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10 CFR 50.90

RS-21-040

March 31, 2021

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

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

Subject: Response to Second Round Request for Additional Information (RAIs) for LaSalle License Amendment Request to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

References:

1. Letter from D. Murray (Exelon Generation Company, LLC) to U.S. Nuclear Regulatory Commission, "Application to Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, 'Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b,' (EPID L-2020-LLA-0018)," dated January 31, 2020.

2. Letter from B. Vaidya (Project Manager, U.S Nuclear Regulatory Commission) to B. Hanson (Exelon Generation Company, LLC), "LaSalle County Station Unit 1 and 2 – Request for Additional Information for LaSalle License Amendment Request to Adopt Risk-Informed Completion Times TSTF-505, Revision 2, 'Provide Risk-Informed extended Completion Times - RITSTF Initiative 4b' (EPID L-2020-LLA-0018)," dated September 3, 2020.

3. Letter from B. Vaidya (Project Manager, U.S Nuclear Regulatory Commission) to B. Hanson (Exelon Generation Company, LLC), "LaSalle County Station Unit 1 and 2 – Correction to Request for Additional Information Regarding License Amendment Request to Adopt TSTF-505, Revision 2, "Provide Risk-Informed extended Completion Times - RITSTF Initiative 4b' (EPID L-2020-LLA-0018)," dated September 16, 2020.

4. Letter from D. Murray (Exelon Generation Company, LLC), "LaSalle County Station, Unit Nos. 1 And 2 – Response to Request for Additional Information Regarding License Amendment Request to Adopt TSTF-505, Revision 2, 'Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b,' (EPID L-2020-LLA-0018)," dated October 1, 2020.

5. Letter from B. Vaidya (Project Manager, U.S Nuclear Regulatory Commission) to D. Rhoades (Exelon Generation Company, LLC), "Second Round - Request for Additional Information (RAIs) for LaSalle License Amendment Request to Adopt Risk Informed Completion Times TSTF-505, Revision 2, 'Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b,' (EPID L-2020-LLA-0018)" dated March 1, 2021.

In Reference 1, Exelon Generation Company, LLC (EGC) submitted a request to the U.S. Nuclear Regulatory Commission (NRC) for a revision to the Technical Specifications (TS) (Appendix A) of Renewed Facility Operating License Nos. NPF-11 and NPF-18 for LaSalle County Station, Units 1 and 2.

EGC's proposed license amendment request (LAR) would revise Technical Specifications (TS) requirements to permit the use of Risk-Informed Completion Times (RICT) for actions to be taken when limiting conditions for operation are not met. The proposed changes are based on Technical Specifications Task Force Traveler (TSTF)-505, Revision 2, "Provide Risk Informed Extended Completion Times – RITSTF Initiative 4b," dated July 2, 2018 (ADAMS Package Accession No. ML18269A041).

On September 3, 2020, the NRC provided a Request for Additional Information (RAI) (Reference 2) to support their continued review of Reference 1. On September 16, 2020, the NRC amended its September 3, 2020 letter to revise the due dates for its requests for additional information (Reference 3). On October 1, 2020, Reference 4 was submitted in response to Reference 2.

On March 1, 2021, the NRC provided EGC with a second round RAI (Reference 5) to support their continued review of Reference 1.

Attachment 1 to this letter contains the NRC's request for additional information along with EGC's response to Reference 5. Attachment 2 to this letter contains the relevant steps of LOA-AP-201 procedure along with descriptions of each step. Attachment 3 to this letter contains Table 8.3-1, "Loading on 4160-Volt Buses," of the LaSalle County Station Updated Final Safety Analysis Report.

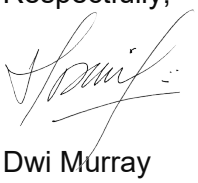
EGC has reviewed the information supporting a finding of no significant hazards consideration and the environmental consideration provided to the NRC in Reference 1. The supplemental information provided in this letter does not affect the bases for concluding that the proposed license amendment does not involve a significant hazards consideration. Furthermore, the supplemental information provided in this letter does not affect the bases for concluding that neither an environmental impact statement nor an environmental assessment needs to be prepared in connection with the proposed amendment.

There are no regulatory commitments contained in this letter.

Should you have any questions regarding this submittal, please contact Jason Taken at 630-657-3660.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 31st day of March 2021.

Respectfully,



Dwi Murray
Sr. Manager – Licensing
Exelon Generation Company, LLC

Attachments:

1. Response to Request for Additional Information
2. LOA-AP-201 Actions with Descriptions
3. Load List and Equipment Response During a LOCA

cc: NRC Regional Administrator, Region III
NRC Senior Resident Inspector – LaSalle County Station
NRC Project Manager, NRR – LaSalle County Station
Illinois Emergency Management Agency – Division of Nuclear Safety

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

Response to Request for Additional Information

ATTACHMENT 1
Response to Request for Additional Information

RAI-R2 EEEB 1: By letter dated October 1, 2020, Exelon's response to EEOB TSTF-505 RAI No. 1, "Technical Specifications Associated with TS 3.8 'Electrical Power Systems impact on Non-accident Unit'," indicates the use of site procedure LOA-AP-101, "Unit 1, AC Power System Abnormal". For the same scenario specified in the September 3, 2020, staff RAI, please provide the following:

Details of any additional defense-in-depth capabilities at LaSalle, in line with stated criteria above, that would allow for a controlled, safe shutdown of the non-accident unit. This pertains to the requested changes to TS 3.8.1.B, TS 3.8.1.C, and TS 3.8.1.E for the Division 2 DGs.

EGC RESPONSE:

The NRC previously approved a time extension for EDG Allowed Outage Time (AOT) from 72 hours to 14 days, as noted in its Safety Evaluation dated January 30, 2002 (ML012780141). The NRC's Safety Evaluation provides, in pertinent part:

> *Due to the redundancy of each unit's respective ESF divisions and EDGs, the loss of any one of the EDGs, (i.e., the respective unit's associated Division 1, 2, and 3 EDGs or the opposite unit Division 2 EDG) will not prevent the safe shutdown of the respective unit.* The total standby power system, including EDGs and electrical power distribution equipment, satisfies the single failure criterion. LaSalle County Station is able to withstand and recover from a station blackout (SBO) event of 4 hours in accordance with 10 CFR 50.63, "Loss of all alternating current power." For each unit, an SBO occurs as a result of a loss of offsite power in conjunction with a loss of onsite AC power from the respective unit's Division 1 and 2 EDGs, and failure of the cross-tie breaker to the other unit. The Division 3 EDGs are assumed to be available to support the operation of the high-pressure core spray (HPCS) system during an SBO, but are not classified as "Alternate AC" power sources, because Division 3 EDGs do not supply power to safe shutdown loads. Therefore, even though the Division 3 EDGs are available, the LaSalle County Station coping analysis uses the AC independent approach. The proposed changes do not affect the LaSalle County Station SBO analysis. (emphasis added)

Exelon Generation Company, LLC (EGC) confirms that the NRC's statements above, specifically that the loss of any one of the Emergency Diesel Generators (EDGs) will not prevent the safe shutdown of the respective unit, are reflective of the current licensing basis, and remain true and provide context to the responses provided herein.

Consistent with TSTF-505, Revision 2 and EGC's application to adopt TSTF-505, Revision 2 into the LaSalle County Station (LSCS) licensing basis, there are no conditions presented in EGC's application that represent a loss of function. In considering the adoption of the risk-informed approach to completion times, and applying it to the limiting condition for operation (LCO) identified in this question, EGC identified that in many cases, the backstop completion times are conservative compared to what the probabilistic risk assessment (PRA) model would normally allow. This additional margin demonstrates that sufficient redundancy and diversity exist to mitigate common cause events, and that the configuration presented in each Technical Specifications (TS) Condition are not risk significant.

For illustrative purposes of describing how LSCS would respond to the postulated scenario, LSCS, Unit 1, is assumed to be the "accident unit" and LSCS, Unit 2, is the "non-accident unit" with its Division 2 Emergency Diesel Generator (EDG) out of service in a Risk-Informed Completion Time (RICT). The actions and conclusions discussed below would be equivalent if the "accident unit' and "non-accident unit" were reversed, with the assumed EDG in a RICT being on the "non-accident unit." Procedure LOA-AP-101, "Unit 1, AC Power System Abnormal," is specific to the actions for Unit 1 during an abnormal power event. Procedure LOA-AP-201, "Unit 2, AC Power System Abnormal," is the identical procedure for Unit 2, and will be referenced when describing actions taken on Unit 2.

Consistent with the TS Bases, Sections 3.8.1 D.1 and D.2, with two of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a design basis accident (DBA) or transient. In fact, a simultaneous loss of offsite AC sources, a loss of coolant accident (LOCA), and a worst-case single failure were postulated as a part of the design basis in the safety analysis.

As described in TS Bases Section 3.8.1, the OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

1) An assumed loss of all offsite power or all onsite AC power; and
2) A worst case single failure.

The postulated scenario is recognized as a DBA, and is discussed in detail in LSCS Updated Final Safety Analysis Report (UFSAR) Chapter 15, Section 6.5, which discusses the LOCA analysis, and UFSAR Chapter 15, Section 9, which discusses Station Blackout (SBO).

Detailed Overview of Operator Actions and Their Impact

Attachment 2 to this letter contains the applicable portions of LOA-AP-201 for Unit 2 along with annotations providing further guidance on what is performed in the respective steps. Attachment 3 encompasses Table 8.3-1 of the LSCS UFSAR and contains a load list, associated equipment requirements, start times, and loading requirements, to add granularity on loads powered by AC Buses at LSCS and equipment responses and availability following a LOCA.

Figure 1 represents the initial electric plant line-up following a DLOOP (Dual Unit Loss of Off-Site Power) with a LOCA on Unit 1 and the Unit 2 'A' EDG out of service.

