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Docket Nos.: 50-348

NL-12-1552

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

Joseph M. Farley Nuclear Plant Unit 1
Emergency Technical Specification Revision Request for 3.8.1
AC Sources - Operating

Ladies and Gentlemen:

Pursuant to 10 CFR 50.90 and 10 CFR 50.91(a)(5), Southern Nuclear Operating Company (SNC) hereby requests an emergency amendment to Farley Nuclear Plant (FNP) Unit 1 Technical Specifications (TS), Appendix A to Operating License No. NPF-2. SNC proposes a one-time change to TS 3.8.1, "AC Sources – Operating" Required Action B.4 Completion Time. This request is to add a note allowing a Completion Time of "15 days AND 18 days from discovery of failure to meet LCO," on a one-time basis. This allowance will expire at 21:52 on July 31, 2012.

During performance of a maintenance run following an outage for the 1B Diesel Generator (DG), a deficiency with the intercooler system was identified. The inspections of the 1B DG have identified one piston and one cylinder liner requiring replacement. The damage was most likely caused by overheating of the engine due to mechanical failure of the intercooler heat exchanger thermostatic bypass valve, which must be repaired. The proposed change is required to complete the replacement of the damaged components and return the DG to operable status without requiring a plant shutdown.

Enclosure 1 provides a description and evaluation of the proposed TS changes. Enclosure 2 provides the proposed changes to the current TS on a marked up page. Enclosure 3 provides the proposed TS changes in final typed format. Enclosure 4 provides simplified diagrams of the Electrical Distribution System.

SNC requests approval of the proposed License Amendment prior to 21:52 on July 26, 2012 to avoid a unit shutdown. The amendment will be implemented immediately. SNC has determined that the proposed change meets the requirements of 10 CFR 50.92(c) and does not involve a significant hazards consideration.

This letter contains no Nuclear Regulatory Commission (NRC) commitments. Should you have any questions concerning this submittal, please contact Doug McKinney at (205) 992-5982.

Mr. M. J. Ajluni states he is the Nuclear Licensing Director of Southern Nuclear Operating Company, is authorized to execute this oath on behalf of Southern Nuclear Operating Company, and to the best of his knowledge and belief, the facts set forth in this letter are true.

Respectfully submitted,

Mark J Ajluni

M. J. Ajluni
Nuclear Licensing Director

Sworn to and subscribed before me this 23 *day of* July, *2012.*

Laura L. Crumpton
Notary Public

My commission expires: 11-2-2013

MJA/EMW/ lac

Enclosures:
1. Description and Evaluation of the Proposed TS Changes
2. Proposed Changes to the Current TS on Marked up Pages
3. Proposed TS Changes in Final Typed Format
4. Simplified Diagrams of the Electrical Distribution System

cc: Southern Nuclear Operating Company
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Joseph M. Farley Nuclear Plant Unit 1
Emergency Technical Specification Revision Request for TS 3.8.1
AC Sources - Operating

Enclosure 1

Description and Evaluation of the Proposed TS Changes

Enclosure 1

Description and Evaluation of the Proposed Change

Table of Contents

1.0 Summary Description

This license amendment request is to amend Operating License No. NPF-2 for Farley Nuclear Plant (FNP) Unit 1. The proposed change would revise the Technical Specification (TS) 3.8.1 Required Action B.4 Completion Time, on a one-time basis by adding a footnote to the Completion Time. The proposed note would read:

> "For the 1B Diesel Generator (DG) only, the Completion Time that the DG can be inoperable as specified by Required Action B.4 may be extended beyond the "10 days AND 13 days from discovery of failure to meet LCO" up to "15 days AND 18 days from discovery of failure to meet LCO," to support repair and restoration of the 1B DG. Upon completion of the repair and restoration, this footnote is no longer applicable and otherwise will expire at 21:52 on July 31, 2012."

2.0 Detailed Description

On July 16, 2012 at 21:52 Farley entered voluntary LCO 3.8.1 and took 1B DG out of service for the 24-month maintenance activities. Five days into the Required Action Statement (RAS) maintenance was completed and the DG entered a post maintenance run. Approximately two hours into the run just after reaching full load the diesel tripped on high crank case pressure. Based on initial inspections, abnormal indications were seen on seven of twelve cylinders. Metallic debris believed to be from the piston was found in the lube oil strainer. The current repair plan is included under Section 3.3 below.

An Incident Response Team was formed to investigate the cause of the 1B DG trip. It was determined that the most likely cause of the damage was related to overheating of the engine due to mechanical failure of the intercooler heat exchanger bypass valve. The thermostatic bypass valve did not function properly which prevented adequate cooling of the intercooler system. Surveillance Requirement (SR) 3.8.1.6 was completed to ensure operability of 1-2A DG and no common cause failure. The 1-2A DG 24-hour run surveillance was previously completed satisfactorily on July 9, 2012. All surveillance and testing requirements are current for 1-2A, 2B, and 1C DGs; therefore, these emergency power sources will remain OPERABLE during the requested LCO extension and the station blackout diesel 2C will remain functional.

