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NUCLEAR ENERGY INSTITUTE

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Mr. Eric Benner
Director, Division of Engineering
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Subject: Summary of Information Provided at the October 17, 2018 Public Meeting Associated with Implementation of Open Phase Isolation Systems (OPIS) - ML18271A111

Project Number: 689

Dear Mr. Benner:

The Nuclear Energy Institute (NEI),[1] on behalf of its industry members, appreciates the opportunity to provide input to the staff's technical evaluation of the Open Phase Isolation System (OPIS) modifications, including the discussion at the public meeting on October 17, 2018. The meeting was an important forum for the industry to discuss with NRC staff their observations and questions concerning the implementation of the open phase isolation systems. The information presented during the public meeting was intended to support the staff's evaluation of licensee implementation of the NEI Open Phase Condition Initiative, or Voluntary Industry Initiative (VII).

The staff's observations and questions were categorized in four topics of interest: (1) Open Phase Condition (OPC) detection and alarm, (2) OPC protective action, (3) updated final safety analysis report update, and (4) surveillance and limiting condition for operation requirements. NEI, along with industry members, presented responses to each of these questions during the public meeting. As a follow-up to the industry presentation and discussions at the meeting, this letter and attachment are provided to document the information provided to the staff.

[1] The Nuclear Energy Institute (NEI) is responsible for establishing unified policy on behalf of its members relating to matters affecting the nuclear energy industry, including the regulatory aspects of generic operational and technical issues. NEI's members include entities licensed to operate commercial nuclear power plants in the United States, nuclear plant designers, major architect and engineering firms, fuel cycle facilities, nuclear materials licensees, and other organizations involved in the nuclear energy industry.

If you have questions or need additional information, please contact Frances Pimentel (202-739-8132; fap@nei.org) or me (202-739-8111; seg@nei.org).

Sincerely,

Stephen Geier

Attachment

cc: Mr. Ho Nieh, NRR, NRC
Mr. Brian J. McDermott, NRR, NRC
Mr. Jessie F. Quichocho, NRR/DE/EEOB, NRC
Ms. Leslie Perkins, NRR, NRC

Attachment 1

Summary of Answers Provided During Public Meeting on October 17, 2018

The questions cited below were those provided by the NRC prior to the meeting (ML18271A111) to help focus the discussion and interaction. The responses provided reflect the information included on the industry slides (ML18289A992) provided at the 10/17/18 public meeting (ML18277A137) supplemented with some additional information provided during the discussions.

1 - Open Phase Condition (OPC) Detection and Alarm

Questions:

None.

The proposed OPC detection and alarm design schemes appeared technically adequate to detect and alarm in the main control room in the event of an unbalanced voltage from an OPC.

2 - OPC Protective Actions

Questions:

a. What actions are being taken to mitigate the potential consequences resulting from a potential OPIS failure? How do these actions meet the OPC VII criteria?

b. If there was a failure of the OPIS, how would the plant meet the provisions for single failure of the onsite power system to mitigate against Design Basis Accidents (DBAs)? If so, describe how.

Response:

The potential failure of the OPIS is mitigated by both design features and response actions. From a design perspective the OPIS typically fails in a non-trip state in that it will not result in the loss of the offsite power circuit or affect the functionality of connected equipment. If the OPIS spuriously actuates, the consequences are bounded by the response of the existing protective relaying system associated with the offsite power system. The affected source would be isolated, and the plant response would respond as designed—i.e., the load would be transferred to standby sources. Further, existing relaying, e.g., ground fault protection, neutral overcurrent protection and degraded voltage protection, will be able to detect certain open phase conditions. Therefore, even with the OPIS not functional and without operator actions, certain open phase conditions can still be detected.

From a mitigation perspective the operators are alerted to an OPIS failure or malfunction via the Main Control Room (MCR) alarm(s). The typical OPIS is self-checking and capable of indication upon failure or malfunction. Given the indication of a failure or malfunction, the operators would implement corresponding mitigative measure per alarm response and/or other procedures. For example, the interim measures, including operator training, similar to those implemented prior to installation of OPIS (e.g., operator rounds, monitoring bus voltages, etc.) would be implemented.

From a repair perspective, each station's Corrective Action Program would minimize the time that OPIS is non-functional. Failures are screened and assigned a significance level based on specific site criteria and procedures to ensure issues are resolved within days to weeks depending on the type of failure, plant risk and electric power system configuration requirements. Additionally, a non-functional relay would be identified as an "Unresolved Maintenance Issue" per North American Electric Reliability Corporation (NERC) Standard PRC-005-6, if applicable, that would require the site to take action to correct the issue further ensuring a timely repair. Operating experience from our industry members indicates that these relays are highly reliable.

