REGULATORY SUMMARY DOCUMENT

(ISSUES RELATED TO OPEN PHASE CONDITIONS)

1.0 Background

Electrical power systems at existing nuclear power plants consist of an onsite electric power system and an offsite electrical power system. The offsite power system is not safety-related (i.e., Non-Class 1E) while the onsite power system is safety-related (i.e., Safety-Related Class 1E). Typically, the offsite electrical power is connected to the onsite electrical power system through transformers, such as system auxiliary transformers. The offsite power system is fed by the transmission system and is the preferred power supply to the engineered safety features (ESF) buses. The onsite power supply typically includes emergency diesel generators (EDGs), and is the standby power supply. Upon detection of the loss of the preferred power supply, relays on the Class 1E buses actuate to transfer loads to the standby power supply.

Electrical power systems in nuclear plants utilize three phase alternating current (AC) power. In January 2012, an open phase condition (OPC) occurred at the Byron Station, Unit 2 in the switchyard portion of the offsite circuit. An OPC is a single or double open electrical phase, with or without ground that is located on the primary or high voltage side of a transformer connecting a credited offsite power circuit to the transmission system. When an OPC occurs, the remaining intact phases continue to provide power, resulting in a power supply to downstream components that is "unbalanced" among the phases.

The OPC is a previously unrecognized vulnerability that was not considered in the design of any nuclear power plant in the current operating fleet. Based on the January 2012 event at Byron Station, the nuclear industry and the NRC identified that most nuclear generating station plant designs are vulnerable to an OPC. Specifically, an OPC can result in the affected offsite power system (i.e., the preferred power system) being incapable of supplying sufficient power to perform its safety function.

The OPC vulnerability is a complex technical issue, because an OPC is not readily detectable by the type of instruments that were typically installed as part of the initial design of any of the operating nuclear generating stations in the nuclear fleet. Without the implementation of design modifications, the fault may go undetected and unisolated using equipment existing at the time of the Byron Station, Unit 2 event. If the faulted circuit remains connected to the Class 1E ESF buses downstream, it could likewise render the downstream onsite power system incapable of performing its designated safety functions.

As the understanding of this complex issue has evolved, it has become apparent that the design vulnerability at some nuclear generating stations could be perceived as affecting how licensees address the last paragraph of 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants," General Design Criteria 17 (GDC 17), or other Principle Design Criteria. Specifically, at the time of the January 2012 event at Byron Station, no provisions were in-place in the electric power system design for the majority of licensed nuclear generating stations to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power from the transmission network caused by an OPC. Detection of an OPC was beyond the approved design and licensing basis of all operating U. S. nuclear generating stations. The current licensing basis (CLB) for existing nuclear generating stations, as described in the Updated Final Safety Analysis Report (UFSAR) and Technical Specifications (TS), did not address the OPC. Moreover, an OPC was not considered as part of the design criteria for loss of voltage or degraded voltage protection systems.

2.0 NRC and Industry Have Aggressively Pursued a Resolution to the OPC Vulnerability

Following consideration of the January 2012 OPC at Byron Station, the nuclear industry united to aggressively pursue resolution of this issue. Within days of the event, the Exelon Generation Company, LLC., licensed operator and owner of the Byron Station conducted an Institute of Nuclear Power Operations (INPO) sponsored webinar to inform all licensees of the vulnerability. In response, INPO issued a Level 2 Event Report (IER), and the NRC issued Information Notice 2012-03, "Design Vulnerability in Electric Power System," and Bulletin 2012-01, "Design Vulnerability in Electric Power System." The nuclear industry Chief Nuclear Officers (CNOs) collectively endorsed a Nuclear Energy Institute (NEI) Initiative that commits to resolving the OPC design vulnerability by the end of 2018. In response to the INPO IER, compensatory measures that effectively minimize plant risk were aggressively implemented. These measures ensure adequate safety margins for this concern across the industry. These compensatory measures are described in each individual licensee's response to the NRC's, "Request for Additional Information Regarding Response to Bulletin 2012-01, 'Design Vulnerability in Electric Power System,'" dated December 20, 2013. These responses were due by February 3, 2014, and can be found under each licensee's docket number in the NRC's Agencywide Documents Access and Management System (ADAMS).

