DG(s) to OPERABLE status.	~~72 hours~~ 14 DAYS AND 17 ~~10~~ days from discovery of failure to meet LCO 3.8.1.a or b

1C

1C

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. ~~Required Action B.1 and associated Completion Time not met.~~ ~~OR~~ ~~One~~ R~~r~~equired Division ~~1, 2, or~~ 3 DG inoperable ~~for reasons other than Condition B~~. ~~OR~~ ~~Required opposite unit Division 2 DG inoperable~~. OR One required Division 1, 2, or 3 DG inoperable and the required opposite unit Division 2 DG inoperable.	C.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter 1C
	AND		
	C.2	Declare required feature(s), supported by the inoperable DG(s), inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	AND		
	C.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours 1C
	OR		
	C.3.2	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	AND		
	C.4	Restore required DG(s) to OPERABLE status.	72 hours AND ~~10~~ 17 days from discovery of failure to meet LCO 3.8.1.a or b

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. Two required Division 1, 2, or 3 DGs inoperable. OR Division 2 DG and the required opposite unit Division 2 DG inoperable.	F.1	Restore one required DG to OPERABLE status.	2 hours OR 72 hours if Division 3 DG is inoperable
G. Required Action and associated Completion Time of Condition A, B, C, D, E, or F not met. ~~OR~~ ~~Required Action and associated Completion Time of Required Action B.2, B.3, or B.4 not met.~~	G.1 AND G.2	Be in MODE 3. Be in MODE 4.	12 hours 36 hours
H. Three or more required AC sources inoperable.	H.1	Enter LCO 3.0.3.	Immediately

BASES

ACTIONS (continued)

A.3

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours.

With one required offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E distribution system.

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

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, the common DG is inoperable ~~for pre planned maintenance~~ and that
14 DG is subsequently returned ~~OPERABLE, the LCO may already
17 have been not met for up to~~ ~~7~~ days. This situation could
lead to a total of ~~10~~ days, since initial failure to meet
the LCO, to restore the offsite circuit. At this time, a
14 DAYS ~~unit DG could again become inoperable,~~ the circuit restored
OPERABLE, and an additional ~~72 hours~~ (for a total of
31 ~~13~~ days) allowed prior to complete restoration of the LCO.
17 The ~~10~~ day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.a or b. This limit is considered reasonable for situations in which Conditions are entered concurrently for combinations of Conditions A, B, and C.
17 The "AND" connector between the 72 hour and ~~10~~ day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

Similar to Required Action A.2, the Completion Time of Required Action A.3 allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

(continued)

BASES

ACTIONS

A.3 (continued)

This exception results in establishing the "time zero" at the time LCO 3.8.1.a or b was initially not met, instead of at the time that Condition A was entered.

B.1

Condition B provides appropriate compensatory measures to allow performance of pre-planned maintenance or testing on the common DG. Pre-planned maintenance or testing includes preventative maintenance, modifications, and performance of Surveillance Requirements. The Note effectively only allows Condition B to be used for the common DG when the opposite unit is not in MODE 1, 2, or 3. When the common DG becomes inoperable while both units are in MODE 1, 2, or 3, Condition C must be entered for both units and the associated Required Actions performed.

Required Action B.1, is intended to provide assurance that a loss of offsite power, during the period that the common DG or its supported equipment is inoperable for the purposes of completing pre-planned maintenance, modifications, or Surveillance Requirements, does not result in a complete loss of safety function of critical systems. This is accomplished by making an additional source available to support the unit and opposite unit Division 2 emergency buses. This additional source is the unit or opposite unit Division 2 DG. To ensure this alternate highly reliable power source is available during operation in Condition B, it is necessary to temporarily modify the control circuit for the unit crosstie circuit breakers between 4.16 kV emergency buses 142Y and 242Y to allow the breakers to be closed with a DG powering one of the Division 2 emergency buses (142Y or 242Y) so that the unit or opposite unit Division 2 DG can supply the unit and opposite unit Division 2 emergency buses. Therefore, the unit or opposite unit Division 2 DG must be OPERABLE with the capability to be manually aligned to the unit and opposite unit Division 2 emergency buses. The Completion Time ensures the alternate source to the Division 2 emergency buses is available whenever the plant is operating in Condition B. If Required Action B.1 and the associated Completion Time are not met, Condition C must the entered and the Required Actions taken.

(continued)

BASES

ACTIONS (continued)

B.2

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

B.3

Required Action B.3 is intended to provide assurance that a loss of offsite power, during the period that the common DG is inoperable for the purposes of completing pre-planned maintenance, modifications, or Surveillance Requirements on the common DG or its support systems, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included, although for this Required Action, Division 3 (HPCS) is considered redundant to Division 1 and Division 2 ECCS). Redundant required feature failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

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

a. An inoperable common DG exists; and

b. A redundant required feature on another division is inoperable.

If, at any time during the existence of this Condition (the common DG inoperable due to pre-planned maintenance, modification, or testing), a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

(continued)

BASES

ACTIONS

B.3 (continued)

Discovering the common DG inoperable coincident with one or more redundant required support or supported features, or both, that are associated with the redundant OPERABLE DG(s), results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown. The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and low probability of a DBA occurring during this period.

B.4

One common DG provides onsite standby power to the Division 1 emergency buses on both units. This Required Action provides a 7 day time period to perform pre-planned maintenance or testing on the common DG while precluding the shutdown of both units. Pre-planned maintenance or testing includes preventative maintenance, modifications, and performance of Surveillance Requirements. The Note to Condition B effectively only allows the 7 day Completion Time to be used for the common DG when the opposite unit is not in MODE 1, 2, or 3. When the common DG becomes inoperable while both units are in MODE 1, 2, or 3, Condition C must be entered for both units and the associated Required Actions performed. The 4.16 kV emergency bus design is sufficient to allow operation to continue in Condition B for a period that should not exceed 7 days. In this condition, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 7 day

(continued)

BASES

ACTIONS

B.4 (continued)

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

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1.a or b. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 10 days, since initial failure of the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 13 days) allowed prior to complete restoration of the LCO. The 10 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.a or b. This limit is considered reasonable for situations in which Conditions are entered concurrently for combinations of Conditions A, B, and C. The "AND" connector between the 7 day and 10 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

Similar to Required Action B.3, the Completion Time of Required Action B.4 allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time LCO 3.8.1.a or b was initially not met, instead of the time that Condition B was entered.

B → C.1

To ensure a highly reliable power source remains, it is necessary to verify the availability of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of

(continued)

BASES

ACTIONS

B ~~C~~.1 (continued)

SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

B ~~C~~.2

Required Action B ~~C~~.2 is intended to provide assurance that a loss of offsite power, during the period that the DG~~(s)~~ is inoperable as described in Condition B ~~C~~, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included, although, for this Required Action, Division 3 (HPCS System) is considered redundant to Division 1 and 2 ECCS). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

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

a. An inoperable DG exists; and

b. A redundant required feature on another division is inoperable.

If, at any time during the existence of this Condition (DG~~(s)~~ inoperable as described in Condition B ~~C~~), a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering required DG(s) inoperable coincident with one or more redundant required support or supported features, or both, that are associated with the redundant OPERABLE DG(s), results in starting the Completion Time for the Required

(continued)

BASES

ACTIONS

B ~~C~~.2 (continued)

Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

B ~~C~~.3.1 and B ~~C~~.3.2

Required Action B ~~C~~.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG(s) does not exist on the OPERABLE DG(s), SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DGs, the other DGs are declared inoperable upon discovery, and Condition F or H of LCO 3.8.1 is entered, as applicable. Once the failure is repaired, and the common cause failure no longer exists, Required Action B ~~C~~.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DG(s).

