NEI | White Paper

Guidance for Assessing Open Phase Condition Implementation Using Risk Insights

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Executive Summary

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1 INTRODUCTION

This document provides the guidance and template for applying a plant-specific risk evaluation to compare the difference between operator manual response and automatic response to an Open Phase Condition (OPC) at a nuclear power plant.

2 PURPOSE

The purpose of this document is to provide guidance and a general framework for performing a plant-specific risk evaluation of an Open Phase Condition (OPC) at a nuclear power plant. Potential options and considerations are provided to support a realistic risk assessment of the open phase condition based on plant specific electrical designs and response to such a condition. The primary focus is to provide guidance regarding comparison of the change in risk between operating with automatic functions to isolate a power supply affected by an OPC versus reliance on operator manual action.

3 BACKGROUND

This section discusses the background information driving the need to represent an OPC in a nuclear plant PRA, based on existing operating experience and preliminary risk assessments of the OPC performed by the NRC and industry.

3.1 The Byron Event

On January 30, 2012 [1], a mechanical failure of an insulator on the Startup Auxiliary Transformer (the SAT) providing offsite power to Byron 2 caused an open circuit on one phase of the transformer primary (an OPC). The SAT supplies the Byron 4.16kV emergency buses and to two of the four 6.9kV RCP buses. The OPC did not cause an undervoltage signal on the 4.16kV emergency buses but resulted in a reactor trip on 6.9kV bus undervoltage. The turbine and main generator did not immediately trip. Although the power to the emergency buses was insufficient due to the OPC, the emergency diesel generator (EDG) did not start and load because of the lack of undervoltage trip of the emergency bus. After approximately 30 seconds had passed, the main generator tripped on reverse power. During the 30 seconds after the reactor trip and prior to main generator trip, the two RCPs powered by the 6.9kV buses being fed from the SAT with the OPC remained running on only two phases. After the main generator trip, the non-safety related buses being supplied by the UAT fast transferred to the SAT with the OPC, and 40 seconds later, all four RCPs tripped on overcurrent.

The OPC also resulted in the tripping of equipment on the emergency bus, including a charging pump, component cooling water pump, and service water pump. An AFW pump tripped on overcurrent after auto-start signal occurred on RCP bus undervoltage. A component cooling water pump tripped on overcurrent after an automatic start signal on low suction pressure. Operators attempted to restart the service water pump but were not successful. Several pieces of equipment powered by the 480V buses began to trip due to activation of the thermal overload relays.

Operators diagnosed the problem in approximately eight minutes and tripped the SAT breakers to the 4.16kV emergency buses, triggering an undervoltage signal. The EDGs started and the bus loads sequenced, restoring power and equipment on the 4.16kV emergency buses.

3.2 Additional Operating Experience

Operating experience has shown that OPC events have occurred at multiple sites. Some of the events, with applicable Agency-wide Document Access and Management System (ADAMS) accession number documenting the Licensee Event Report reference are shown below.

- Oconee Unit 3 – 2015 (ML16057A062)
- Byron Unit 1 – 2012 (ML12272A358)
- Beaver Valley Unit 1 – 2007 (ML080280592)
- Fitzpatrick – 2005 (ML011010017)
- Nine Mile Point – 2005 (ML060620519)
- South Texas Project Unit 2 – 2001 (ML011200051)

3.3 NRC Risk Assessment

In May of 2017, the NRC performed a risk assessment to estimate ~~of~~ the impact of a postulated loss of a single phase in a three-phase high voltage offsite power circuit [2]. The results of the risk assessment supported the preposition that the original, as-discovered electrical configuration of nuclear power plants was susceptible to an Open Phase Condition (OPC), and has the potential of being risk significant. However, this evaluation is considered conservative and not necessarily representative of the risk at a specific site.

3.4 Open Phase Isolation Systems

An Open Phase Isolation System (OPIS) was proposed [3] to detect the OPC and actuate alarms and/or automatic circuit breaker operation, as appropriate based on plant design requirements. The function of the OPIS reduces the chance that an OPC affects the emergency bus equipment before action or automatic actuations and ensures the bus can be disconnected from the OPC supply and an alternate power supply can be aligned.

3.5 Plant Impact Summary

Conceivably, an OPC can result in an initiating event at any nuclear power plant. Various plant equipment whose failure would result in a reactor, turbine, or main generator trip depend on AC power for continued plant operation. The specific initiating event impact to a nuclear power plant is dependent on the location of the OPC in the electrical system supporting this equipment, the specific status (e.g., degraded, available) of any electrical power bus affected by the OPC if protective relaying detected the condition, and the status of equipment using the buses for AC power to support continued safe and stable operation or safe shutdown of the plant.

In some configurations, an OPC will result in an immediate plant trip. In other configurations, an OPC would not result in an immediate plant trip but could cause a plant trip if equipment affected by the

OPC trips due to protective relaying action, and the plant is manually tripped in response to the loss of the equipment. In others, the OPC will not cause immediate trip but may impact the emergency buses after an unrelated plant trip or independent event results in the transfer of electrical power to a standby source with an OPC. This would apply to all other initiating events such as Transients, Loss of Coolant Accidents (LOCAs), etc.

