Exelon Nuclear

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July 13, 2001

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: Response to Request for Additional Information Extension of Allowable Completion Times for Division 1 and 2 Emergency Diesel Generators

References: (1) Letter from C. G. Pardee (EGC) to the NRC, "Request for Amendment to Technical Specifications, Extension of Allowable Completion Times for Division 1 and 2 Emergency Diesel Generators," dated February 20, 2001.

(2) Letter from J. B. Hopkins (NRC) to O. D. Kingsley (EGC), LaSalle County Station, Units 1 and 2 – Request for Additional Information (TAC Nos. MB1224 and MB1225)," dated June 5, 2001.

Exelon Generation Company (EGC), LLC, in Reference No. 1, proposed changes to the Technical Specifications (TS) of LaSalle County Station, Units 1 and 2, that would extend the allowable completion times for the Required Actions associated with restoration of an inoperable Division 1 or Division 2 Emergency Diesel Generator (EDG). The NRC in Reference No. 2, requested additional information to complete their review. Additionally, during a telephone conference on June 14, 2001, Mr. J. B. Hopkins, the NRC Project Manager for LaSalle County Station, agreed to a date of July 13, 2001 for submitting the requested information. Attached are EGC's responses to the requested information.

A001

Should you have any questions concerning this letter, please contact Mr. William Riffer, Regulatory Assurance Manager, at (815) 415-2800.

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

Response to Request for Additional Information
LaSalle County Station, Units 1 and 2

Emergency Diesel Generator Allowed Outage Time Extension
Technical Specifications Change Request

Quality of Probabilistic Risk Assessment (PRA)

1. The submittal indicated that LaSalle participated in the BWROG PRA Peer Review Certification program. A PRA Certification Team completed an inspection and review of the LaSalle PRA. The team found that the LaSalle PRA was a sound model and was adequate for use in regulatory submittals.

   a. Did the peer review group specifically address application of the PRA to the emergency diesel generator (EDG) allowed outage time (AOT) extension changes, or was it a general assessment for application to AOT changes?

   Response
   The peer review group did not specifically address application of the Probabilistic Risk Assessment (PRA) to the Emergency Diesel Generator (EDG) Allow Outage Time (AOT) extension changes, nor to other generalized AOT changes. Rather, the Nuclear Energy Institute (NEI) (formerly Boiling Water Reactor Owners Group) PRA Peer Review Guideline 00-02, "NEI Probabilistic Safety Study (PSA) Certification Peer Review Process," is designed to examine and grade aspects of the PRA model in terms of it being a defensible model with sufficient level of detail to support regulatory applications.

   The LaSalle County Station PRA received a grade of 3 out of 4 in all eleven of the major elements reviewed during the PRA Review. A grade of 3 is defined in the PRA Peer Review process [i.e., "Probabilistic Risk Assessment (PRA) Peer Review Process Guidance," Rev A2, NEI Risk-Based Applications Task Force] as adequate "...for assessing safety significance of equipment and operator actions. This assessment can be used in licensing submittals to the NRC to support positions regarding absolute levels of safety significance if supported by deterministic evaluations." The review was conducted using NEI Guideline 00-02.

   b. A peer review is one element in a PRA's quality program. Explain what other elements are used to assure quality of the LaSalle PRA.

   Response
   While a peer review is one element in establishing the quality of the LaSalle County Station PRA, it is not the only element. Other elements used to assure quality of the LaSalle County Station PRA include the following.

   - Program policy and procedures for maintaining the station PRA, including the frequency of periodic updates, identification of changes that warrant immediate model update, and PRA update integration with other existing plant processes to assure the PRA remains consistent with the as-built and as-operated plant.
   - Thorough and traceable documents that comprise the basis of the model and assumptions.
   - Original PRA modeling and analysis was performed by qualified contractors with continual involvement of Exelon Generation Company (EGC), LLC, staff.
   - Independent review and acceptance by EGC.

- Consistency with other EGC Boiling Water Reactor (BWR) PRA updates, including consideration of insights from an independent review of the Quad Cities Nuclear Power Station PRA for applicability.

c. What were a few enhancements identified, and how were they addressed in the analysis performed to support the proposed changes?

Response
The PRA Peer Review Team identified several enhancements to improve the LaSalle County Station PRA. It documented these enhancements, in accordance with the Peer Review Process Fact & Observation (F & O) forms. These F&O items are rated by their significance to the overall quality of the station PRA.

The significance ratings used for F&O items range from a priority "A" finding representing extreme importance for technical accuracy or quality, to a priority "D" finding representing editorial or minor technical item of low significance.

LaSalle County Station received no priority "A" F&O findings, and 15 priority "B" F&O findings. Priority "B" findings do not require immediate corrective action, but are strongly recommended for evaluation at the next periodic update. These findings are not considered necessary corrective actions for using the PRA for regulatory applications, such as the proposed Technical Specifications (TS) change for the EDG AOT. Two enhancements were believed to be important to the overall quality and scope of the PRA. These enhancements involved updating the human reliability analysis (HRA) and developing an internal flood analysis for the PRA, which were implemented prior to developing the EDG AOT assessment.

The remaining priority "B" F&O findings were evaluated and found to have negligible impact on the EDG AOT extension assessment. For example, one finding involved recognition that the failure to scram probability of 3.0E-5 per demand is conservative and outdated, and that use of a conservative value tends to over predict the importance of Anticipated Transient Without Scram (ATWS) events. This finding and the remaining priority "B" F&O findings will be considered for incorporation in the next PRA update.

d. Were the enhancements peer reviewed, and if so, by whom?

Response
The PRA Peer Review Team identified the enhancements documented in the F & O forms. However, the process does not require that the team review implementation of these items. The process does provide a mechanism to make certification contingent upon satisfactory completion of deficient elements in a station PRA. However, LaSalle County Station's certification was not contingent upon future actions to correct any deficiencies.

e. Who participated in the LaSalle PRA peer review, and what were their qualifications?

Response
The LaSalle County Station PRA peer review team consisted of members from various sectors of the nuclear industry with extensive backgrounds in PRA methodology and experience with risk-informed regulations. These individuals came from contractor agencies, nuclear utilities, Owners Groups and NEI.

The NEI PRA Peer Review Guideline (NEI 00-02) describes minimum qualifications for individuals that comprise a review team. The peer review team is composed of five to six utility and contractor personnel knowledgeable in PRA issues and experienced in the performance and application of PRAs. The peer review teams include peers that are knowledgeable in PRAs for plants similar to that being evaluated, but that have remained independent of the plant PRA that is being evaluated. The team must contain members that taken as a whole, are experts in all technical areas of PRA methodology and application.

The LaSalle County Station PRA Peer Review team members and their qualifications at the time of the LaSalle County Station review, are summarized in the following table.

PSA PEER REVIEW CERTIFICATION TEAM EXPERIENCE

TEAM MEMBER	EXPERIENCE SUMMARY			
	Degree	Years Experience	Years of PSA Experience	Selected PSA Projects
Ed Ingram	BS, Mechanical Engineering, University of Alabama. MS, Nuclear Engineering, Georgia Institute of Technology	29	4	• Converted RISKMAN PRA model to CAFTA • Construction of EOOS model for Hatch Units 1 & 2 • Conducted MAAP analyses
Hahn K. Phan	BS, Electrical Engineering, Washington State University. MS Electrical Engineering, Seattle University	11	11	• WNP-2 Risk Informed Inservice Inspection program • WNP-2 PSA • WNP-2 Fire PSA • PSA for hydroelectric generating stations
Richard T. Turcotte	BS, Mechanical Engineering Technology, Central New England College of Technology AS, Engineering, Electro/Mechanical Technology, Worcester Industrial Technology Institute	25	11	• Evaluation of nuclear power plant design, operation, and licensing using PSA.. • Provided fire and flood PSA evaluations in support of an IPEEE assessment. • Level 2 PSA systems analysis, dependencies, common mode failure analysis, data evaluation, human error, event sequence quantification
Donald E. Vanover	BS, MS Mechanical Engineering, University of Delaware	13	12	• Numerous IPE's in both US and Spain • Project manager for several Software Development Programs • PSA Models and MAAP Modeling
Edward E. Vezey	BS Mechanical Engineering - Texas A & M University	45+ years	30	• 17 years of BWR experience with GENE Division • PSA application to Tech Specs for Taiwan Power Co. • Managed PSA for a BWR 6
S. Visweswaran	M Enng., University of California, Berkeley B Tech (Hons),, Indian Institute of Technology, Kharagpur, India	31	22	• Completed PSA's for many plants • Seismic PSA for a Japanese Plant • Modernization of Swedish Plant

2. The staff SER for the LaSalle IPE suggested that the methods for both common cause failure and human reliability analysis could be suspect based on staff reviews of Zion, Dresden, and Quad Cities IPEs. Explain how these potential weaknesses were addressed in your subsequent PRA updates.