In the event the inoperable DG(s) is restored to OPERABLE status prior to completing either B ~~C~~.3.1 or B ~~C~~.3.2, the station corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B ~~C~~.

(continued)

BASES

ACTIONS B C.3.1 and B C.3.2 (continued)

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable time to confirm that the OPERABLE DG(s) are not affected by the same problem as the inoperable DG.

B C.4

~~According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 72 hours.~~ In this condition, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. The 72 hour (14 DAY) Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

The second Completion Time for Required Action B C.4 established a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1.a or b. If Condition C (B) is entered while, for instance, the common DG (ONE REQUIRED OFFSITE CIRCUIT) is inoperable ~~due to pre-planned maintenance~~ and that DG is subsequently restored OPERABLE, the LCO may already have been not met for up to 7 (3) days. This situation could lead to a total of 10 (17) days, since initial failure to meet the LCO, to restore the ~~unit DG~~ (OFFSITE CIRCUIT). At this time, ~~an~~ (ANOTHER) offsite circuit could become inoperable, the ~~unit~~ DG restored OPERABLE, and an additional 72 hours (for a total of 13 (20) days) allowed prior to complete restoration of the LCO. The 10 (17) day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.a or b. This limit is considered reasonable for situations in which Conditions are entered concurrently for combinations of Conditions A, B, and C. The "AND" connector between the ~~72 hour~~ (14 DAYS) and 10 (17) day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

(continued)

BASES

ACTIONS

B ~~C~~.4 (continued)

Similar to Required Action B ~~C~~.2, the Completion Time of Required Action B ~~C~~.4 allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B ~~C~~ was entered.

~~D.1 and D.2~~

~~Required Action D.1 addresses actions to be taken in the event of concurrent failure of redundant required features. Required Action D.1 reduces the vulnerability to a loss of function. The Completion Time for taking these actions is reduced to 12 hours from that allowed with only one division without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety divisions are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are designed with redundant safety related divisions (i.e., single division systems are not included in the list, although, for this Required Action, Division 3 (HPCS System) is considered redundant to Division 1 and 2 ECCS). Redundant required features failures consist of any of these features that are inoperable, because any inoperability is on a division redundant to a division with inoperable offsite circuits.~~

~~The Completion Time for Required Action D.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:~~

~~a. Two required offsite circuits are inoperable; and~~

(continued)

BASES

ACTIONS

B.4 (continued)

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

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1.a or b. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of 10 days, since initial failure of the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 13 days) allowed prior to complete restoration of the LCO. The 10 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.a or b. This limit is considered reasonable for situations in which Conditions are entered concurrently for combinations of Conditions A, B, and C. The "AND" connector between the 7 day and 10 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

Similar to Required Action B.3, the Completion Time of Required Action B.4 allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time LCO 3.8.1.a or b was initially not met, instead of the time that Condition B was entered.

C.1

To ensure a highly reliable power source remains, it is necessary to verify the availability of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of

(continued)

BASES

ACTIONS

C.1 (continued)

SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

C.2

Required Action C.2 is intended to provide assurance that a loss of offsite power, during the period that the DG(s) is inoperable as described in Condition C, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included, although, for this Required Action, Division 3 (HPCS System) is considered redundant to Division 1 and 2 ECCS). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

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

a. An inoperable DG exists; and

b. A redundant required feature on another division is inoperable.

If, at any time during the existence of this Condition (DG(s) inoperable as described in Condition C), a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering required DG(s) inoperable coincident with one or more redundant required support or supported features, or both, that are associated with the redundant OPERABLE DG(s), results in starting the Completion Time for the Required

(continued)

BASES

ACTIONS

C.2 (continued)

Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

C.3.1 and C.3.2

Required Action C.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG(s) does not exist on the OPERABLE DG(s), SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DGs, the other DGs are declared inoperable upon discovery, and Condition F or H of LCO 3.8.1 is entered, as applicable. Once the failure is repaired, and the common cause failure no longer exists, Required Action C.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DG(s).

In the event the inoperable DG(s) is restored to OPERABLE status prior to completing either C.3.1 or C.3.2, the station corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition C.

(continued)

BASES

ACTIONS

C.3.1 and C.3.2 (continued)

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable time to confirm that the OPERABLE DG(s) are not affected by the same problem as the inoperable DG.

C.4

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 72 hours. In this condition, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

The second Completion Time for Required Action C.4 established a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1.a or b. If Condition C is entered while, for instance, the common DG is inoperable ~~due to pre planned maintenance~~ (14) and that DG is subsequently restored OPERABLE, (17) the LCO may already have been not met for up to 7 days. This situation could lead to a total of 10 days, since initial failure to meet the LCO, to restore the ~~unit~~ DG(s). At (S) this time, an offsite circuit could become inoperable, the ~~unit~~ DG(s) restored OPERABLE, and an additional 72 hours (for a (20) total of 13 days) allowed prior to complete restoration of (17) the LCO. The 10 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.a or b. This limit is considered reasonable for situations in which Conditions are entered (17) concurrently for combinations of Conditions A, B, and C. The "AND" connector between the 72 hour and 10 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

(continued)

BASES

ACTIONS

C.4 (continued)

Similar to Required Action C.2, the Completion Time of Required Action C.4 allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered.

D.1 and D.2

Required Action D.1 addresses actions to be taken in the event of concurrent failure of redundant required features. Required Action D.1 reduces the vulnerability to a loss of function. The Completion Time for taking these actions is reduced to 12 hours from that allowed with only one division without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety divisions are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are designed with redundant safety related divisions (i.e., single division systems are not included in the list, although, for this Required Action, Division 3 (HPCS System) is considered redundant to Division 1 and 2 ECCS). Redundant required features failures consist of any of these features that are inoperable, because any inoperability is on a division redundant to a division with inoperable offsite circuits.

The Completion Time for Required Action D.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. Two required offsite circuits are inoperable; and

(continued)

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

A.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Separate and independent diesel generators~~*~~, 0, 1A, 2A and 1B with:

   1. For diesel generator 0, 1A and 2A:

      a) A separate day fuel tank containing a minimum of 250 gallons of fuel.

      b) A separate fuel storage system containing a minimum of 31,000 gallons of fuel.

   2. For diesel generator 1B, a separate fuel storage tank and a day tank containing a minimum of 29,750 gallons of fuel.

   3. A separate fuel transfer pump.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one offsite circuit of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the offsite circuit to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With either the 0 or 1A diesel generator inoperable, demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE

~~*See page 3/4 8-1(a).~~

LIMITING CONDITION FOR OPERATION (Continued)

*For the purposes of completing maintenance, modification, and/or technical specification surveillance requirements, on the 0 diesel generator and its support systems during a refuel outage, as part of pre-planned maintenance, modifications, and/or the surveillance program, the requirements of action statement b are modified to:

1. Eliminate the requirement for performing technical specification surveillance requirements 4.8.1.1.1.a on each operable AC source, immediately and once per 8 hours thereafter, when the 0 diesel generator is declared inoperable.

2. Allow an additional 96 hours in excess of the 72 hours allowed in action statement b for the 0 diesel generator to be inoperable.

Provided that the following conditions are met:

A. Unit 2 is in operational condition 4 or 5 or defueled prior to taking the 0 diesel generator out of service.

B. Surveillance requirements 4.8.1.1.1a and 4.8.1.1.2a.4 are successfully completed, for the offsite power sources and the 1A and 2A diesel generators, within 48 hours prior to removal of the 0 diesel generator from service.

C. No maintenance is performed on the offsite circuits or the 1A or 2A diesel generators, while the 0 diesel generator is inoperable.