Assuming potential impact to the emergency buses, the immediate concern is similar to a LOOP/SBO, with the emergency buses and associated equipment rendered potentially unavailable. For PWRs, loss of seal cooling to the reactor coolant pumps (RCPs) is an immediate concern (particularly those where RCPs are not tripped automatically by the nature of the event and plant configuration). Core cooling can be provided by AC independent or steam driven pumps, but may depend ultimately on restoration of AC power to support DC power. For BWRs, continued core cooling via AC independent or steam driven pumps may depend on the eventual restoration of AC power. Plant specific timing and mitigation capability can impact the risk associated with an OPC.

3.6 Evaluation Decision Guidance

This section provides risk evaluation decision guidance to facilitate an understanding of the plant-specific electrical design and the potential impact an OPC may have on the facility prior to embarking on a detailed risk evaluation. This is based on the benchmarking effort that applied the pilot PRA method to a variety of plant designs and electrical configurations.

The decision to operate the plant relying on the alarm function of the OPIS (i.e., not the automatic power supply trip function) can be based on a qualitative assessment of the factors that have significant impact on the risk of operating the plant. These factors are based on the results of the application of the guidance to a wide variety of plant types and operating configurations that influence the risk of alternatives.

Based on the insights, plants with electrical configuration with diverse emergency bus power supplies during normal operation or automatically aligned post-trip will likely have very small difference in risk between operating with the automatic function and manual alarm function only. Plants with this configuration should be able to demonstrate, by documenting the potential OPC impact and qualitative assessment of risk, a very small difference in risk between automatic and manual implementation alternatives.

Plants with an electrical configuration that provides power to the emergency buses from the same source during normal operation or aligned post-trip potentially have greater than very small difference in risk between operating in automatic function and manual alarm function only. Factors that influence the risk are the reliability of the operator response (time available to diagnose and perform the action, clarity of cues and procedures, frequency and quality of training) and overall low plant conditional core damage probability in SBO conditions (plants with AC independent core cooling means with sufficiently long coping capability, such as diesel driven equipment, FLEX strategies, and/or isolation condensers, etc.).

Plants that normally provide power to emergency buses via independent transmission and transformer circuits that align both emergency buses to a single transmission circuit represent a higher risk potential because an OPC in the transmission circuit would propagate to all emergency buses.

Plants in the latter two categories may still show very small change in risk via combination of operator action reliability and low plant conditional core damage probability (CCDP) in SBO conditions. Electrical loads that are demanded and trip/lock out during an OPC would need to be recoverable and easily reset so they can operate on diesel generator power. If the combination of operator action reliability and plant CCDP still result in greater than very small change in risk between the alternatives, global reduction of the importance of OPC by performing a plant-specific OPC frequency evaluation may reduce the OPC frequency, which would reduce the overall difference in risk between alternatives but would require an evaluation of the OPC operating experience against the plant-specific configuration.

Spurious operation of the OPIS, if operating in automatic mode, could trip the plant if the plant is designed to trip on loss of offsite power to the emergency buses or emergency bus transformer(s). The trip response would be uncomplicated outside of the need to verify emergency bus status and therefore would have a low overall impact to risk. Some plants do not automatically trip on a loss of the emergency bus power supply because there is a fast bus transfer scheme designed to preclude a trip on loss of offsite power to the emergency buses. Although other failures could occur concurrent with the spurious OPIS and result in a trip (e.g., failure of the fast transfer scheme), these scenarios are of low probability. These plants should have time to assess whether an OPC is present prior to the need to shut down.

Ultimately, for plants with emergency buses susceptible to an OPC on one part of the transmission or switchyard circuit, the risks and benefits of the alternatives are plant-specific and should be weighed for the specific plant. However, it is envisioned that the plant-specific design, mitigation features, operator response and potential increases in risk from enabling the automatic function of the OPIS can show that the difference between automatic and manual response to an OPC from a risk perspective can be small.

All plants, no matter the applicable influencing factors provided in the table below, can pursue the risk evaluation to credit operation in the alarm mode only. The description of the configurations and the number of potential plants within each configuration is taken from an NRC Memorandum [11]. This differentiation of electrical configurations, and the benchmark applications of this methodology across 22 U.S. nuclear units, is used to facilitate the scope and depth of the risk evaluation. The following tables summarize the potential factors that influence the risk comparison of the automatic and manual OPC mitigation response with a characterization of the impact.

Configuration	Description	Number of Plants	Potential difference in risk: manual vs. automatic mitigation
1	Single connection to offsite power source (switchyard) feeding both ESF buses through one or two offsite power transformers (SATs) during normal power operating conditions	19	Small (Less than 1E-05 for CDF and 1E-06 for LERF)
2	Plants with ESF buses normally aligned to the UAT during power operation. Upon unit trip, the ESF buses are transferred (using a bus transfer scheme) to the offsite power transformers that are normally energized but may be on standby mode (no load condition) or partially loaded with some nonsafety-related loads	27	Very Small (less than 1E-06 for CDF and 1E-07 for LERF)
3	Only one train of ESF buses may be potentially vulnerable to open-phase condition between the switchyard and a SAT, as it is it is unlikely that redundant trains will be impaired simultaneously.	40	Very Small (less than 1E-06 for CDF and 1E-07 for LERF)
4	Generator output breaker design using the generator step up transformer and the unit auxiliary transformers as the immediate access power source from the grid after the turbine or generator trip. ESF buses do not automatically transfer to redundant offsite circuits	9	Judged to be small (less than 1E-05 for CDF and 1E-06 for LERF), based on plant type “1” result.
5	Normal feeds to ESF buses split between UATs and SATs. In seven out of nine plants, after the unit trip, the ESF bus fed from UAT will also be automatically transferred to a common SAT	9	Small (Less than 1E-05 for CDF and 1E-06 for LERF)