Response
The issues raised by NRC staff in their safety evaluation for the LaSalle County Station Individual Plant Examination (IPE) regarding common cause failure (CCF) and HRA are discussed below.

CCF Issue 1
Common cause analysis is not specific for LaSalle. Generic common-cause failure databases were used in the development of the common cause factors for the Risk Methods Integration and Evaluation Program (RMIEP) analysis.

The latest common cause data compiled for the NRC by Idaho National Engineering and Environmental Laboratory (INEEL) in NUREG/CR-5497, "Common-Cause Failure Parameter Estimates," dated October 1998 were used in the LaSalle PRA update. This "generic" data is considered to be the best available generic data source for CCFs. The amount of plant-specific common cause data is quite small and insufficient to provide a basis for the derivation of CCF probabilities.

A statistically meaningful CCF analysis needs to be based on both generic and plant-specific information due to the scarcity of plant-specific CCF experience. Plant-specific reliability and unavailability data has been used in the LaSalle County Station PRA updates for selected components and systems, including the EDGs. The common cause factors for the EDGs were obtained by quantitatively applying INEEL generic common cause event data. Thus, the CCF rates for the EDGs are based on plant-specific individual EDG failure rates along with generic industry common cause factors.

CCF Issue 2
The Beta Factor common cause analysis is too conservative.

The original PRA developed for the IPE used a simplified Beta Factor method for addressing common cause. However, the current CCF analysis is based on the more realistic Multiple Greek Letter (MGL) method and uses the latest INEEL work on common cause parameters from NUREG/CR-5497. This is considered to be a significant step forward in the PRA methods for LaSalle County Station.

HRA Issue 1
The RMIEP HRA results are expected to be non-conservative. Comparisons to other EGC PSAs show that the LaSalle County Station HEPs are generally lower. It is expected that the difference in HEPs is due in large part to the methods used to incorporate the use of plant procedures in performance of the actions.

The human reliability analysis in the current LaSalle County Station PSA has been completely modified as part of the update to incorporate operator and trainer interviews, as well as procedure reviews to verify the Human Error Probability (HEP) assessments.

Evaluation of Post-Initiating Event HEPs
The Cause-Based Decision Tree (CBDT) method, developed by Garreth Parry, and others for the Electric Power Research Institute [EPRI], was used to quantify the likelihood of errors in detection, diagnosis, and decision-making. The diagnosis and decision-making HEP estimate was supplemented by also using the Time Reliability Correlation from NUREG/CR-1278, "Handbook of Human Reliability Analysis With Emphasis On Nuclear Power Plant Applications, Final Report," and Accident Sequence Evaluation Program (ASEP). Finally, the Technique for Human Error Rate Prediction (THERP) described in NUREG/CR-1278 was used to quantify errors associated with task execution. Compared with the method used in the base IPE for LaSalle County Station, the combination of the CBDT, Time Reliability Correlation, and THERP methods provides a more realistic basis for assessing post-initiator human actions.

Evaluation of Pre-Initiator HEPs
Pre-initiator HEPs were screened and evaluated using the Accident Sequence Evaluation Program Human Reliability Analysis Procedure (ASEP), NUREG/CR-4772, "Accidents Sequence Evaluation Program Human Reliability Analysis Procedure," dated February 1987. Most of the pre-initiator HEPs were added to the PRA subsequent to the IPE.

The complete update of the HRA using the above methods, operator staff interviews and training observations was judged to resolve all issues related to inconsistency with other EGC sites and to remove the suspected non-conservatisms. The Dresden Nuclear Power Station, LaSalle County Station, and Quad Cities Nuclear Power Station had their HRAs updated to use the same methods and approaches for consistency.

HRA Issue 2
The HRA should reflect the content and employment of the plant procedures that are in effect at LaSalle. The RMIEP analysis process did not specifically attempt to include all the operator actions in the LaSalle EOPs as implemented during the progression of an accident.

The station has performed updated HEPs from the IPE based on plant-specific review of operating, abnormal, and emergency procedures plus operator interviews and training observations. Identification of post-initiator actions in the current LaSalle County Station PSA is based on review of past PSAs and current LaSalle County Station procedures, including LaSalle General Abnormal (LGAs) and LaSalle Operating Abnormal (LOAs), and interviews with operators and trainers. All key actions to accident sequence progression are modeled. The two primary reasons that not all LGA directed actions are specifically modeled are: 1) the action is subsumed by a broader action, and 2) the action does not impact the modeling of the progression of the accident sequence.

The number and types of operator actions modeled are similar to other BWR PSAs that were reviewed by the BWR Owners Group Peer Review Teams.

3. The submittal indicated that the current PRA has been updated three times since the development of the IPE.

   a. How does LaSalle assure that the current PRA used for this application represents the as-built and as-operated plant? Have all significant plant operational changes, both hardware and procedural, been appropriately incorporated into the current PRA?

   Response
   An EGC guideline provides a mechanism for tracking, evaluating, and dispositioning both hardware and procedural plant changes that potentially may impact the station PRA. This process is called an Update Requirements Evaluation (URE). This process includes not only a process to evaluate the significance of the potential model change, but also a mechanism to identify the appropriate update period to make the model update for the item. The update periods include "immediate update required," "defer until next periodic update," and "screened as no impact on model." This process assures that the PRA is modified periodically to reflect the as-built and as-operated plant.

   b. List significant plant operational changes and how such changes were incorporated during the updates.

   Response
   Significant modifications and operational changes that have been incorporated into the PRA since the IPE/RMIEP study are as follows.

   1. New Emergency Core Cooling System (ECCS) Strainer Design resulting in lower Strainer Common Cause Plugging values.
   2. Upgraded LaSalle County Station Emergency Operating Procedures and Severe Accident Management Guidelines incorporated through revised HEPs.
   3. Elimination of Reactor Core Isolated Cooling (RCIC) System "sneak circuit."

   Prior to the 1999 PRA Update, a "Living PRA" program was not in place. Several steps were taken to assure that the PRA represented the as-built and as-operated plant.

   1. The latest plant procedures and drawings were used to update the model.
   2. Operator interviews were conducted as part of the HRA analysis.
   3. Plant modifications installed during the extended 1997-1998 plant shutdown were reviewed for PRA model impact.
   4. PRA System Notebooks were reviewed with LaSalle County Station System Engineers to assure key modeling assumptions were correct and to verify that the model reflected the current plant configuration.

In addition, there have been many modifications not requiring explicit PRA model logic changes that will ultimately be reflected in the PRA plant data. For example, modifications that result in fewer plant trips and lower failure probabilities as the result of increased equipment performance will be incorporated as part of the PRA periodic update. However, these operational changes will impact the PRA after several years of operation through plant data updates rather than through logic changes in the PRA model.

4. Your submittal indicated that you had updated the LaSalle PRA to include plant and procedure changes. Please discuss the process for assuring important changes are included in PRA updates in a timely manner.

   Response
   An EGC guideline provides a mechanism for tracking, evaluating, and dispositioning both hardware and procedural plant changes that potentially may impact the station PRA. This process is called an URE. This process includes not only a process to evaluate the significance of the potential model change, but also a mechanism to identify the appropriate update period to make the model update for the item. The update periods include "immediate update required," "defer until next periodic update," and "screened as no impact on model." This classification within the URE process assures that potential change items are included in PRA updates in a timely manner.

Risk impact due to external initiating events

5. Your submittal indicated that the risk impact from fire scenarios would be minimal. However, certain fire scenarios not only could cause a loss of offsite power initiator, but also fail systems needed to mitigate the initiator (e.g., a train or part of a train of ECCS). Similarly, if a fire occurs during a period when an EDG that has significant safety loads is out of service for on-line maintenance, a fire in another fire zone/area could cause station blackout and simultaneously fail another EDG.

   a. Evaluate your fire areas for such scenarios to assess the potential risk impact due to the proposed change. Provide the fire ignition frequencies used for the related fire areas. For each fire area, the conditional core damage probability (with an EDG out of service) could also be useful to demonstrate the fire risk significance.

   Response
   Accident sequence analyses of fire compartment scenarios using the current LaSalle County Station PRA models were performed in support of the TS submittal. The TS submittal states that the results of the fire models are not integrated into a total plant risk measure, but this statement is not intended to convey that a fire risk evaluation was not performed.

The internal fire risk assessment work performed in support of the LaSalle County Station proposed TS change for the EDG AOT extension is characterized as follows.

