September 21, 2001

MEMORANDUM TO: Anthony J. Mendiola, Chief
Project Directorate Section III-2
Division of Licensing Program Management

FROM: Cornelius Holden, Chief ***(/RA by CHolden)***
Electrical Engineering Section B
Electrical & Instrumentation And Controls Branch
Division of Engineering

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2
REQUEST FOR AMENDMENT TO TECHNICAL SPECIFICATIONS
EXTENSION OF ALLOWABLE COMPLETION TIMES
FOR DIVISION 1 AND 2 EMERGENCY DIESEL GENERATORS
(TAC Nos.: MB1224 AND MB1225)

Plant Name:	LaSalle County Station, Units 1 and 2
Docket Nos.:	50-373 and 50-374
Operating License:	NPF-11 and NPF-18
Licensee:	Exelon Generation Company (Formerly Commonwealth Edison Company)
Project Directorate:	PD-III
Project Manager:	Jon Hopkins
Review Branch:	EEIB
Review Status:	Complete

By letter dated February 20, 2001, Exelon Generation Company, LLC, formerly Commonwealth Edison Company requested changes to Technical Specifications of LaSalle County Station, Units 1 and 2. The original application was supplemented by letter from the licensee on July 13, 2001.

The proposed changes to Current Technical Specifications (CTSs) Section 3/4.8.1, “A.C. sources - Operating” and the proposed Improved Technical Specifications (ITSs) Section 3.8.1, “A.C. sources - Operating” will extend to 14 days the Allowable Completion Time for the Required Actions associated with restoration of an inoperable Division 1 or Division 2 Emergency Diesel Generator (EDG). In addition, another change is requested in the proposed ITS completion time period associated with discovery of failure to meet TS Limiting Condition of Operation (LCO) 3.8.1 from 10 days to 17 days.

The staff of the Electrical & Instrumentation and Controls Branch and the Probabilistic Safety Assessment Branch reviewed the licensee submittals. On the basis of the reviews, we find the proposed Technical Specifications changes acceptable as discussed in the attached safety evaluation.

Attachment: As stated

CONTACT: Saba N. Saba, EEIB
415-2781

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Attachment: As stated

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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

TECHNICAL SPECIFICATION CHANGES
EXTENSION OF ALLOWABLE COMPLETION TIMES FOR DIVISION 1 AND 2
EMERGENCY DIESEL GENERATORS
LASALLE COUNTY STATION, UNITS 1 AND 2
EXELON GENERATION COMPANY
(TAC Nos.: MB 1224 AND MB 1225)

1. INTRODUCTION

By letter dated February 20, 2001, supplemented by a letter dated July 13, 2001, Exelon Generation Company, LLC, (EGC, the licensee) formerly Commonwealth Edison Company proposed changes to Appendix A, Technical Specifications of Facility Operating License Nos. NPF-11 and NPF-18 for LaSalle County Station (LaSalle), Units 1 and 2.

The proposed changes to Current Technical Specification (CTS) Section 3/4.8.1, "A.C. Sources - Operating" and to the proposed Improved Technical Specifications (ITS) Section 3.8.1, "A.C. Sources - Operating" will extend the allowable completion time for the Required Actions associated with restoration of an inoperable Division 1 or Division 2 Emergency Diesel Generator (EDG) from 3 days to 14 days.

In addition, another change is requested in the proposed ITS completion time period associated with discovery of failure to meet TS limiting condition of operation (LCO) 3.8.1 from 10 days to 17 days.

The Electrical & Instrumentation and Controls Branch (EEIB) with support from the Probabilistic Safety Assessment Branch (SPSB) has reviewed and evaluated the licensee request as follows:

2. BACKGROUND

Power to LaSalle Units 1 and 2 switchyard is supplied from four 345 k V 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 system auxiliary transformer (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 Division 3 emergency bus has no second offsite source, and will automatically be supplied by the Division 3 EDG after the bus is de-energized.