SR 3.8.1.6 was successfully performed as required by TS to address common cause. However, the extent of condition of the intercooler thermostatic heat exchanger bypass valves for 1-2A and 2B DG should be assessed to ensure reliability of the DGs. Since running of the DGs does not assist in prediction of failure, FNP will perform causal analysis of the 1B DG failure. In addition, to address extent of condition, the 1-2A DG has a scheduled outage later in 2012 in which the thermostatic bypass valve will be inspected and replaced. The 2B DG thermostatic bypass valve was replaced in 2009 and will not be inspected at this time. The results of the causal analysis for 1B DG will be provided to the site NRC senior resident.

The proposed one-time change to the Completion Time of TS 3.8.1, Required Action B.4, is needed to avoid the unnecessary shutdown of the unit due to the additional time required to complete repair of the 1B DG. Emergency AC power is needed whether the unit is shutdown or not and shutting down FNP Unit 1 would incur the inherent risks associated with a shutdown transient. Plant shutdown also reduces the available margin for grid electrical reserve during the current high demand summer period while providing little corresponding safety benefit. Finally, by allowing management to focus on 1B DG repair instead of plant shutdown, repairs can proceed at an expedited pace with a high level of oversight.

By granting the one-time allowance of 15 days for completion of TS 3.8.1 Required Action B.4, unnecessary challenges to plant operations personnel performing plant shutdown will be avoided.

3.0 Technical Evaluation

3.1 System Description:

Offsite Power:

Simplified diagrams of FNP's start up transformers and switchyard arrangement are provided in Enclosure 4. The four startup transformers, two for each unit, are connected to the Alabama Power Company (APC) transmission system through four separate 230-kV oil-static cables. These transformers provide a source of power for startup, shutdown, and after-shutdown requirements for both units. Under normal operating conditions, these startup transformers supply power to 4.16-kV busses A, B, C, D, and E for Unit 1 and D and E only for Unit 2 along with 4.16-kV emergency busses F, G, H, J, K, and L. The unit auxiliary transformer (2B) normally supplies power to 4.16-kV busses A, B, and C of Unit 2. A spare startup transformer, which can be fed by the overhead bus system, is available and can be moved in place in case one of the four startup transformers fails.

The breaker arrangement employed by APC provides breaker-and-a-half protection for all four startup transformers (1A, 1B, 2A, and 2B). A single failure of any electrical component employed by this arrangement will preclude a simultaneous trip of both units due to the loss of one offsite power source and loss of all onsite power. This breaker arrangement provides for greater overall system protection and is designed to minimize the simultaneous failure of the circuits under postulated accident and environmental conditions.

Each circuit supplies power to the associated emergency busses under normal operating conditions, with a provision for supplying the other redundant bus if the second circuit is not available. A simultaneous loss of all onsite AC power supplies and loss of one of the offsite power circuits will fail a maximum of one group of emergency busses. The redundant emergency busses continue to supply the safety-related loads and are designed to shut down the unit safely. Power to the failed emergency busses can be restored in a few seconds by closing the normally open

breaker on the affected emergency bus. An interlock is provided to prevent simultaneous closing of both the normal and standby supply breakers.

Onsite Power:

Simplified diagrams of FNP's electrical distribution system are provided in Enclosure 4. The onsite emergency power supply for Units 1 and 2 is obtained from five diesel generators (1- 2A, 1B, 2B, 1C, and 2C) feeding the 4.16-kV emergency busses. Of these DGs, 1- 2A, 1C, 1B, and 2B are dedicated for use during design basis events. DG 2C is dedicated as the Alternate AC (AAC) power source for station blackout (SBO) events. Three DGs (1-2A, 1C, and 2C) are shared between Units 1 and 2. DGs 1B and 2B are lined up to supply emergency power to Units 1 and 2, respectively. Upon loss of offsite power, the DGs supply the engineered safeguard loads.

A complete train B of safe shutdown loads (LOSP loads) of Unit 1 can be powered by DG 2C as the dedicated AAC source in place of the 1B DG. The starting and unit selection are performed manually by operator actions from the Emergency Power Board (EPB) in the control room. The Unit 1 output breaker (DJ06-1) will close automatically when the 2C DG is running at rated voltage and frequency, when the DG is manually started from the EPB in mode 1 with the Unit Selector Switch in the Unit 1 position. Also, an undervoltage condition must exist on the 1J bus, and the 1B DG output breaker must be open. The Unit 1 train B LOSP shutdown loads are sequenced onto 2C DG by the Unit 1 train B LOSP sequencer automatically. This is identical to the loading of 1B DG with Unit 1 train B LOSP shutdown loads during a LOSP event on Unit 1.

Although 2C DG is the dedicated ACC power source, it still may be used during design basis events if 1B or 2B DG fails. 2C DG does not have the capacity to carry a complete train of LOCA loads for one unit in the event of a LOSP and LOCA, but it can be used to power additional train B loads. The continuous rating for the 2C DG is 2850 kW. The 1B DG continuous rating is 4075kW. Although the 2C DG continuous rating is lower than the 1B DG, the 2C DG is allowed up to 300 hours per year at 3250kW. Guidance is provided to the operators on which loads to manually align and loading requirements for the 2C DG in plant emergency procedures.

In conclusion, FNP electrical design provides multiple and diverse means of supplying both normal and emergency power to 4.16-kV busses.

3.2 Deterministic Justification

The Completion Time extension contained within this submittal is based on a deterministic approach with risk insights provided. The deterministic considerations include Abnormal Operating Procedures (AOPs), grid reliability, weather, redundant equipment and electrical design features, and compensatory measures.