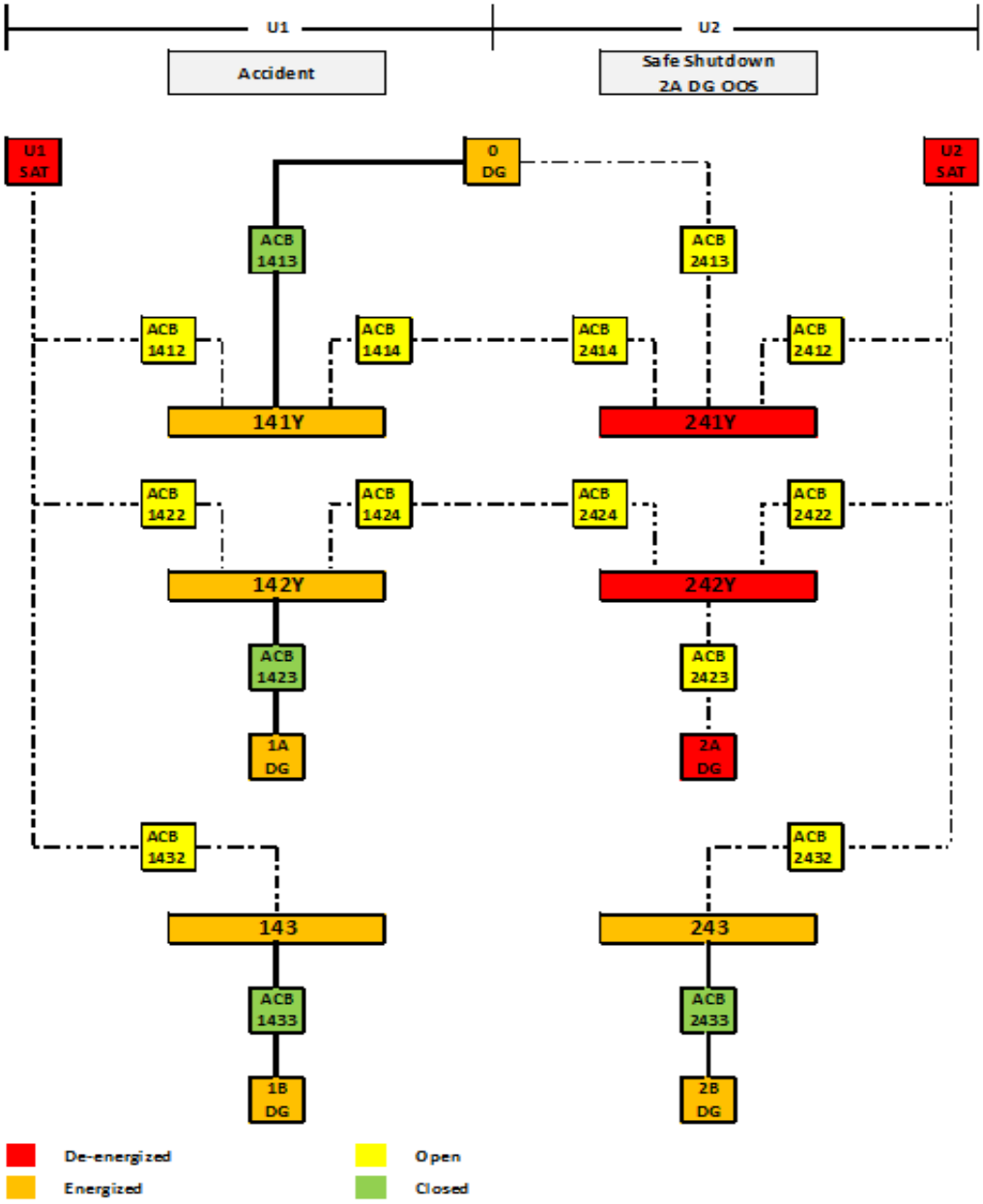


Figure 1 - Initial electric plant line-up following a DLOOP with a LOCA on Unit 1 and Unit 2 'A' EDG out of service

The postulated scenario results in a Station Blackout (SBO) on Unit 2. LSCS SBO coping method uses Reactor Core Isolation Cooling (RCIC) or High Pressure Core Spray (HPCS) to provide makeup water for core cooling. The HPCS system normally takes suction from the suppression pool, and RCIC suction automatically transfers to the

suppression pool on low condensate storage tank level. Decay heat is removed by discharge of steam through the Safety/Relief Valves into the suppression pool, where the steam is condensed. As a result, gradual heat up of the suppression pool is expected. Per analysis, the suppression pool water inventory is sufficient to make up for decay heat removal requirements and expected leakage during a four-hour station blackout. The suppression pool temperature will remain below the heat capacity temperature limits while providing this water, if cooldown is limited to 20°F/hr.

LSCS, Unit 1 (the accident unit) operators will enter Emergency Operating Procedures (EOP) based on High Drywell Pressure and Low Reactor Water level. LSCS, Unit 2 (the non-accident unit with its Division 2 EDG out of service) operators will enter Emergency Operating Procedures (EOP) based on Low Reactor Water level.

LSCS, Unit 2 will enter LOA-AP-201 due to loss of AC power to Division 1 (241Y) and Division 2 (242Y) 4.16k-volt Safety Related Busses. The procedure starts at step B.1, "Decision Tree."

LOA-AP-201 Step B.1, Decision Tree, directs operators to perform Attachment K, "Station Blackout Contingencies," B.2, "Loss of Bus 241Y," and B.3, "Loss of Bus 242Y."

Note: Either Unit 2 Division 1 AC bus (241Y) or Division 2 AC bus (242Y) may be recovered first. For this postulated scenario, Unit 2 Division 1 AC bus (241Y) has been chosen to be recovered first (LOA-AP-201, B.2, "Loss of Bus 241Y").

LOA-AP-201, Step B.2, "Loss of Bus 241Y," restores AC power to the Unit 2 Division 1 AC bus from the Division 1 EDG (the common EDG, 0 DG) using the Division 1 Unit tie breakers (ACB 1414 and ACB 2414). To accomplish this, Division 1 Unit tie breakers (ACB 1414 and ACB 2414) interlocks will be defeated per LOA-AP-201, Attachment C.

Figure 2 represents the final Division 1 AC electrical lineup.

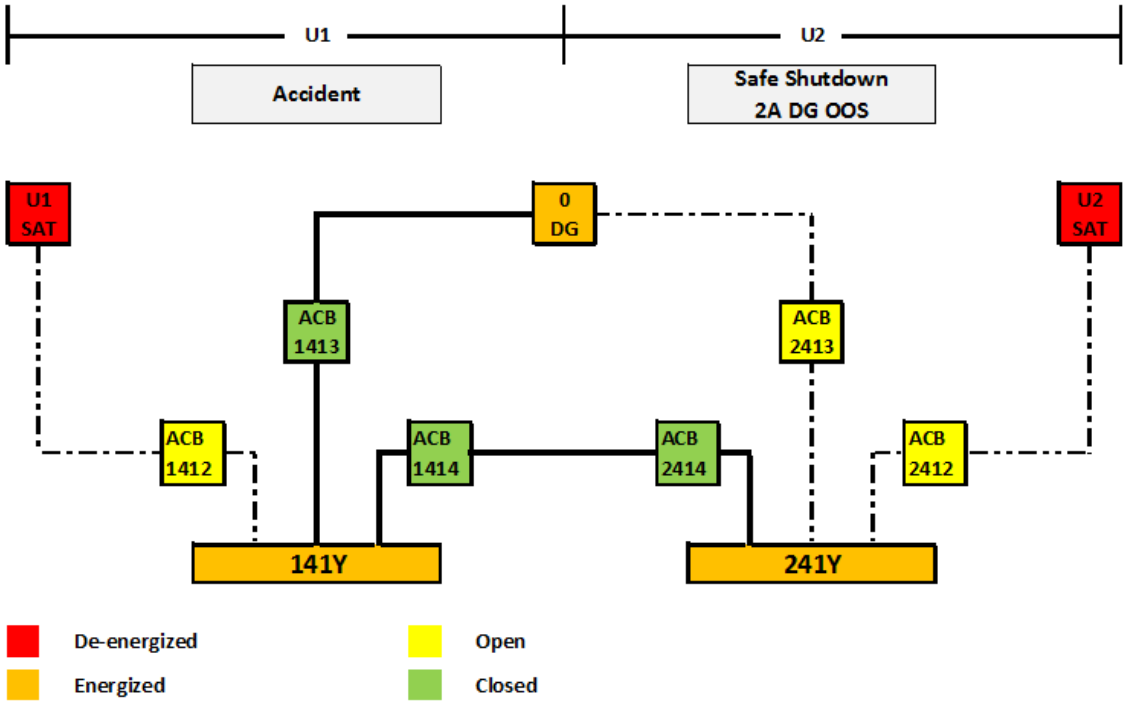


Figure 2 – AC power restored to Unit 2 Division 1 AC Bus from Division 1 EDG (0 DG)

Concurrently, operators will perform LOA-AP-201, Attachment K, "Station Blackout Contingencies." Actions in LOA-AP-201, Attachment K, include load shedding of non-essential DC loads, establishing reactor pressure control with Safety Relief Valves (SRV's) from the Auxiliary Electric Equipment Room (AEER) and opening panel doors in the Main Control Room (MCR) and AEER. Attachment 2, Table 1, of this letter provides a timeline of Unit 2 response and key operator actions during the 4-hour SBO coping time.

Following restoration of Unit 2 Division 1 AC power (LOA-AP-201, Step B.2.15), 2A Residual Heat Removal (RHR) will be placed in the Suppression Pool cooling mode (containment cooling) within 15 minutes per LOA-AP-201, Attachment K, LGA-003, "Primary Containment Control," and LGA-RH-203, "Unit 2 A/B RHR Operations in the LGAS/LSAMGS."

Once Suppression Pool cooling is placed into operation, reactor depressurization may continue at a rate not to exceed 100°F/hr.

LOA-AP-201, B.3, "Loss of Bus 242Y," will be performed next to restore AC power to the Unit 2 Division 2 AC bus (242Y) from the Unit 1 Division 2 EDG (1A DG) using the Division 2 Unit tie breakers (ACB 1424 and ACB 2424). To accomplish this, Division 2 Unit tie breakers (ACB 1424 and ACB 2424) interlocks will be defeated per LOA-AP-201,

Attachment G. LOA-AP-201, Attachment G, Step 6.10, is the step that will energize the Unit 2 Division 2 AC bus.

Figure 3 represents the final Division 2 AC electrical lineup.