Normal Operating Configuration	Influencing Factor	OPIS Mode	Potential Impact	Specific Mitigating Factors
1, 4, 5	Emergency bus electrical loads and supporting loads are demanded prior to OPIS success.	Manual	High Impact – Actuation of loads may trip protective relaying which may require manual reset, all three phases may not be monitored for input to protective relaying at each electrical load.	AC-independent core cooling systems such as Diesel-Driven AFW (PWR) and high reliability RCP seals, FLEX systems, Isolation condensers. Protective relaying confirmed adequate to protect demanded loads under unbalanced phase conditions. Emergency bus loads easily recoverable from the main control room.
		Automatic	Low Impact – OPIS timing designed to actuate prior to load protective relaying	N/A
1, 4, 5, and RCPs powered from bus not affected by OPC	All RCPs do not automatically trip via protective relaying if OPC occurs or RCPs on separate power supply (PWR).	Manual	High Impact – RCP seal cooling may be lost due to the OPC with the RCPs running.	Reliable operator action to trip RCPs, loss of seal cooling alarms and response procedures, guidance to trip RCPs given an OPC alarm.
		Automatic	Low Impact – Automatic OPIS designed to ensure seal cooling remains available given OPC.	N/A

Normal Operating Configuration	Influencing Factor	OPIS Mode	Potential Impact	Specific Mitigating Factors
2, 3, 5 (if independent source to each emergency bus aligned after transfer for configuration 5)	Emergency bus electrical loads and supporting loads are demanded prior to OPIS success.	Manual	Low – Actuation of loads may trip protective relaying which may require manual reset, all three phases may not be monitored for input to protective relaying at each electrical load, however, another division remains available, and for some plants trip would potentially have to occur to result in demands on emergency buses.	N/A
		Automatic	Low Impact – OPIS timing designed to actuate prior to load protective relaying. Opposite division remains available and trip would have to occur to result in demands for emergency buses.	N/A
2, 3, 5 (if independent source to each emergency bus aligned after transfer for configuration 5)	All RCPs do not automatically trip via protective relaying if OPC occurs or RCPs on separate power supply (PWR).	Manual	Low Impact – One division remains available, and plant trip would have to occur to align supply with OPC.	N/A
		Automatic	Low Impact – One division remains available, and emergency diesel power aligned to support seal cooling.	N/A

4 PRA MODELING GUIDANCE

This section provides guidance on performing a plant-specific Probabilistic Risk Assessment (PRA) of an OPC at two nuclear power plants. The plant specific PRA approach utilizes the existing PRA accident sequence models, specifically, the transient, LOOP, and SBO models, as appropriate based on the plant design, configuration, and impact of OPC on the electrical distribution at the plant. The two pilot assessments are for a PWR (Byron [7]) and a BWR (LaSalle [8]). The two dual-unit plants normally provide offsite power to emergency buses for a single unit through two transformers with a common switchyard feed (Byron) or one transformer (LaSalle). This type of configuration is somewhat unique and considered bounding when compared to other safety related emergency bus configurations at other US facilities.

Although the OPIS is designed to automatically trip the circuit breakers and isolate the power supply with the OPC to the plant emergency buses, this assessment credits manual operator action in response to the OPIS alarm in the main control room. It also addresses the factors required to develop the Human Failure Event (HFE) Human Error Probability (HEP). This guidance can be used to compare the risk between operating with the automatic isolation function of the OPIS and operating with reliance on operator manual action only.

4.1 Initiating Event Analysis

For plants where an OPC causes an automatic trip, several existing plant initiating events or categories adequately represent the initiating event impact. Review of the Byron event [1] shows the possible initiating events are:

- Transient (reactor trip, turbine trip, main generator trip)
- Loss of offsite power (LOOP) to the emergency buses (may progress to SBO-like conditions)

Depending on the specific plant design and electrical configuration, other initiating events may be possible. For example, an OPC on a power supply unique to the balance of plant equipment (main feedwater, condensate, etc.) or a specific loss of single bus initiating event may result in loss of the equipment, causing the existing initiating event to occur. This guidance focuses on the loss of offsite power initiating event (e.g., loss of three phase power to all plant emergency buses) as a surrogate measure to facilitate use of existing utility PRA tools to evaluate the risk or change in risk associated with an OPC. For a PWR, the event may progress to RCP seal LOCA via loss of seal cooling depending on the plant specific design. Plants with physically and electrically independent offsite power supplies to the emergency buses would experience a response similar to a loss of bus initiating event.

4.2 OPC Frequency and Probability Analysis

In Section 4.2 of Reference [2], the NRC's provided conservative estimate for the OPC frequency of 8.1E-03/year, is based on 7 failures in 10.1 years, 100 reactors, and a plant capacity factor of 0.92. Per a review of the 7 failures listed on Table 1 of Reference [2], only two of the events (i.e., events on 8/9/06 and 5/14/07) appear to have affected downstream plant equipment. It is unclear whether these two events are temporary conditions that were corrected by protective circuitry. Also, it is not clear why the data window was limited to 2001 to 2015. Offsite power data has been collected since the 1990s (References [5] and [6]).