D. Technical specification requirement 4.8.1.1.1a is performed daily, while the 0 diesel generator is inoperable.

E. The control circuit for the unit cross-tie circuit breakers between buses 142Y and 242Y are temporarily modified to allow the breakers to be closed with a diesel generator feeding the bus, while the 0 diesel generator is inoperable.

The provisions of technical specification 3.0.4 are not applicable.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the diesel generator to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

14 DAYS

c. With one offsite circuit of the above required A.C. sources and diesel generator 0 or 1A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 8 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore at least one of the inoperable A.C. sources to OPERABLE status within 12 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore at least two offsite circuits and diesel generators 0 and 1A to OPERABLE status within 72 hours from the time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With diesel generator 1B of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the offsite A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore diesel generator 1B to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by specification 3.5.1.

*This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABILITY. The provisions of Specification 3.0.2 are not applicable.

ACTION (Continued)

e. With both of the above required offsite circuits inoperable, restore at least one offsite circuit to OPERABLE status within 24 hours, or be in at least HOT SHUTDOWN within the next 12 hours. With only one offsite circuit restored to OPERABLE status, restore at least two offsite circuits to OPERABLE status within 72 hours from the time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

f. With diesel generators 0 and 1A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter, and Surveillance Requirement 4.8.1.1.2.a.4 for the 1B and 2A diesel generators, separately, within 8 hours*. Restore at least one of the inoperable diesel generators 0 or 1A to OPERABLE status within 2 hours, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore both diesel generators 0 and 1A to OPERABLE status within 72 hours, from the time of initial loss, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

g. With diesel generator 2A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the 2A diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the 1A diesel generator, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the inoperable diesel generator 2A to OPERABLE status within ~~72 hours~~ 14 DAYS or declare standby gas treatment system subsystem B, Unit 2 drywell and suppression chamber hydrogen recombiner system, and control room and auxiliary electric equipment room emergency filtration system train B inoperable, and take the ACTION required by specifications 3.6.5.3, 3.6.6.1, and 3.7.2. Continued performance of Surveillance Requirement 4.8.1.1.1.a is not required provided the above systems are declared inoperable and the action of their respective specifications is taken.

*This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABILITY. The provisions of Specification 3.0.2 are not applicable.

ACTION (Continued)

h. With one offsite circuit of the above required A.C. electrical power sources and diesel generator 1B inoperable, apply the FOLLOWING: ~~requirements of ACTION a and d specified above~~.

INSERT A

i. With either diesel generators 0 or 1A inoperable and diesel generator 1B inoperable, apply the FOLLOWING ~~requirements of ACTION b and d specified above.~~

INSERT B

j. With one offsite circuit of the above required A.C. electrical power sources and diesel generator 2A inoperable, apply the FOLLOWING ~~requirements of ACTION a and g specified above.~~

INSERT C

k. With diesel generator 1B and diesel generator 2A inoperable, apply the ~~requirements of ACTION d and g specified above~~. FOLLOWING

INSERT D

l. With diesel generator 0 and diesel generator 2A inoperable, apply the ~~requirements of ACTION b and g specified above.~~ FOLLOWING

INSERT E

Insert A

1

~~With one offsite circuit of the above required A.C. electrical power sources inoperable,~~ demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the offsite circuit to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2

~~With diesel generator 1B of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the offsite A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter~~. If the diesel generator 1B became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore diesel generator 1B to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by specification 3.5.1.

INSERT B

1

~~With either the 0 or 1A diesel generator inoperable,~~ demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the 0 or 1A diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE

diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the diesel generator to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2

~~With diesel generator 1B of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the offsite A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter~~. If the diesel generator 1B became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore diesel generator 1B to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by specification 3.5.1.

INSERT C

1 ~~With one offsite circuit of the above required A.C. electrical power sources inoperable,~~ demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the offsite circuit to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2 ~~With diesel generator 2A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter~~. If the 2A diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the 1A diesel generator, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the inoperable diesel generator 2A to OPERABLE status within 72 hours or declare standby gas treatment system subsystem B, Unit 2 drywell and suppression chamber hydrogen recombiner system, and control room and auxiliary electric equipment room emergency filtration system train B inoperable, and take the ACTION required by specifications 3.6.5.3, 3.6.6.1, and 3.7.2. Continued performance of Surveillance Requirement 4.8.1.1.1.a is not required provided the above systems are declared inoperable and the action of their respective specifications is taken.

Insert D

1 ~~With diesel generator 1B of the above required A.C. electrical power sources inoperable,~~ demonstrate the OPERABILITY of the offsite A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator 1B became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore diesel generator 1B to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by specification 3.5.1.

2 ~~With diesel generator 2A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter.~~ If the 2A diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the 1A diesel generator, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the inoperable diesel generator 2A to OPERABLE status within 72 hours or declare standby gas treatment system subsystem B, Unit 2 drywell and suppression chamber hydrogen recombiner system, and control room and auxiliary electric equipment room emergency filtration system train B inoperable, and take the ACTION required by specifications 3.6.5.3, 3.6.6.1, and 3.7.2. Continued performance of Surveillance Requirement 4.8.1.1.1.a is not required provided the above systems are declared inoperable and the action of their respective specifications is taken.

Insert E

1 ~~With either the 0 or 1A diesel generator inoperable~~, demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the O diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE

diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the diesel generator to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2 ~~With diesel generator 2A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter.~~ If the 2A diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the 1A diesel generator, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the inoperable diesel generator 2A to OPERABLE status within 72 hours or declare standby gas treatment system subsystem B, Unit 2 drywell and suppression chamber hydrogen recombiner system, and control room and auxiliary electric equipment room emergency filtration system train B inoperable, and take the ACTION required by specifications 3.6.5.3, 3.6.6.1, and 3.7.2. Continued performance of Surveillance Requirement 4.8.1.1.1.a is not required provided the above systems are declared inoperable and the action of their respective specifications is taken.

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

A.C. SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Separate and independent diesel generators* 0, 1A, 2A and 2B with:

   1. For diesel generator 0, 1A and 2A:

      a) A separate day fuel tank containing a minimum of 250 gallons of fuel.

      b) A separate fuel storage system containing a minimum of 31,000 gallons of fuel.

   2. For diesel generator 2B, a separate fuel storage tank and a day tank containing a minimum of 29,750 gallons of fuel.

   3. A separate fuel transfer pump.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, and 3.

ACTION:

a. With one offsite circuit of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the offsite circuit to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With either the 0 or 2A diesel generator inoperable, demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE

~~*See page 3/4 8-1(a)~~.

ELECTRICAL POWER SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

~~*For the purposes of completing maintenance, modification, and/or technical specification surveillance requirements, on the 0 diesel generator and its support systems during a refuel outage, as part of pre-planned maintenance, modifications, and/or the surveillance program, the requirements of action statement b are modified to:~~

1. ~~Eliminate the requirement for performing technical specification surveillance requirements 4.8.1.1.1.a on each operable AC source, immediately and once per 8 hours thereafter, when the 0 diesel generator is declared inoperable.~~

2. ~~Allow an additional 96 hours in excess of the 72 hours allowed in action statement b for the 0 diesel generator to be inoperable.~~

~~Provided that the following conditions are met:~~

A. ~~Unit 1 is in operational condition 4 or 5 or defueled prior to taking the 0 diesel generator out of service.~~

B. ~~Surveillance requirements 4.8.1.1.1a and 4.8.1.1.2a.4 are successfully completed, for the offsite power sources and the 1A and 2A diesel generators, within 48 hours prior to removal of the 0 diesel generator from service.~~

C. ~~No maintenance is performed on the offsite circuits or the 1A or 2A diesel generators, while the 0 diesel generator is inoperable.~~

D. ~~Technical specification requirement 4.8.1.1.1a is performed daily, while the 0 diesel generator is inoperable.~~

E. ~~The control circuit for the unit cross-tie circuit breakers between buses 142Y and 242Y are temporarily modified to allow the breakers to be closed with a diesel generator feeding the bus, while the 0 diesel generator is inoperable.~~

The provisions of technical specification 3.0.4 are not applicable.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the diesel generator to OPERABLE status within ~~72 hours~~ 14 DAYS or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. With one offsite circuit of the above required A.C. sources and diesel generator 0 or 2A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 8 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore at least one of the inoperable A.C. sources to OPERABLE status within 12 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore at least two offsite circuits and diesel generators 0 and 2A to OPERABLE status within 72 hours from the time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With diesel generator 2B of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the offsite A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore diesel generator 2B to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by specification 3.5.1.