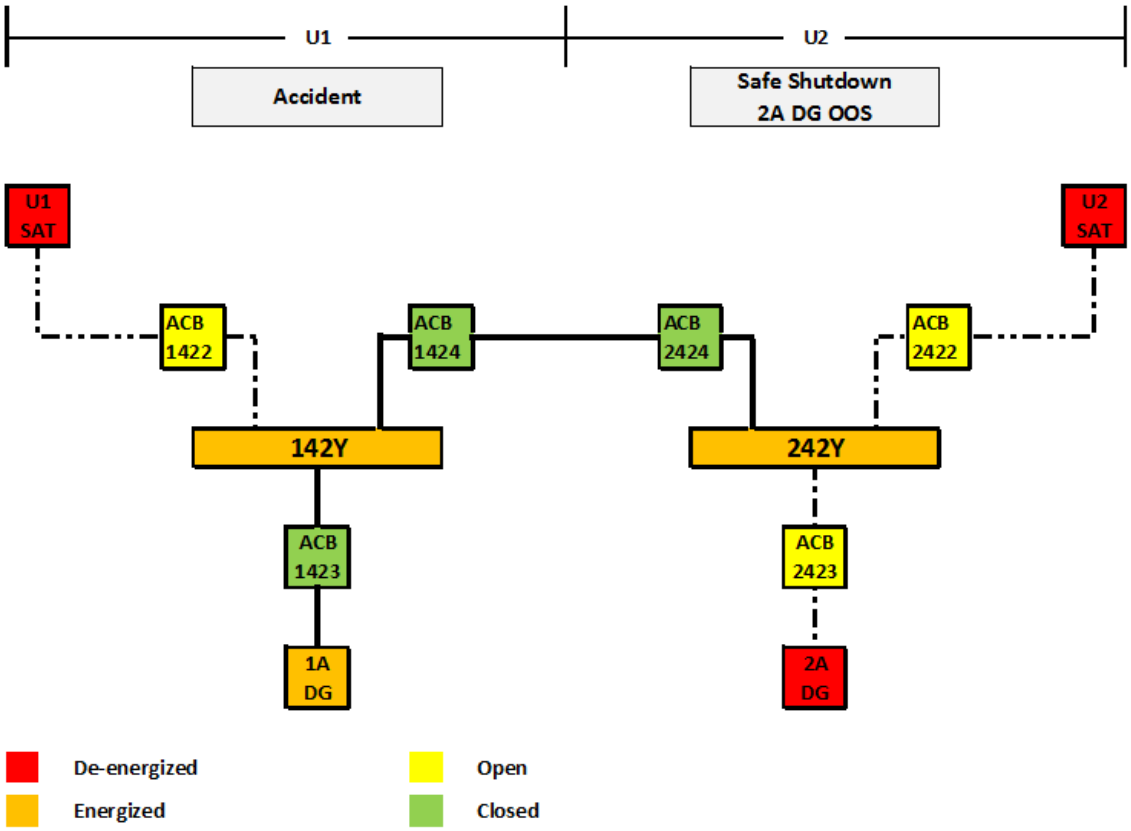


Figure 3 – AC power restored to Unit 2 Division 2 AC Bus from Unit 1 Division 2 EDG (1A DG).

At this point in the electrical plant system restoration, Unit 2, the non-accident unit, has AC power to Division 1 and Division 2 AC buses required to support safe shutdown. Consistent with the LSCS design basis and current Technical Specifications, only one division of AC power on Unit 2, the non-accident unit, would be required to permit safe shutdown.

Operator Staffing

Technical Specifications (TS) 5.0, "Administrative Controls," Section 5.1.2, TS Section 5.2.2, "Unit Staff," and OP-LA-101-111-1001, "On-Shift Staffing Requirements," provide the minimum shift staffing requirements with both Unit 1 and Unit 2 in Modes 1, 2 or 3. The minimum shift requirements are (1) Shift Manager, (1) Unit Supervisor, (1) Shift Technical Advisor (STA), (3) Reactor Operators, (3) Non-Licensed Operators, (1) Fire Brigade Leader and (4) Fire Brigade Members. Operator Staffing is sufficient to respond

to a LOCA on one unit with a corresponding loss of off-site power on both Units with any one Emergency Diesel Generator (EDG) in RICT.

Administrative Controls Supporting Defense-In-Depth

EGC applies rigor in protecting operable equipment when a system is taken out of service for maintenance. For example, if LSCS were to be in Condition TS 3.8.1.A, One required offsite circuit inoperable, and a RICT was used, compensatory measures and risk management actions (RMAs), not credited in the RICT calculation, would be implemented. The RMAs support redundant or diverse SSCs that perform the function(s) of the inoperable SSCs, and, if practicable, reduce the frequency of initiating events that challenge the function(s) performed by the inoperable SSCs. Such RMA's are intended to maintain the risk below acceptable regulatory risk thresholds, and account for any uncertainties associated with the calculated RICT. The actions for TS 3.8.1.A are described in Enclosure 12 of Reference 1 and include:

- Actions to increase risk awareness and control such as: briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate EOPs for a Loss of Offsite Power and station blackout including bus crossties; notification of the TSO of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred; and, proactive implementation of RMAs during times of high grid stress conditions prior to reaching the RMAT, such as during high demand conditions.

- Actions to reduce the duration of maintenance activities such as: creation of a sub-schedule related to the specific evolution (if preplanned) which is reviewed for personnel resource availability; confirmation of parts availability prior to entry into a preplanned RICT; and, walkdown of work prior to execution.

- Actions to minimize the magnitude of the risk increase, such as: evaluation of weather conditions for threats to the reliability of remaining offsite power supplies; deferral of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit; protection of the remaining offsite source, including switchyard and transformer, and deferral of planned maintenance or testing that affects the reliability of DGs and their associated support equipment (i.e. treat these as protected equipment); and, implementation of 10 CFR 50.65(a)(4) fire-specific RMAs associated with the affected offsite source.

- If severe weather or conditions are expected, then planned unavailability of AC power sources would be deferred. If an offsite power source becomes unavailable or degraded, or the risk of losing offsite power significantly increases due to severe weather, then systems required to mitigate the loss of offsite power would be made available as soon as possible.

In addition to the above-described RMAs, the RMAs for TS Conditions 3.8.1.B and 3.8.1.E are provided in Enclosure 12 of Reference 1.

EGC Processes Used To Implement Risk Management Actions During Equipment Unavailability

OP-AA-108-117, "Protected Equipment Program," provides guidance for protecting equipment to minimize plant risk. This involves limiting or prohibiting operation or maintenance of plant equipment when SSCs are made unavailable.

The intent of protecting systems and components is to provide additional administrative barriers to guard against inadvertently rendering a component or system, which is important to unit risk and nuclear safety, inoperable or unavailable. It is also applicable to those systems and activities that pose a potential risk to generation.

Protected equipment actions taken in accordance with this procedure support the Configuration Risk Management Program and are classified as risk management actions for the purpose of compliance with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," subsection (a)(4).

This procedure applies to online and shutdown conditions.

- The online goal is to maintain plant risk within acceptable levels by maintaining defense in depth of key safety functions, preventing inadvertent plant trips, transients, or Technical Specification Limiting Conditions for Operations (LCO) entries.

- The shutdown goal is to maintain shutdown risk within acceptable levels by maintaining defense in depth of key safety functions.

- Key Safety Functions:
  - Decay Heat Removal
  - Spent Fuel Pool Cooling
  - Inventory Control
  - Electrical Power (includes both onsite & offsite power)
  - Reactivity Control
  - Primary Containment Integrity (Containment Isolation, Containment Pressure and Temperature Control)

WC-AA-101, "On-Line Work Control Process," establishes the administrative controls for performing on-line maintenance of structures/systems/components (SSC) to enhance overall plant safety and reliability. This procedure applies to units in power operations in Modes 1, 2.

Corrective, preventive, and predictive maintenance activities are performed on SSCs important to safety and reliability at power to ensure that an SSCs overall reliability will be maintained or improved. Maintenance activities are planned and executed within established bounds and acceptable levels of risk maintain overall plant safety. A configuration risk assessment of planned maintenance activities is conducted prior to initiating any maintenance activity.

On-Line Work Control is based upon a 13-week cycle template containing work windows on major safety related and Risk Significant SSCs.

The Operating Shift continuously evaluates the risk of the scheduled on-line maintenance activity based upon conditions, such as the power grid stability, the weather forecast, and the current plant and SSC status. This includes information obtained from day ahead forecasts. If severe weather or conditions that are potential HREs for loss of offsite power are expected, then planned unavailability of AC power sources shall be deferred.

For example, if an offsite power source becomes unavailable or degraded, or the risk of losing offsite power significantly increases due to severe weather, systems required to mitigate the loss of offsite power shall be made available as soon as possible.

OU-AA-103, "Shutdown Safety Management Program," (SSMP) uses as its basis the philosophy and recommendations stated in NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," and INPO 06-008, "Guidelines for Conduct of Outages at Nuclear Power Plants." The SSMP is also designed to meet the applicable requirements of 10 CFR 50.65(a)(4) and NUMARC 93-01, "Industry Guidance for monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

Risk Mitigation Practices with Time Critical Actions

OP-LA-102-106, "LaSalle Station Operator Response Time Program," provides response times for conditions that may be experienced during transients at LSCS. Noteworthy time critical actions relevant to the question are provided below.

Several time-critical risk-significant operator actions are well-practiced, and time validated in accordance with OP-LA-102-106. Relevant examples include:

- **TCA16**: Manual start of RHR Containment Cooling Mode, RHR in pool cooling. The SBO analyses for suppression pool temperature assume that suppression pool cooling is established <=15 minutes following a SBO.
    - Last validated on June 15, 2018.

- **TCA22:** Control of the ADS valves from the AEER can be established within 20 minutes of initiation of SBO.
    - Last validated September 6, 2019.

- **TCA24**: All loads are shed within 30 minutes after SBO begins, with the exception of the 250-Vdc MCC 121X and MCC 221X loads, which are shed within 180 minutes after SBO begins.
    - Last validated September 6, 2019.

Please also identify any capabilities assumed initially unavailable but eventually recovered including their recovery times and relevant impact.

EGC RESPONSE:

As described in the response to the first question of RAI-R2 EEEB 1, a loss of all AC power occurs on the non-accident (Unit 2), initially rendering all Division 1 and 2 AC powered loads on the non-accident unit unavailable. AC power is re-aligned and containment cooling established as described in the response, and the associated completion time actions are provided in Table 1 of Attachment 2.