These actions meet the OPC VII criteria since the OPIS failures described previously either do not affect offsite power availability or are bounded by the response of the existing protective relaying system to malfunctions. Per the VII, OPIS is designed to minimize misoperation that could cause spurious separation from an operable off-site General Design Criteria (GDC) 17 source. An OPIS failure, which could cause spurious actuation, results in actions that are bounded by current design and licensing basis—e.g., LOOP. Also, interim measures are implemented until OPIS is restored.

An OPC, OPIS failure and a DBA are independent events and the simultaneous occurrence of three independent events is not considered credible. Therefore, an OPIS failure does not affect the plant's ability to mitigate a DBA given a single failure in the onsite power system, since OPIS failures either do not affect offsite power availability or are bounded by the response of the existing protective relaying system to malfunctions—spurious actuation. As such, OPIS is an enhancement to the electric power system design on the offsite power circuit and the single failure criterion, as defined in IEEE 279 and IEEE 603, is not applicable to OPIS since these systems do not scram or trip the reactor or actuate any engineered safety features.

Table 1 in the NEI Regulatory Summary Document dated March 2016 (ML16091A100) identifies applicable failure scenarios including single failure criteria in the onsite power system. A summary for each scenario in the table is provided below:

- Scenario #1: An OPC occurs on an offsite power circuit and is isolated by the OPIS which is functional. Loads are transferred to a healthy source and the onsite power system remains operable.
- Scenario #2: A single train of the onsite power system is inoperable with the other remaining operable. OPIS and the offsite power system are both functional.
- Scenario #3: OPIS is non-functional and unable to isolate an OPC – notification is provided in the MCR of the failure. The affected offsite power circuit is operable but temporary interim measures are implemented until OPIS is restored. The onsite power system remains operable.

- Scenario #4: OPIS malfunctions and spuriously isolates one offsite power circuit. Loads are transferred to a healthy source and the onsite power system remains operable.

Additionally, the loss-of-single-phase event is not explicitly modeled in the current Probable Risk Analysis (PRA) model of record. Adding it to the PRA would be expected to have the effect described in the table below. The data table was developed by a study preformed from the Byron event. Note that without any of the current tools for manual open phase detection and without operator awareness at Byron, the event lasted eight minutes but did not result in any equipment damage.

Table 1: A Comparison of CDF Impact as a Function of OPC Configurations

Condition	Failures Modeled	Increase in CDF	
Pre-Event	Operator action	3E-6	~7.5%
Current Configuration	Alarm or operator action	6E-7	~1.5%
Planned Configuration	Automatic actuation and operator backup	1E-8	~0.03%

3 - Updates to the Updated Final Safety Analysis Report (UFSAR)

Questions:

What is NEI's expectations for updates to UFSAR with regard to the level of technical content detail and schedule for implementation? What is sufficient detail to reflect the licensing basis for protection against OPCs? Could you provide examples?

Response:

It is expected that licensees update their UFSAR by following NRC-endorsed guidance for adding new information to the UFSAR and complying with 10 CFR 50.71(e). Specifically, NEI 98-03[2], "Guidelines for Updating Final Safety Analysis Reports," Revision 1, Section 6.2, "Level of Detail for FSAR Updates," states:

> "... The description shall be sufficient to permit understanding of the system designs and their relationship to safety evaluations." As described in 1980 FSAR update rule, "The level of detail to be maintained in the UFSAR should be at least the same as originally provided. Thus, existing UFSAR information of a similar nature may provide a guide for determining the level of detail for new information to be included in UFSAR Updates. However, the primary consideration in determining the level of detail for new information is whether updated information is sufficient to permit understanding of new or modified safety analyses, design bases and facility operation."

A visual representation of the relationship of Design Bases and Supporting Design Information to the UFSAR and Licensing Basis was provided in industry slides at the 10/17/18 public meeting that depicted

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[2] NEI 98-03, "Guidelines for Updating Final Safety Analysis Reports," Revision 1 (ML15089A319); endorsed by Regulatory Guide 1.181, "CONTENT OF THE UPDATED FINAL SAFETY ANALYSIS REPORT IN ACCORDANCE WITH 10 CFR 50.71(e)"

how the licensing basis is made up of a combination of sources including commitments and supporting design information such as design calculations and engineering change packages.