*This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABILITY. The provisions of Specification 3.0.2 are not applicable.

ELECTRICAL POWER SYSTEMS

LIMITING CONDITION FOR OPERATION (Continued)

ACTION (Continued)

e. With both of the above required offsite circuits inoperable, restore at least one offsite circuit to OPERABLE status within 24 hours, or be in at least HOT SHUTDOWN within the next 12 hours. With only one offsite circuit restored to OPERABLE status, restore at least two offsite circuits to OPERABLE status within 72 hours from the time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

f. With diesel generators 0 and 2A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter, and Surveillance Requirement 4.8.1.1.2.a.4 for the 2B and 1A diesel generators, separately, within 8 hours*. Restore at least one of the inoperable diesel generators 0 or 2A to OPERABLE status within 2 hours, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore both diesel generators 0 and 2A to OPERABLE status within 72 hours, from the time of initial loss, or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

g. With diesel generator 1A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the 1A diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the 2A diesel generator, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the inoperable diesel generator 1A to OPERABLE status within ~~72 hours~~ 14 DAYS or declare standby gas treatment system subsystem A, Unit 1 drywell and suppression chamber hydrogen recombiner system, and control room and auxiliary electric equipment room emergency filtration system train A inoperable, and take the ACTION required by specifications 3.6.5.3, 3.6.6.1, and 3.7.2. Continued performance of Surveillance Requirement 4.8.1.1.1.a is not required provided the above systems are declared inoperable and the action of their respective specifications is taken.

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*This test is required to be completed regardless of when the inoperable diesel generator is restored to OPERABILITY. The provisions of Specification 3.0.2 are not applicable.

LIMITING CONDITIONS FOR OPERATION (Continued)

ACTION (Continued)

h. With one offsite circuit of the above required A.C. electrical power sources and diesel generator 2B inoperable, apply the ~~requirements of ACTION a and d specified above.~~ FOLLOWING.

INSERT F

i. With either diesel generators 0 or 2A inoperable and diesel generator 2B inoperable, apply the ~~requirements of ACTION b and d specified above.~~ FOLLOWING

INSERT G

j. With one offsite circuit of the above required A.C. electrical power sources and diesel generator 1A inoperable, apply the ~~requirements of ACTION a and g specified above.~~ FOLLOWING

INSERT H

k. With diesel generator 2B and diesel generator 1A inoperable, apply the ~~requirements of ACTION d and g specified above.~~ FOLLOWING

INSERT I

l. With diesel generator 0 and diesel generator 1A inoperable, apply the ~~requirements of ACTION b and g specified above.~~ FOLLOWING

INSERT J

INSERT F

1 ~~With one offsite circuit of the above required A.C. electrical power sources inoperable,~~ demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the offsite circuit to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2 ~~With diesel generator 2B of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the offsite A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter.~~ If the diesel 2B generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore diesel generator 2B to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by specification 3.5.1.

INSERT G

1

~~With either the 0 or 2A diesel generator inoperable,~~ demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the 0 or 2A diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE

diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the diesel generator to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2

~~With diesel generator 2B of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the offsite A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter.~~ If the diesel generator 2B became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore diesel generator 2B to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by specification 3.5.1.

INSERT H

1 ~~With one offsite circuit of the above required A.C. electrical power sources inoperable,~~ demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the offsite circuit to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2 ~~With diesel generator 1A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter.~~ If the 1A diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the 2A diesel generator, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the inoperable diesel generator 1A to OPERABLE status within 72 hours or declare standby gas treatment system subsystem A, Unit 1 drywell and suppression chamber hydrogen recombiner system, and control room and auxiliary electric equipment room emergency filtration system train A inoperable, and take the ACTION required by specifications 3.6.5.3, 3.6.6.1, and 3.7.2. Continued performance of Surveillance Requirement 4.8.1.1.1.a is not required provided the above systems are declared inoperable and the action of their respective specifications is taken.

INSERT I

1 ~~With diesel generator 2B of the above required A.C. electrical power sources inoperable,~~ demonstrate the OPERABILITY of the offsite A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator 2B became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore diesel generator 2B to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by specification 3.5.1.

2 ~~With diesel generator 1A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter.~~ If the 1A diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the 2A diesel generator, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the inoperable diesel generator 1A to OPERABLE status within 72 hours or declare standby gas treatment system subsystem A, Unit 1 drywell and suppression chamber hydrogen recombiner system, and control room and auxiliary electric equipment room emergency filtration system train A inoperable, and take the ACTION required by specifications 3.6.5.3, 3.6.6.1, and 3.7.2. Continued performance of Surveillance Requirement 4.8.1.1.1.a is not required provided the above systems are declared inoperable and the action of their respective specifications is taken.

Insert J

1 ~~With either the 0 or 2A diesel generator inoperable,~~ demonstrate the OPERABILITY of the above required A.C. offsite sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. If the diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE

diesel generators, separately, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the diesel generator to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2 ~~With diesel generator 1A of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter.~~ If the 1A diesel generator became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned maintenance or testing, demonstrate the OPERABILITY of the 2A diesel generator, by performing Surveillance Requirement 4.8.1.1.2.a.4 within 24 hours*, unless the absence of any potential common mode failure for the remaining diesel generator is demonstrated. Restore the inoperable diesel generator 1A to OPERABLE status within 72 hours or declare standby gas treatment system subsystem A, Unit 1 drywell and suppression chamber hydrogen recombiner system, and control room and auxiliary electric equipment room emergency filtration system train A inoperable, and take the ACTION required by specifications 3.6.5.3, 3.6.6.1, and 3.7.2. Continued performance of Surveillance Requirement 4.8.1.1.1.a is not required provided the above systems are declared inoperable and the action of their respective specifications is taken.

INFORMATION SUPPORTING A FINDING OF NO SIGNIFICANT HAZARDS CONSIDERATION

Exelon Generation Company (EGC), LLC has evaluated the proposed changes and determined that they do not involve a significant hazards consideration. According to 10 CFR 50.92(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:

Involve a significant increase in the probability of occurrence or consequences of an accident previously evaluated;

Create the possibility of a new or different kind of accident from any previously analyzed; or

Involve a significant reduction in a margin of safety.

EGC proposes changes to Appendix A, Technical Specifications (TS), to Facility Operating Licenses NPF-11 and NPF-18. The proposed changes to Current Technical Specifications (CTS) Section 3/4.8.1, "A.C. Sources – Operating," and the proposed Improved Technical Specifications (ITS) Section 3.8.1, "A.C. Sources – Operating," will extend the allowable completion times for the Required Actions associated with restoration of an inoperable Division 1 or Division 2 Emergency Diesel Generator (EDG) to 14 days.