Clarification on when procedure LOA-AP-101(201) would be implemented (i.e. (1) prior to entry into the TS LCO or (2) during a postulated design basis accident condition).

EGC RESPONSE:

The purpose of LOA-AP-101(201), "Unit 1(2), AC Power System Abnormal," is to respond to a transient on the LSCS electrical power system.

LOA-AP-101(201) is designed to provide flexibility to operators to restore the electrical plant system from a transient based on conditions present at the time of the transient. The symptoms or entry conditions that may necessitate executing the procedure are as follows:

- Loss of 345KV grid.
- Loss of Ring Bus.
- Loss of SAT 142 and/or UAT 141.
- Failure of DGs 0, 1A, and/or 1B to start when required.
- Loss of various 4KV & 480 VAC ESS and Non-ESS buses.
- 4kV ESS Bus Degraded Voltage.
- Failure of Voltage Regulating Transformer.
- Loss of single phase or degraded single phase.

These entry conditions intend to capture the diversity of events that may require AC power restoration, but there may be conditions not expressly covered by the list above which would also require entry into this procedure. This procedure is not used under normal operating conditions absent an electrical power system transient, and therefore, this abnormal procedure would not be entered prior to entry into a TS Condition Statement without a corresponding transient. During planned TS Completion Time, equipment is taken out of service consistent with normal operating procedures.

In summary, based on the information provided in the above response for RAI-R2-EEEB 1, which is supported by the current licensing basis, the inoperability of any one of the EDGs, concurrent with the postulated scenario (DBA LOCA with a complete loss of off-site power) will not prevent safe shutdown of the unit with its Division 1 or Division 2 EDG out of service. Whether the EDG is in a RICT, or in the already-approved Allowed Outage Times for EDGs being inoperable, this conclusion remains unchanged.

RAI-R2 EEEB 2: For the conditions postulated in Table E1-1, please clarify if procedure LOA-AP-101, "Unit 1, AC Power System Abnormal," would be implemented for the safe shutdown of the non-accident unit under the same conditions specified in RAI EEEB 1 above, including the requested information for defense-in-depth capabilities, when the indicated Division 2 SSC is in a RICT for the following TSs:

TS 3.3.8.1.A - One or more loss of power (LOP) instrument channels

EGC RESPONSE:

With one or more channels of a Function inoperable, the Function may not be capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the channel in trip would result in a DG initiation), Condition B must be entered and its Required Action taken.

For the postulated scenario (Unit 1 LOCA and DLOOP with Unit 2 Division 2 EDG (2A) OOS) the Unit 2 Division 2 EDG (2A) is assumed to be out of service (OOS). Each Division 1, 2, and 3 Emergency Busses has its own independent loss of power instrumentation and associated trip logic. For example, a loss of 2A EDG will not affect the Division 1 loss of power instrumentation or its trip logic.

In the event the Unit 2 Division 2 Loss of Power (LOP) Instrumentation is inoperable at the time of the postulated scenario (Unit 1 LOCA and DLOOP with Unit 2 Division 2 EDG (2A) OOS) were to occur, the response would be similar to that described in RAI-R2-EEEB 1 response.

LOA-AP-201 would be entered to restore Unit 2 Division 1 AC bus (241Y) from the Division 1 EDG (0 DG) and LOA-AP-201, Attachment K, "Station Blackout Contingencies," would be implemented.

LOA-AP-201 would be entered to restore Unit 2 Division 2 AC bus (242Y) from the Unit 1 Division 2 EDG (1A DG). With Unit 2 Division 2 Loss of Power (LOP) Instrumentation inoperable and not placed in the trip condition, this condition does not prevent restoring Unit 2 Division 2 AC bus (242Y) from the Unit 1 Division 2 EDG (1A DG).

Additionally, consistent with the EGC Work Management process and measures described in RAI-R2-EEEB 1 response, with the Unit 2 Division 2 EDG (2A) OOS, no activities would be scheduled or performed on Unit 1 Division 2, Unit 2 Division 1 or Unit 2 Division 3 Loss of Power Instrumentation. For planned activities, TS 3.3.8.1 Required Action A.1 would not be entered concurrently for Division 1, 2 or 3 Loss of Power Instrumentation.

Furthermore, consistent with NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b Risk-Managed Technical Specifications (RMTS) Guidelines," RMTS cannot be voluntarily entered if:

1) the configuration-specific risk exceeds the instantaneous limits of 10-3/year CDF or 10-4/year LERF;
2) the ICDP or ILERP limit has been reached prior to exceeding the frontstop CT; or
3) a total loss of specified safety function for the affected TS system occurs.

If an emergent failure, or degraded or non-conforming condition is discovered for a redundant SSC that results in a total loss of TS specified safety function while the RMTS are in effect, then the RICT is exited and the associated applicable TS Required Actions are considered not met, and subsequent TS required actions are required to be implemented.

Additionally, LSCS procedure LOA-DG-201, "DG Failure," provides the operator direction to start and load any EDG's that does not start on bus undervoltage when required.

TS 3.8.4.A – 125 VDC battery charger

EGC RESPONSE:

To aid in understanding equipment line-ups, and power sources, Figure 4 is provided for the 125 VDC power subsystems.

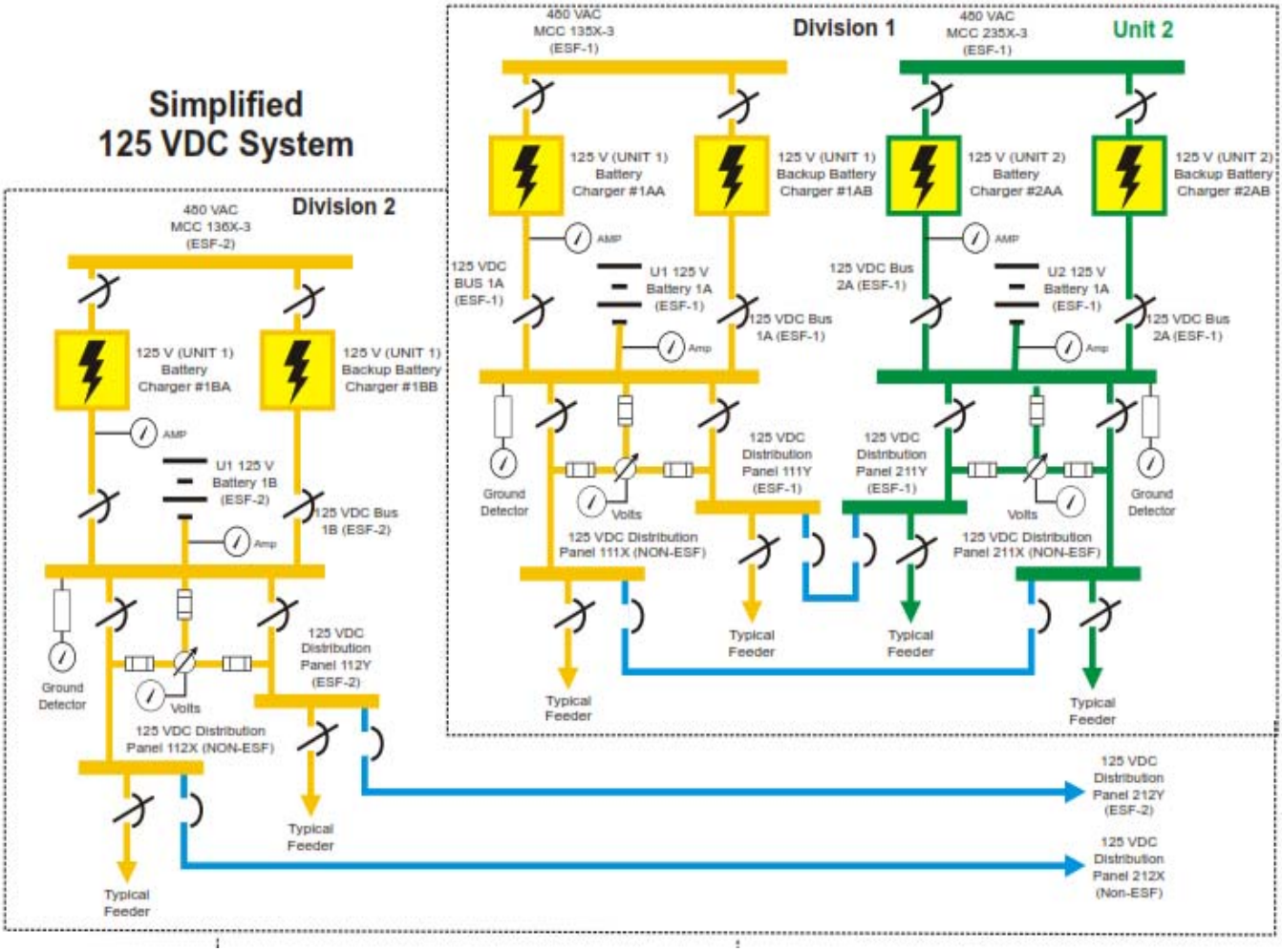


Figure 4 – 125 VDC Subsystem Drawing

Both Units at LSCS are designed with (2) fully qualified battery chargers for the 125 VDC Division 1 and Division 2 electrical power subsystems. Only 1 battery charger per division is online at any given time except when swapping battery chargers from primary to backup. Maintenance is performed periodically on the alternate (offline) battery charger. Scheduled maintenance is not performed on both the alternate and required battery chargers at the same time.

Entry into TS LCO 3.8.4 would result from an emergent failure of the online (required) battery charger.

In the event of a failure of the online (required) battery charger, the alternate (offline) battery charger would be placed online per LOA-DC-101(201), "Unit 1(2) DC Power System Failure," Section B.1, "Loss of a Battery Charger."

If the postulated scenario (Unit 1 LOCA and DLOOP with Unit 2 Division 2 EDG (2A) OOS) were to occur with no operating Unit 2 Division 2 battery charger providing DC power, the response would be similar to that described in RAI-R2-EEEB 1 response.

LOA-AP-201 would be entered to restore Unit 2 Division 1 AC bus (241Y) from the Division 1 EDG (0 DG) and LOA-AP-201, Attachment K, "Station Blackout Contingencies," would be implemented.