- The fire compartment definitions, equipment locations, fire detection/suppression features, and barrier attributes documented in the RMIEP Study (i.e., NUREG/CR-4832) are maintained.
- The qualitative area/compartment screening process of the RMIEP study is appropriate and maintained.
- The fire compartment ignition frequency calculations of the RMIEP study are maintained.
- Automatic and manual fire suppression failure probabilities of the RMIEP study are maintained.
- The fire severity factors used in the RMIEP study are maintained.
- The fire-induced damage analyses of the RMIEP study are maintained.
- The RMIEP study conservatively assumes each identified fire scenario represents 100% of the fire compartment ignition frequency. This approach is maintained except in the case of the switchgear rooms. To reduce excess conservatism, the two identified switchgear room fires, electrical cubicle fire and large floor fire, are divided into 90% and 10%, respectively, of the total compartment ignition frequency.
- The fire ignition frequencies and damage states are propagated through the current LaSalle County Station PRA model logic structures.

Fire scenarios causing loss of offsite power were calculated in the RMIEP study to result in a negligible contribution (i.e., <1%) to the overall plant fire risk. As such, these scenarios were not carried forward into the model quantification performed in support of the EDG AOT TS submittal. The fire risk evaluation in support of the EDG AOT TS submittal included a quantification of the top seven fire initiators that comprised the top 90% RMEIP fire scenarios, by applying the current PRA models. The results of this work concluded that EDG availability has a negligible impact on fire-induced Core Damage Frequency (CDF) (i.e., the Risk Achievement Worth (RAW) of the EDGs for fire scenarios is approximately 1.0).

Sensitivity Studies

In addition, quantitative sensitivity studies of internal fire scenarios have recently been performed and are described below.

The total internal fire CDF is calculated from the RMEIP Study to be 3.21E-5/yr. For the fire areas probabilistically quantified, only two resulted in a fire-induced loss of offsite power:

- Fire area 4E2-1: Auxiliary Equipment Room
- Fire area 5B13-2: BOP Cable Area (North)

The fire scenario frequency for an individual fire can be calculated by multiplying the following factors:

- Fire area ignition frequency
- Fire room to fire area ratio
- Fire scenario to fire room ratio
- Fire severity ratio
- Automatic fire suppression failure probability
- Manual fire suppression failure probability

The calculated frequency for the scenario involving fire-induced Loss of Offsite Power (LOOP) of fire area 4E2-1 is approximately 4.4E-5/yr. This is based multiplying the fire area ignition frequency of 4.90E-02/yr with the other factors listed above. Similarly, the fire scenario frequency for fire area 5B13-2 is approximately 7.0E-5/yr, based on a fire area ignition frequency of 4.90E-02/yr and the other factors listed above. Either fire scenario results in the following.

- Single unit LOOP
- Loss of containment venting capability

All other mitigation systems credited in the PRA (e.g., EDGs and EDG support systems) are undamaged by these fire scenarios. They may still fail as a result of non-fire causes.

Based on the RMIEP information, a fire in area 4E2-1 results in a CDF contribution of approximately 5.9E-9/yr. A fire in area 5B13-2 results in a CDF contribution of approximately 7.3E-9/yr. Both CDF values are small.

These fire-induced LOOP scenarios are investigated further by quantification of sensitivity cases using the current LaSalle County Station PSA models. Table 5-1 provides the results of the cases quantified. The cases in Table 5-1 can be summarized as follows:

- *Case 1*: The total fire-induced CDF from the RMIEP study is calculated to be 3.21E-5/yr.

- *Case 2:* The Base internal fire induced LOOP scenarios quantified using the current LaSalle County Station internal events PRA model upgrade with the following modifications:
  - Single-unit LOOP initiating event frequency set to 1.14E-4/yr (based on combining initiating event frequencies from fire areas 4E2-1 and 5B13-2)
  - All other initiating events set to zero.
  - No offsite alternating current (AC) power recovery for fire sequences
  - Containment vent system failure assumed
- *Case 3:* Same as Case 2 except EDG 0 system assumed to be in maintenance. It is assumed that other EDG maintenance will not be performed concurrently.
- *Case 4:* Same as Case 2 except EDG 2A system assumed to be in maintenance. It is assumed that other EDG maintenance will not be performed concurrently.
- *Case 5:* Same as Case 2 except EDG 1A system assumed to be in maintenance. It is assumed that other EDG maintenance will not be performed concurrently.

Table 5-1 shows that the Base fire induced LOOP sequences (i.e., Case 2) contribute approximately 1.5E-8/yr to the total internal fire CDF of 3.21E-5/yr. This Conditional Core Damage Probability (CCDP) for the base fire induced LOOP is approximately 1.3E-4. The CCDP calculated with the LaSalle County Station PRA model is consistent with the CCDP range of 1E-4 to 2E-4 estimated in the RMIEP model.

For the case with EDG 2A out for maintenance, the CCDP increases from 1.3E-4 to approximately 2.3E-4. In addition, the increase in CDF over the base fire LOOP sequences is approximately 1.2E-8/yr. The increase in CCDP and CDF for cases with EDG 0 or EDG 1A out for maintenance are less limiting than for the EDG 2A case.

Assuming that an EDG out for maintenance has a negligible risk impact on non-LOOP initiating events (e.g., fire induced turbine trip), the total internal fire CDF risk profile is estimated to increase by 1.2E-8/yr over the internal fire CDF from 3.21E-5/yr to 3.211E-5/yr for the case with EDG 2A out for maintenance (i.e., an increase of less than 0.1%). Therefore, the EDG completion time has a negligible impact on internal fire CDF.

Table 5-1

FIRE INDUCED LOOP PRA CASES

Case	Description	IE Frequency	CCDP	CDF (/yr)	Delta CDF (/yr) (5)
1	Base RMIEP Fire Model (NUREG/CR-4832)	N/A	N/A	3.21E-05	N/A
2	Base Fire Induced LOOP Contribution (1), (2)	1.14E-04(3)	1.31E-04(4)	1.49E-08	N/A
3	Base Fire LOOP with DG0 Out for Maintenance (1)	1.14E-04	2.25E-04	2.56E-08	1.07E-08
4	Base Fire LOOP with DG2A Out for Maintenance (1)	1.14E-04	2.33E-04	2.66E-08	1.17E-08
5	Base Fire LOOP with DG1A Out for Maintenance (1)	1.14E-04	1.31E-04	1.49E-08	ε

(1) All PRA runs quantified using current LaSalle County Station PRA Model with augmented piping inspection program (CDF = 6.92E-6/yr). This is the same model used to support the EDG AOT extension.

(2) Fire in areas 5B13-2 or 4E2-1 causes a single unit LOOP and failure of Containment Venting. Offsite AC power recovery not credited for fire scenarios.

(3) Fire induced LOOP frequency includes 7E-5/yr contribution from fire area 5B13-2 and 4.4E-5/yr contribution from fire area 4E2-1.

(4) The CCDP of 1.31E-4 based on the current LaSalle PRA model is consistent with the RMIEP results which had CCDPs in range of 1E-4 to 2E-4.

(5) Change in CDF from Base Fire LOOP model (i.e., Case 2) given that specified EDG is in maintenance.

5.b. LaSalle should justify whether or not the fire risk impact would clearly meet the acceptable guidelines in RGs 1.174 and 1.177. Further, explain how your programs or analyses employed for the Tier 2 and 3 aspects of RG 1.177 would address these potentially risk significant configurations.

Response
The following quantitative information is provided to support the negligible impact of the fire events, using data described in the response to question number 5a.

The fire risk impact of the EDG completion time can be justified using similar methods as used for the internal events provided in the EDG AOT TS submittal. Table 1 from the TS submittal provided the planned EDG maintenance unavailability criteria to be imposed. Similar to Table 2 in the TS submittal, Table 5-2 summarizes the results of the internal fire EDG sensitivity cases. Table 5-3 shows that the results of the internal fire risk evaluation for the completion time extension are within the guidelines of Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis," and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications." All numerical results were obtained by applying the same equations described in the TS submittal but using the fire risk as inputs.

For completeness, the integrated results of both the internal fire risk evaluation and the internal events risk evaluation for the EDG completion time extension are provided in Table 5-4 and 5-5. Table 5-5 shows that the integrated results of the internal fire risk evaluation and the internal events risk evaluation for the completion time extension, including Incremental Conditional Core Damage Probability (ICCDP) and Incremental Conditional Large Early Release Probability (ICLERP), are within the guidelines of RG 1.174 and RG 1.177.

The Tier 2 aspects of RG 1.177 can be qualitatively supported by the following items:

- No other EDG and/or EDG support equipment shall be voluntarily removed from service.

- Fire induced LOOP scenarios do not fail any EDG and/or EDG support equipment. Therefore, no single fire during a scheduled EDG maintenance activity could result in a LOOP and unavailability of an EDG. An EDG in maintenance is accounted for explicitly.