Additionally, the proposed extension of the completion time to 14 days for a Division 1 or Division 2 EDG results in a corresponding extension of the proposed ITS time period associated with discovery of failure to meet Limiting Condition for Operation (LCO) 3.8.1 from 10 days to 17 days.

The proposed changes will provide operational flexibility allowing more efficient application of plant resources to safety significant activities. The proposed changes will allow performance of periodic EDG overhauls and post-maintenance testing on-line, reducing plant refueling outage duration and improving EDG availability during shutdown.

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

The proposed changes include the extension of the completion time for the Emergency Diesel Generators (EDGs) from 72 hours to 14 days to allow on-line preventive maintenance to be performed. The EDGs are not initiators of previously evaluated postulated accidents. Extending the completion times of the EDGs would not have any impact on the frequency of any accident previously evaluated, and therefore the probability of a previously analyzed accident is unchanged. The proposed change to the completion time for EDGs will not result in any changes to the plant activities associated with EDG maintenance, but rather will enable a more efficient planning and scheduling of maintenance activities that will minimize potential adverse interactions with concurrent outage activities.

The consequences of a previously analyzed event are the same during a 72 hour EDG completion time as the consequences during a 14 day completion time. Thus the consequences of accidents previously analyzed are unchanged between the existing TS requirements and the proposed change. In the worst case scenario, the ability to mitigate the consequences of any accident previously analyzed is preserved. The consequences of an accident are independent of the time the EDGs are out-of-service. As a general practice, no other additional failures are postulated while equipment is inoperable within its TS completion time.

Therefore the proposed changes do not involve a significant increase in the probability or consequences of an accident previously analyzed.

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

The proposed changes do not involve a physical change to the plant. No new equipment is being introduced, and installed equipment is not being operated in a new or different manner. Therefore, these proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

The proposed changes will extend the allowable completion times for the Required Actions associated with restoration of an inoperable Division 1 or Division 2 EDG. The proposed 14 day EDG completion time is based upon both a deterministic evaluation and a risk-informed assessment. The availability of offsite power coupled with the availability of the opposite unit EDG via the unit cross-tie breaker and the use of the Configuration Risk Management Program (CRMP) provide adequate compensation for the potential small incremental increase in plant risk of the EDG extended completion time. In addition, the increased availability of the EDGs during refueling outage offsets the small increase in plant risk during operation. The proposed EDG extended completion times in conjunction with the availability of the opposite unit EDG continues to provide adequate assurance of the capability to provide power to the Engineered Safety Feature (ESF) buses. The risk assessment concluded that the increase in plant risk is small and consistent with the NRC's Safety Goal Policy Statement, "Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," Federal Register, Volume 60, p. 42622, August 16, 1995, and guidance contained in Regulatory Guides (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 Decision Making: Technical Specifications," dated August, 1998. Together, the deterministic evaluation and the risk-informed assessment provide high assurance of the capability to provide power to the ESF buses during the proposed 14 day EDG completion time.

Therefore implementation of the proposed changes will not involve a significant reduction in the margin of safety.

Therefore, based upon the above evaluation, we have concluded that the proposed changes do not constitute a significant hazards consideration.

INFORMATION SUPPORTING AN ENVIRONMENTAL ASSESSMENT

Exelon Generation Company (EGC), LLC has evaluated these proposed changes against the criteria for identification of licensing and regulatory actions requiring environmental assessment in accordance with 10 CFR 51.21. EGC has determined that these proposed changes meet the criteria for a categorical exclusion set forth in 10 CFR 51.22(c)(9) and as such, has determined that no irreversible consequences exist in accordance with 10 CFR 50.92(b). This determination is based on the fact that these changes are being proposed as an amendment to a license issued pursuant to 10 CFR 50 that changes a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or that changes an inspection or a surveillance requirement, and the amendment meets the following specific criteria.

(i) The proposed changes involve no significant hazards consideration.

As demonstrated in Attachment C, these 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 allow performance of Emergency Diesel Generator (EDG) overhauls on-line is consistent with the design basis of the plant. These changes do 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. Therefore the proposed changes will not affect the types or increase the amounts of any effluents released offsite.

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

The proposed changes will not result in changes in the configuration of the facility. The proposed changes only affect operation of the plant in that EDG preventive maintenance may be performed on-line rather than while shutdown. The EDGs are in a relatively low dose location within the Radiological Protection Area. The EDG area dose rates do not vary significantly between operating and shutdown conditions. The manner in which the maintenance is performed will not be affected by these proposed changes. Therefore, there will be no increase in individual or cumulative occupational radiation exposure resulting from these proposed changes.

There will be no change in the level of controls or methodology used for processing radioactive effluents or handling of solid radioactive waste, nor will the proposed changes result in any change in the normal radiation levels within the plant. Therefore, there will be no increase in individual or cumulative occupational radiation exposure resulting from these proposed changes.

Attachment E

Summary of the LaSalle County Station
Probabilistic Risk Assessment

1. Background

The LaSalle County Station Individual Plant Examination (IPE) and IPE for External Events (IPEEE) were simultaneously submitted to the NRC in letter dated April 28, 1994, with a follow-up clarification letter dated December 12, 1994 to respond to Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities – 10 CFR 50.54(f)." Requests for Additional Information (RAIs) were sent by the NRC subsequently. As a result of the RAIs, a Modified IPE was developed for the LaSalle County Station and submitted to the NRC. The Modified IPE was approved by the NRC Staff Evaluation Report (SER) by letter dated March 14, 1996. The NRC letter noted that the Modified IPE submittal met the intent of Generic Letter 88-20.

The current LaSalle County Station Probabilistic Risk Assessment (PRA) was prepared by major upgrades and updates of the Modified IPE, which were completed in early 2000. The following section highlights changes to the Modified IPE made during the development of the PRA upgrades.

2. Changes to the Modified IPE

An overview of the upgrades that have been made to the LaSalle County Station PRA since the modified IPE was submitted are described below.

2.1 Conversion to Linked Fault Tree Models

Significant changes were made to the logic models in the PRA upgrades. The models were changed from a support state methodology to a linked fault tree methodology using Computer Aided Fault Tree Analysis (CAFTA). One of the benefits of this methodology is the ability to calculate the importance of specific components or groups of components to the overall risk of the plant.

Given that the performance of the front line mitigation systems is highly dependent upon the performance of those systems supporting their operation, combining (i.e., linking) a front line system to its support system creates a "complete" system model. All known combinations of failures of the front line systems, including those due to support systems failures, are modeled. The resulting fault tree model is a "large" fault tree.

The majority of industry IPEs and PRAs currently performed employ fault tree linking. Major industry resources have been devoted to the development of software for large fault tree quantification. Examples include the Electric Power Research Institute (EPRI) Risk and Reliability Workstation and the Integrated Risk and Reliability System developed by the Idaho National Engineering and Environmental Laboratories (INEEL) under NRC sponsorship. The developments in quantifying these complex fault trees are such that the computation time currently is in terms of minutes. Given these considerations, the modified IPE model was converted to a linked fault tree model from a support state model.