Once Unit 2 Division 2 AC bus is energized from the Unit 1 Division 2 EDG (1A DG), the alternate (offline) Unit 2 Division 2 DC battery charger would be placed online.

No loss of safety functions occurs.

TS 3.8.4.B & E - 125 VDC electrical power subsystem

EGC RESPONSE:

TS 3.8.4 Condition B:

This condition represents one division with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation.

In the event the Unit 2 Division 2 125 VDC electrical power subsystem is inoperable at the time of the postulated scenario (Unit 1 LOCA and DLOOP with Unit 2 Division 2 EDG (2A) OOS) were to occur, the response would be similar to that described in RAI-R2-EEEB 1 response.

LOA-AP-201 would be entered to restore Unit 2 Division 1 AC bus (241Y) from the Division 1 EDG (0 DG) and LOA-AP-201, Attachment K, "Station Blackout Contingencies," would be implemented.

However, in this case, the Unit 2 Division 2 125 VDC electrical power subsystem would have to be restored to a functional state to allow restoring the Unit 2 Division 2 AC bus (242Y) from the Unit 1 Division 2 EDG (1A DG).

No loss of safety functions occurs.

TS 3.8.4 Condition E:

In the postulated scenario (Unit 1 LOCA and DLOOP with Unit 2 Division 2 EDG (2A) OOS), Unit 1 Division 2 125 VDC electrical power subsystem remains energized from the Unit 1 Division 2 EDG (1A) and provides power to the Unit 1 Division 2 Battery Charger ensuring redundant Division 2 features (e.g., a standby gas treatment subsystem, Control Room Area Filtration (CRAF) subsystem, Control Room Area Ventilation Air Conditioning (AC) System) will function in the event of a design basis event.

LOA-AP-201 would be entered to restore Unit 2 Division 1 AC bus (241Y) from the Division 1 EDG (0 DG) and LOA-AP-201, Attachment K, "Station Blackout Contingencies," would be implemented.

However, in this case, the Unit 2 Division 2 125 VDC electrical power subsystem would have to be restored to a functional state to allow restoring the Unit 2 Division 2 AC bus (242Y) from the Unit 1 Division 2 EDG (1A DG).

LOA-AP-201 would be entered regarding any loss of AC power that occurred as a result of the postulated scenario and sequence to restore equipment would be as discussed previously in RAI-R2-EEEB 1 response.

No loss of safety functions occurs.

TS 3.8.7.A – AC Electrical power distribution subsystem

EGC RESPONSE:

With one or more Division 1 and 2 required AC buses, load centers, motor control centers, or distribution panels inoperable and a loss of function has not yet occurred, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure.

In the event the Unit 2 Division 2 AC Electrical power distribution subsystem is inoperable at the time of the postulated scenario (Unit 1 LOCA and DLOOP with Unit 2 Division 2 EDG (2A) OOS) were to occur, the response would be similar to that described in RAI-R2-EEEB 1 response.

LOA-AP-201 would be entered to restore Unit 2 Division 1 AC bus (241Y) from the Division 1 EDG (0 DG) and LOA-AP-201, Attachment K, "Station Blackout Contingencies," would be implemented.

However, in this case, the Unit 2 Division 2 AC Electrical power distribution subsystem would have to be restored to a functional state to allow restoring the Unit 2 Division 2 AC bus (242Y) from the Unit 1 Division 2 EDG (1A DG) or restoring redundant Division 2 equipment (e.g. Division 2 ECCS or Suppression Pool subsystems).

For the postulated scenario (Unit 1 LOCA and DLOOP with Unit 2 Division 2 EDG (2A) OOS), the Unit 2 Division 2 EDG (2A) is assumed to be OOS. Consistent with the EGC Work Management process, with the Unit 2 Division 2 EDG (2A) OOS, no activities would be scheduled or performed on Unit 2 Division 1, Unit 1 Division 2, or Unit 2 Division 3 AC Electrical power distribution subsystems. For planned activities, TS 3.8.7 Required Action A.1 would only be entered for either Division 1 or 2 AC electrical power distribution subsystems, and not both.

Furthermore, consistent with NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b Risk-Managed Technical Specifications (RMTS) Guidelines," RMTS cannot be voluntarily entered if:

1) the configuration-specific risk exceeds the instantaneous limits of 10-3/year CDF or 10-4/year LERF;
2) the ICDP or ILERP limit has been reached prior to exceeding the frontstop CT; or
3) a total loss of specified safety function for the affected TS system occurs.

If an emergent failure, or degraded or non-conforming condition is discovered for a redundant SSC that results in a total loss of TS specified safety function while the RMTS are in effect, then the RICT is exited and the associated applicable TS Required Actions are considered not met, and subsequent TS required actions are required to be implemented.

No loss of safety functions occurs.

TS 3.8.7.B – DC electrical power distribution subsystem

EGC RESPONSE:

With one or more Division 1 and 2 DC electrical distribution subsystems inoperable and a loss of function has not yet occurred, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure.

In the event the Unit 2 Division 2 DC Electrical power distribution subsystem was inoperable at the time of the postulated scenario (Unit 1 LOCA and DLOOP with Unit 2 Division 2 EDG (2A) OOS) were to occur, the response would be similar to that described in RAI-R2-EEEB 1 response.

LOA-AP-201 would be entered to restore Unit 2 Division 1 AC bus (241Y) from the Division 1 EDG (0 DG) and LOA-AP-201, Attachment K, "Station Blackout Contingencies," would be implemented.

However, in this case, the Unit 2 Division 2 DC Electrical power distribution subsystem may have to be restored to a functional state to allow restoring the Unit 2 Division 2 AC bus (242Y) from the Unit 1 Division 2 EDG (1A DG) and restoring redundant Division 2 equipment (e.g. Division 2 ECCS or Suppression Pool subsystems).

Furthermore, consistent with NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b Risk-Managed Technical Specifications (RMTS) Guidelines," RMTS cannot be voluntarily entered if:

1) the configuration-specific risk exceeds the instantaneous limits of 10-3/year CDF or 10-4/year LERF;
2) the ICDP or ILERP limit has been reached prior to exceeding the frontstop CT; or
3) a total loss of specified safety function for the affected TS system occurs.

If an emergent failure, or degraded or non-conforming condition is discovered for a redundant SSC that results in a total loss of TS specified safety function while the RMTS

are in effect, then the RICT is exited and the associated applicable TS Required Actions are considered not met, and subsequent TS required actions are required to be implemented.

For the postulated scenario, the Unit 2 Division 2 EDG (2A) is assumed to be OOS. Consistent with the EGC Work Management process with the Unit 2 Division 2 EDG (2A) OOS, no activities would be scheduled or performed on Unit 1 Division 2, Unit 2 Division 1, or Unit 2 Division 3 DC electrical distribution subsystems. For planned activities in this configuration, TS 3.8.7 RA B.1 would only be entered for the Unit 2 Division 2 DC electrical power distribution subsystem.

No loss of safety functions occurs.

TS 3.8.7.D – Opposite unit Division 2 AC or DC electrical power distribution subsystem

EGC RESPONSE:

In the postulated scenario (Unit 1 LOCA and DLOOP with Unit 2 Division 2 EDG (2A) OOS), the Unit 1 Division 2 AC and DC electrical power subsystems remains energized from the Unit 1 Division 2 EDG (1A). Unit 1 Division 2 AC and DC electrical power subsystems provide power to ensure redundant Unit 1 Division 2 features (e.g., a standby gas treatment subsystem, Control Room Area Filtration (CRAF) subsystem, Control Room Area Ventilation Air Conditioning (AC) System) will function in the event of a design basis event.

LOA-AP-201 would be entered regarding any loss of AC power that occurred as a result of the postulated scenario and sequence to restore equipment would be as discussed previously in RAI-R2-EEEB 1 response.

Furthermore, consistent with NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b Risk-Managed Technical Specifications (RMTS) Guidelines," RMTS cannot be voluntarily entered if:

1) the configuration-specific risk exceeds the instantaneous limits of 10-3/year CDF or 10-4/year LERF;
2) the ICDP or ILERP limit has been reached prior to exceeding the frontstop CT; or
3) a total loss of specified safety function for the affected TS system occurs.

If an emergent failure, or degraded or non-conforming condition is discovered for a redundant SSC that results in a total loss of TS specified safety function while the RMTS are in effect, then the RICT is exited and the associated applicable TS Required Actions are considered not met, and subsequent TS required actions are required to be implemented.

For the postulated scenario, the Unit 2 Division 2 EDG (2A) is assumed to be OOS. Consistent with the EGC Work Management process with the Unit 2 Division 2 EDG (2A) OOS, no activities would be scheduled or performed on Unit 1 Division 2 AC or DC electrical distribution subsystems. For planned activities in this configuration, TS 3.8.7

Required Action D.1 would not be entered for the Unit 1 Division 2 AC and DC electrical power distribution subsystem.

No loss of safety functions occurs.

RAI-R2 EEEB 3: The LAR also proposes changes to RHR systems or subsystems in TS sections 3.6 and 3.7. For the conditions postulated in Table E1-1, please clarify if procedure LOA-AP-101, "Unit 1, AC Power System Abnormal," would be implemented for the same scenario requiring safe shutdown of the non-accident unit when the TS-indicated Division 2 SSC is in a RICT.

EGC RESPONSE:

In the event the Unit 2 Division 2 RHR system or subsystem identified in TS Sections 3.6 and 3.7 were inoperable at the time of the postulated scenario (Unit 1 LOCA and DLOOP with Unit 2 Division 2 EDG (2A) OOS) were to occur, the response would be similar to that described in RAI-R2-EEEB 1 response.

LOA-AP-201 would be entered to restore Unit 2 Division 1 AC bus (241Y) from the Division 1 EDG (0 DG) and LOA-AP-201, Attachment K, "Station Blackout Contingencies," would be implemented.

Unit 2 (the non-accident unit) Division 1 RHR subsystems would be restored following restoration of Unit 2 Division 1 AC power as described in RAI-R2-EEEB 1 response.

However, Unit 2 Division 2 RHR systems or subsystem identified in TS Sections 3.6 and 3.7 would have to be restored to a functional state to perform its intended function once Unit 2 Division 2 AC power was restored.