In response to NEI letters dated March 21, and August 14, 2014, the NRC's Director of the Office of Nuclear Reactor Regulation, William Dean, acknowledged the nuclear industry's efforts to address the OPC vulnerability via a letter to NEI CNO, Anthony Pietrangelo, dated November 25, 2014. Further, in this letter, the NRC provided guidance for addressing the OPC by defining four functional requirements that any solution intended to resolve the vulnerability must possess. This letter also defined a path forward including the steps that licensees would have to take in order to receive relief from potential regulatory enforcement for any alleged failure to comply with the applicable regulatory requirements. This discretion would be afforded to licensees while they worked to meeting the intent of GDC 17 or the applicable principal design criteria defined in the individual licensee's UFSAR.

Additionally, since no regulatory requirements or guidance documents describing the treatment of the OPC existed, the NRC issued Branch Technical Position (BTP) 8-9, "Open Phase Conditions in Electric Power System (ML15057A085)," in July 2015.

In contrast to the assertion in a recent petition filed in accordance with 10 CFR 2.206, industry efforts under the NEI initiative and NRC guidance have resulted in the design and installation of several solutions for this issue.

By following the time line of the NEI Initiative, the Industry will have nearly thirty units protected from an OPC by design solutions that are in-service either in monitoring or trip mode by the end of the first quarter of 2016. Others have completed analyses that determined that their existing systems would be able to detect and trip should an OPC occur. Designs at another 40 units are complete with installation scheduled to be completed by the end of the first quarter of 2017. All U.S. operating units are progressing toward completion of design and implementation activities by the end of 2018, based on plant operating cycles. Units with near term permanent shutdown plans will provide NRC with alternatives to the industry initiative, if appropriate based on risk considerations. These licensee actions make NRC enforcement action of the type contemplated in the 10CFR2.206 Petition unnecessary and unwarranted.

3.0 An OPC Is Different from Degraded Voltage.

An OPC must be distinguished from degraded voltage. The potential for degraded voltage has long been known to exist, and NRC has had guidance applicable to degraded voltage since the 1970s.

In July 1981, the NRC issued BTP PSB-1, "Adequacy of Station Electric Distribution System Voltages."[1] This BTP was written to address industry experience that demonstrated that a balanced but degraded grid voltage condition could exist for extended periods of time and could damage Class 1E loads if a Class 1E bus remained connected to the affected offsite source and was not isolated by existing loss of power (LOP) protection circuits. In the early 1970s, protection circuits were designed to detect a loss of power and transfer power to another supply. The LOP circuits were not designed to detect sustained degraded voltage and had setpoints that were too low to detect certain degraded grid voltage conditions that could damage safety components. As a result, utilities implemented enhancements to the LOP schemes on the Class 1E ESF buses to provide an intermediate (i.e., higher) voltage setpoint that could detect sustained degraded voltage conditions, isolate the source of the degraded voltage, and transfer loads to the standby ESF power source (e.g., the EDGs). In order to address degraded voltage conditions, existing nuclear power plants contain protective circuitry that will separate the ESF buses due to a loss of voltage or a sustained degraded grid voltage concurrent with certain design basis accidents (DBAs). The degraded voltage relays include time delays, such that a brief period of degraded voltage would not result in the separation of the preferred offsite power supply from the Class 1E ESF buses. Based on operating experience, degraded voltage provisions were ultimately deemed necessary to satisfy GDC 17.

OPCs and degraded grid voltage conditions are fundamentally different from each other, and solutions for degraded voltage are not appropriate for resolving the OPC vulnerability. A degraded grid voltage condition is characterized by a balanced but low voltage condition that can readily be detected at the Class 1E ESF bus. In contrast, the OPC has the following characteristics with regard its detectability:

- An OPC is an unbalanced condition on the offsite circuits feeding the onsite system that may not be detected by relay schemes for degraded voltage because the faulted phase(s) voltage may be reconstituted by the interaction of the connected transformer upstream and the auxiliary power system loads downstream of the fault.
- Secondary voltages and currents (i.e., at the Class 1E bus downstream of the fault), while useful to sense unbalanced conditions, may not be a reliable indication of an OPC on the primary or high voltage side of an auxiliary transformer in all situations (i.e.: no load conditions)
- Transformer primary side sequence parameters (e.g., voltage and current parameters calculated from the unbalanced phases) can also be effective indicators of an OPC.
- An OPC on the primary side of a transformer may not be detected and reliably isolated using existing conventional protective relaying schemes and may introduce spurious trips. Since conventional relays may not be capable of detecting an OPC and avoiding spurious trips under all conditions, new types of solution were pursued.