- Fire induced LOOP scenarios are evaluated to remain isolated to a single unit. Therefore, alternating current (AC) power could be cross-tied to the unaffected unit.

The above items support that adequate defense-in-depth remains available during scheduled EDG maintenance activities. These are consistent with the Configuration Risk Management Program (CRMP).

The Tier 3 aspect of R.G. 1.177 is assured by the CRMP that addresses 10 CFR 50.65(a)(4) assessments for maintenance induced risk configuration combinations. The LaSalle County Station CRMP provides protected systems during EDG maintenance activities, as well as the estimated risk increase if additional systems are made unavailable for emergent situations.

Table 5-2

FIRE PSA MODEL RESULTS FOR THE RISK METRIC CALCULATIONS

CDF	Frequency (Per Rx Yr)	(LERF)	Frequency (Per Rx Yr)
$CDF_{2A\text{-}OOS}$	3.211E-5 (2), (3)	$LERF_{2A\text{-}OOS}$	(6)
$CDF_{0\text{-}OOS}$	3.211E-5 (2), (4)	$LERF_{0\text{-}OOS}$	(6)
$CDF_{1A\text{-}OOS}$	3.21E-5 (2), (5)	$LERF_{1A\text{-}OOS}$	(6)
CDF_{BASE}	3.21E-5 (1)	$LERF_{BASE}$	(6)

(1) Based on results in RMIEP study (NUREG/CR-4832," Analysis of the LaSalle Unit 2 Nuclear Power Plant: Risk Methods Integration and Evaluation Program (RMIEP) Internal Fire Analysis, Volume 9."

(2) All CDF estimates based on a truncation of 1E-13/yr. All initiator events set to zero besides LOOP.

(3) CDF increase of 1.17E-8 when EDG 2A set to unavailable and all other EDG maintenance terms set to zero.

(4) CDF increase of 1.07E-8 when EDG0 set to unavailable and all other EDG maintenance terms set to zero.

(5) Negligible CDF increase when EDG1A set to unavailable and all other EDG maintenance terms set to zero.

(6) LERF not calculated for Fire PRA model. The negligible increase in the internal fire CDF would result in a negligible increase in the internal fire LERF. In addition, due to the design of the LaSalle County Station Mark II containment and information from the internal events EDG completion time LERF evaluation, LERF will not be the limiting factor for the EDG AOT extension risk assessment.

Table 5-3

RESULTS OF FIRE RISK EVALUATION FOR LASALLE COUNTY STATION

Risk Metric	Risk Significance Guideline	Risk Metric Results Unit 2[1]
ΔCDF_{AVE}	< 1.0E-06/yr	ε
$\Delta LERF_{AVE}$	< 1.0E-07/yr.	ε
$ICCDP_{EDG\ 0}$	< 5.0E-07	3.8E-10
$ICLERP_{EDG\ 0}$	< 5.0E-08	ε
$ICCDP_{EDG2A}$	< 5.0E-07	3.8E-10
$ICLERP_{EDG2A}$	< 5.0E-08	ε
$ICCDP_{EDG1A}$	< 5.0E-07	Same as 2A for Unit 1[1]
$ICLERP_{EDG1A}$	< 5.0E-08	Same as 2A for Unit 1[1]

[1] The evaluation has been performed for LaSalle County Station, Unit 2. However, the models for Units 1 and 2 are essentially symmetrical. Therefore, the calculated values apply to Unit 1 also with EDG 1A exchanging values with EDG 2A.

Table 5-4

TOTAL PSA MODEL RESULTS FOR THE RISK METRIC CALCULATIONS

CDF	Fire PRA (Per Reactor Year)[1]	Internal Events PRA (Per Reactor Year)[2]	Total Internal and External Events (Per Reactor Year)
$CDF_{2A\text{-}OOS}$	3.211E-5	7.22E-6	3.93E-5
$CDF_{0\text{-}OOS}$	3.211E-5	1.66E-5	4.87E-5
$CDF_{1A\text{-}OOS}$	3.21E-5	7.08E-6[3]	3.92E-5
CDF_{BASE}	3.21E-5	6.92E-6	3.90E-5

(1) Based on results of Table 5-2.

(2) Based on information in Base case internal events EDG completion time evaluation submittal. Also includes CDF contribution from seismic initiating event contributions.

(3) The EDG AOT submittal table listed this value conservatively as 7.22E-06 for simplification of comparison between Unit 1 and Unit 2, since a Unit 2 PRA model was used for all calculations.

Table 5-5

TOTAL RESULTS OF RISK EVALUATION FOR LASALLE COUNTY STATION

Risk Metric	Risk Significance Guideline	Risk Metric Results Unit 2[1]
ΔCDF_{AVE}	< 1.0E-06/yr	2.0E-7
$\Delta LERF_{AVE}$	< 1.0E-07/yr.	2.0E-8
$ICCDP_{EDG\ 0}$	< 5.0E-07	3.7E-7
$ICLERP_{EDG\ 0}$	< 5.0E-08	1.2E-8
$ICCDP_{EDG2A}$	< 5.0E-07	1.2E-8
$ICLERP_{EDG2A}$	< 5.0E-08	1.2E-8
$ICCDP_{EDG1A}$	< 5.0E-07	Same as 2A for Unit 1[1]
$ICLERP_{EDG1A}$	< 5.0E-08	Same as 2A for Unit 1[1]

(1) The evaluation has been performed for LaSalle County Station Unit 2. However, the models for Units 1 and 2 are essentially symmetrical. Therefore, the calculated values apply to Unit 1 also with EDG 1A exchanging values with EDG 2A.

6. What is the seismic initiating event frequency for causing a loss of offsite power at your plant?

   Response
   The seismic-induced LOOP initiating event frequency for LaSalle County Station is composed of multiple seismic-induced DLOOP event categories based on their severity, with the greater severity seismic events having frequencies lower than those categories of lesser severity. The seismic-induced DLOOP event frequency ranges from low-level severity of 6.70E-05 to 4.70E-06 for the highest severity evaluated.

   The table below provides the breakdown of the seismic-induced DLOOP frequencies.

Initiating Event Designator	Description	Severity Level	Event Frequency (per year)
%SEIS-LL1	Low Level 1 Seismic-Induced DLOOP Event	0.10 – 0.18 g	6.70E-05
%SEIS-L1	Level 1 Seismic-Induced DLOOP Event	0.18 – 0.27 g	2.70E-05
%SEIS-L2	Level 2 Seismic-Induced DLOOP Event	0.27 – 0.36 g	1.60E-05
%SEIS-L3	Level 3 Seismic-Induced DLOOP Event	0.36 – 0.46 g	1.10E-05
%SEIS-L4	Level 4 Seismic-Induced DLOOP Event	0.46 – 0.58 g	8.50E-06
%SEIS-L5	Level 5 Seismic-Induced DLOOP Event	0.58 – 0.73 g	6.30E-06
%SEIS-L6	Level 6 Seismic-Induced DLOOP Event	> 0.73 g	4.70E-06

7. On pages 20 and 21 of Attachment A to your February 20, 2001 submittal, you stated that turbine building flooding would be "assessed" as part of the CRMP and preventative actions will help assure there is no precursor degradation in the structural integrity of turbine building basement piping. Does this statement indicate that your reported risk metrics include no increase in risk from turbine building flooding events if the EDG AOT were extended?

   Response
   The results presented in the TS submittal already include the risk produced by the turbine building flooding scenarios. This calculated risk (i.e., total and turbine building flood-induced) increases as the EDG AOT increases. These impacts are included in the numerical results presented in the TS submittal. The flooding risk represented in the TS submittal includes credit for preventative actions (i.e., inspections).

8. On page 21 of Attachment A to your February 20, 2001 submittal, you indicate that the fire analysis for LaSalle was based on conservative assumptions used during the RMIEP Study. In the next sentence you state that the key elements of the fire assessment are

consistent with current approaches. These statements appear to be in contradiction. Please explain.

Response
Key conservative elements in the LaSalle County Station RMIEP fire analyses include the following.

1. Exposure fires instantly attain peak intensity.

2. Compartment fire scenarios are generally modeled with two fire types:

   a. "Small fire": 1 gallon oil spill,
   b. "Large fire": 10 gallon oil spill.

3. Conservative modeling of fire-induced equipment damage:

   a. Fire-induced failure of any main steam equipment is modeled as failure of all Feedwater, Condensate, and Power Conversion System,

   b. Fire-induced failure of any mode of Residual heat Removal (RHR) System is modeled as failure of all modes of RHR,

   c. Fire-induced failure of RHR and containment vent is modeled as also failing the Power Conversion System (PCS).