The NRC analysis in Reference [2] assumed a conservative worst-case scenario where a single OPC occurs on the high voltage side of the line feeder to the transformer(s) providing offsite AC power to the plant emergency buses. The OPC was assumed to impact all downstream buses. The location of an OPC requires additional apportionment which would further reduce this probability. It is not clear that a single OPC will always impact all downstream buses. Many plants have separate transformers that supply normal power to the emergency buses. In some cases, these are only powered from a common source in a ring bus configuration at the highest voltage levels in the nuclear power operator switchyard. Faults at this level require an additional failure layer.

For plants which have offsite power feeds in a reserve standby state, absent of an independent detection/isolation system, the impact of an OPC on the offsite power feed will only be detected after a reactor/turbine/main generator trip event has occurred. For these cases, a dimensionless probability of OPC is developed derived from the yearly frequency for a one-year duration. The probability of latent OPC affecting the emergency buses post-trip depends on failure of the OPIS to alarm the condition. In this scenario, operator rounds may still detect the OPC. If the OPIS fails and self-alarms the failure, repair of the OPIS in a timely manner minimizes the chance a latent OPC can affect the emergency bus.

Additionally, a post-trip, 24-hour mission failure could occur in configurations where offsite power to the emergency buses is available initially but an OPC develops during the 24-hour mission time. In this case, it would not be an initiating event but could result in an OPC plant response that occurs after an initial, unrelated plant initiating event (e.g., Transients, LOCAs, etc.).

Alternative OPC frequencies and probabilities have been estimated beyond that developed in the NRC analysis. For example, Reference [4] provides OPC frequency of 1.56E-03/year, based on 4 events in 2465.59 reactor-years and a plant capacity factor of 0.96.

Reference [4] utilized data from the NRC website, and identifies operating events with an OPC occurrence. The events are described at the following website.

(https://www.nrc.gov/reactors/operating/ops-experience/open-phase-electric-systems.html)

A review of this industry operating experience identified the following OPC events:

- Beaver Valley Unit 1 – 2007 (ML080280592)
- Fitzpatrick – 2005 (ML011010017)
- Nine Mile Point – 2005 (ML060620519)
- Byron Unit 2 – 2012 (ML12272A358)
- Byron Unit 1 – 2012 (ML12272A358)

According to Reference [4], the Fitzpatrick and Nine Mile Point events were actually the same event as the plants share a switchyard. Only one failure of a single phase occurred so this was counted as only one event. Therefore 4 OPC events were used to calculate OPC frequency. Each event was assumed applicable to the OPC initiating event frequency.

The NRC website contains reactor operating data for the number of critical reactor years. Using the web site for Operating Time, http://nrcoe.inel.gov/resultsdb/ReactorYears/, and selecting the "By Plant Calendar Year" link, a total of 2750 reactor-years of critical operation between 1987 and 2017 is provided. Operating experience used in the NRC study [2] is 7 plants. This equates to an OPC frequency of:

- OPC Frequency = 7.5 events / 2750 reactor-years = 2.73E -03 per reactor-year
- The post-trip OPC probability is calculated for an annual exposure time and a 24-hour mission time
- OPC Post-Trip Probability (1-year exposure) = (1.45E-03 per reactor-year) * 1 year = 2.73E-03
- OPC Post-Trip Probability (24-hour mission) = (1.45E-03 per reactor-year) * (1 year / 365 days) = 7.47E-06

The alternative frequency assessment above assumes no open phase events have occurred, beyond the events identified on the NRC website and only the domestic plant data used in Reference 2 is applicable.

An alternative, plant-specific assessment can be performed utilizing plant-specific experience. Such an assessment should be performed consistent with the data analysis in the existing PRA loss of offsite power initiating event frequency estimate. The steps to complete the estimate are as follows:

1. Perform a search for industry loss of phase events for the data period consistent with the existing PRA. Sources of loss of phase events may include Licensee Event Reports (LERs) and existing LOOP data sources such as those published by the NRC and by EPRI (References [5] and [6]).
2. Estimate a prior frequency based on the number of occurrences of a loss of phase event and the reactor critical years or calendar years for the data period.
3. If necessary, perform a Bayesian update of the prior with plant specific loss of phase event occurrences and reactor critical or calendar years.

Based on the above two examples, the OPC initiating event frequency could be expected to fall in the range of 2.73E-03 to 8.1E-03. The same value can be used to estimate the post-trip probabilities for a 1-year exposure and 24-hour mission time. Care should be taken to properly categorize a specific event as either a full LOOP (applicable to LOOP frequency) or applicable as an OPC only. For example, the Byron Unit 1 event included a ground fault which resulted in electrical conditions that actuated the existing undervoltage relaying which isolated the OPC from the emergency buses and aligned the emergency diesel generators. Byron Unit 1 is designed not to trip on loss of power to the emergency buses, and within hours, cross-tie from Unit 2 restored offsite power to the emergency buses.

The Byron [7] and LaSalle [8] pilot assessments conservatively utilize the OPC initiating event frequency of 8.1E-03, and a post-trip 24-hour mission estimates based on this frequency. A plant specific OPC data analysis or calculation of an OPC frequency is not required to get a bounding estimate of the change in risk between alternatives. Use of the conservative NRC value can be used as was the case for the example risk evaluation performed for this document.