In summary, an OPC is not simply a form of degraded voltage, but is a new condition requiring new regulatory guidance and new types of systems to detect and isolate it.

[1] The current version is BTP 8-6, “Adequacy of Station Electric Distribution System Voltages” (Rev. 3 – March 2007).

3.1 Solutions for the Detection and Isolation of the OPC are Located on the Non-Class 1E Circuits Where OPCs Occur.

Since an OPC may not be reliably detected on the Class 1E buses, under certain loading conditions using existing technology, a new technology, the Open Phase Isolation System (OPIS), is required to: 1) detect the OPC, 2) immediately notify licensed operators of the OPC by providing a Main Control Room alarm, and 3) initiate isolation of the faulted circuit, where appropriate.

The industry has developed several designs for the OPIS. A typical OPIS has the following attributes:

- Located on either the the Non-Class 1E offsite electric power system zone where OPCs occur;
- Provides a signal to isolate the OPC similar to other switchyard, transformer, and transmission network fault isolation circuits;
- Assures the independence of the onsite power system through separation of a faulted offsite power supply; the OPIS isolates the fault and relies on the LOP scheme to perform the bus transfer;
- Allows the Class 1E buses to be repowered by standby GDC 17 sources, thereby preserving designated safety functions;
- Allows other affected important components like alternate AC loads or station blackout loads to be powered from their alternate sources following the isolation of the faulted circuit;
- Utilizes a self-check routine that continuously monitors functional readiness; and
- Immediately alerts operators when OPIS functionality is lost by providing a Main Control Room alarm upon system malfunction.

Since each plant has different electrical power system configurations, it is possible that some plants will have an OPIS with characteristics that vary from those described above. For example, depending upon the transformers being used, it is possible that analyses may determine that some plants will be able to accommodate an OPC without adverse effects on any safety function. In such a case, the plant would not need to isolate the Class 1E ESF buses from the OPC. As technology and analyses have evolve, a solution has been developed to detect the effects of an OPC using instrumentation on the Class 1E ESF buses rather than the Non-Class 1E circuits. Thus, to a certain extent, the OPIS can be plant-specific.

At this time, however, most licensees are using an OPIS located on Non-Class 1E circuits and will use technologies that can be deployed on these Non-Class 1E circuits. In accordance with the NEI Initiative, plants must demonstrate through analyses that they can reliably detect an OPC and provide alarm and/or isolation functions as required. These features of OPIS will preserve the important-to-safety functions of the electric power system (i.e., onsite plus offsite electric power systems).

4.0 Regulatory Issues related to the Design of the OPIS

This section describes various regulatory issues related to the design of the OPIS. It begins with a discussion of the potentially applicable portions of GDC 17, and then addresses various design-related issues, such as the location of the OPIS, conformance with GDC 17, and use of a Non-Class 1E OPIS.

4.1 Applicable Regulatory Requirements

As discussed in Section 1.0 above, the guidance most applicable to the OPC is found in 10 CFR 50, Appendix A, GDC 17 which states:

> ***Criterion 17 - Electric power systems.*** *An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.*
>
> *The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.*
>
> *Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.*
>
> *Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electric power supplies.*

With respect to the OPC, the last paragraph of GDC 17 is of special importance. As applied to the OPC, it essentially requires provisions "to minimize the probability of losing electric power" to the Class 1E buses as a result of an OPC. Thus, in the event of an OPC, plant safety-related equipment must either be able to continue to perform its designated safety functions in the presence of an OPC, or the OPIS must isolate the OPC and allow the transfer of ESF power to another supply, such as the EDGs.

As discussed above, the onsite power system must be able to perform its safety function assuming a single failure. Appendix A to Part 50 defines a single failure as follows:

> ***Single failure.*** *A single failure means an occurrence which results in the loss of capability of a component to perform its intended safety functions. Multiple failures resulting from a single occurrence are considered to be a single failure. Fluid and electric systems are considered to be designed against an assumed single failure if neither (1) a single failure of any active component (assuming passive components function properly) nor (2) a single failure of a passive component*

(assuming active components function properly), results in a loss of the capability of the system to perform its safety functions.[2]

Footnote:

[2] *Single failures of passive components in electric systems should be assumed in designing against a single failure. The conditions under which a single failure of a passive component in a fluid system should be considered in designing the system against a single failure are under development.*

4.2 Location of the OPIS on Non-Class 1E Circuits is Consistent with GDC 17.

As previously discussed, subsequent to the Byron Station, Unit 2 OPC, the NRC and the industry have worked aggressively to understand the OPC vulnerability through system modeling, and studying the response of the models to OPCs.