AOPs address the loss of individual 4.16 –kV busses, the loss of station batteries, and in the worst case, Station Blackout. These procedures are

periodically reviewed in licensed and non-licensed operator continuing training. These procedures provide guidance for achieving a safe shutdown. FNP electrical design is flexible and redundant as discussed in Section 3.1. However, it is important to note that plant shutdown does not eliminate the need for DGs since backup electrical power for core cooling is needed.

Grid reliability is improved with Unit 1 online, reducing the chance DG power will be needed. Shutting down FNP Unit 1 would incur the inherent risk associated with a shutdown transient and, further, reduce the available margin for grid electrical reserve during the current high demand summer period while providing little safety benefit given the need of the DGs for all Modes including shutdown Modes.

Management can better focus on 1B DG repair if Unit 1 remains online rather than having to focus on DG repair and plant shutdown. FNP has a success path for repair, including parts, personnel, and vendor support on site. A monitoring program is being developed which will be implemented following engine repair and during DG testing.

The thermostatic bypass valve that malfunctioned is not the same design as installed on 1C and 2C DGs. As stated in section 2.0 above, TS SR 3.8.1.6 has been completed to ensure operability of 1-2A DG and no common cause failure.

SR 3.8.1.6 was successfully performed as required by TS to address common cause. However, the extent of condition of the intercooler thermostatic heat exchanger bypass valves for 1-2A and 2B DG should be assessed to ensure reliability of the DGs. Since running of the DGs does not assist in prediction of failure, FNP will perform causal analysis of the 1B DG failure. In addition, to address extent of condition, the 1-2A DG has a scheduled outage later in 2012 in which the thermostatic bypass valve will be inspected and replaced. The 2B DG thermostatic bypass valve was replaced in 2009 and will not be inspected at this time. The results of the causal analysis for 1B DG will be provided to the site NRC senior resident.

A long range weather forecast has been reviewed and no indication of tropical storms exists, only typical afternoon thunderstorms are predicted.

3.3 Repair Details and Return to Service Timeline

Below are the remaining major milestones for repair of the 1B DG and timeline:

1. Maintenance complete on all cylinders to support Lube Oil flush — 24 Jul 1900
2. Engine auxiliaries reassembled and Lube Oil flush completed to support engine break in runs — 26 Jul 1000
3. Commence performance of maintenance runs — 26 Jul 2200
4. Complete maintenance runs — 28 Jul 1900
5. Commence Operability surveillance test — 28 Jul 2300
6. Exit LCO — 29 Jul 0500

3.4 Risk Insights, Configuration Controls, and Compensatory Measures

The proposed change is not based directly on any risk-informed approach. However, SNC did use plant-specific internal event and fire probabilistic risk assessment (PRA) models, as well as qualitative methods for external events, to provide risk insights. These insights were used to enhance existing compensatory actions and ensure plant risk is minimized. The FNP internal events model is a fully functional Regulatory Guide (RG) 1.200 compliant model. However, the fire PRA model was specifically developed to support NFPA-805 and as a result does not reflect the current plant configuration and therefore should only be used for risk insight.

External Event Risk

The Individual Plant Examination of External Events (IPEEE) was performed as a one-time assessment of the impact of external events and is not periodically updated. SNC is developing a state-of-the-art fire PRA model but it is not yet ready to support detailed risk calculations required for this Emergency TS change. Also, a full update of the IPEEE fire PRA model to incorporate changes in methodology and plant modification would be manpower intensive and could not be completed in the time frame needed. Therefore, the IPEEE results are used to obtain qualitative risk insights due to the proposed TS change for the 1B DG.

Seismic Hazard

The seismic risk increase due to the 1B DG unavailability is judged to be negligible on the following bases:

- Due to low seismic hazard, FNP is categorized as a reduced scope plant. Therefore, the baseline seismic risk is judged to be minimal.
- The FNP IPEEE study did not identify any seismic vulnerabilities.
- In general seismic events are considered to result in non-recoverable loss of offsite power events. Therefore, it can be assumed that seismic-induced loss of offsite power would present a challenge to the 1B DG unavailability. However, it is judged that this challenge (increase in risk) is bounded by the risk-increase due to a traditional grid-induced loss of offsite power or a fire-induced loss of offsite power on the basis that:

    - during a low severity seismic event, the diesels and other safety related components are not likely to fail due to the seismic event (i.e., safety related components are designed to a higher standard than offsite power related components).
    - during a high severity seismic event, current seismic models assume full correlation for similar, redundant trains. Therefore, if the seismic event is severe enough, all DGs would be assumed to fail and the unavailability of one diesel is not risk significant.

- the frequency of seismic-induced loss of offsite power is lower than the frequency of the traditional or fire-induced loss of offsite power.

Other External Hazards

In addition to internal fires and seismic events, the FNP IPEEE analysis of external hazards, resulting from high winds, external floods, and transportation and nearby facilities accidents was accomplished by using a progressive screening approach described in NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities." No vulnerabilities were identified for FNP as a result of these evaluations. In addition, no other plant-unique external event was identified that poses any significant threat of severe accident within the context of the screening approach for "High Winds, Floods, and Others" provided by NUREG-1407. As such these hazards were determined to be negligible contributors to the overall plant risk.