4.3 Plant Response Analysis

An OPC which is not isolated from the emergency buses is similar initially to a LOOP with no emergency power to the emergency buses, which is effectively a Station Blackout (SBO). The OPC has the potential to render safety buses unavailable until the buses are recovered. In some plant configurations, the non-safety buses might still be available if fed by another transformer with a diverse high voltage feed. The availability of non-safety buses could provide decay heat removal option not available in a typical SBO. In an OPC, the emergency power supply is available, but the safety buses are in a degraded condition and not in a failed condition. The OPC could result in damage to equipment if circuit protective devices (e.g., overcurrent trips) fail to function. The plant response to an OPC is a function of plant specific design (PWR versus BWR) and/or operational differences.

<u>Pressurized Water Reactor (PWR)</u>

The immediate concern for a PWR during an OPC is the response to a loss of seal cooling. At Westinghouse sites, this requires the loss of both injection and thermal barrier cooling to reactor coolant pumps (RCS Seal LOCA). An OPC, unlike an SBO, does not ensure the RCP are secured. If power to the RCP is not lost due to the same OPC, then operations must trip the RCPs. Westinghouse PWRs have traditionally been more susceptible to RCP Seal LOCA issues. Core cooling is maintained via the Steam Generators which are fed from Steam Turbine Driven Feedwater Systems (e.g., Steam Turbine Driven EFW or AFW) or other AC independent core cooling pumps. The Steam Turbine Driven Feedwater Systems are normally controlled by DC power. The available core damage mitigation time is a function of the time it takes to uncover the core due to RCP Seal LOCA or a loss of secondary heat removal. The time to the loss of secondary heat removal is related to battery depletion time. The degraded condition on the safety buses could cause the component cooling water (CCW - thermal barrier cooling) and charging pumps to trip (loss of seal injection), resulting in a loss of RCP cooling. Some plants have a diverse alternate RCP seal injection system that is independent of AC Power. If the RCPs are tripped due to loss of the non-safety buses, the probability of seal failure is much lower. Also, if an RCP Seal LOCA occurs due to loss of seal cooling, hours are available to restore power before core damage occurs. Many plants have installed the shutdown seals. For these seals, RCP seal LOCA is precluded beyond 24 hours if the RCPs are tripped with secondary heat removal available, thereby affording greater operator response times in response to an OPC event.

For other initiating events, post-trip, the plant response would reflect the loss of emergency bus power. Transients would proceed similar to the LOOP/SBO response. Other initiating events, such as LOCAs would introduce timing different than a transient or a LOOP with RCP trip.

<u>Boiling Water Reactor (BWR)</u>

The immediate concern for a BWR is limited due to the availability of steam driven DC powered mitigation systems (e.g. HPCI, RCIC, etc.). The Steam Turbine Driven Injection Systems are normally controlled by DC power and are therefore not impacted by the OPC effecting AC buses. The available core damage mitigation time is a function of continued core makeup and cooling from Steam Turbine Driven Injection Systems (i.e., battery depletion time). During an OPC, the Steam Turbine Driven

Injection Systems will be controlled by the safety batteries. The time to deplete the batteries and the time to core damage after loss of all core cooling will determine the time available to restore power before core damage occurs. Some BWRs have a HPCS instead of one of the steam driven core cooling sources. The HPCS bus may be powered by the same supply affected by the OPC. Many plants have procedures that direct the operators to strip DC loads during a SBO, thereby extending the battery depletion time and the time to core damage. Most plants now have FLEX strategies in place to provide an alternate means to power the steam driven pumps directly or the chargers. For those plants that also have a long battery life, this is an effective additional mitigation strategy.

For other initiating events, post-trip, the plant response would reflect the loss of emergency bus power. Transients would proceed similar to the LOOP/SBO response. Other initiating events, such as LOCAs would introduce timing different than a transient or a LOOP.

The modeling approach here assumes the OPIS is installed which will either detect the OPC and initiate automatic trip function and provide an alarm in the main control room, alerting the operators of the condition affecting the emergency buses. The model is adjusted to credit either automatic trip function or the alarm mode in order to develop change in risk estimates.

4.4 Plant Electrical Distribution

The plant impact of the OPC is driven primarily by the impact to the emergency buses. Depending on the configuration of the electrical distribution system, primarily the offsite power scheme, the impact could affect all emergency buses. Example configurations of an OPC that can impact the emergency buses are discussed in this section and are considered bounding compared to other designs across the US nuclear fleet.

Examples of configurations are shown in Figures 1 and 2 [2]. Figure 1 shows both emergency buses are normally fed by the same power transformer from the 345 kV switchyard. An OPC on or upstream of the transformer primary winding would propagate to each emergency bus. In this example, multiple units are therefore affected by the same OPC.