2.2 Event Trees

The following event trees are represented in the LaSalle County Station PRA:

- General Transient (structure used for several initiating events)
  - Manual Shutdown
  - Turbine Trip
  - Main Steam Isolation Valve (MSIV) Closure
  - Loss of Feedwater
  - Loss of Condenser Vacuum
  - Special Initiators
- Inadvertently Open Relief Valve (IORV)/Stuck Open Relief Valve (SORV)
- Loss of Offsite Power (LOOP)/ Dual Unit Loss of Offsite Power (DLOOP)/ •
- Station Blackout (SBO)
- LOOP/DLOOP with SORV
- Small Loss if Coolant (LOCA)
- Medium LOCA
- Large LOCA
- LOCA Outside Containment
- Excessive LOCA
- Anticipated Transient without Scram (ATWS) – Transients
- ATWS – Transient/LOOP/DLOOP with SORV
- ATWS – LOOP/DLOOP
- Internal Flooding (multiple event trees)

2.3 Initiating Events Revisions

The initiating event analysis was revised to consider several new initiating events as well as to take advantage of recent industry data. Plant response modeling was enhanced with the addition of several new initiating events and associated logic structures. The following initiating events are used in the current LaSalle County Station PRA.

- Loss of Offsite Power
- Dual Unit LOOP
- Turbine Trip with Bypass
- Loss of Condenser Vacuum
- Inadvertent Open Relief Valve
- MSIV Closure
- Loss of Feedwater
- Manual Shutdown
- Small LOCA
- Medium LOCA
- Large LOCA
- Excessive LOCA
- Interfacing Systems LOCA
- Break Outside Containment
- Loss of Turbine Building Closed Cooling Water (TBCCW)
- Loss of Service Water
- Loss of Instrument Air

- Loss of a Single 4KV AC Bus 241Y
- Loss of a Single 4KV AC Bus 242Y
- Loss of a Single 4KV AC Bus 252
- Loss of a Single 125 VDC Bus Division 1
- Loss of a Single 125 VDC Bus Division 2
- Simultaneous Loss of both DC Buses
- Internal Flooding Events
- Seismic Events

In particular, the internal flooding analysis performed by the Risk Methods Integration and Evaluation Program (RMIEP) study has been revised significantly. The RMIEP Reactor Building flood scenarios have been reassessed to improve modeling assumptions. In addition, previously unanalyzed Turbine Building flood scenarios were quantitatively assessed and incorporated into the PRA model.

2.4 Human Reliability Analysis Update

The Human Reliability Analysis (HRA) was updated in 1999 using plant procedures then in effect and completely revised to apply to the linked fault tree PRA model being developed. All Type C (i.e., post-initiator) operator actions were re-evaluated and additional operator actions were identified which required evaluation. The HRA was independently reviewed in 1999 and again in 2000 to confirm modeling assumptions regarding operator response times. Operator interviews were conducted early in 2000, which led to some changes in Human Error Probability (HEP) values for certain operator actions.

A careful analysis was made to ensure that application of human action non-recovery probabilities take into account sequence dependent and cutset dependent factors that could influence the human error rates. This review also considered significant dependent human actions.

2.5 Success Criteria

The success criteria for direct current (DC) batteries as the sole source of power during SBO has been re-examined. Based on the re-examination which included the use of actual battery test data, the successful mission time of the DC batteries has been extended in the model from 4 hours to 7 hours. This increases the time over which RCIC can operate and thereby increases the time to restore alternating current (AC) power to the station. The procedure to shed DC loads to extend the battery capability from 4 hours (i.e., RMIEP) to 7 hours has been credited in the PRA model.

LaSalle County Station procedures have been updated to ensure that maximum Emergency Diesel Generator (EDG) usefulness is achieved, i.e., for non-DBA event sequences. The current PRA includes these considerations for proceduralized EDG alignments.

2.6 Data Collection and Analysis Update

The failure data used to obtain estimates of the failure rates and equipment unavailability was updated to include recent plant experience though the end of 1999. Similar to other PRA elements, the effort was done in such a way to conform to current industry practice and NRC guidance. Collection and analysis of recent plant data was limited to key components that were initially found to be among the most important in terms of potential impact on system or core damage failure probabilities.

Consistent with NRC guidance and industry practice, this data was used to develop failure probabilities and maintenance component unavailability for systems and components that were sensitive in the PRA model, using a statistical technique known as Bayesian updating. This updating process is a formal mathematical method for combining generic estimates with plant specific evidence. Since generic estimates are needed for a number of components that have not experienced failures at the plant, and Bayesian updating requires the use of a "prior" estimate, then plant-specific evidence can be applied on an as-needed basis or as resources allow.

The industry data was taken from recognized sources. The preferred source was the EPRI Advanced Light Water Reactor (ALWR) failure rate published in NP-6780-L, Revision 1, issued on August 31, 1990.

The following plant specific data, which may be related to the EDG completion time analysis, has been added to the model.

- All 345 kV switchyard lines and associated breakers
- Grid failure induced LOOP during 24 hour mission time
- Weather-induced LOOP during 24 hour mission time
- Grid failure induced LOOP during 24 hour mission time
- Weather-induced LOOP during 24 hour mission time
- EDG 0 (common) fails to start
- EDG 0 unavailable due to maintenance
- EDG 1A fails to start
- EDG 1A unavailable due to maintenance
- EDG 2A fails to start
- EDG 2A unavailable due to maintenance

Other plant specific data have been added or updated which do not relate EDG performance issues.

A comprehensive update of common cause failure treatment was performed. The system fault trees were revised to account for a more complete treatment of common cause basic events in the model, including common cause failures of normally operating equipment that could cause an initiating event. The Multiple Greek Letter (MGL) method was applied to quantify common cause basic event probabilities.

Common cause groupings are primarily defined by INEL-94/0064. MGL parameter values are also taken from INEL-94/0064, Volume 6. When not available from INEL, the ALWR database and INEL-94/0064 Volume 5 were consulted for generic values.

Emergency Diesel Generator Modeling:

Each EDG is modeled for the following.

- Failure to Start
  - Independent failure to start
  - Common cause failure to start
  - Unavailability due to maintenance at power

- Failure to Run
  - Independent failure to run
  - Common cause failure to run

3. PRA Baseline Results for Core Damage Frequency (CDF)

The current baseline PRA results for each reactor unit at the LaSalle County Station are compared with the modified IPE results for each unit in table below. The results of the upgraded PRA shows that the CDF is slightly lower than reported in the Modified IPE. This change is the result of many changes to the modeling of accident sequences, success criteria, quantification of common cause failures and human reliability, characterization of generic data, incorporation of plant specific data, and other modeling changes.

Summary of Mean CDF Baseline PRA Results for LaSalle County Station

Station	Reactor Unit	IPE (RMIEP Study)	Current PRA Update
LaSalle	Unit 1	See Unit 2 (1)	See Unit 2
	Unit 2	4.8E-05 (excluding Fire)	6.92E-06

(1) Note that Unit 2 is chosen to represent both units for generalized results. For specific applications, when appropriate, a Unit 1 model is developed to account for known differences between the units. For example, the online risk monitor PRA tool accounts for differences between the two units explicitly. In these cases, no appreciable numerical differences are evident in the overall CDF and LERF totals.

Fire, seismic, and other external hazards were evaluated in support of the EDG completion time extension request, and have been discussed previously in this submittal.