Through these efforts, the industry has concluded that an OPC is a fault on the offsite power system. As such, an OPC can be likened to other offsite power system faults such as differential, overcurrent, sudden pressure and ground faults that are accounted for in protective relaying schemes within existing transformer, switchyard, and transmission network designs.

Where necessary, the OPIS or other enhanced circuits will address OPC concerns in that the OPC will be sensed and the OPIS will, where appropriate, provide a signal to the existing transformer lockout relays to isolate the affected system auxiliary transformer from the faulted circuit.[2] This action separates the faulted offsite circuit from the onsite power system. Once the faulted offsite circuit is separated from the onsite power system, existing safety-related LOP instruments on the associated downstream Class 1E ESF bus will sense the resulting loss of voltage. This will initiate the automatic restoration of power to the affected Class 1E bus from the associated Class 1E standby power source (e.g., the EDGs).

In summary, the OPC is a fault in the offsite power supply. Similar to other faults in the offsite power supply, many plants have chosen to address the OPC in a similar manner. Specifically, the OPC vulnerability is being resolved by installing detection and isolation equipment on Non-Class 1E circuits upstream of the transformer connecting the offsite power circuit to the transmission network.

There is nothing in GDC 17 or existing regulatory guidance that precludes such a solution for an OPC. Furthermore, location of the OPIS on Non-Class 1E circuits is consistent with the last paragraph of GDC 17. As discussed in Section 4.1 above, GDC 17 requires provisions "to minimize the probability of losing electric power" to the Class 1E buses as a result of an OPC. With an OPIS installed, the probability of losing electric power to Class 1E ESF buses is very low. Such a loss of power would only occur if: 1) there were an OPC that could affect the function of safety-related equipment; 2) the OPIS failed to detect and provide a signal to isolate the fault; and 3) licensed operators, who are trained and qualified on approved procedures that assure that they recognize the effects of an OPC and take action to isolate it, fail to recognize that an OPC has occurred concurrent with the failure of the OPIS. The first and second conditions are independent, involving a passive failure and an active failure, respectively. Although precise probability numbers do not exist, analyses performed for the Byron Station indicated that, subsequent to the installation of the OPIS, the core damage frequency (CDF) associated with an OPC and failure of an OPIS

[2] Some licensees may choose not to automatically separate the faulted offsite electric power system with no loss of coolant accident signal present due to the fact that their offsite power system is normally unloaded.

coupled with the failure of operator actions is on the order of 1E-8 per year.[3] Therefore, by any reasonable standard, use of an OPIS on Non-Class 1E Circuits will "minimize the probability" of the loss of power on Class 1E ESF buses, thereby satisfying the last paragraph of GDC 17.

Furthermore, Section B.2.c.(ii) of BTP 8-9 explicitly allows for design solutions intended to resolve the OPC vulnerability to be installed on the offsite power system. The NRC should continue to allow the location of an OPIS on non-Class 1E circuits in the offsite power system, especially since there is no viable alternative for the detection of OPCs (i.e., some plants will not be able to detect certain OPC using equipment on the Class 1E ESF buses due to things like minimal transformer loading and open phase voltage reconstitution).

4.3 The OPIS is Consistent with Single Failure Criteria

According to GDC 17, the design of the electric power system must ensure 1) that the offsite electric power system is operable assuming that the onsite electric power system is not functioning, and 2) that the onsite electric power system is operable assuming the offsite electric power system is not functioning. In other words, the designated safety functions of the electric power system (i.e., onsite plus offsite electric power system) as described in GDC 17 must be maintained, assuming the loss of either power supply. Additionally, since the onsite electric power system is required to be designed to Class 1E standards, it must not be susceptible to a single failure. The offsite electric power system is tied to the transmission network and is **not** designed and built to Class 1E standards; therefore, it is not required to remain operable with a single failure.