The above fire analyses are all conservative modeling approaches that result in conservative damage states and conservative fire-induced core damage frequencies. For example, a realistic approach to item (1) would be to model a varying heat release rate consistent with the characteristics of a real fire. This would result in less conservative damage states and time to damage assessments. With respect to item (2), assuming oil spill fires as characteristic of the fires indicated by the compartment fire ignition frequencies is very conservative; industry experience shows that such fires are rare. With respect to item (3), assuming failure of various modeled functions given a fire-induced failure of a portion of one function is conservative.

Current fire analyses are generally conservative in comparison to internal events analyses. This is an industry acknowledged characteristic of current fire modeling techniques. The conservative elements, as well as other elements, of the LaSalle County Station RMIEP fire analyses are generally consistent with current industry fire modeling. For example, the RMIEP assumption that fires instantly reach peak and constant heat release rates is consistent with industry approaches. In contrast, the RMIEP assumption of 1 gallon and 10 gallon oil spill fires as representative fires is toward the conservative end of the spectrum of current fire modeling techniques.

In summary, the RMIEP fire analyses and current fire modeling techniques include a variety of key conservative assumptions. As such, the statement that the RMIEP fire analyses have key conservative elements, and the statement that the RMIEP fire analyses are consistent with current approaches are both correct statements.

9. Please explain your reasoning behind concluding that the proposed EDG completion time extension has a negligible effect on the risk profile at LaSalle from fire initiators given that you also stated you did not explicitly model such sequences.

Response
Based on the information contained in Question number 5 including that summarized in Table 5-1, the base fire induced LOOP sequences (i.e., Case 2) contributed approximately 1.5E-8/yr to the total fire CDF of 3.21E-5/yr in the RMIEP report. The fire induced LOOP sequences represent less than 0.1% of the total fire CDF.

The results in Table 5-1 also show that with an EDG out of service (i.e., Case 4), the fire induced LOOP CDF increases by approximately 1.2E-8/yr. Therefore, the increase in CDF would have a negligible impact on the base fire CDF of 3.21E-5/yr or the base internal events CDF of 6.92E-6/yr.

10.(a) Provide the increase in CDF and LERF, and ICCDP and ICLERP from the proposed AOT extension assuming that regular walkdowns and cyclic inspections of piping in the turbine building do not reduce the frequency of floods in the turbine building.

Response
If no credit is taken for piping inspections reducing the probability of turbine building pipe breaks, risk results for the EDG AOT extension are summarized in the table below.

Risk Metric	Risk Significance Guideline	Risk Metric Results for Unit 2[1]
ΔCDF_{AVE}	< 1.0E-06/yr	4.0E-07
$\Delta LERF_{AVE}$	< 1.0E-07/yr	2.0E-08
$ICCDP_{EDG\ 0}$	< 5.0E-07	5.8E-07
$ICLERP_{EDG\ 0}$	< 5.0E-08	1.2E-08
$ICCDP_{EDG\ 2A}$	< 5.0E-07	5.4E-09
$ICLERP_{EDG\ 2A}$	< 5.0E-08	< 1.0E-09
$ICCDP_{EDG\ 1A}$	< 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 evaluation has been performed for LaSalle County Station Unit 2. However, the models for Unit 1 and 2 are essentially symmetrical. Therefore, the calculated values apply to Unit 1 also.

10.(b) Describe what is intended when you state that under CRMP there will be additional (?) walkdowns and cyclic inspections of the subject piping in a piping inspection program. Indicate whether this is a formal commitment.

Response
The piping inspection and walkdowns will be controlled under the CRMP, as the piping inspections and walkdowns are considered a preventative and/or compensatory measure. As plant conditions change due to plant hardware or procedures not directly related to the EDGs, the risk results may change as well. In addition, new industry data may become available in the future to suggest higher or lower pipe break frequencies.

Controlling the pipe inspection program under the CRMP allows the flexibility to refine these inspections when risk results suggest it is appropriate. Use of planned allowed outage time for the subject EDGs is considered a maintenance activity, and hence falls under the existing regulatory requirements of 10 CFR 50.65(a)(4). Thus, it is appropriate to control the piping inspections as part of the CRMP and the piping inspections are performed to meet the requirements of 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power pants."

10.(c) What portions of the turbine building piping will not be covered by the walkdowns?

Response
The piping subject to the augmented walkdowns and cyclic inspections are limited to piping that has the potential for draining the water from the station cooling lake into the turbine building basement. The piping subject to the augmented walkdowns and cyclic inspections include the following.

- Service Water Headers/Standpipes, 48" Diameter (approximately 37 feet per unit)
- Circulating Water Man-ways, 36" Diameter (approximately 37 feet per unit)
- Circulating Water Deicing Lines, 120" Diameter (one per unit, approximately 12 feet)

Additionally, the operations staff routinely performs general-purpose walkdowns of plant areas, including the turbine building basement, for abnormalities including pipe leakage.

Risk Impact due to internal initiating events

11. What is the percentage and absolute CDF contributions due to the LOOP/SBO initiator?

Response
The major CDF contributors by initiator were provided in the EDG AOT TS submittal on page 7 of 13 of Attachment E. This graph includes the percent CDF contribution due to LOOP/Station Blackout (SBO). From the graph, single-unit LOOP represents 2% of the total CDF and dual-unit LOOP represents 17% of the CDF. The absolute CDF for LOOP/SBO is, therefore, 19% X 6.92E-06, or 1.31E-06 per year.

12. What are the top five dominant LOOP/SBO sequences? Describe the sequences.

Response
The top five dominant LOOP/SBO sequences for Core Damage are listed in the table and described below.

Sequence	Description	CDF
DLOP-15	%DLOOP, SPC, HPCS, LPCI-LPCS, PCV3	6.05E-07
DLOP-22	%DLOOP, SPC, HPCS, RCIC-SBO, DEPRESS	3.46E-07
DLOP-08	%DLOOP, SPC, SDC, PCV1	7.98E-08
DLOP-10	%DLOOP, SPC, DEPRESS, PCV6	5.90E-08
LOOP-08	%LOOP, SPC, SDC, PCV1	2.87E-08

The first four of these sequences are initiated by a DLOOP, while the fifth sequences is initiated by a single-unit LOOP. Each of these five sequences also involves loss of suppression pool cooling (SPC). Each sequence is described as follows:

- DLOP-15: DLOOP with failure of SPC, High Pressure Core Spray (HPCS) System , low-pressure makeup, and logic model PCV3.
  PCV3 logic models the situation where RCIC has worked initially but Low Pressure Coolant Injection (LPCI) and Low Pressure Core Spray (LPCS) are unsuccessful in reactor pressure vessel (RPV) injection following depressurization. AC power is recovered but SPC is unavailable. Condensate or heater drain pumps are successful in RPV injection. In this situation, the Control Rod Drive (CRD) system can be used as a viable "late" RPV injection makeup source after RCIC terminates and up to containment failure. After containment failure, the condensate or heater drain pumps are probabilistically assessed for their adequacy to provide RPV injection.

- DLOP-22: DLOOP with failure of SPC, HPCS, RCIC, and Automatic Depressurization System (ADS) for depressurization. This is essentially a SBO scenario at high RPV pressure with no high-pressure makeup capability and the inability to depressurize to use low-pressure systems.

- DLOP-08: DLOOP with failure of SPC, Shutdown Cooling (SDC) includes EDG failures that lead to the loss of these functions and logic model PCV1.
  PCV1 logic models the situation with HPCS initially available, but the Feedwater (FW) system has failed. HPCS can provide RPV injection over the range of containment pressures and temperatures up to the time of vent or containment failure. Past this point, HPCS failure has been identified with a high conditional probability given containment or vent failure using calculated reactor building temperature. If HPCS fails, other RPV injection sources are required to provide makeup.

- DLOP-10: DLOOP with failure of SPC, ADS, and logic model PCV6.
  PVC6 is similar to PVC1 in that HPCS may be initially available, but fails when containment fails and subjects the HPCS system components to harsh environmental conditions.

- LOOP-08: LOOP with failure of SPC, SDC, and logic model PCV1. This sequence is essentially the same as DLOP-08 described above, except that the initiating event is a single-unit loss of offsite power.

13. Given an EDG out of service, what are the top five cutsets with respect to CDF and LERF? What are the sources and values for basic events used in those cutsets? How do the values compare with plant experience?

Response
The top five cutsets for CDF and LERF with one EDG out of service are described below. The Common "0" EDG is chosen to be unavailable for this response since it provides more restrictive results than the Division 2 (i.e., Unit-specific) EDGs. For both CDF and LERF cutsets listed below, they are based on the PRA model with piping inspection program credited.