Configuration Controls - Avoidance of Risk-Significant Plant Configurations

This section is intended to provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when equipment is out of service. SNC plants have a configuration risk management program (CRMP) for compliance to the Maintenance Rule (10 CFR 50.65), and in particular, for compliance with paragraph (a)(4) of the rule. The CRMP provides assurance that risk significant plant equipment configurations are precluded or minimized when equipment is removed from service. Therefore, any risk increase posed by removal of a DG from service and the potential combinations of other equipment out of service are managed in accordance with the CRMP.

Adhering to the current risk management program in combination with current TS requirements and procedures will prevent risk-significant configurations from occurring. Therefore, there is reasonable assurance that risk-significant plant equipment configurations will not occur while the 1B DG is out of service for this one-time proposed change. No other changes to the TSs or procedures are required as the result of this proposed TS change.

Configuration Controls - Risk-Informed Configuration Risk Management

This section documents plant processes which ensure the risk impact of equipment is evaluated prior to removing the equipment from service or performing any maintenance activity. As stated in RG 1.177, "a viable program would be one that is able to uncover risk-significant plant equipment outage configurations as they evolve during real-time, normal plant operation." This is an extension of avoiding risk significant plant configurations described above, but addresses the limitation of not being able to identify all possible risk-significant plant configurations in the second-tier evaluation.

SNC has developed a process for online risk assessment and management. Following plant processes and procedures ensures that the risk impact of equipment unavailability is appropriately evaluated prior to performing any maintenance activity, or following an equipment failure or other internal or external event that impacts risk. Nuclear management procedure NMP-OS-010, "Protected Train/Division and Protected Equipment Program," provides guidance for managing safety function, probabilistic, and plant trip risks as required by 10 CFR 50.65(a)(4) of the Maintenance Rule. The procedure addresses risk management practices in the maintenance planning phase and maintenance execution (real time) phase for Modes 1 through 4. Appropriate consideration is given to equipment unavailability, operational activities such as testing, and weather conditions.

In general, risk from performing maintenance on-line is minimized by:

- Performing only those preventive and corrective maintenance items on-line required to maintain the reliability of systems, structures or components (SSCs).
- Minimizing cumulative unavailability of safety-related and risk-significant SSCs by limiting the number of at-power maintenance outage windows per cycle per train/component.
- Minimizing the total number of SSCs out of service at the same time.
- Minimizing the risk of initiating plant transients (trips) that could challenge safety systems by implementing compensatory measures.
- Avoiding higher risk combinations of out of service SSCs using PRA insights.
- Maintaining defense-in-depth by avoiding combinations of out of service SSCs that are related to similar safety functions or that affect multiple safety functions.
- Scheduling in train/bus windows to avoid removing equipment from different trains simultaneously.

In general, risk is managed by:

- Evaluating plant trip risk activities or conditions and mitigating them by taking appropriate compensatory measures and/or ensuring defense-in-depth of safety systems that are challenged by a plant trip.
- Evaluating and controlling risk based probabilistic and key safety function defense-in-depth evaluations.
- Implementing compensatory measures and requirements for management authorization or notification for certain "high-risk" configurations.

Actions are taken and appropriate attention is given to configurations and situations commensurate with the level of risk. This occurs both during planning and real time (execution) phases.

For planned maintenance activities, an assessment of the overall risk of the activity on plant safety, including benefits to system reliability and performance, is currently performed and documented prior to scheduled work. Consideration is given to plant and external conditions, the number of activities being performed concurrently, the potential for plant trips, and the availability of redundant trains.

Risk is evaluated, managed and documented for all activities or conditions based on the current plant state:

- Before any planned or emergent maintenance is to be performed.
- As soon as possible when an emergent plant condition is discovered.
- As soon as possible when an external or internal event or condition is recognized.

Compensatory measures are implemented as necessary and if the risk assessment reveals unacceptable risk, a course of action is determined to restore degraded or failed safety functions and reduce the probabilistic risk.

Compensatory Measures

During the period of the extended out-of-service time, the A train of emergency power will remain OPERABLE (DG set 1-2A and 1C), both qualified offsite circuits will remain OPERABLE, and SBO DG (2C) on the B train of emergency power will remain functional. The Operations department trains on various scenarios relating to loss of power and off-normal plant conditions. The control room crew is familiar with this configuration and the limitations on an emergency bus with only one DG available.

The following risk management measures will be implemented to increase operator awareness of critical equipment, provide reasonable assurance that the assumptions in the risk model are maintained, and minimize the likelihood of a transient for the duration of 1B DG out of service time. A review of dominant cut sets from the internal events (including flooding) and the FPRA was conducted. As expected, the majority of the risk increase from the unavailability of the 1B DG is due to the increase from the loss of offsite power initiating event. Contribution from these hazards is significantly reduced by implementing the following compensatory measures:

1. The following equipment will be protected in accordance with the procedure NMP-OS-010, "Protected Train/Division and Protected Equipment Program," during the extended out of service time for 1B DG. The Protected Equipment Program requirements include 1) posting of protected equipment with signs and barriers to prevent inadvertent operation; 2) no routine work activities on protected equipment; and 3) Shift Manager approval for any emergent work involving protected equipment.