No regulatory requirements or guidance exists that requires the OPIS to be single-failure proof. GDC 17 requires that licensees design the onsite power supplies to have sufficient independence and redundancy to perform their safety functions assuming a single failure. GDC 17 does not require that the offsite power system be able to withstand a single failure. Likewise, the OPIS located on the offsite electric power system does not need to be single-failure proof.

Additional guidance on the single failure criterion as applied to electric power systems is contained in Table 8-2 of Standard Review Plan (SRP) 8.1, "Electric Power - Introduction" (Revision 4 - February 2012). As indicated in that table: "The only requirement in GDC 17 for explicitly meeting the single failure criterion relates to the onsite power system;" however, the NRC also considers whether the offsite and onsite power systems together meet the single failure criterion.

In summary, GDC 17 and applicable NRC guidance does not require the OPIS to be single-failure proof.

While the OPIS is not required to satisfy the single failure criterion, the offsite and onsite power systems considered together satisfy the intent of the single failure criterion. In particular, the Definitions and Explanations Section of 10 CFR 50 Appendix A, "General Design Criteria for Nuclear Power Plants," describes the types of failures that must be considered in the designs of nuclear power plants as follows:

> *A single failure means an occurrence which results in the loss of capability of a component to perform its intended safety functions. Multiple failures resulting from a single occurrence are considered to be a single failure. Fluid and electric systems are considered to be designed against an assumed single failure if neither (1) a single failure of any active component (assuming passive components function properly) nor (2) a single failure of a passive component (assuming active*

[3] "Review of the Regulatory Requirements for Open Phase Condition (OPC) Detection and Isolation," submitted to the NRC by the Nuclear Energy Institute on March 21, 2014, available in ADAMS at ML14087A254, pg. 9.

components function properly), results in a loss of the capability of the system to perform its safety functions.

The OPIS would be considered an active component since it changes state upon detection of an OPC, and an OPC is a failure of a passive electric system component. The electric power system (i.e., offsite plus onsite electric power system) would not need to consider the failure of the OPIS coincident with the failure of a passive component like an OPC to meet the single failure criteria as defined in 10 CFR 50, Appendix A. This is due to the fact the passive components are assumed to function properly in the presence of an active component failure and vice versa.

All potential single failure scenarios associated with the OPC on the electrical power system are described in Table 1 below. In no instance with the OPIS functional, will a single failure result in a loss of the electric power system's capability or capacity to perform its safety functions as described in GDC 17.

Table 1: Single failure scenarios

OPIS	Offsite Power System	Onsite Power System
Functional	OPC – inoperable – affected circuit(s) isolated	Operable – standby power
Functional	Operable	Single train inoperable
Non-Functional (one train unable to isolate an OPC – failure annunciated in MCR)	Affected offsite circuit Operable but degraded – temporary compensatory measures in-place to ensure accident analysis assumptions are met while OPIS is restored to Functional status	Operable
Non-Functional (spuriously isolates)	Inoperable (One circuit isolated)	Operable

In summary, once the OPIS is installed and declared functional, it will ensure that the electric power system supports its designated safety functions considering all single failures as described in 10 CFR 50, Appendix A, including an OPC. Moreover, it will ensure that no single failure will result in the simultaneous failure of the offsite and onsite electric power systems.

4.4 Technical Specifications for the OPIS

As discussed above, it is expected that the OPIS for many plants will be non-safety-related. Furthermore, even without the consideration of an OPIS, when considering the training and compensatory actions that were completed in response to the Byron Station, Unit 2 event, the change in CDF for Byron Station OPCs is estimated to be 6E-7 per year, indicating that the addition of an OPIS is not a safety-significant change.

Given these facts, separate TS for an OPIS on a Non-Class 1E circuit is not warranted. 10 CFR 50.36, "Technical Specifications," provides the following four criteria for determining whether an SSC warrants a limiting condition for operation (LCO) in the TS:

(A) Criterion 1. Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

(B) Criterion 2. A process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

(C) Criterion 3. A structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

(D) Criterion 4. A structure, system, or component which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

An OPIS on a Non-Class 1E circuit does not satisfy any of these criteria. In particular with respect to Criterion 3, an OPIS is not part of the primary success path to mitigate a DBA (i.e., a DBA and an OPC are independent events, and absent an OPC the OPIS is not needed to operate in the event of a DBA).