The top five CDF cutsets are listed in the following table:

#	Inputs	Description	Event Probability	Cutset Frequency
1	%TBFS8	CIRC WATER MANWAYS AND SW ATTACHED PIPE RUPTURES (36" DIAM.)	3.30E-06	3.30E-06
	BDGDG-DG0----X--	EDG 0 LOCAL FAILS TO RUN	1.00E+00	
2	%TBFS7	SW RETURN LINE RUPTURES	1.90E-06	1.90E-06
	BDGDG-DG0----X--	EDG 0 LOCAL FAILS TO RUN	1.00E+00	
3	%TBFS9	SW ATTACHED PIPE RUPTURES (24" DIAM.)	1.30E-06	1.30E-06
	BDGDG-DG0----X--	EDG 0 LOCAL FAILS TO RUN	1.00E+00	
4	%TBFS11	24" DIAM SW PIPE RUPTURES AND FAIL TO ISOLATE	1.00E-05	5.00E-07
	2WSOP-24TBISLH--	FAIL TO ISOLATE 24" DIAM SW PIPE	5.00E-02	
	BDGDG-DG0----X--	EDG 0 LOCAL FAILS TO RUN	1.00E+00	
5	%TBFS4	CIRC WATER COMPONENT RUPTURE	5.00E-03	5.00E-07
	2CWDR-FLOOD—O--	FLOOD DOORS LEFT OPEN OR FAILED	1.00E-04	
	BDGDG-DG0----X--	EDG 0 LOCAL FAILS TO RUN	1.00E+00	

For LERF, these cutsets are listed in the following table:

#	Inputs	Initiator or Basic Event Description	Event Probability	Cutset Frequency
1	%TT	TURBINE TRIP WITH BYPASS	2.36E+00	1.69E-07
	2RPCDRPS-MECHFCC	MECHANICAL SCRAM FAILURE	1.00E-05	
	2SLEVF004A&B-DCC	SBLC EXPLOSIVE VALVES F004A & B COMMON CAUSE FAILURE TO OPEN	1.40E-02	
	LERF-IV-51	UNMITIGATED ATWS SCENARIOS	5.10E-01	
2	%TBFS5	120" DEICING LINE RUPTURES (UNIT 2)	7.06E-07	1.10E-07

	2CNDMFLOOD---F--	FLOOD FAILS TO CLOSE CHECK DAMPERS TO RB	9.00E-01	
	2CNOP-DIC-DMPH--	OP FAILS TO CLOSE CHECK DAMPERS TO RB GIVEN CIRC OR DEICING LINE BREAK	7.20E-01	
	LERF-IIA-24	LOSS OF DECAY HEAT REMOVAL LEADS TO LOSS OF CONTAINMENT & MAKE-UP TO R	2.40E-01	
3	%TBFS6	120" DEICING LINE RUPTURES (UNIT 1)	7.06E-07	1.10E-07
	2CNDMFLOOD---F--	FLOOD FAILS TO CLOSE CHECK DAMPERS TO RB	9.00E-01	
	2CNOP-DIC-DMPH--	OP FAILS TO CLOSE CHECK DAMPERS TO RB GIVEN CIRC OR DEICING LINE BREAK	7.20E-01	
	LERF-IIA-24	LOSS OF DECAY HEAT REMOVAL LEADS TO LOSS OF CONTAINMENT & MAKE-UP TO R	2.40E-01	
4	%DLOOP	DUAL UNIT LOSS OF OFFSITE POWER	1.87E-02	9.54E-08
	2RPCDRPS-MECHFCC	MECHANICAL SCRAM FAILURE	1.00E-05	
	BDGDG-DG0----X--	DG0 LOCAL FAILS TO RUN	1.00E+00	
	LERF-IV-51	UNMITIGATED ATWS SCENARIOS	5.10E-01	
5	%TBFS4	CIRC WATER COMPONENT RUPTURE	5.00E-03	7.78E-08
	2CNDMFLOOD---F--	FLOOD FAILS TO CLOSE CHECK DAMPERS TO RB	9.00E-01	
	2CNOP-DIC-DMPH--	OP FAILS TO CLOSE CHECK DAMPERS TO RB GIVEN CIRC OR DEICING LINE BREAK	7.20E-01	
	2CWDR-FLOOD—O--	FLOOD DOORS LEFT OPEN	1.00E-04	
	LERF-IIA-24	LOSS OF DECAY HEAT REMOVAL LEADS TO LOSS OF CONTAINMENT & MAKE-UP TO REACTOR	2.40E-01	

The sources and values for the basic events used in these cutsets are listed in the following table:

Inputs	Desc.	Value	Source
%DLOOP	DUAL UNIT LOSS OF OFFSITE POWER	1.87E-02	Value based on data in EPRI TR-106306, "Losses of Off-Site Power at U.S. Nuclear Power Plants – Through 1995. Industry data was used as LaSalle Nuclear Station has not experienced a Dual Unit Loss of Off-Site Power.
%TBFS11	24" DIAM SW PIPE RUPTURES AND FAIL TO ISOLATE	1.00E-05	Calculation using methodology described in "Piping System Failure Rates and Rupture Frequencies for Use in Risk Informed Inservice Inspection Applications", EPRI TR-111880, September 1999. This methodology accounts for improved pipe reliability as a function of increased pipe inspection frequency.
%TBFS4	CIRC WATER COMPONENT RUPTURE	5.00E-03	Same as %TBFS11 source.

%TBFS5	120" DEICING LINE RUPTURES (UNIT 2)	7.06E-07	Same as %TBFS11 source.
%TBFS6	120" DEICING LINE RUPTURES (UNIT 1)	7.06E-07	Same as %TBFS11 source.
%TBFS7	SW RETURN LINE RUPTURES	1.90E-06	Same as %TBFS11 source.
%TBFS8	CIRC WATER MANWAYS AND SW ATTACHED PIPE RUPTURES (36" DIAM.)	3.30E-06	Same as %TBFS11 source.
%TBFS9	SW ATTACHED PIPE RUPTURES (24" DIAM.)	1.30E-06	Same as %TBFS11 source.
%TT	TURBINE TRIP WITH BYPASS	2.36E+00	Calculated using Bayes' Theorem and industry generic frequency from INEEL/EXT-98-00401 ["Rates of Initiating Events at U.S. Commercial Nuclear Power Plants, 1987 through 1995 (Draft)"] with LaSalle Specific data from 1990 to 1996.
2CNDMFLOOD---F--	FLOOD FAILS TO CLOSE CHECK DAMPERS TO RB	9.00E-01	Engineering Judgement based on discussion with EOP writer and SROs. Judged to be at the high end of the realistic failure probability.
2CNOP-DIC-DMPH--	OP FAILS TO CLOSE CHECK DAMPERS TO RB GIVEN CIRC OR DEICING LINE BREAK	7.20E-01	HRA Calculation using cause based HRA method plus ASEP and THERP methodology. Governing procedure LOA-FLD-001.
2CWDR-FLOOD--O--	FLOOD DOORS LEFT OPEN	1.00E-04	THERP
2RPCDRPS-MECHFCC	MECHANICAL SCRAM FAILURE	1.00E-05	Browns Ferry (scram discharge volume event) described in NUREG-0460
2SLEVF004A&B-DCC	SBLC EXPLOSIVE VALVES F004A & B COMMON CAUSE FAILURE TO OPEN	1.40E-02	Calculated using industry data. Industry events at Vermont Yankee, Monticello and Cooper were used in the calculation.
2WSOP-24TBISLH--	FAIL TO ISOLATE 24" DIAM SW PIPE	5.00E-02	HRA Calculation using cause based HRA method plus ASEP and THERP methodology. Governing procedure is LOA-FLD-001.
BDGDG-DG0----X--	DG0 LOCAL FAILS TO RUN	1.00E+00	Probability of 1 used to represent unavailable component.
LERF-IIA-24	LOSS OF DECAY HEAT REMOVAL LEADS TO LOSS OF CONTAINMENT & MAKE-UP TO REACTOR	2.40E-01	Calculation uses a containment event tree to quantify the plant damage state. The methodology is similar to that developed as part of NUREG/CR-6595. Documented in LaSalle Level 2/LERF Evaluation Notebook, LS PSA-015.
LERF-IV-51	UNMITIGATED ATWS SCENARIOS	5.10E-01	Same as for LERF-IIA-24.

These basic event values are consistent with LaSalle County Station operating experience. For example, the turbine trip initiator has been calculated using plant data. The remaining basic events/Initiating events that are associated with system or equipment failures have relatively low failure probabilities. LaSalle County Station operating experience demonstrates these low values.

15. What is the LOOP initiating event frequency used? What is the basis for the value?

    Response
    The dual-unit LOOP initiating event frequency used in the LaSalle County Station PRA is 1.87E-02 per year. This value was derived for a typical EGC Midwest dual unit site based on event data and switchyard configuration as described in EPRI TR-106306, "Losses of Off-Site Power at U.S. Nuclear Power Plants – Through 1995."