- Emergency Diesel Generators rooms for 1C, 1-2A and 2C.
- Emergency Diesel Generators Mode Selector Switch for 1C and 1-2A DG on the Emergency Power Board in the control room
- Unit 1 A train DC Switchgear Room
- Unit 1 A Train Battery Chargers
- 1A Auxiliary Builiding Battery Room
- Unit 1 A and B Train 4160V Emergency Switchgear Rooms
- Unit 1 A train Motor Driven Auxiliary Feedwater Pump
- Unit 1 Turbine Driven Auxiliary Feedwater Pump
- Unit 1 A train Service Water Pumps
- Unit 1 A train Residual Heat Removal pump
- Unit 1 A train Charging Pump.
- Unit 1 A train Component Cooling Water Pump
- Diesel Driven Fire Pump
- Unit 1 Main Transformers
- Unit 1 Start-Up Transformer

2. Increased administrative control will be exercised for any proposed hot work in the vicinity of protected equipment and in the impacted fire zones 0335/0343 (Train A Switchgear Room), 0318 (Cable Spreading Room), 1-080G (Start-up Transformer 1A), 1-080H (Start-up Transformer 1B), 1-085 (Turbine Building General Area) and 1-088 (Turbine Building Switchgear Room).

3. No planned maintenance on fire detection or fire suppression equipment that will impact the fire detection or fire suppression equipment in the impacted fire zones listed in item 2.

4. Transient combustible loading in these areas (item 2) will be reviewed and any unnecessary transient combustibles will be removed.

5. The plant Operations crew and Maintenance staff will be briefed on these risk management measures.

6. Operations will monitor weather conditions to assess potential impacts on plant conditions due to adverse weather conditions.

7. Maintenance and surveillance activities which could increase the risk of a Main Turbine trip or Reactor trip will be avoided.

8. Work on any activity that could impact loss of offsite power availability will be avoided. For example, all switchyard related activities with potential to result in the loss of offsite power shall be postponed. This reduces the frequency of the random loss of offsite power initiating event. Additionally, FNP has procedure NMP-GM-021, "Switchyard Access and Maintenance Controls," to control work in the switchyard.

9. Roving fire watches will reduce the frequency of damaging fires.

    - Zone 0335/0343: A Train Switchgear Room - Fire watch in these zones, specifically focused on preventing the fire originating from Bus 1F for early suppression of the fire.

    - Zone 1-080G/1-080H: Start-up Transformers - Fire watch for early actuation of fire suppression to prevent the damage to overhead cables.

    - Zone 1-085: Turbine Building General Area - Fire watch at the 125V DC Distribution Cabinet 1J.

10. Operator actions will improve mitigation capability and will be reviewed at the start of each shift as a Standing Order.

    - Each shift operators will review actions per procedure for alignment of DG 2C to power Bus 1G through Bus 1J. This will reduce risk for fire-induced and random events in the event of a loss of power to 1G bus.

11. The following compensatory actions will improve mitigation capability for fire risk in specific areas:

    - Zone 0335/0343: Train A Switchgear Room

        - Each shift operators will review actions per procedure to cross-connect offsite power from Start up Transformer 1A to Bus 1G.
        - Each shift operators will review actions per procedure to terminate a spurious SI signal and to establish charging.

    - Zone 1-080G/1-080H: Start-up Transformers and 1-085/1-088: Turbine Building General Area and Switchgear Room

        - Maintain operability of DG 1-2A.
        - Each shift operators will review actions per procedure for DG 1C connection to the Bus 1F through Bus 1H.

4.0 Regulatory Evaluation

4.1 Significant Hazards Consideration

SNC has performed a "no significant hazards consideration determination" for the proposed amendment focusing on the three standard considerations

as set forth in 10 CFR 50.92 (c), "Issuance of Amendment," as described below:

1. Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The proposed license amendment introduces a one-time 15 day completion time allowance for TS 3.8.1, Required Action B.4. The proposed change does not alter any plant equipment or operating practices in such a manner that the probability of an accident is increased. The proposed change will not alter assumptions relative to the mitigation of an accident or transient event. Therefore, the proposed completion time does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed amendment create the possibility of a new or different kind of accident from any previously evaluated?

Response: No.

The proposed amendment makes a one-time allowance of a 15 day completion time for TS 3.8.1 Required Action B.4. The proposed amendment does not introduce any new equipment, create any new failure modes for existing equipment, or create any new limiting single failures. The plant equipment considered when evaluating the existing completion time remains unchanged. The 2C DG availability as a compensatory measure is not considered to be new equipment since it was previously installed in the plant and has procedural guidance for aligning it to supply emergency busses. The extended completion time will permit completion of repair activities without incurring transient risks associated with performing a shutdown with one DG unavailable. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed amendment involve a significant reduction in the margin of safety?

Response: No.

The proposed license amendment makes a one-time allowance of a 15-day completion time for TS 3.8.1 Required Action B.4. The proposed completion time has been evaluated as discussed in the deterministic arguments above. The proposed compensatory measures provide reasonable assurance that no significant reduction to the margin of safety will occur.

Based on the above, SNC concludes that the proposed change presents no significant hazards consideration under the standards set forth in 10 CFR

50.92(c), and accordingly, a finding of "no significant hazards consideration" is justified.