LaSalle units 1 and 2 has five EDGs supplying power to the Division 1, 2 and 3 emergency power buses. Division 1 of each unit is powered by one swing EDG (i.e. EDG O). Division 2 of 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).

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.

3. EVALUATION

The licensee has proposed the following changes to LaSalle 1 and 2 TS:

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.

The changes allow an EDG to be inoperable for up to 14 days and 17 days from discovery of failure to meet LCO.

The justification for the extended Completion Time is based upon a risk-informed and deterministic evaluation as follows:

DETERMINISTIC EVALUATION

The LaSalle 1 and 2 station proposed changes increase the length of time an EDG can be out of service during unit operation, however the system is designed with adequate defense-in-depth philosophy to accomplish the safety functions and prevent release of radioactive material. The LaSalle 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.

System redundancy, independence and diversity are maintained commensurate with the expected frequency and consequences of challenges to the system. 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.

Additionally, the licensee has committed to include the following previsions/limitations/ compensatory actions during the extended EDG allowed outage time (AOT) that can mitigate any increase in risk:

- Availability of the “preferred” and “reserve” offsite source via System Auxiliary Transformers (SATs) and verification of the cross-tie breaker operability prior to voluntary entry into proposed AOT.

- Verification that the dual unit power supplies and the offsite power sources are operable.

- 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 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.

- Implementation of the Configuration Risk Management Program (CRMP) which helps ensure that these extended maintenance activities are carried out with no significant increase in the consequences of a severe accident while any EDG maintenance is performed.

- No scheduling preplanned maintenance when severe weather conditions are expected.

- 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.

DETERMINISTIC CONCLUSION

We find the proposed change to extend the EDG AOT from the current 72-hours to 14 days to be acceptable. Our conclusion is based on the following: (1) The availability of the "preferred and "reserve" offsite power sources and unit cross-tie; (2) Verification that the opposite unit EDGs and offsite power source are operable; and (3) Implementation of the CRMP while and EDG is in an extended completion time. Further, the licensee's plans preclude testing and maintenance of other electrical systems during extended outage and not scheduling preplanned maintenance when adverse weather is expected will minimize the impact of the longer AOT.

Also we find that the changes made to the TS Bases section is consistent with the requested EDG AOT and is, therefore acceptable.

3.1 PRA EVALUATION

The staff used a three-tiered approach to evaluate the risk associated with the proposed TS changes. The first tier evaluated the PRA model and the impact of the completion time extensions for the EDGs on plant operational risk. The second tier addressed the need to preclude potentially high risk configurations should additional equipment outages occur during the time when an EDG is out of service. The third tier evaluated the licensee's configuration risk management program to ensure that the applicable plant configuration will be appropriately assessed from a risk perspective before entering into or during the proposed completion times. Each tier and the associated findings are discussed below.

Tier 1 Evaluation

The licensee used traditional PRA methodology to evaluate the requested completion time extension for Division 1 or Division 2 EDGs. The Tier 1 NRC staff review of the licensee's PRA involved three aspects: (i) evaluation of the PRA model and application to the proposed completion time extension, (ii) evaluation of PRA results and insights stemming from the application, and (iii) discussion of the quality of the PRA.

(i) Evaluation of PRA Model and Application to the Completion Time Extension

The staff reviewed the capability of the licensee's PRA model to analyze the risk stemming from the proposed completion time changes for Division 1 and Division 2 EDGs and did not perform a general review of the LaSalle County Station PRA, which was extensively based on the NRC's Risk Methods Integration and Evaluation Program (RMIEP) study (NUREG/CR-4832). The NRC previously performed a review of the licensee's IPE submittal, which was documented in a safety evaluation report on March 14, 1996. The RMIEP study and the Phenomenology and Risk Uncertainty Evaluation Program (PRUEP) developed for the NRC detailed Level 1 and a Level 2/3 analysis of the LaSalle County Station, Unit 2. The current review was based on the staff's previous evaluation of LaSalle under the RMIEP study and the PRUEP, as well as the staff's evaluation of the licensee's IPE and IPEEE submittals. The staff concludes that the licensee's PRA results are reasonable, and the scope and depth of the PRA analysis support such a finding. Discussions with the licensee regarding recent data for EDG reliability and availability did not indicate any adverse trends.