16. What are the common cause failure rates used for EDGs? What is the basis for the values?

    Response
    The basis for the CCF rates applied for the EDGs is the application of the MGL data from NUREG/CR-5497 Volume 6, Section 5, Table 5-2 and Table 5-5. Data for a four-component group applies to EDG 1A, 0, 2A, and 2B (i.e., HPCS EDG). It is noted that the HPCS EDGs (i.e., 1B and 2B) have nearly identical design and capacity as the station EGDs (i.e., 0, 1A, and 2A). Therefore, the common cause treatment includes the unit-specific HPCS EDG in the same common cause group as the 3 EDGs. However, the opposite unit HPCS EDG is not credited for mitigative protection for unit-specific events, so a five-component group is not modeled.

    The common cause failure groupings and probabilities are as follows:

    - Random independent failure probabilities
      - EDG Fails to run: 1.44E-2
      - EDG Fails to start: 6.67E-3
    - Common Cause Calculations

      The calculation of the common cause failure probabilities using the NUREG-5497 data is performed as follows:

      4 of 4 EDGs Common Cause Failure to Start (CCFTS) $= \lambda \bullet \beta \bullet \gamma \bullet \delta$

      $= 6.67E\text{-}3 \bullet 3.63E\text{-}2 \bullet 6.27E\text{-}1 \bullet 5.01E\text{-}1$

      $= 7.60E\text{-}5$

4 of 4 EDGs Common Cause Failure to Run (CCFTR) $= \lambda \bullet \beta \bullet \gamma \bullet \delta$

$= 1.44E\text{-}2 \bullet 5.10E\text{-}2 \bullet 5.72E\text{-}1 \bullet 4.99E\text{-}1$

$= 2.10E\text{-}4$

3 of 4 EDGs CCFTS $= 1/3 \bullet \lambda \bullet \beta \bullet \gamma \bullet (1 - \delta)$

$= 1/3 \bullet 6.67E\text{-}3 \bullet 3.63E\text{-}2 \bullet 6.27E\text{-}1 \bullet (1 - 5.01E\text{-}1)$

$= 2.53E\text{-}5$

3 of 4 EDGs CCFTR $= 1/3 \bullet \lambda \bullet \beta \bullet \gamma \bullet (1 - \delta)$

$= 1/3 \bullet 1.44E\text{-}2 \bullet 5.10E\text{-}2 \bullet 5.72E\text{-}1 \bullet (1 - 4.99E\text{-}1)$

$= 7.01E\text{-}5$

2 of 4 EDGs CCFTS $= 1/3 \bullet \lambda \bullet \beta \bullet (1\text{-}\delta)$

$= 1/3 \bullet 6.67E\text{-}3 \bullet 3.63E\text{-}2 \bullet (1 - 6.27E\text{-}1)$

$= 3.01E\text{-}5$

2 of 4 EDGs CCFTR $= 1/3 \bullet \lambda \bullet \beta \bullet (1\text{-}\delta)$

$= 1/3 \bullet 1.44E\text{-}2 \bullet 5.10E\text{-}2 \bullet (1 - 5.72E\text{-}1)$

$= 1.05E\text{-}4$

17. The proposed changes would allow, if approved, LaSalle to perform a corrective maintenance for a failed EDG using the 14-day AOT. For corrective maintenance, a typical PRA assumes that the remaining EDG would be subject to a potential common cause failure. The corresponding ICCDP/ICLERP can be significantly higher than that calculated for a preventive, planned, maintenance. Provide the ICCDP/ICLERP for a corrective maintenance and demonstrate that it meets the acceptable guidelines set forth in RG 1.177.

Response
We concur that the remaining EDGs would be subject to a potential CCF and that the corresponding ICCDP/ICLERP can be significantly higher than that calculated for a preventive, planned, maintenance. However, TS 3.8.1, "AC Sources – Operating," Required Action C.3.1 requires confirmation that other EDGs are not inoperable due to CCF within 24 hours. Therefore, a CCF mode is precluded from not being discovered

while the plant continues to operate in an extended AOT, since any potential CCF would be detected and appropriate actions would be taken in accordance with TS.

Despite the TS requirement to preclude the possibility of CCFs within 24 hours, the PRA model conservatively treats the possibility of a CCF of the remaining EDGs at their normal value. This approach is slightly conservative.

Risk Assessment - General

18. You explained how you estimated the effect of extending the completion time to 14 days for a Division 1 or Division 2 EDG. Explain how your analysis (i.e., CDF, LERF, ICCDP and ICLERP) factored in the increase of the ITS period associated with discovery of failure to meet TS LCO 3.8.1 from 10 days to 17 days.

    Response
    The 72 hour completion time of TS 3.8.1, Condition A, Required Action A.3, takes into account the capacity and the capability of the remaining AC sources, reasonable time for repairs, and the low probability of a design basis accident during this period.

    The proposed 17 day completion time of TS 3.8.1, Condition A, 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 failure to meet the Limiting Condition for Operation (LCO). The 17 day completion time is derived from the sum of the 14 day EDG AOT and 72 hour offsite power circuit AOT. The 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 3.8.1.b.

19. Explain how the ability of the opposite unit's EDG to compensate for a unit's loss of emergency power source is credited in the risk assessment. Discuss to what extent this capability is assured by CTS or proposed TS.

    Response
    The LaSalle County Station PRA models the opposite unit for cross ties and the use of opposite unit's Division 2 EDG. The PRA model distinguishes between a LOOP and a DLOOP. Explicit procedures at LaSalle County Station specify the use of electrical cross ties between units. Specifically, any single EDG has sufficient load margin when load shedding is coordinated between the units and has procedures to align equipment from both units to achieve a safe shutdown condition. Both the operating crew response and the failure of the equipment required are explicitly modeled in the PRA to represent the failure of this cross tie capability.

    An SBO would involve a DLOOP with subsequent failure of all three EDGs, or failure to provide shared power between the units. LaSalle County Station Operating Abnormal (LOA) procedures provide direction to cross-tie the facility for supplying emergency power from the opposite unit's Division 2 EDG. The TS addresses this capability by requiring shorter allowed outage times if the opposite unit EDG is inoperable at the same

time that the Unit AC electrical power subsystems are degraded. This is addressed in TS 3.8.1, Conditions C and F. Condition C allows an AOT of 72 hours if the opposite Unit EDG is inoperable, concurrent with the inoperable status of a Unit EDG. Condition F allows an AOT of 2 hours if the opposite Unit EDG is inoperable, concurrent with the inoperable status of a Unit EDG.

20. On page 12 of Attachment A to your February 20, 2001 submittal you stated that your analysis assumed only one major EDG overhaul per refueling cycle. What is the duration of the EDG vendor's recommended period between overhauls?

    Response
    The EDG vendor recommends distinct periods between overhauls for various levels of maintenance activities. The Engine Services Incorporated-Electro Motive Division (ESI-EMD) Diesel Owners Group Recommended Maintenance Program provides vendor approved overhaul guidance for EDGs used in nuclear standby service. The applicable portions of this document provide recommendations for maintenance activities based on time. Specifically, there are recommended activities for:

    - Every Refueling Cycle,
    - Alternate Refueling Cycle,
    - Every 6 years, and
    - Every 12 years

    Typically, the activities performed every refueling cycle are less complex, non-intrusive inspections and include replacement of lubricants and filters. These activities become progressively more intrusive and complex. At the 12 year point, they include an overhaul involving removal of cylinder heads and power packs to replace lower liner seals, and replacement of engine driven pumps. This program has been incorporated into Exelon standard NES-MS-09.01, "Diesel Generator Preventive Maintenance Basis Document."

    The vendor-recommended periods are independent of whether we perform the maintenance online, shutdown, or the frequency of overhaul allowed by technical specifications. Each EDG could have one overhaul per cycle in accordance with the vendor's recommendations for preventative maintenance.

21. Footnote 5 to Table 2 on page 15 of Attachment A to your February 20, 2001 submittal noted that the base CDF assumed an augmented piping inspection program for service water system is in place. What is the status of this program and is it actually in place? If not, when will it be in place?

    Response
    The augmented turbine building piping inspection program was credited for purposes of the analysis.Our intent is to implement this program within the implementation period of the TS amendment.

22. Footnote 7 to Table 2 on page 15 of Attachment A to your February 20, 2001 submittal noted that the LERF results shown are conservative because the EDGs and their support systems are treated as being vulnerable to turbine building floods. However, on page 8 of Attachment E you state that the Core Standby Cooling System (that provides essential cooling to the EDGs) and other front line systems have room doors that are not flood-proof. If that is so, why are the LERF results in Table 2 conservative for EDGs as claimed in footnote 7?