4.2 Applicable Regulatory Requirements/Criteria

The changes proposed by this license amendment request have been evaluated based on the following criteria:

Offsite Power
The system of lines, switchyards, and transformer connections are planned around the requirements of General Design Criterion (GDC) No. 17 and RG 1.32 and are considered to meet the requirements of these criteria for the offsite power system. The design of the switchyard and connections to the plant are considered to meet the requirements of GDC No. 18 as applicable to the offsite power system.

Onsite Emergency Power Systems
The onsite emergency ac power supply for Units 1 and 2 consists of five diesel generators which supply standby power for 4160-V emergency busses F, G, H, J, K, and L of each unit when offsite power is unavailable. These busses provide power to the emergency loads. As documented in Section 8.3.3 of NUREG 0117, Supplement 5 to NUREG-75/034 dated March 1981, the NRC acceptance criteria associated with the design of the DGs and their auxiliary systems is contained in GDC 17, 18, 21, and NUREG/CR-0660.

The proposed amendment does not alter FNP's compliance with the intent of the criterion above. The one-time allowance of a 15 day completion time for TS 3.8.1 Required Action B.4 does not change the requirement to restore the inoperable DG to operable status.

4.3 Conclusion

In conclusion, based upon the considerations described above:

1. there is reasonable assurance that the health and safety of the public will not be adversely affected by operation in the proposed manner,
2. such activities will be conducted in compliance with the Commission's regulations,
3. the issuance of the amendment will not be detrimental to the common defense and security or to the health and safety of the public.

5.0 Environmental Consideration

SNC has evaluated the proposed amendment change and determined the changes do not involve (i) a significant hazards consideration, (ii) a significant change in the types or a significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or

environmental assessment need be prepared in connection with the proposed amendment.

6.0 References

1. Farley FSAR, Rev. 24, June 2012, Sections: 8.1.2, 8.3.1.1.7.3, 8.2.1.3
2. Farley Unit 1 & 2 Technical Specifications, Rev. 188/183, Section 3.8.1, "AC Sources - Operating"
3. Farley Unit 1 and 2 Environmental Protection Plans, Rev. 90/83, Including Appendix "B."
4. Regulatory Guide 1.177, Revision 1, "An Approach for Plant-Specific, Risk-Informed Decision making: Technical Specifications."
5. Regulatory Guide 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-informed Activities"
6. NMP-OS-010, "Protected Train/Division and Protected Equipment Program"
7. NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities"

Joseph M. Farley Nuclear Plant Unit 1
Emergency Technical Specification Revision Request for TS 3.8.1
AC Sources - Operating

Enclosure 2

Proposed Changes to the Current TS on Marked up Pages

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.3.2	Perform SR 3.8.1.6 for OPERABLE DG set.	24 hours
	AND		
	B.4	Restore DG set to OPERABLE status.	10 days AND 13 days from discovery of failure to meet LCO *
C. Two required offsite circuits inoperable.	C.1	Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required features
	AND		
	C.2	Restore one required offsite circuit to OPERABLE status.	24 hours

* For the 1B Diesel Generator only, the Completion Time that the DG can be inoperable as specified by Required Action B.4 may be extended beyond the "10 days AND 13 days from discovery of failure to meet LCO" up to "15 days AND 18 days from discovery of failure to meet LCO," to support repair and restoration of the 1B DG. Upon completion of the repair and restoration, this footnote is no longer applicable and otherwise will expire at 21:52 on July 31, 2012.

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Enclosure 3

Proposed TS Changes in Final Typed Format

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.3.2	Perform SR 3.8.1.6 for OPERABLE DG set.	24 hours
	AND		
	B.4	Restore DG set to OPERABLE status.	10 days AND 13 days from discovery of failure to meet LCO *
C. Two required offsite circuits inoperable.	C.1	Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required features
	AND		
	C.2	Restore one required offsite circuit to OPERABLE status.	24 hours

* For the 1B Diesel Generator only, the Completion Time that the DG can be inoperable as specified by Required Action B.4 may be extended beyond the "10 days AND 13 days from discovery of failure to meet LCO" up to "15 days AND 18 days from discovery of failure to meet LCO," to support repair and restoration of the 1B DG. Upon completion of the repair and restoration, this footnote is no longer applicable and otherwise will expire at 21:52 on July 31, 2012.