The contributions to CDF from specific initiating events at LaSalle County Station, Unit 2 are depicted in the figure below. As seen in this figure, the dominant initiating events include:

- Dual Unit LOOP, 17%
- Turbine Trip, 17%
- Reactor Building Floods (sum of FS2 and FS1), 14%
- Turbine Building Floods (sum of TBSF), 13%
- Loss of Instrument Air, 8%
- MSIV Closure, 4%
- Loss of Condenser Vacuum, 4%

- Loss of 241Y AC Bus, 4%
- Loss of Service Water, 3%

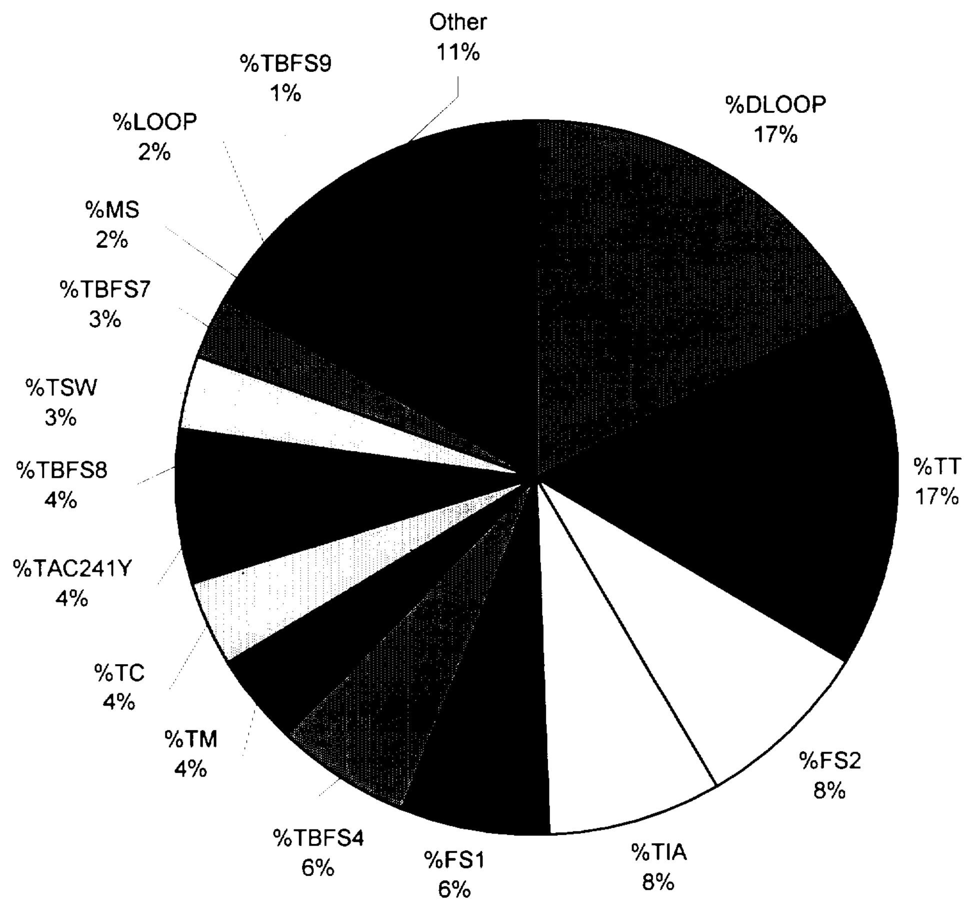
Attachment E

Summary of the LaSalle County Station
Probabilistic Risk Assessment

LaSalle County Station Level 1 PRA Results (by Initiating Event contribution)

CDF = 6.92E-06

LaSalle Level 1 PSA Results (By Initiating Event)
Augmented Pipe Inspection Credited



Dual Unit Loss of Offsite Power (DLOOP)

A DLOOP event is a dual unit loss of offsite power, which essentially represents a total loss of grid. This event may be caused by such things as severe weather or grid reliability issues. A DLOOP event affects both units, and therefore this event limits the capability to cross-tie the two units either by switchyard connections or by internal plant bus cross-ties. It is more severe than a single unit LOOP event. Station Blackout, involving failures or unavailabilities of the onsite emergency power sources (i.e., diesel generators) are a subset of the DLOOP accident sequences that lead to core damage. Emergency Diesel Generator unavailability is a significant mitigation factor for such scenarios, and the risk impact due to the increased completion time is reflected in the risk calculations.

General Plant Trip/Transient Initiating Events

This broad category of initiating events include turbine trips, loss of main condenser, MSIV closure events, loss of feedwater events, etc. These initiators are not significantly impacted by an increase in EDG completion times.

Turbine Building Flooding

Flooding was evaluated in the internal flooding analysis and flooding initiators are included in the LaSalle County Station PRA. The EDGs are located in areas that are not vulnerable to flooding. However, the Core Standby Cooling System (CSCS) which provides essential cooling for the EDGs and other front line systems are located in rooms that are below lake level. While evaluating the baseline risk profile a significant risk contributor associated with lake flooding into the Turbine Building due to a piping failure among various service water and circulating water piping systems was identified. In particular, because of the configuration of the watertight doors protecting these rooms from turbine basement flooding, the Division 2 CSCS room doors (each unit) are not flood-proof for this scenario. Therefore, an internal flooding potential was identified which impacts risk when the 0 EDG or supporting CSCS pump is unavailable due to maintenance.

Exelon Generation Company (EGC), LLC will address this consideration through the CRMP by performing regular walkdowns and cyclic inspections of the subject piping, to assure there is no precursor degradation in the piping structural integrity. It is believed that through regular inspections, a precursor flaw can be detected well in advance of substantial piping degradation, and therefore, the likelihood of an undetected pipe break mechanism can be significantly reduced. The pipe inspection program involves an ongoing walk around by Operators for most portions of the subject piping. In addition, a formal visual inspection will be performed on a periodic basis, similar to a fuel cycle, to inspect all the subject piping. The augmented pipe inspection program will be implemented prior to implementing the proposed changes in the EDG completion times, once they are approved.

Loss of Instrument Air

Similar to general transients discussed above, loss of instrument air accident sequences are not sensitive to the availability and reliability of the EDGs.

Loss of Electrical AC or DC Bus

Similar to the loss of offsite power initiators, a loss of electrical bus (i.e., AC or DC) can represent a significant electrical challenge to the plant. Hence, such event categories are influenced by the unavailability and reliability of the EDGs.

Loss of Service Water Event

A loss of service water event, while considered to be a small likelihood, is treated explicitly in the LaSalle County Station PRA model. At least one precursor event for a common mode failure of all service water has been observed at the LaSalle County Station site. While this event is modeled, loss of service water events are not sensitive to the availability and reliability of the EDGs.

Anticipated Transient without Scram (ATWS)

The contribution of ATWS to CDF is distributed among the various initiators shown in the above pie chart. ATWS event sequences are not sensitive to the availability and reliability of the EDGs.

The most significant initiator group with respect to the EDG completion time extension request is the loss of offsite power events, particularly dual unit LOOPs. LOOP events, which have been delineated to distinguish between events that impact both units concurrently and each unit singly, combine for about 19% of the total CDF risk contribution. It should be noted that the accident sequences and cutsets that could be impacted by the proposed increase in the EDG completion time are a small subset of the contributions from LOOP and DLOOP events. Only the maintenance scenarios would be impacted by an increase in the EDG completion times.