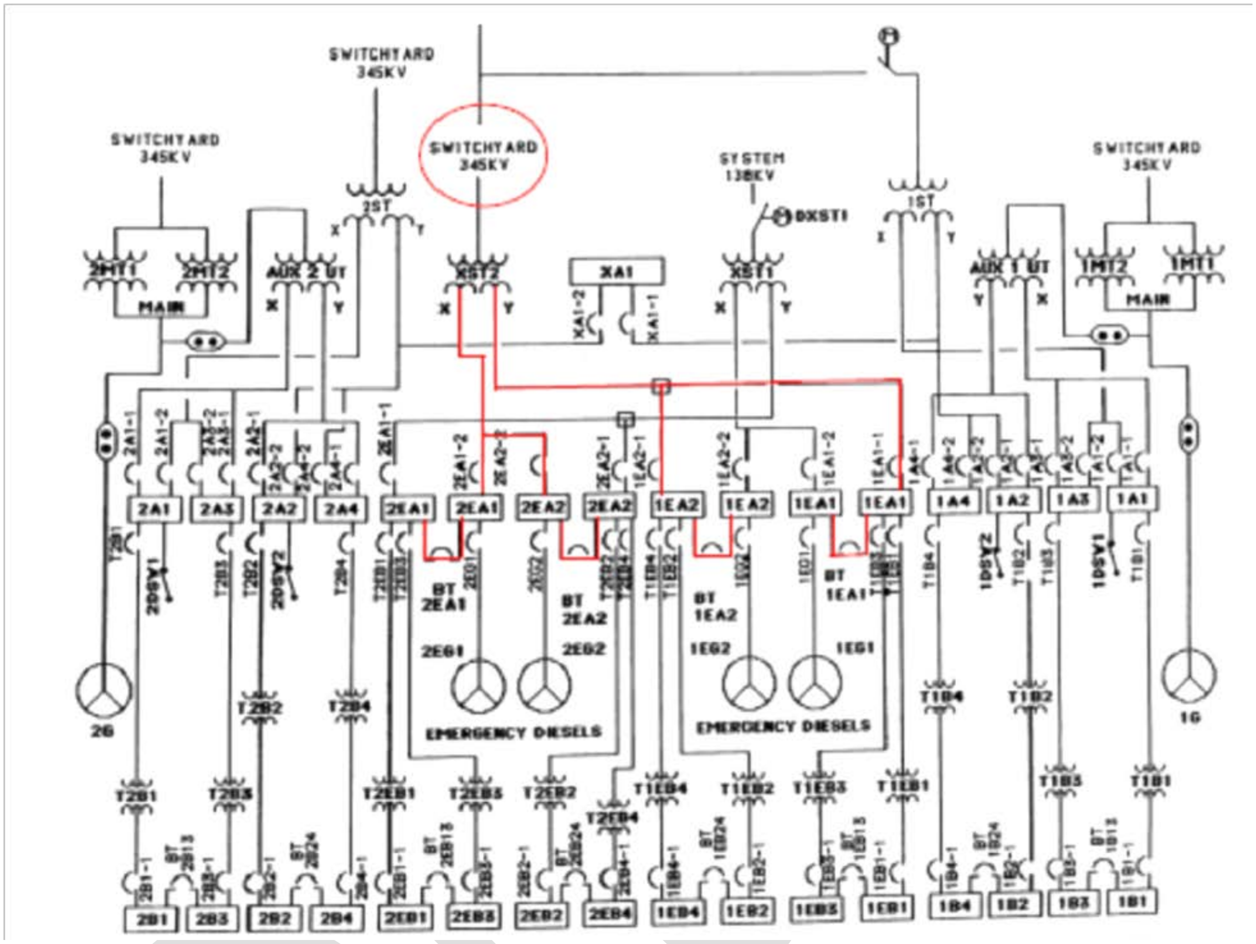

Figure 1 - Example Electrical Configuration 1 – Both Safeguards Buses Affected

Figure 2 [2] shows an OPC that affects multiple transformers, when fed by the same offsite transmission line, propagating to affect all safety buses. If the plant is normally operated with diverse high voltage feeds to the transformers, one OPC would not affect both buses, however, if the unusual configuration is not prohibited the condition may be possible. A fraction of time in a given alignment could be developed and applied to reduce the frequency of OPC events that propagate to all emergency buses.