The restoration times, as applicable, are identified in Table 1 of Attachment 2. The required loads, affected loading requirements, and power supplies for individual loads are provided in Attachment 3.

For the postulated scenario, the Unit 2 Division 2 EDG (2A) is assumed to be OOS. Consistent with the EGC Work Management process with the Unit 2 Division 2 EDG (2A) OOS, no activities would be scheduled or performed on the Unit 2 Division 1 RHR system or subsystem identified in TS Sections 3.6 and 3.7.

No loss of safety functions occurs.

REFERENCES:

1. Letter from D. Murray (Exelon Generation Company, LLC) to U.S. Nuclear Regulatory Commission, "Application to Revise Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, 'Provide Risk- Informed Extended Completion Times - RITSTF Initiative 4b,' (EPID L-2020-LLA-0018)," dated January 31, 2020.

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

LOA-AP-201 Actions with Descriptions

ATTACHMENT 2
LOA-AP-201 Actions with Descriptions

B.	ACTION/EXPECTED RESPONSE		RESPONSE NOT OBTAINED
B.2	Loss of Bus 241Y		

NOTE

Loss of Bus 241Y results in loss of door interlock power to airlocks F-21 (Doors 402 & 507, U2 710' RB to DG Corridor).

Appropriate administrative controls should be put in place to ensure that the requirements of Tech Spec SR 3.6.4.1.2 are NOT violated. Reference Attachment L.

1.	**CHECK RBCCW header discharge pressure – GREATER THAN 50 psig.**	**1.1** ☞Immediate Action	**START standby RBCCW pump and followup with LOA-WR-201**
Operator recognizes power to standby RBCCW pump is not available and continues.		**1.2** ☞Immediate Action	**If NO RBCCW pumps can be operated, ENTER LOA-WR-201**
2.	CHECK one CRD Pump is running.	2.1	START standby CRD Pump by HOLDING Control Switch to START position for at least 5 seconds, and then release.
Operator recognizes power to standby CRD pump is not available and continues.		2.2	VERIFY proper operation.
		2.3	If in Mode 1, IMMEDIATELY REFER to LOR-2H13-P603-A204, CRD Charging Water Pressure Low, if in alarm.

ATTACHMENT 2
LOA-AP-201 Actions with Descriptions

		2.4	Follow-Up Procedure: LOP-RD-01
3.	CHECK 2A RPS Bus - LIVE.	3.1	PERFORM RPS quick swap hard card.
	Operator recognizes power to alternate RPS is not available and continues. 	3.2	At Panel 2PM16J, DEPRESS Division 1 and Division 2 RE/RF reset pushbuttons.
4.	PERFORM IA to IN Cross-Tie hardcard.		
	Operator recognizes power to cross tie Inst Air to Inst N2 is not available and continues. 		
5.	At Panel 2PM01J, CHECK A214 CLEAR.	5.1	GO TO Attachment A.
	Operator will verify no overcurrent condition exists on Division 1 AC Bus (241Y) 		

NOTE

Even if actual bus voltage is correct, ECCS logic may not allow ECCS pumps to start automatically or manually.

6. At panel 2PM01J, using the 241X-241Y Voltmeter Selector Switch, CHECK all 3 phases of 241Y voltage read approximately the same:
   - AB
   - BC
   - CA
   - INSPECT the switchyard lines and transformer equipment for an open phase, while continuing. See Discussion C.23.

6.1 If voltages are not approximately equal, CHECK any of the following to determine if the bus pot fuses are blown.
   - Bus alive light may not be fully lit.
   - ☞EO INSPECT the UV relays for targets.

Operator will check for no loss of phase on Division 1 AC Bus (241Y) and arrange for switchyard inspection while continuing. No loss of phase exists.

6.2 INITIATE action to inspect / replace the bus pot fuses.

7. IF the 0 DG is running, VERIFY 0 DG CWP is running from Unit 1 power supply.

7.1 Minimize the time the 0 DG is running without the 0 DG CWP.

Operator will check Division 1 EDG Cooling Water Pump powered from Unit 1. Power will be provided from Unit 1.

8. Check 241X - DEAD

8.1 SYNCHRONIZE and CLOSE ACB 2415.

Operator will check Non-Safety Related Bus 241X de-energized. 241X will not be energized due to the loss of offsite power.

8.2 GO TO Step 16.

9. CHECK 242Y - LIVE.

Operator will check Division 2 AC Bus (242Y) energized. 242Y will not be energized due to 2A DG OOS and the loss of offsite power.

9.1 PERFORM the following while continuing at Step 10.

- MONITOR Reactor power using SRMs.
- MONITOR Reactor level using B/C Narrow Range Instruments/Remote Shutdown Instruments.
- MONITOR Reactor pressure using MCR/Remote Shutdown RCIC Steam Supply Pressure Instruments.
- Perform attachment K while continuing in this subsection.

Step provides operator with instrumentation to monitor for Reactor Power, Reactor Water Level and Reactor Pressure. Step also provides direction to perform Station Blackout Contingencies.

10. CHECK 141Y - LIVE.

Operator will check Unit 1 Division 1 AC Bus (141Y) energized. 141Y will be energized from Division 1 DG.

10.1 PERFORM Attachment B while continuing in this procedure.

11. CHECK 241Y-141Y Unit Tie - AVAILABLE

Operator will check Division 1 AC Bus crosstie breakers available (ACB 1414 / 2414). Division 1 AC Bus crosstie breakers will be available with DC control power.

11.1 PERFORM Attachment B.

12.	CHECK 141Y - LIVE from SAT 142.	12.1	If 141Y is live from 0 DG, PERFORM Attachment C.
	Operator will check Unit 1 Division 1 AC Bus (141Y) energized from System Aux Transformer 142 (SAT 142). SAT 142 will not be available with loss of offsite power.		Unit 1 Division 1 AC Bus (141Y) energized from Division 1 EDG (0 DG). Operator directed to perform Attachment C.
		12.2	If 141Y is live from UAT 141, PERFORM Attachment D.

ATTACHMENT C

RESTORE POWER TO 241Y USING UNIT TIE BREAKERS,

0 DG ALIGNED TO UNIT 1

C.	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE

- Required tooling can be found in the LOA locker by the WEC.
- Test jumper continuity prior to installation.
- Maintain jumper separation in accordance with drawing 1E-0-3333. See Discussion C.25.
- Loading the DG beyond the maximum 2600 kW/451 amps continuous rating results in additional fuel oil consumption. This will impact the 7-day supply and may necessitate ordering fuel oil.

CAUTION

Jumpers will be installed on live 120VAC / 125VDC circuits. Electrical precautions must be taken while performing jumper installations.

1. OBSERVE the following maximum DG limits, when re-energizing loads.

   - Continuous Rating, 2600 kW, 451 Amps.

1.1 NOTIFY System Engineering of total time DG exceeds 2860 kW (494 amps).

1.2 START Special Log to monitor load when operating > 451 amps / 2600 kW

Information provided to prevent exceeding EDG continuous ratings.

2. PLACE following breakers on 241Y in PULL-TO-LOCK:

   - ACB 2412, SAT Feed to Bus 241Y.
   - ACB 2415, 241Y/241X Bus Tie Breaker.
   - ACB 2413, 0 DG Feed to Bus 241Y.

Operator directed to place source breakers to Unit 2 Division 1 AC Bus (241Y) in Pull To Lock.

3. PLACE following equipment powered off 241Y in PULL-TO-LOCK:

   - LPCS Pump, 2E21-C001.
   - RHR Pump 2A, 2E12-C002A.

Operator directed to place control switches for equipment powered from Unit 2 Division 1 AC Bus (241Y) in Pull To Lock.

4. VERIFY following breakers powered off Bus 241Y are OPEN:

   - CRD Pump 2A, 2C11-C001A.

- PCCW Chiller 2A, 2VP01CA.
- Reactor Recirculation LFMG Set 2B33-S001A Drive Motor Breaker 2A.
- Bus 241Y Feed to Swgr 233.
- Bus 241Y Feed to Swgr 235X/235Y.

Operator directed to verify breakers powered from Unit 2 Division 1 AC Bus (241Y) are open.

☞EO 5. At Bus 141Y cubicle 12, LIFT lead to defeat trip of ACB 1414.

- DOCUMENT below.
- COMPLETE Attachment AC, when time permits.

BUS/PANEL	TERMINAL	TCCP Tag #	INSTALLED SIGN/DATE	RESTORED SIGN/DATE
141Y, cub 12	AL1		1st /	1st /
			2nd /	2nd /

Reference Drawing: 1E-1-4005AK

Operator directed to defeat Unit 1 Division 1 AC Unit Crosstie Breaker (ACB 1414) trip. ACB 1414 is designed to trip if SAT 142 Feed Breaker ACB 1412 and SAT 242 Feed Breaker ACB 2412 are open and Unit 2 Division 1 AC Unit Crosstie Breaker (ACB 2414) is closed.

☞EO

6. At Bus 141Y cubicle 1, INSTALL > 8" banana jack jumper to defeat ACB 2414 closed permissive interlock. Ensure jumper is a minimum of 14# AWG.

   - DOCUMENT below.
   - COMPLETE Attachment AC, when time permits.

BUS/PANEL	TERMINALS	TCCP Tag #	INSTALLED SIGN/DATE	RESTORED SIGN/DATE
141Y, cub 1	AB18 to AB19		1st /	1st /
			2nd /	2nd /

Reference Drawing: 1E-1-4005AK

Operator directed to defeat Unit 2 Division 1 AC Unit Crosstie Breaker (ACB 2414) closure permissive interlock for Unit 1 Division 1 AC Unit Crosstie Breaker (ACB 1414).

7. At Bus 241Y cubicle 1, LIFT lead to defeat trip of ACB 2414.

☞EO

- DOCUMENT below.
- COMPLETE Attachment AC, when time permits.

BUS/PANEL	TERMINAL	TCCP Tag #	INSTALLED SIGN/DATE	RESTORED SIGN/DATE
241Y, cub 1	AK1		1st /	1st /
			2nd /	2nd /

Reference Drawing: 1E-2-4005AK

Operator directed to defeat Unit 1 Division 2 AC Unit Crosstie Breaker (ACB 2414) trip. ACB 2414 is designed to trip if SAT 142 Feed Breaker ACB 1412 and SAT 242 Feed Breaker ACB 2412 are open and Unit 1 Division 1 AC Unit Crosstie Breaker (ACB 1414) is closed.