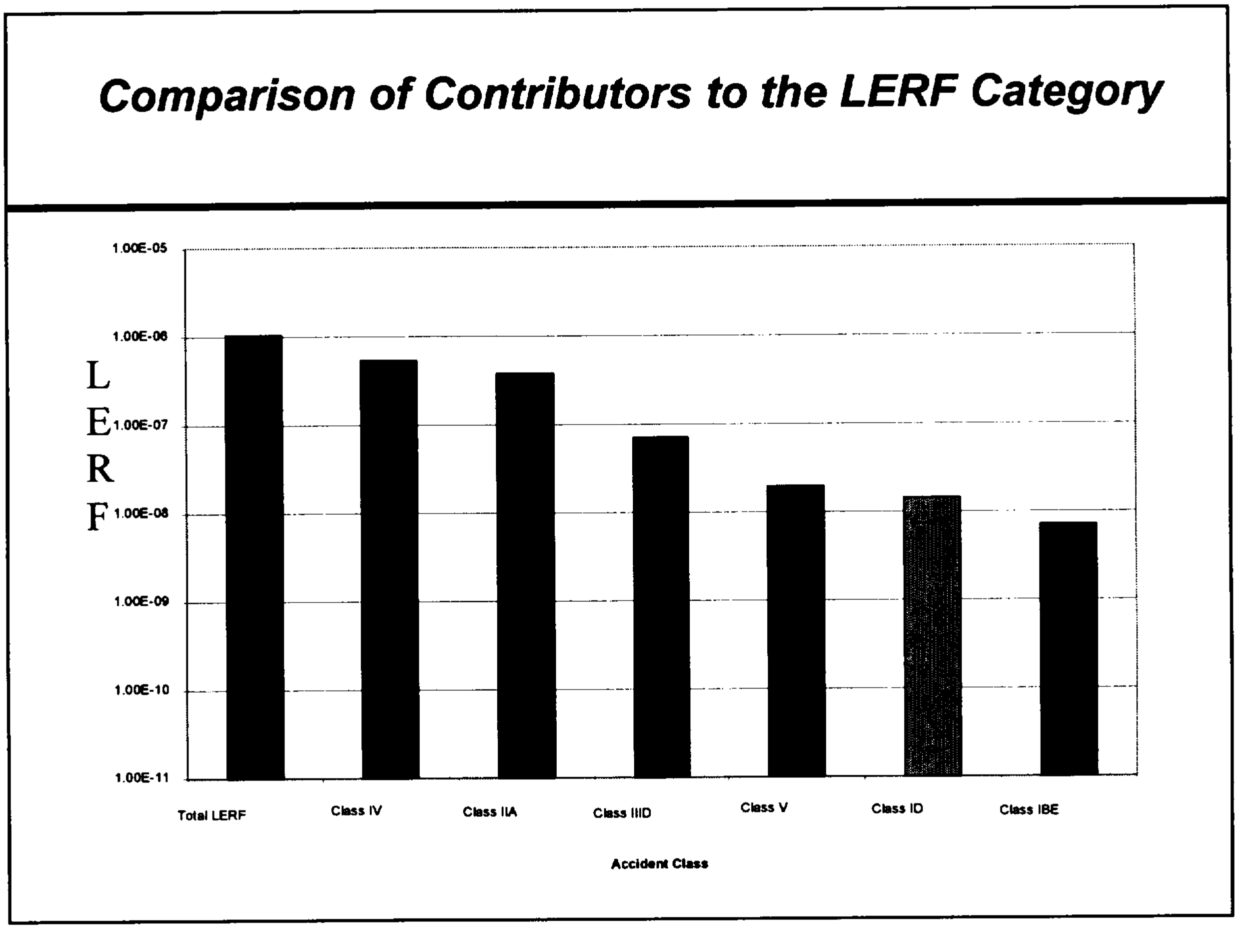
4. Evaluation of Large Early Release Frequency (LERF)

As part of the current LaSalle County Station PRA, a simplified LERF analysis was performed in accordance with NUREG/CR-6595, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events." This analysis was used to evaluate the impacts of the proposed increase in EDG completion time on annual average LERF and to evaluate the Incremental Conditional Large Early Release Probability (ICLERP) for comparison against the risk significance criteria in RGs 1.174 and 1.177.

This approach captures the plant specific factors associated with active systems whose failures contribute to LERF such as containment isolation and bypass, and the frequency of severe accident challenges of the containment. These aspects of the LERF analysis are as realistic as the Level 1 CDF determination. There are other aspects of this simplified approach that provide a rather conservative treatment of the phenomenological issues that contribute to LERF such as high pressure melt ejection, direct containment heating, and thermal creep rupture of Reactor Coolant System (RCS) components. These conservatisms include a very conservative definition for high pressure core melt sequences and conservative split fractions for modeling the impact of severe accident challenges to

containment performance. Hence, these LERF results should be regarded as conservative estimates in relation to the CDF results.

The results of the LERF quantification for LaSalle County Station Unit 2 are shown in the following figure.



These results are all within the criteria for risk significance in Section 2.2.4 of RG 1.174 and are consistent with the results from other BWRs.

It is expected that if a more realistic treatment of the above issues were performed, the above estimates of LERF would be substantially reduced. However, this LERF analysis is sufficient to support evaluation of the risk significance of the requested increase in the EDG completion time, as many of the conservative assumptions, while affecting the baseline LERF values, do not impact the change in risk metrics associated with the requested increased completion time.

5. Maintenance and Update Process

An administratively controlled process is used to maintain configuration control of the LaSalle County Station PRA models, data, and software. In addition to model control, administrative mechanisms are in place to assure that plant modifications, procedure changes, calculations, operator training, and system operation changes are appropriately screened, dispositioned, and scheduled for incorporation into the

model in a timely manner. These processes help assure that the LaSalle County Station PRA reflects the as-built, as-operated plant within the limitations of the PRA methodology and as resources allow the level of modeling detail.

This process involves a periodic review and update cycle to model any changes in the plant design or operation. Not only are the models appropriately controlled to reflect the plant, but also the supporting PRA basis documentation is maintained under a similar update process, to reflect the in-use PRA model.

6. PRA Quality

The LaSalle County Station PRA used for the risk determinations for this regulatory application are recent upgrades to the "Modified Individual Plant Examination (IPE)," submitted to the NRC by letters dated April 28, 1994 and December 12, 1994. The modified IPE had been accepted by the NRC by Staff Evaluation Report (SER) letter dated March 14, 1996. The NRC letter noted that the modified IPE submittal met the intent of Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities – 10 CFR 50.54(f)," dated November 23, 1988.

The original LaSalle County Station PRA was performed by Sandia National Labs, on behalf of the NRC, as part of the Risk Methods Integration and Evaluation Program (RMIEP) Study (NUREG/CR-4832). The current LaSalle County Station PRA is a third generation upgrade to that study. The LaSalle County Station PRA addresses internal events at full power, and it includes internal flooding, as well as certain other external events. Internal fire risk is taken from the original LaSalle County Station RMIEP Study, but its results are considered to be conservative in many of their assumptions. Therefore, fire risk is not directly comparable to other quantified internal events risk results.

For the Level 2 analysis (i.e., the containment analysis), LERF was estimated using the methology in NUREG/CR-6595, January 1999, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events." This approach to LERF evaluation, while somewhat simplified, supports a realistic quantification of systemic contributions to containment isolation failures and bypass sequences that are actually derived from the Level 1 event sequence model.

Both the LaSalle County Station PRA model and its supporting bases documentation were reviewed by a BWROG Peer Certification Team in early 2000. The review was conducted using Nuclear Energy Institute (NEI) NEI 00-02, "NEI Probabilistic Safety Study (PSA) Certification Peer Review Process," using a team of industry PRA experts. This independent review was performed to evaluate the quality of the PRA and completeness of the PRA documentation. The Certification Team found that the LaSalle County Station PRA was a sound model, and its element grades demonstrate that it is adequate for use in regulatory submittals.

The NEI PSA certification process assesses a PRA in eleven functional elements. Each element is graded on a scale of 1 to 4. A grade 3 indicates "that risk significance determinations made by the PRA are adequate to support regulatory applications, when combined with deterministic insights." A grade of 4 indicates that the PRA "is usable as a primary basis for developing licensing positions...," however, "it is expected that few PRAs

would currently have many elements eligible for this grade." The LaSalle County Station PRA was graded 3 in all eleven of the PRA elements.

Based on the results of past NRC Staff reviews and the BWROG Certification Peer Review, EGC believes that the level of detail and quality of the LaSalle County Station PRA fully supports this risk-informed regulatory application.