The licensee recalculated its PRA to determine the effect of extending the completion time from 72 hours to 14 days. The PRA model for LaSalle County Station was developed for the Individual Plant Examination (IPE) that was submitted to the NRC by letter dated April 28, 1994, in response to Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities - 10 CFR 50.54(f)." The NRC staff issued its Safety Evaluation (SE) for the LaSalle IPE by letter dated March 14, 1996, wherein the NRC staff concluded that the LaSalle County Station IPE submittal met the intent of Generic Letter 88-20. In the SE accompanying this letter, the NRC cited weaknesses in the licensee's method for both common cause and human reliability analysis in other licensee PRAs reviewed by the staff (i.e., Zion, Dresden, and Quad Cities). The major PRA limitations identified in the NRC SER were addressed in subsequent updates to the PRA.

(ii) Evaluation of PRA Results and Insights

Risk-informed support for the proposed changes to the EDG completion time (for either Division 1 or Division 2) is based on PRA calculations performed by the licensee to quantify the change in average core damage frequency (CDF) and average large early release frequency (LERF) resulting from the increased completion time. To determine the effect of the proposed changes with respect to plant risk, the licensee used the guidance provided in Regulatory Guides (RGs) 1.174 and RG 1.177.

The licensee performed an evaluation based on the assumption that the full, extended completion time (i.e., 14 days) would be applied once per EDG per refueling cycle. The cycle time is based on the current 18-month fuel cycle (allowing for 30 days planned and unplanned plant outage time) for LaSalle County Station for a net total cycle length of 517.5 operating days. EDG reliability and availability are monitored and evaluated in relationship to Maintenance Rule goals to ensure that EDG outage times do not degrade operational safety over time.

The licensee computed the incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) per the definitions in RG 1.177. The results of the risk evaluation, including the computed ICCDP and ICLERP, were submitted to the staff as follows: the reported base CDF estimate was $6.9\text{x}10^{-6}$ per year for internal events plus seismic events (if the fire PRA results are included, the base case CDF was $3.9\text{x}10^{-5}$ per year) assuming that an augmented piping inspection program for service water piping located in the turbine building is in place; the base LERF estimate was $1.0x10^{-6}$ per year and does not credit an augmented piping inspection process; the differential CDF was $2.8x10^{-7}$ per year; the ICCDP was $3.7x10^{-7}$; the differential LERF was $2.0x10^{-8}$ per year; and the ICLERP as $1.2x10^{-8}$. If no credit were given for piping inspections reducing the probability of turbine building pipe breaks, risk results for the EDG completion time extension would be slightly higher with the $ICCDP_{EDG\ O}$ (i.e., the ICCDP when EDG 0 is the failed EDG) equal to $5.8x10^{-7}$ per year, which slightly exceed RG 1.177 guidance. However, in its February 20, 2001, and July 13, 2001, letters to the NRC, the licensee stated that the augmented pipe will be implemented prior to implementing the proposed changes in the EDG completion times. In addition, the licensee stated the piping inspections and walkdowns of the piping will be controlled under the CRMP such that, as appropriate, the inspection frequencies could be modified based on plant changes or new industry data. The staff finds that credit for the piping inspections is reasonable.

The results of the risk evaluation were compared with risk significance criteria from RG 1.174 for changes in the annual average CDF and LERF and from RG 1.177 for ICCDP and ICLERP. The ICCDP and ICLERP evaluation was based on EDG 0, which provides the limiting values for these risk metrics. The value for the ICCDP (i.e., $3.7x10^{-7}$) is considered small, includes seismic events and internal floods, but excludes fires. A separate licensee analysis in its July 13, 2001, letter to the NRC demonstrated that the effect of EDG completion time extension is negligible on CDF and LERF for fire initiated events. Finally, the value of ICLERP developed by the licensee meets the guidance given in RG 1.177 for a “small” risk.