8. GO TO Subsection B.2, Step 13.

B. ACTION/EXPECTED RESPONSE RESPONSE NOT OBTAINED

B.2 Loss of Bus 241Y (continued)

13. CHECK ACB 1415 - OPEN.

13.1 IF desired, PERFORM the following to open ACB 1415 to split buses 141Y and 141X:

Operator will check open Unit 1 Non-Safety Related Bus 141X Crosstie Breaker (ACB 1415) open. ACB 1415 will trip open on loss of offsite power.

13.1.1 SYNCHRONIZE and CLOSE ACB 1411, UAT Feed to Bus 141X.

		13.1.2 OPEN ACB 1415, Bus 141X-141Y Tie.
		13.2 If desired, INSTALL jumpers per Attachment E to allow closure of ACB 1414 with ACB 1415 closed.
14.	SYNCHRONIZE and CLOSE ACB 1414.	14.1 PERFORM Attachment B.
	Operator will close Unit 1 Division 1 AC Unit Crosstie Breaker (ACB 1414).	
15.	SYNCHRONIZE and CLOSE ACB 2414.	15.1 PERFORM Attachment B.
	Operator will close Unit 2 Division 1 AC Unit Crosstie Breaker (ACB 2414).	
16.	CHECK 241Y - LIVE.	16.1 GO TO Attachment A.
	Unit 2 Division 1 AC Bus (241Y) is energized.	
17.	RESTORE essential loads.	

ATTACHMENT K

STATION BLACKOUT CONTINGENCIES

19. Within 15 minutes of restoration of a Divisional Bus (241Y or 242Y) ESTABLISH Suppression Pool Cooling per LGA-RH-203.

    - VERIFY RHR system fill and vent.
    - CHECK differential temperature between the lake and the suppression pool.

(Note: Only applicable steps regarding containment cooling included for Attachment K)

Table 1 – SBO Equipment Restoration and Coping Timeline

Time (sec)	Event
Approx. – 0.015	Loss of grid causes turbine generator to detect a loss of electrical load.
0	Turbine trip initiated by loss of generator load. Turbine-generator PLU trip initiates main turbine control valve fast closure. Recirculation system pump motors trip off. Circulating water pump trip. Condensate and condensate booster pump trip. Turbine stop valve closure initiates reactor scram. Electric feedwater pump motor is tripped.
0.01	Turbine control valves closed.
0.10	Turbine steam bypass valves open to regulate pressure.
1.61, 1.76, 1.92, 2.12 and 2.56	Relief valves actuated sequentially by Groups 1, 2, 3, 4 and 5.
Est. 5.1, 5.4, 5.8, 6.0 and 6.9	Relief valves reclose sequentially by Groups 5, 4, 3, 2 and 1.
< 13	Division 3 EDG starts and energizes Bus 243.
30	Loss of condenser vacuum initiates MSIV closure and turbine steam bypass valve(s) closure.
32.4	Reactor vessel low level 2 trip initiates HPCS and RCIC.
50+	Group 1 relief valves automatically cycle to regulate pressure.
< 20 min	Establish Reactor Pressure control with ADS SRV's from Auxiliary Electric Equipment Room (AEER).

ATTACHMENT 2
LOA-AP-201 Actions with Descriptions

Time (sec)	Event
< 20 min	Restore MCR/AEER Ventilation
< 30 min	Open all panel doors in AEER.
< 30 min	Open all panel doors in Main Control Room (MCR).
< 30 min	Initiate DC load shedding per LOA-AP-201 Attachment N (Step 1 & 2).
< 180 min	Secure DC powered lube oil pumps per LOA-AP-201 Attachment N (Step 3).
< 4 hours	Restore AC power to Division 1 or Division 2 AC bus to support restoration of containment cooling.
< 4 hours 15 minutes	Establish Suppression Pool (containment) Cooling.

ATTACHMENT 3
LaSalle County Station, Units 1 and 2
Renewed Facility Operating License Nos. NPF-11 and NPF-18
NRC Docket Nos. 50-373 and 50-374

Load List and Equipment Response During a LOCA

Table 8.3-1, "Loading on 4160-Volt Buses," of LaSalle County Station Updated Final Safety Analysis Report

ATTACHMENT 3
Load List and Equipment Response During a LOCA

Table 8.3-1 of LSCS UFSAR

LOADING ON 4160-VOLT BUSES**

EQUIPMENT	UNIT #1 LOCA	DELAY TIME AFTER ESF BUS IS ENERGIZED (SEC)[1]	UNIT #2 SS	NUMBER INSTALLED UNIT 1	NUMBER INSTALLED UNIT 2	REQUIRED BHP EACH	MINIMUM IMMEDIATE REQUIREMENTS UNIT 1	MINIMUM IMMEDIATE REQUIREMENTS UNIT 2	ESF BUSES (Note 9) UNIT 1 BUS 141Y	UNIT 1 BUS 142Y	UNIT 2 BUS 143	UNIT 2 BUS 241Y	UNIT 2 BUS 242Y	UNIT 2 BUS 243
HPCS pump	X*	0	-	1	1	3050	1	0	----	----	3050	----	----	----
LPCS pump	X	0	-	1	1	1490	1	0	1490	----	----	----	----	----
RHR pump 1C	X	0	X	1	1	765	1	0	----	765	----	----	----	----
RHR pumps 1A & 1B	XX	5	XX	2	2	765	2	1	765	765	----	----	765	----
RHR service water pump	X<>	-	X<>	4	4	200	2	2	400	400	----	----	400	----
Diesel-generator auxiliaries:														
(a) Water pumps	X	0	X	3	2	125/75/77.5	3	2	125	75	77.5	----	75	77.5
(b) Starting air comp.	XXXX	0	XXXX	4	4	12.2/10.7/7.5	4	3	12.2	22.9	7.5	----	22.9	7.5
(c) DG rm. exh. fan	X	0	X	3	2	40/30.2	3	2	40	40	30.2	----	40	30.2
(d) Fuel oil rm. fan	X	0	X	3	2	3	3	2	3	3	3	----	3	3
(e) Fuel oil trans. pump	XXXX	0	XXXX	3	2	5	3	2	5	5	5	----	5	5
(f) Lube oil soak back pump	X	-	X	2	1	0.75	2	1	0.75	0.75	----	----	0.75	----
(g) Engine oil circ pump	X	-	X	2	1	1	2	1	1	1	----	----	1	----

The 250 V Div. 1 and 125 V Div 1 battery charger data above are revised for record.

ATTACHMENT 3
Load List and Equipment Response During a LOCA

Table 8.3-1 of LSCS UFSAR

LOADING ON 4160-VOLT BUSES**

EQUIPMENT	UNIT #1 LOCA	DELAY TIME AFTER ESF BUS IS ENERGIZED (SEC)[1]	UNIT #2 SS	NUMBER INSTALLED UNIT 1	NUMBER INSTALLED UNIT 2	REQUIRED BHP EACH	MINIMUM IMMEDIATE REQUIREMENTS UNIT 1	MINIMUM IMMEDIATE REQUIREMENTS UNIT 2	ESF BUSES (Note 9) BUS 141Y	UNIT 1 BUS 142Y	BUS 143	BUS 241Y	UNIT 2 BUS 242Y	BUS 243
Battery charger - 250 Vdc	X	0	-	1	1	89.8kVA	1	0	102.3	----	----	----	----	----
Battery charger - 125 Vdc	X	0	X	3	3	44.1kVA	2	1	50.3	50.3	----	----	50.3	----
Essential lighting	X	0	X	3	3	27.3kW/ 46kW/ 5kVA/ 22.7kW	3	2	36.6	61.7	6	----	30.5	6
Computer power supply	X	0	X	1 (Note 4)	1 (Note 4)	25kVA	1	0	57	----	----	----	----	----
Aux. equipment room:														
Sup. sys. refrig. comp.	XXXXXX	-	-	1	1	115.1	1	1	----	115.1	----	----	115.1	----
Air cooled cond. fan	XX	Note 5	-	1	1	100	1	1	----	100	----	----	100	----
Supply fan	XX	Note 5	-	1	1	78/76	1	1	----	78	----	----	76	----
Return fan	XX	Note 5	-	1	1	50/46	1	1	----	50	----	----	46	----
Cont. rm. refrig. comp.	XXXXXX	-	-	1	1	90.7	1	1	----	90.7	----	----	90.7	----
Cont. rm. air-cooled cond. fan	XX	Note 5	-	1	1	85.2/71	1	1	----	85.2	----	----	71	----
Hydrogen recombiner power cabinet	XXX	-	-	1	1	100kVA	1	1	---	134	---	---	114	---
Post LOCA containment monitor sample panel	X	-	-	2	2	1	2	0	1	1	---	---	---	---

The 250 V Div. 1 and 125 V Div 1 battery charger data above are revised for record.

ATTACHMENT 3
Load List and Equipment Response During a LOCA

Table 8.3-1 of LSCS UFSAR

LOADING ON 4160-VOLT BUSES**

EQUIPMENT	UNIT #1 LOCA	DELAY TIME AFTER ESF BUS IS ENERGIZED (SEC)[1]	UNIT #2 SS	NUMBER INSTALLED UNIT 1	NUMBER INSTALLED UNIT 2	REQUIRED BHP EACH	MINIMUM IMMEDIATE REQUIREMENTS UNIT 1	MINIMUM IMMEDIATE REQUIREMENTS UNIT 2	ESF BUSES (Note 9) BUS 141Y	UNIT 1 BUS 142Y	BUS 143	BUS 241Y	UNIT 2 BUS 242Y	BUS 243
SLCS tank heater	XXXX	-	XXXX	1	1	10kW	1	0	13	----	----	----	----	----
SLCS pump	X<>	Note 10	XXX	2	2	40kW	1	0	----	----	----	----	----	----
SLCS mixing heater	XXX	-	XXX	1	1	40kW	0	1	----	----	----	----	54	----
Battery room exhaust fans	X	-	X	6	6	1	6	4	2	3	1	----	3	1
Standby gas treatment blower	X	-	X	1	1	20	1	1	----	20	----	----	20	----
Standby gas elect. duct heater	XX	Note 5	XX	1	1	23	1	1	----	30.8	----	----	30.8	----
Standby gas cooling fan	XXXX	-	XXXX	1	1	1.5	1	0	----	1.5	----	----	----	----
RX protection MG set	XXX	-	XXX	2	2	25	0	1	----	----	----	----	25	----
Primary containment vent. sup. fan	XXX	-	XXX	2	2	100	0	1	----	----	----	----	100	----
RX protection MG room supply fan	X	-	X	1	1	20	1	1	----	20	----	----	20	----
Control room supply fan	XX	Note 5	-	1	1	50	1	1	----	50	----	----	50	----
Control room return fan	XX	Note 5	-	1	1	25	1	1	----	25	----	----	25	----
Control room emergency makeup fan	XX	Note 5	-	1	1	15	1	1	----	15	----	----	15	----
Fuel pool emergency makeup pump	XXX	-	XXX	2	2	75	0	0	----	----	----	----	----	----

The 250 V Div. 1 and 125 V Div 1 battery charger data above are revised for record.