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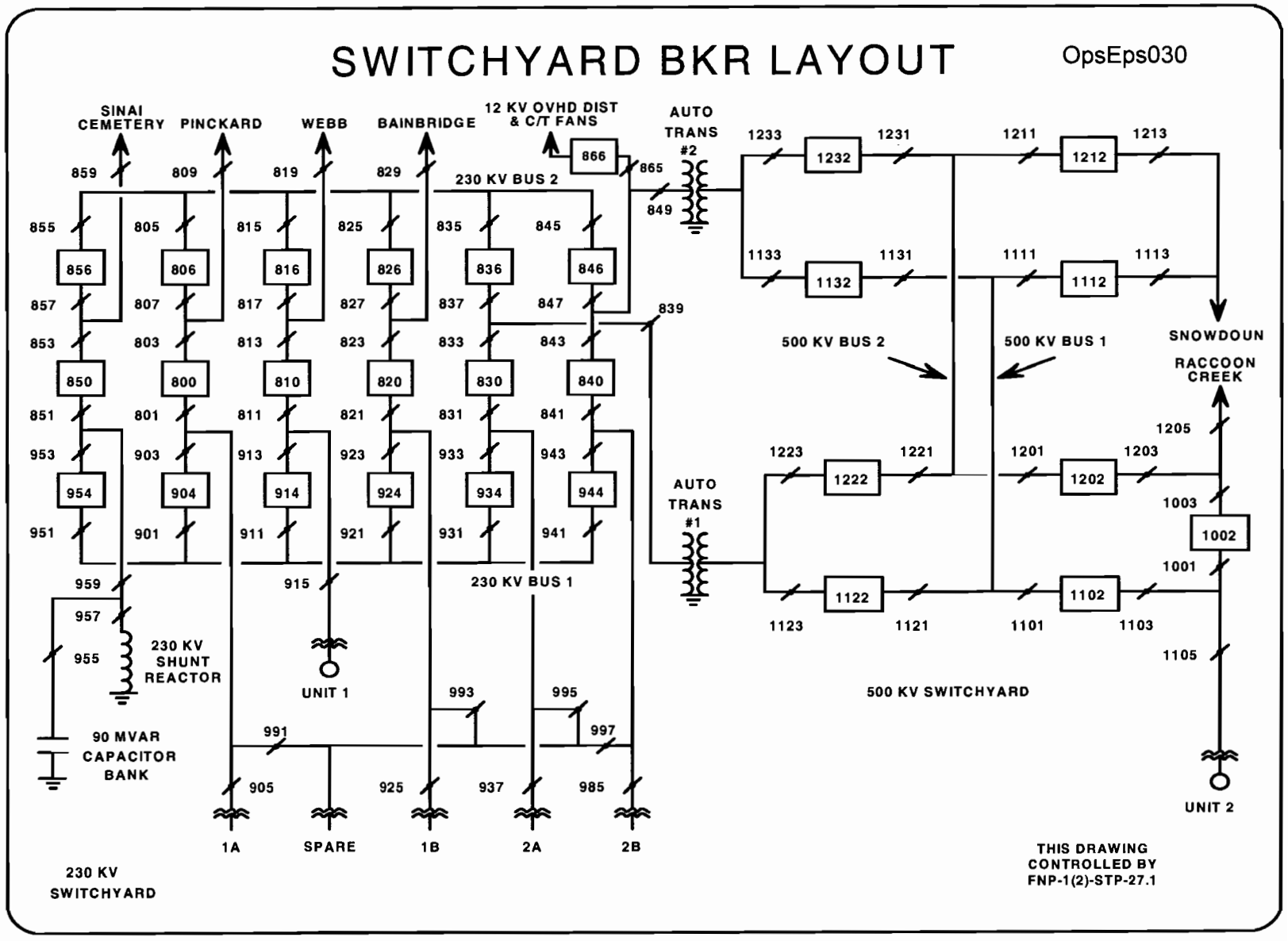
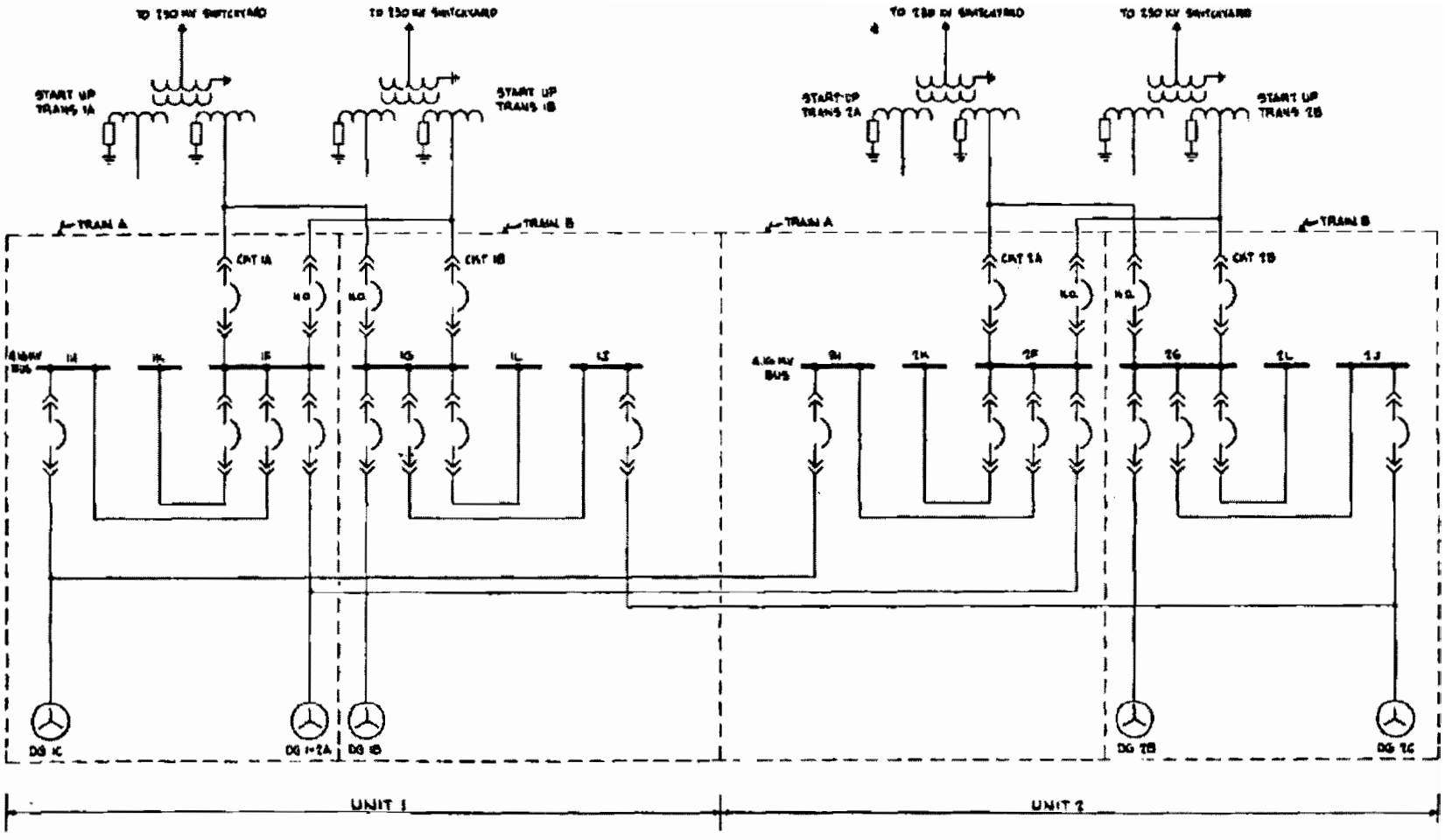
Enclosure 4