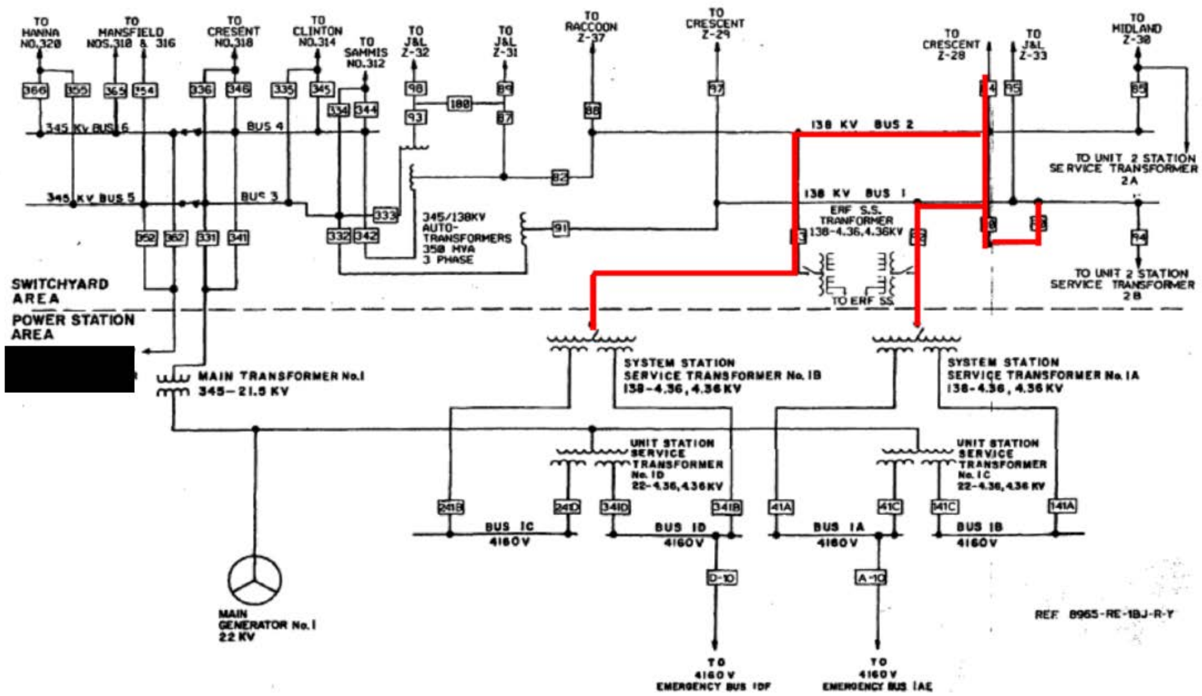

Figure 1: Example Electrical Configuration 2 – Both Safeguards Buses Affected

4.5 OPC Event Tree

The OPC event tree is based on transfers to existing accident sequences that model the plant response to an event that is similar to the conditions induced by the OPC impact on plant equipment. The unique model impact of the OPC relates to success or failure of the OPIS, operator action(s) cued by the OPIS and OPC conditions, and bus overcurrent relays that function to protect running motor loads from the degraded bus conditions.

The event tree is simply one that models the OPIS detection and response to an OPC initiating event. It includes the expected automatic and operator response to the initiator.

Figures 3 and 4 show example event tree models of the plant response to the OPC for the example electrical configurations shown in Figures 1 and 2. Figure 3 shows the plant response to an OPC affecting emergency buses that directly results in a plant trip. Figure 4 shows the plant response to an OPC affecting emergency buses that occurs prior to the plant trip and the plant trip transfers the emergency buses to the supply with the OPC.

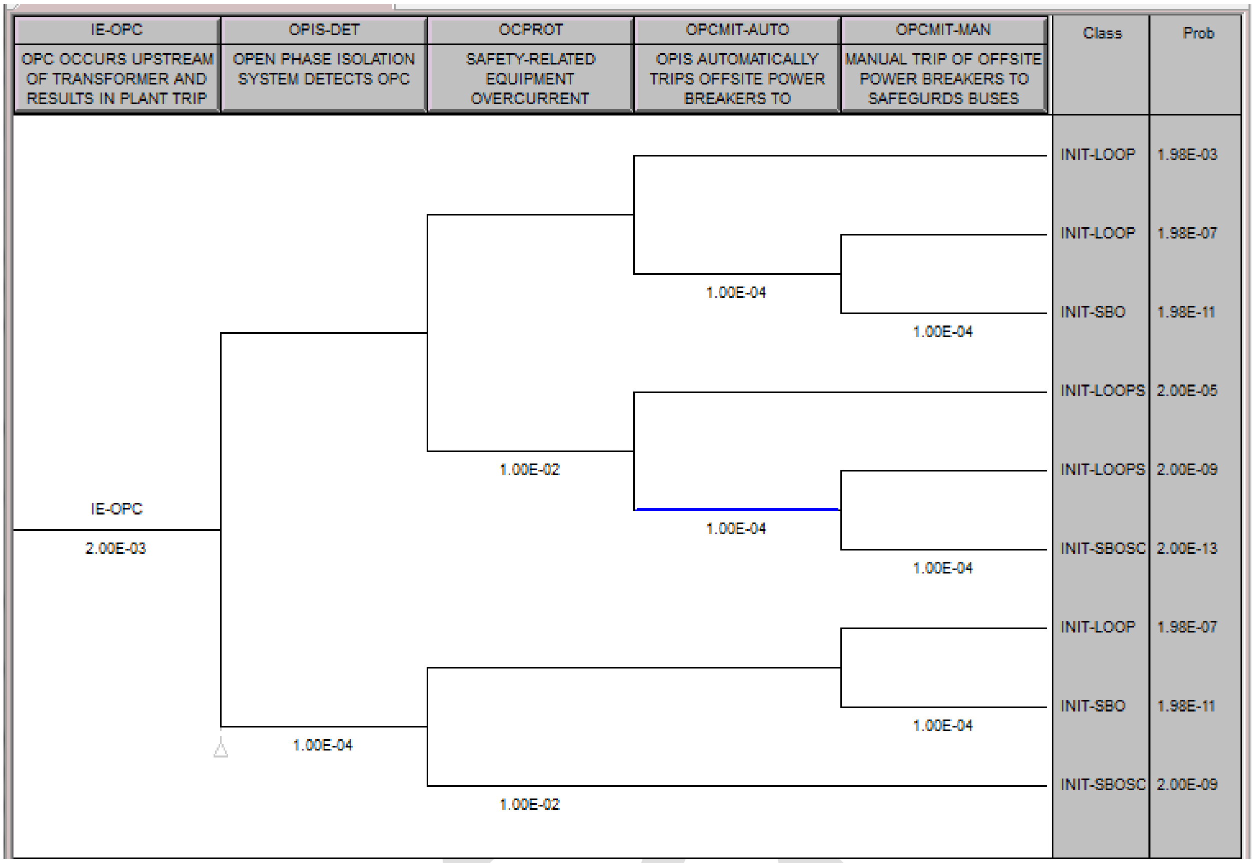

Figure 2 - Example OPC Initiating Event Model for Electrical Configurations with Both Safeguards Buses Impacted

Event Tree Headings

IE-OPC

Heading IE-OPC represents the occurrence frequency of the OPC initiating event, which is the entry condition to the event tree. An open phase condition occurs that results in loss of phase to the emergency buses and automatic plant trip. The trip can occur due to loss of the emergency buses directly or because of OPC impact to other buses where equipment is lost. For A PWR, the trip may occur if seal cooling is lost due to trip of the equipment being fed from the emergency bus. In this case, the operator actions modeled focus on the trip of the RCPs and the plant in response to the loss of seal cooling.