Furthermore, the TS already contain LCOs and associated Surveillance Requirements (SRs) for the offsite electric power system that the OPIS will support. For example, Technical Specification 3.8.1, "AC Sources – Operating," for the Byron Station contains the following SR:

AC Sources-Operating
3.8.1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required qualified circuit.	7 days

The addition of the OPIS can be addressed through an update to the TS Bases for these LCOs and SRs. In particular, once the OPIS is implemented for a facility, the LCO Section of TS Bases for Technical Specification 3.8.1, "AC-Sources Operating," or its equivalent should be updated. This update should clarify that, unless analysis indicates otherwise, in order for an offsite circuit to be considered Operable, sufficient capacity and capability must be available on all three phases of the circuit. The ability to assess the capacity and capability of the circuit is aided by a functional OPIS. If the OPIS is non-functional, the Operability of the affected required qualified offsite circuit must be assessed and the appropriate compensatory measures must be implemented until the OPIS is restored to a functional status.

4.5 Operability of the Offsite Circuits

The Improved Standard Technical Specifications define Operability as follows: *A system, subsystem, train, component, or device shall be Operable or have Operability when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).*

The offsite power system is considered Operable when it is capable of performing its specified safety functions as described in the UFSAR. So long as an OPC or some other condition that renders the offsite power system incapable of performing its safety function is not present, the offsite power system would be considered Operable.

Absent an OPC or other condition that impairs it capability or capacity to perform its designated safety functions, an offsite power source would be operable even if the associated OPIS is not functional. In particular, if the OPIS is not functional, the offsite electric power system may be considered degraded or non-conforming since the capability to detect and automatically isolate the OPC is lost; however, even if it were assumed that an OPIS would not exist, the electric power system is still capable of performing its specified safety functions. Therefore, the offsite source would be considered operable.

Typically, the TS require two qualified circuits per bus between the offsite transmission network and the onsite Class 1E AC electrical power distribution system to be operable. These requirements are applicable at all times when a unit is operating in modes above cold shutdown. To ensure that the vulnerability to OPCs is further minimized, licensees must evaluate the operability of the affected qualified circuit between the offsite transmission network and the onsite Class 1E AC electrical power distribution system when the OPIS associated with the circuit is not functional. If effective compensatory measures consistent with NRC Inspection Manual Chapter 0326, "Operability Determinations and Functionality Assessments for Conditions Adverse to Quality or Safety," Appendix C, "Specific Operability Issues," Section C.05, "Use of Temporary Manual Action in Place of Automatic Action in Support of Operability," to offset the loss of OPIS functionality are not available, licensees must enter the applicable TS Actions Conditions for an inoperable offsite circuit. This includes taking the appropriate TS Required Actions up to and including placing the unit in cold shutdown if the OPIS is not restored to a functional status within the Completion Time allowed by TS.

Given these actions, no changes to the Technical Specifications would be necessary for an OPIS installed on a Non-Class 1E circuit. Licensees must evaluate the effect of the loss of OPIS functionality on the TS Operability of the affected offsite circuit, implement the appropriate compensatory measures upon loss of OPIS functionality, and minimizing the time that the OPIS not functional in accordance with their Corrective Action Program. These actions will ensure that the vulnerability to OPCs is minimized.

4.6 It Is Permissible To Use Non-Class 1E and Non-Safety-Related Components for the OPIS

BTP 8-9 acknowledges that an OPIS may be installed on a Non-Class 1E circuit; however, it also states that the OPIS must satisfy the provisions in Institute of Electrical and Electronics Engineers (IEEE) Std. 279 "Criteria for Protection Systems for Nuclear Power Generating Stations," or IEEE Std. 603, "IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations." This is incorrect. These standards apply to safety-related Protection Systems. Specifically, the instrumentation and devices that initiate reactor scrams or trips or in some cases initiate an engineered safety feature. As discussed in a paper submitted to the NRC by the Nuclear Energy Institute on March 21, 2014,[4] these IEEE Std. requirements do not apply to the OPIS. Furthermore, Non-Class 1E OPC detection and actuation systems ensure that OPCs would result in a very small increase in CDF. As stated in that paper with respect to an analysis of the use of Non-Class 1E equipment to detect and protect against OPCs at the Byron Station:

> *The loss-of-single-phase event is not explicitly modeled in the current PRA model of record. Adding it to the PRA would be expected to have the following effect under the different conditions presented above.*

[4] Available in ADAMS at ML14087A254, pg. 9.