ATTACHMENT 3
Load List and Equipment Response During a LOCA

Table 8.3-1 of LSCS UFSAR

EQUIPMENT	UNIT #1 LOCA	DELAY TIME AFTER ESF BUS IS ENERGIZED (SEC)[1]	UNIT #2 SS	NUMBER INSTALLED UNIT 1	NUMBER INSTALLED UNIT 2	REQUIRED BHP EACH	MINIMUM IMMEDIATE REQUIREMENTS UNIT 1	MINIMUM IMMEDIATE REQUIREMENTS UNIT 2	ESF BUSES (Note 9) UNIT 1 BUS 141Y	UNIT 1 BUS 142Y	UNIT 2 BUS 143	UNIT 2 BUS 241Y	UNIT 2 BUS 242Y	UNIT 2 BUS 243
Cleanup recirc. pump	XXX	-	XXX	2 (NOTE 2)	2 (NOTE 2)	55.3	0	1	----	----	----	----	55.3	----
Switchgear heat removal fan	X	-	X	2	2	25	2	1	25	25	----	----	25	----
LPCS & RCIC pumps cub. cooler fan	XXXX	-	XXXX	1	1	25	1	0	25	----	----	----	----	----
RHR pump cubicle cooler fan	XXXX	-	XXXX	2	2	20/25	2	1	20	25	----	----	25	----
LPCS & RHR "A" water leg pump	X	-	X	1	1	7.5	1	0	7.5	----	----	----	----	----
RCIC water leg pump	X	-	X	1	1	7.5	1	0	7.5	----	----	----	----	----
RHR B/C water leg pump	X	-	X	1	1	7.5	1	1	----	7.5	----	----	7.5	----
RHR service water pump cub. fan	XXXX	-	XXXX	2	2	5	2	1	5	5	----	----	5	----
Annunciator supply	X	-	X	2	2	5kVA	2	1	6	6	----	----	6	----
120/208-V dist. pnl. on MCC	X	-	X	9	9	10.5kVA/ 15kVA	8	5	48	68	----	----	85.5	----
Primary containment water chiller	XXX	-	XXX	2	2	600kW	0	0	----	----	----	----	----	----
Control rod drive feed pump	XXX	-	XXX	2	2	300	0	0	----	----	----	----	----	----
HPCS water leg pump	X	-	X	1	1	7.5	1	1	----	----	7.5	----	----	7.5
HPCS - pump cubicle cooler fan	XXXX	-	XXXX	1	1	17	1	0	----	----	17	----	----	17

ATTACHMENT 3
Load List and Equipment Response During a LOCA

Table 8.3-1 of LSCS UFSAR

EQUIPMENT	UNIT #1 LOCA	DELAY TIME AFTER ESF BUS IS ENERGIZED (SEC)[1]	UNIT #2 SS	NUMBER INSTALLED UNIT 1	NUMBER INSTALLED UNIT 2	REQUIRED BHP EACH	MINIMUM IMMEDIATE REQUIREMENTS UNIT 1	MINIMUM IMMEDIATE REQUIREMENTS UNIT 2	ESF BUSES (Note 9) UNIT 1 BUS 141Y	UNIT 1 BUS 142Y	UNIT 2 BUS 143	UNIT 2 BUS 241Y	UNIT 2 BUS 242Y	UNIT 2 BUS 243
Control room emergency makeup air heaters	XX	Note 5	-	1	1	20kW	1	1	----	27	----	----	27	----
Primary containment water chiller pump	XXX	-	XXX	2 (Note 2)	2 (Note 2)	50	0	0	----	----	----	----	----	----
Carbon dioxide refrig. unit	XXXX	-	XXXX	1	0	3	1	0	3	----	----	----	----	----
Laboratory receptacles transformer	XXXXXX	-	XXXXXX	3	0	15.6/ 12kW	3	0	Note 7	Note 7	----	----	----	----
Fire evacuation sirens transformer	X	-	X	1	1	7.5kVA	1	1	----	10	----	----	10	----
HPCS switchgear room supply fan	X	-	X	1	1	13	1	1	----	----	13	----	----	13
HPCS switchgear room exh. fan	X	-	X	1	1	13	1	1	----	----	13	----	----	13
HPCS diesel auxiliaries(Note 6)	XXXX	-	XXXX	1	1	11kW	1	1	----	----	14.7	----	----	14.7
Turbine turning gear	XXXXX	-	XXXXX	1 (Note 2)	1 (Note 2)	60	0	1	----	----	----	----	60	----
Turbine turning gear oil pump	XXXXX	-	XXXXX	1 (Note 2)	1 (Note 2)	50	0	1	----	----	----	----	50	----
Turbine bearing lift pumps	XXXXX	-	XXXXX	8 (Note 2)	8 (Note 2)	5	0	8	----	----	----	----	40	----
Reactor feed pump turb. turbine gear	XXXXX	-	XXXXX	2 (Note 2)	2 (Note 2)	1.5	0	2	----	----	----	----	3	----
Reactor feed pump turb. aux. oil pump	XXXXX	-	XXXXX	1 (Note 2)	1 (Note 2)	2	0	1	----	----	----	----	2	----

ATTACHMENT 3
Load List and Equipment Response During a LOCA

Table 8.3-1 of LSCS UFSAR

EQUIPMENT	UNIT #1 LOCA	DELAY TIME AFTER ESF BUS IS ENERGIZED (SEC)[1]	UNIT #2 SS	NUMBER INSTALLED UNIT 1	NUMBER INSTALLED UNIT 2	REQUIRED BHP EACH	MINIMUM IMMEDIATE REQUIREMENTS UNIT 1	MINIMUM IMMEDIATE REQUIREMENTS UNIT 2	ESF BUSES (Note 9) UNIT 1 BUS 141Y	UNIT 1 BUS 142Y	UNIT 1 BUS 143	UNIT 2 BUS 241Y	UNIT 2 BUS 242Y	UNIT 2 BUS 243
Generator main seal oil pump	XXXXX	-	XXXXX	1 (Note 2)	1 (Note 2)	20	0	1	----	----	----	----	20	----
Generator recirc. seal oil pump	XXXXX	-	XXXXX	1 (Note 2)	1 (Note 2)	7.5	0	1	----	----	----	----	7.5	----
Generator seal oil vac. pump	XXXXX	-	XXXXX	1 (Note 2)	1 (Note 2)	2	0	1	----	----	----	----	2	----
Reactor Bldg. closed cooling water pump	XXX	-	XXX	2 (Note 2)	2 (Note 2)	150	0	0	----	----	----	----	----	----

* Key to symbols used in this table:

X	Loads are energized immediately upon restoration of bus voltage.	Total Coincidental BHP on Each Bus	3251	3182	3244	----	3354	195
XX	Loads are applied automatically in sequence listed above.	Total Motor Output kW = (.746) (BHP)	2425	2374	2420	----	2502	146
XXX	Loads are applied manually by operator as required within diesel-generator rating.	# Total Motor Input kW Based on actual efficiencies for individual loads and includes electrical losses.	2594.1	2580.3	2587	----	2717	166
XXXX	Loads cycle automatically, as required.	Diesel-Generator Rating (kW) (8760-hour maintenance interval)	2600	2600	2600	----	2600	2600
XXXXX	Bus must be manually reenergized by operator before loads can automatically start.	Diesel-Generator Rating-kVA @ 80% PF	3250	3250	3250	----	3250	3250
XXXXXX	Loads must be manually reset locally upon restoration of bus voltage.	Diesel-Generator Rating (kW) (2000-hour maintenance Interval)	2860	2860	2860	----	2860	2860
X<>	Manually started when required.							

**Assumptions:

A. Total loss of plant normal ac auxiliary power
B. Unit 1 in LOCA condition (Note 8)
C. Unit 2 in hot shutdown condition
D. Five diesel-generator sets start
E. Intermittent loads expected to operate for very short periods of time, such as motor-operated valves and sump pumps, are not included in the tabulation since inherent conservatism already contained in the tabulated values more than accounts for these loads.

Notes:

[1]Delay times may exceed those indicated by 2 seconds except for RHR pumps 1A and 1B. The delay time for RHR pumps 1A and 1B may exceed that indicated by 1 second.

[2]Loads have access to ESF buses (manual)

[4]Computer power supplies can be powered from either unit

[5]Delay time is dependent on system component operating times

[6]The following loads are fed from a common source of power: starting air compressor, air compressor dryer, lube oil soak back pump, engine oil circulating pump and 125 Vdc battery charger.

[7]Each laboratory receptacle circuit powered by Regular Lighting Cabinets 27A, 27B and 28 must be individually reset prior to use after a loss of power. The use of these receptacle circuits is expected to be limited after a LOOP/LOCA event and considered intermittent and therefore are not included in the EDG loading Tabulation.

[8]A detailed analysis was completed for the condition where Unit 2 is in LOCA and Unit 1 is in Hot shutdown, coincident with a Loss of Offsite Power (LOOP). The analysis showed minor differences in the ESF bus electrical loadings between Units 1 and 2. However, these differences were a very small percentage of the diesel generator continuous rating.

[9]The numerical electric loading values in this Table are historical. Refer to the most recent version of the DG Loading Calculations for the Current Load values.

[10]The SLCS Pump is started within the first few minutes but no later than 85 minutes following a LOCA and run until the SLCS tank contents are depleted (maximum of 125 minutes).