In determining the values above, the licensee set the PRA quantification truncation limit to 1E-11/yr for sequence quantification. This is more than five orders of magnitude below the total CDF. The staff finds this an acceptable truncation limit for this risk-informed application.

With regard to plant risk during shutdown conditions, the licensee did not perform a quantitative evaluation of the proposed changes. The licensee expressed its opinion that it is reasonable to conclude that performing EDG overhauls on-line rather than during outages will increase EDG availability during outages. This should reduce shutdown risk by improving the availability of standby AC power sources for shutdown cooling equipment and other equipment needed to mitigate events that may be postulated to occur during shutdown. The staff concurs in this conclusion.

(iii) Quality of the LaSalle County Station, Unit 2 PRA

The LaSalle County Station PRA is developed from the Individual Plant Examination (IPE) and Individual Plant Examination for External Events (IPEEE) results, which were based on 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 LaSalle PRA constructed by Sandia National Laboratories for the NRC with the results reported in NUREG/CR-4832.

The latest and most current PRA model used by the licensee for this analysis has also

undergone an external peer review from the Nuclear Energy Institute (NEI) Probabilistic Safety Assessment (PSA) Peer Certification Process in early 2000. The Certification Team found the PRA to be sound and adequate for use in regulatory submittals. The team identified a number of areas as needing enhancement (none of which required immediate corrective action, but the peer review group recommended that 15 enhancements should be evaluated at the next periodic update). The licensee examined these recommendations and found that two were 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. These enhancements were developed and implemented prior to the evaluation of the EDG completion time assessment.

The licensee stated it administratively controls the maintenance and configuration control of the LaSalle County Station PRA models, data, and software. In addition to model control, the licensee indicated that 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. The application of this process was reviewed by a BWROG Peer Certification Team (peer review) in early 2000. The licensee stated the review was conducted following the Nuclear Energy Institute (NEI) 00-02, "NEI Probabilistic Safety Study (PSA) Certification Peer Review Process," using a team of PRA experts. The licensee stated the peer review found the LaSalle County Station PRA was a sound model and rated all 11 areas reviewed as adequate to support regulatory applications when combined with deterministic insights.

The staff finds that a small incremental increase in core damage frequency estimated for the change in completion time from 3 to 14 days is consistent with the credit taken for the system in the PRA modeling, and that the review and updating of the PRA models by the licensee provide reasonable assurance that the models appropriately reflect the equipment and procedural characteristics at the plant.

Tier 2 Evaluation

The second tier addressed the need to preclude potentially high risk configurations by identifying the need for any additional constraints or compensatory actions that, if implemented, would avoid or reduce the probability of a risk-significant configuration during the time when one EDG is out of service. The licensee did not identify any actions that should be taken beyond those associated with the LaSalle County Station configuration risk management program (CRMP). The licensee's CRMP was developed in a manner to meet the requirements of the NRC's Maintenance Rule, 10 CFR 50.65.

Tier 3 Evaluation

The licensee stated that it has developed a CRMP for the LaSalle County Station that ensures that the risk impact of equipment out-of-service is appropriately evaluated prior to performing any maintenance activity. This program involves both a probabilistic and deterministic review to uncover risk-significant plant equipment outage configurations in a timely manner both during the work management process and for emergent conditions during normal plant operation. Consideration is given to equipment unavailability, operational activities like testing or load dispatching, and weather conditions.

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 percent 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, the licensee performs a risk assessment to ensure that the activity does not pose any unacceptable risk.

- While in the extended EDG completion time, additional elective equipment maintenance or testing, or equipment failure will be evaluated using the CRMP.

The licensee stated that its 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. For example:

- 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 high pressure core spray (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.

PRA CONCLUSION

The staff finds that the completion time for the LaSalle County Station EDGs may be extended to 14 days with a small effect on risk.

CONCLUSION

Based on the above, the staff concluded that the licensee's request to extend the EDG AOT from 7 days to 14 days is acceptable and recommend that the Exelon Generation Company LLC request for amendment of the Technical Specification be approved.