Condition	***Failures Modeled***	***Approximate 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%*

Since implementing anything beyond an automatic open phase isolation feature would result in an insignificant improvement in CDF, there is essentially no significant risk reduction to be gained by increasing the reliability of these modifications through employing additional Class 1E or Non-Class 1E equipment.

In summary, it is inappropriate to apply IEEE Std. 279 or IEEE Std. 603 to an OPIS installed on a Non-Class 1E circuit, because such systems do not scram or trip the reactor or actuate an engineered safety feature. Furthermore, it is not necessary to apply IEEE Std. 279 or IEEE Std. 603 to OPC detection and actuation systems installed on Non-Class 1E circuits in order to achieve an acceptable level of safety. Accordingly, any further reference to IEEE Std. 279 and IEEE Std. 603 as applied to the OPIS should be discontinued.

Although the OPIS installed on Non-Class 1E circuits do not need to be Class 1E or safety-related, it is subject to the Maintenance Rule in 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants." Specifically, 10 CFR 50.65(b)(2) includes non-safety-related structures, systems, and components (SSCs) within the scope of the rule if, for example, the SSCs are relied upon to mitigate accidents or transients or if failure of such SSCs could prevent safety-related SSCs from fulfilling their safety-related function. NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 4A, (endorsed by NRC Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 3, dated May 2012) is the NRC-endorsed guidance for implementing 10 CFR 50.65. Within NUMARC 93-01 is a description of the scoping assessment that licensees must perform to determine the impact of the failure of non-safety-related SSCs on safety-related SSCs. Specifically, Section 8.2.1.4 requires each utility to investigate their systems and system interdependencies to determine failure modes of non-safety-related SSCs that will directly affect safety-related functions. If this assessment determines that a non-safety-related SSC can impair the ability of a safety-related SSC to perform its safety function, that SSC must be included in the licensees Maintenance Rule Program. Examples of non-safety-related SSCs whose failure prevents safety-related SSCs from fulfilling their safety-related function include:

- A non-safety-related instrument air system that opens containment isolation valves for purge and vent
- A non-safety-related fire damper in standby gas treatment system whose failure would impair air flow
- In some cases the condensate storage tank is not safety-related but is a source of water for ECCS
- Failure of a non-safety system fluid boundary causing loss of a safety system function (e.g., heating system piping over a safety-related electrical panel)

It is clear from the provision of 10 CFR 50.65(b)(2)(ii), the NUMARC 93-01 examples listed above, and the existence of non-safety-related protective relaying schemes similar to the OPIS that are currently installed in nuclear generating station switchyard designs, that non-safety-related SSCs can be used to protect safety features. The caveat for utilizing non-safety-related SSCs in this manner is that if analysis determines that a non-safety-related SSC is relied upon to mitigate accidents or transients or has a failure mode that prevents a safety-related SSC from fulfilling its designated safety function, then the non-safety-related SSC must be included within the scope of a licensee's Maintenance Rule Program. This inclusion is necessary to ensure that the non-safety-related SSC is maintained at the appropriate level of reliability to minimize the probability of its failure.

10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors," also recognizes that some SSCs may perform safety functions without being classified as safety-related (i.e., Risk Informed Safety Class (RISC)-2; non-safety-related SSCs that perform safety-significant functions). However, as provided in 10 CFR 50.69(d), such SSCs require special treatment (e.g., inspection and testing) to ensure that they perform their functions consistent with assumptions in the categorization process.

In summary, significant regulatory guidance and precedent exists for the use of non-safety-related SSCs in the switchyard to support safety features, provided that such SSC are subject to the Maintenance Rule. Therefore, the use of non-safety-related SSCs like the OPIS to detect and isolate an OPC on the offsite power system is allowed and appropriate.

5.0 Conclusions

The OPC is a previously unrecognized design vulnerability. NEI has established an Initiative to address the OPC at all nuclear generating stations through plant modifications, analysis or exemption. As outlined in the NRC's December 2014 Letter to NEI, the NRC should continue to allow licensees to implement the NEI Initiative to resolve the OPC vulnerability by the end of 2018. The NRC has established the functional requirements required to resolve the identified vulnerability and should not impose any specific design requirements on existing licensees. Instead, the NRC should review each licensee's approach for addressing OPCs to ensure they are consistent with existing design criteria.