Simplified Diagrams of the Electrical Distribution System

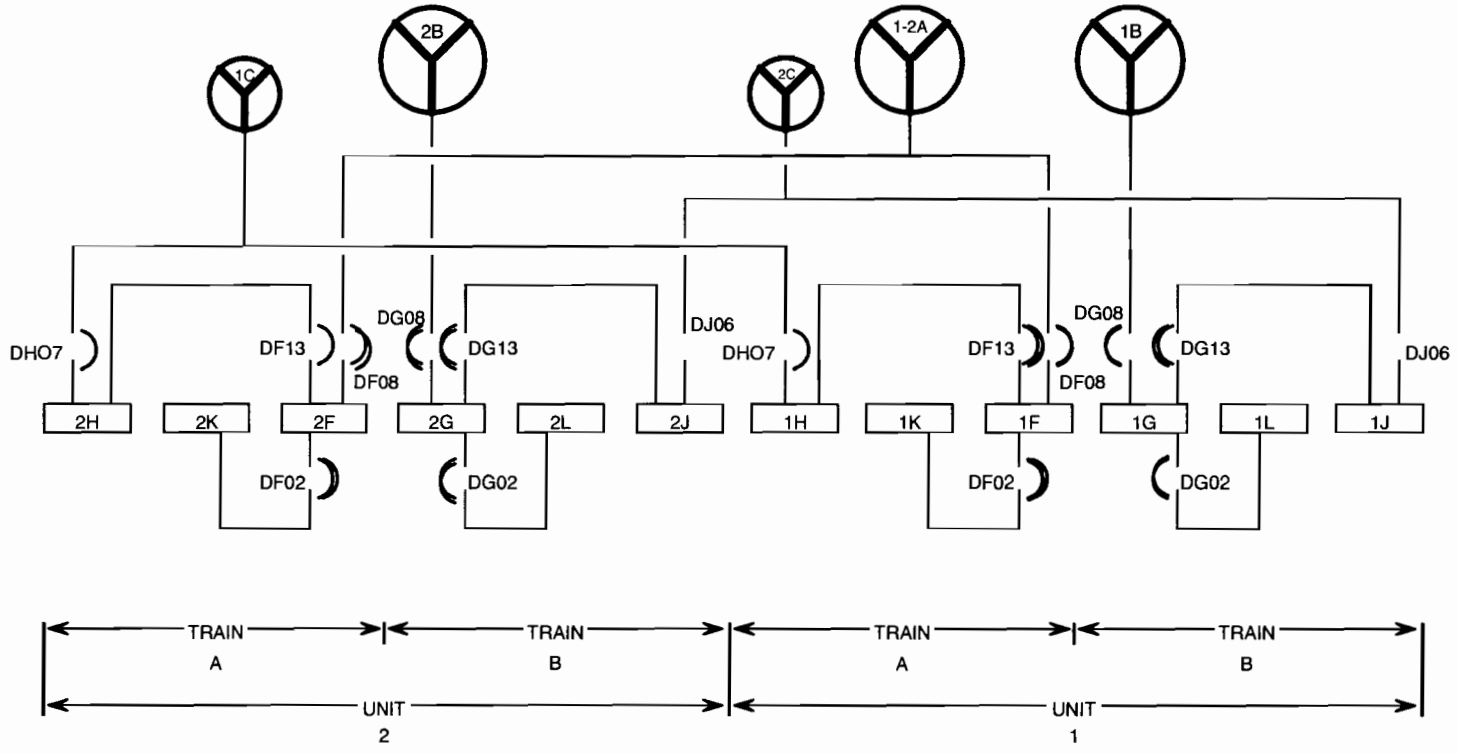


SWITCHYARD ARRANGEMENT



START UP TRANSFORMERS

OpsDgs040



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