The schedule for updating the UFSAR is guided by 10 CFR 50.71(e)(4) which specifies,

> "Subsequent revisions must be filed annually or 6 months after each refueling outage provided the interval between successive updates does not exceed 24 months. The revisions must reflect all changes up to a maximum of 6 months prior to the date of filling ..."

Also, per the VII, licensees are expected to perform UFSAR updates in conjunction with their installation timelines and as required per the station's modification process. Further, NEI 98-03, Section 6.1, "What the Regulations Require," states, "Per 10 CFR 50.71(e)(4), the UFSAR is required to reflect changes up to a maximum of six months prior to the date that the last update was submitted to the NRC."

Therefore, unless otherwise approved by the NRC, a revision to a UFSAR shall be submitted within six months after each refueling outage provided the interval between successive updates does not exceed 24 months from the date of the previous submittal. This schedule works well for single-unit sites on a 24-month refueling interval. However, for dual-unit sites on a 24-month refueling interval, in which there would be a refueling outage each year, licensees may request an exemption to avoid submitting updates an annual basis; i.e., six months after each refueling outage. Some licensees have obtained exemptions for their operating units, and established a 24-month update frequency based on a lead unit. Single-unit plants that utilize an 18-month refueling interval are required by regulation to submit their updates six months after their outages unless otherwise exempted.

4 - <u>Surveillance & LCO Requirements:</u>

<u>Questions:</u>

What types of periodic tests, calibrations, setpoint verifications or inspections are anticipated to be established, consistent with the VII? What are NEI's expectations for having licensee's update their TSs in order to meet the VII criteria? Could you provide examples?

<u>Response:</u>

Consistent with the VII, it is anticipated that stations will review Maintenance Rule & NERC applicability and the associated maintenance requirements and frequencies for their individual OPIS design solutions. For example, at Byron Station, the SEL-451 relays have been classified as monitored microprocessor protective relays that, according to NERC PRC-005-02 criteria, have a maximum maintenance interval of 12 years. If a station's review determines their OPIS solutions are not within NERC scope, maintenance activities will be developed utilizing vendor guidance and preventative maintenance practices (PMs) currently utilized for similar plant equipment. For example, PSStech recommends that the Active Neutral Injection System be tested on an annual basis utilizing the Active Test Function. PMs would then be created to ensure this maintenance is performed as described on an annual basis within the controlled PM program.

To address the potential need for changes to station Technical Specifications, NEI OPC Working Group requested that the Technical Specification Task Force (TSTF) evaluate whether the planned OPC detection and mitigation equipment satisfied any of the regulatory criteria for inclusion in the Technical Specifications (TS). The TSTF developed a position paper that was reviewed and commented on by the Pressurized Water Reactor Owner's Group (PWROG) and Boiling Water Reactor Owner's Group (BWROG) Licensing Committees, the AP1000 Owner's Group (APOG), and the NEI OPC Working Group. The position paper was published on October 8, 2015, and distributed to the Owners Group members and NEI and provides the basis for evaluations by utilities on whether TS changes are needed when installing OPC equipment. Additionally, the evaluation was also recently provided to the NRC.[3]

The evaluation concluded that the regulations and regulatory guidance do not require additional TS requirements on the OPC detection and mitigation equipment unless the OPC equipment interfaces directly with the engineered safety features actuation logic, bypassing the existing undervoltage function. The offsite AC power sources meet Criterion 3 in 10 CFR 50.36(c)(2)(ii) and require a specific limiting condition for operation (LCO) per the regulations. LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown," are the only LCOs which discuss offsite power and require one (LCO 3.8.2) or two (LCO 3.8.1) qualified circuits between the offsite transmission network and the onsite electrical power distribution system to be operable. The OPC equipment functions as a support system to the offsite power sources, similar to other support systems not addressed in the TS. There are many non-TS support systems that support TS functions, such as room and pump coolers, overcurrent protection, transformer protective functions, barriers, doors and circulating water screens, among others.

Surveillance Requirement 3.8.1.1 requires verification of correct breaker alignment and indicated power availability for each offsite circuit. An OPC is created when there is not proper circuit continuity or breaker alignment for one or more phases of an offsite source. Therefore, the OPC function is verified by the existing Surveillance Requirement 3.8.1.1.

[3] ADAMS accession number ML18262A377, "Evaluation of Inclusion of Open Phase Condition Equipment Requirements in the Technical Specifications"