    Response
    The LERF results presented in Table 2, and described by Footnote 7, are results obtained from using the PRA without giving any credit for the augmented piping inspection. This slightly increases the importance of LERF, since the LERF sequences are based on higher initial CDF sequences. Because the LERF values were small relative to the acceptance criterion in RG 1.174, it was concluded that more bounding LERF calculations (i.e., without credit for piping inspections) were sufficient to demonstrate these parameters were not limiting with regard to the EDG AOT extension.

23. On page 20 of Attachment A to your February 20, 2001 submittal you provided a table summarizing the calculated risk values and comparing these values to Regulatory Guide 1.174 and 1.177 guidance. Please indicate which initiators are included in your risk metric results so reported (e.g., do they include fire, internal flood, seismic initiators?).

    Response
    Attachment A of the TS submittal includes internal event initiators, seismic, and internal flooding. These results do not include fire risk, since that portion is not integrated into the LaSalle County Station PRA. Fire risk was not combined with the internal events PRA results since the fire analysis was based on the NRC sponsored RMIEP study. Fire risk impact was evaluated separately. The conclusion was that fire risk was not a significant contributor to the EDG AOT extension, therefore, fire risk is not included in the summary results. Additional information is contained in the response to Question number 5.

Tier 2

24.a. With an EDG out of service, what are the most risk significant equipment, or basic events, based on your PRA? Have you performed a systematic search for such equipment?

    Response
    See Table 24-1 for the top 10 risk significant events based on RAW. Table 24-2 lists the important trains based on basic events RAW values. These trains are limited to active components, such as pump trains. Not included are highly reliable "passive components" such as pipe, transformers and batteries.

    Important active equipment trains are identified during the LaSalle County Station On-line Maintenance planning process. This process will identify active components such as those found in Table 24-2. The CRMP is used to assure that risk-significant

equipment is identified, and appropriate compensatory actions are taken in response to elevated risk levels for EDGs taken out-of-service. The identification of important equipment is performed by risk calculations built into the software tool that is used in order to satisfy the requirements of 10 CFR 50.65(a)(4).

24.b. What are the restrictions currently placed on such risk significant equipment?

Response
Procedures establish administrative controls for performing on-line maintenance of systems/structures/components (SSC) in order to enhance overall plant safety and reliability. Maintenance activities are planned and executed within established bounds and acceptable levels of risk to maintain overall plant safety and reliability. A configuration risk assessment of planned maintenance activities is conducted prior to initiating a maintenance activity.

The risk of scheduled on-line maintenance activities is continuously evaluated based upon conditions such as the power grid stability, the weather forecast, plant status, and SSC status. If severe weather is expected, planned unavailability of AC power sources are deferred. Risk is re-assessed if an emergent condition places the plant in a configuration that has not been previously assessed. When multiple SSCs are removed from service, an assessment is conducted to ensure acceptable risk levels are maintained.

When risk significant SSCs are made unavailable, actions are taken to protect redundant/diverse SSCs. SSCs needing protection are those SSCs which, if lost concurrent with other SSCs being unavailable for planned maintenance, would cause an unplanned entry into an orange or red risk configuration. Protective actions to be taken are commensurate with the risk significance of the work. Protective actions may include, but are not limited to, announcement of risk status, notification of protected trains and divisions, posting of signs, or placement of barriers.

24.c. Are there any additional restrictions, in terms of enhancements in TS or procedures, needed to avoid risk-significant configurations?

Response
On-line maintenance procedures establish administrative controls for performing maintenance of SSC on-line in order to enhance overall plant safety and reliability. Maintenance activities are planned and executed within established bounds and acceptable levels of risk to maintain overall plant safety and reliability. The on-line maintenance process and CRMP are administered by the work management process. The CRMP controls how work is scheduled, analyzed, and implemented. A configuration risk assessment of planned maintenance activities is conducted prior to initiating a maintenance activity. Potential risk-significant configurations are adequately planned with compensatory actions, establishing protected pathways and systems where needed, or work combinations that should be avoided altogether while operating the units at power. The CRMP provides the staff with the tools to manage risk-

significant configurations in compliance with federal standards, industry guidance, and station policies. No further enhancements to TS or procedures are necessary in order to implement the extended AOTs for the EDGs.

Technical Specifications

25. Why is Action B being deleted on page 3.8.1-3 of the Improved Technical Specifications?

    Response
    The current TS 3.8.1, Condition B provided the requirements for extending the AOT of a Division 1 EDG to 7 days and is being replaced with a revised Condition B that increases the AOT of a Division 1 or Division 2 EDG to 14 days.

Table 24-1
Important Basic Events/Initiating Events
With 0 EDG Unavailable

Event Name	Probability	Fus Ves	Risk Achievement Worth	Description
BDCBS125-ALL-FCC	1.40E-09	2.98E-04	7.80E+04	CCF 125 VDC U2 DIV. 1, 2 & 3 AND U1 DIV. 1 & 2 BUSES
BSYFL-8STRNR-PCC	6.90E-08	1.64E-02	7.41E+04	CCF OF ALL 5 CSCS STRAINERS AND 3 PSW STRAINERS
%BOC	5.40E-08	3.63E-03	6.60E+04	LARGE LOCA (BREAK) OUTSIDE CONTAINMENT INITIATOR
%TBFS5	8.10E-08	5.34E-03	6.60E+04	120" DEICING LINE RUPTURES (UNIT 2)
%TBFS6	8.10E-08	5.34E-03	6.60E+04	120" DEICING LINE RUPTURES (UNIT 1)
%TBFS7	1.90E-06	1.25E-01	6.60E+04	SW RETURN LINE RUPTURES
%TBFS8	3.30E-06	2.18E-01	6.60E+04	CIRC WATER MANWAYS AND SW ATTACHED PIPE RUPTURES (36" DIAM.)
%TBFS9	1.30E-06	8.58E-02	6.60E+04	SW ATTACHED PIPE RUPTURES (24" DIAM.)
%R	1.00E-08	1.32E-04	1.25E+04	EXCESSIVE LARGE LOCA
%TDCAB	6.00E-07	4.95E-03	8.08E+03	LOSS OF 125V DC BUS 2A AND 2B IE

Table 24-2
Important Basic Events/Initiating Events
Active Components/Trains Only[1]
With 0 EDG Unavailable

Basic Event	Description	Prob.	Risk	Associated Train
2CWDR-FLOOD--O--	FLOOD DOORS LEFT OPEN	1.00E-04	331.53	N/A
2DCBC2DC17E--F--	2DC17E DIV2 BAT CHARGER (300 AMP) FAULTS	1.68E-04	19.89	Div 2 Battery Charger
2DCBC2DC09E--F--	2DC09E DIV1 BAT CHARGER FAULT	1.68E-04	17.7	Div 1 Battery Charger
2RHFNSECORNERM--	SE CORNER ROOM COOLING/VENTILATION UNSCHEDULED MAINTENANCE	3.00E-03	11.18	RHR B/C Room Cooler
2DGPMCS2DG01PF--	2DG01P (DG2A COOL. WTR PMP) PLANT SPECIFIC FAULT DATA (PSD)	1.30E-03	9.87	DG2A Cooling Water Pump
2RHHETRAINB--M--	RHR TRAIN B HTX UNAVAILABLE DUE TO MAINTENANCE	5.00E-03	5.23	RHR Train B HTX
2RHPME12C002BA--	2E12C002B RHR PUMP B" FAILS TO START"	2.30E-03	4.77	RHR Train B Pump
BDGHUCSTRN2A-H--	DG 2A COOLING TRAIN MANUAL VALVES MISALIGNED	1.00E-04	3.5	DG2A Cooling Water Pump
2DGDG-DG2B---X--	DIESEL GENERATOR DG2B FAILS TO RUN	1.44E-02	3.23	Diesel Generator 2B
2HCMV2E22F004D--	MOTOR-OPERATED VALVE 2E22-F004 FAILS TO OPEN	4.00E-03	2.98	HPCS
2RHFNSWCORNERM--	SW CORNER ROOM COOLING/VENTILATION UNSCHEDULED MAINTENANCE	3.00E-03	2.71	HPCS Room Cooler
1WSAVSW029---V--	U1 TBCCW HX SW PNEUMATIC-HYDRAULIC VALVE SW029 FAILS TO REMAIN OPEN	2.64E-04	2.61	TBCCW Ht Exchanger
2DGPMCS22C002A--	2E22C002 DG2B COOL WTR PMP FAILS TO START	1.30E-03	2.39	DG2B Cooling Water Pump

[1] Excluded from table are Common Cause Events, Initiating Events, Spurious Circuit Breaker failures, Transformer failures and Operator Actions involving multiple systems.