OPIS-DET

Heading OPIS-DET represents the success or failure of the OPIS to detect the OPC and provide an alarm in the main control room notifying the operators of the condition or to automatically trip the system. Failure of the system at this heading results in transfer to the SBO response, representing the loss of all equipment on the emergency buses, as the OPC would be affecting equipment on each emergency bus. This results in potential trip of the equipment due to overcurrent relay actuation and/or thermal overload action and/or inability to start needed equipment on the bus. Success represents actuation of the alarm in the main control room or automatic isolation of the OPC.

OCPROT

Heading OCPROT represents the success or failure of the emergency bus motor overcurrent protection to actuate and trip the breaker to the motor given the OPC in the time prior to the trip of the power supply breakers to the emergency bus. Failure represents a transfer to a degraded LOOP or SBO response (LOOP or SBO with equipment that is unavailable/damaged/unrecoverable due to overcurrent and no successful trip of the motor breaker). Success represents trip of circuit breaker motors on overcurrent, so they will be available to automatically or manually start after the power supply affected by the OPC circuit breaker is opened. Electrical studies may exist that show that overcurrent relaying will not actuate in the time it takes the OPIS to automatically trip the circuit breaker from the power supply affected by the OPC. If so, this node would not need to be questioned. If the OPIS fails or manual operator action only is credited, electrical studies may have to be completed to justify whether overcurrent protection is required to protect the bus load.

OPCMIT-AUTO

Heading OPCMIT-AUTO represents the success or failure of the OPIS to automatically trip the supply breakers providing offsite power to the emergency buses (i.e., the supply affected by the occurrence of the OPC). Failure of the system represents loss of the immediate automatic trip function which progresses to the need for manual trip. Success isolates the OPC to the emergency buses resulting in start of the emergency power source and LOOP conditions, or LOOP conditions with some equipment consequences if overcurrent relaying is demanded and fails.

OPCMIT-MAN

Heading OPCMIT-MAN represents the success or failure of the operators to trip the supply breakers providing offsite power to the emergency buses (i.e., the supply affected by the occurrence of the OPC). Failure of the system at this heading represents the loss of all equipment on the emergency buses, as the OPC would be affecting equipment on each emergency buses, resulting in potential trip of the equipment due to overcurrent relay actuation and/or thermal overload action and/or inability to start needed equipment on the bus. Success represents manual trip (opening) the supply breakers allowing a valid bus undervoltage signal to start the emergency AC power supply (e.g., emergency diesel generators) and provide power to the emergency buses and recover loads that require manual reset before being placed back into service.

Event Tree End States

INIT-LOOP

This end state represents transfer to a LOOP sequence based on successful isolation of the power supply affected by the OPC to the emergency buses. The plant response continues as a typical LOOP, although the probability of AC recovery could be affected by the ability to repair the supply with the OPC prior to recovering AC to the emergency buses, if credited in the PRA (see section 3.6 for treatment of AC recovery). If overcurrent relaying was required to protect an emergency bus load, local trip resets and recoveries may need to be modeled in the fault tree.

<u>INIT-LOOPSC</u>

This end state represents transfer to a LOOP sequence based on successful isolation of the power supply affected by the OPC to the emergency buses. However, overcurrent protection associated with the motor loads on the emergency buses has failed which results in potential damage to the motor loads rendering them irrecoverable. Any affected loads would be unavailable given the LOOP. There may be a combination of successful and failed overcurrent relaying on an emergency bus load basis. If overcurrent relaying was required to protect an emergency bus load, local trip resets and recoveries may need to be modeled in the fault tree.

<u>INIT-SBO</u>

This end state represents transfer to an SBO sequence based on failure to isolate the power supply affected by the OPC from the emergency bus, and where overcurrent protection successfully trips the motor loads on the emergency bus. If overcurrent relaying was required to protect an emergency bus load, local trip resets and recoveries may need to be modeled in the fault tree, which may affect the probability of AC (offsite power) recovery, if using one of the existing offsite power recovery curves.

<u>INIT-SBOSC</u>

This end state represents transfer to an SBO sequence based on failure to isolate the power supply affected by the OPC from the emergency bus, and where overcurrent protection fails to trip the motor loads on the emergency bus, which results in potential damage to the motor loads rendering them irrecoverable. Any affected loads would be unavailable given the SBO. There may be a combination of successful and failed overcurrent relaying on an emergency bus load basis. If overcurrent relaying was required to protect an emergency bus load, local trip resets and recoveries may need to be modeled in the fault tree, which may affect the probability of AC (offsite power) recovery, if using one of the existing offsite power recovery curves.

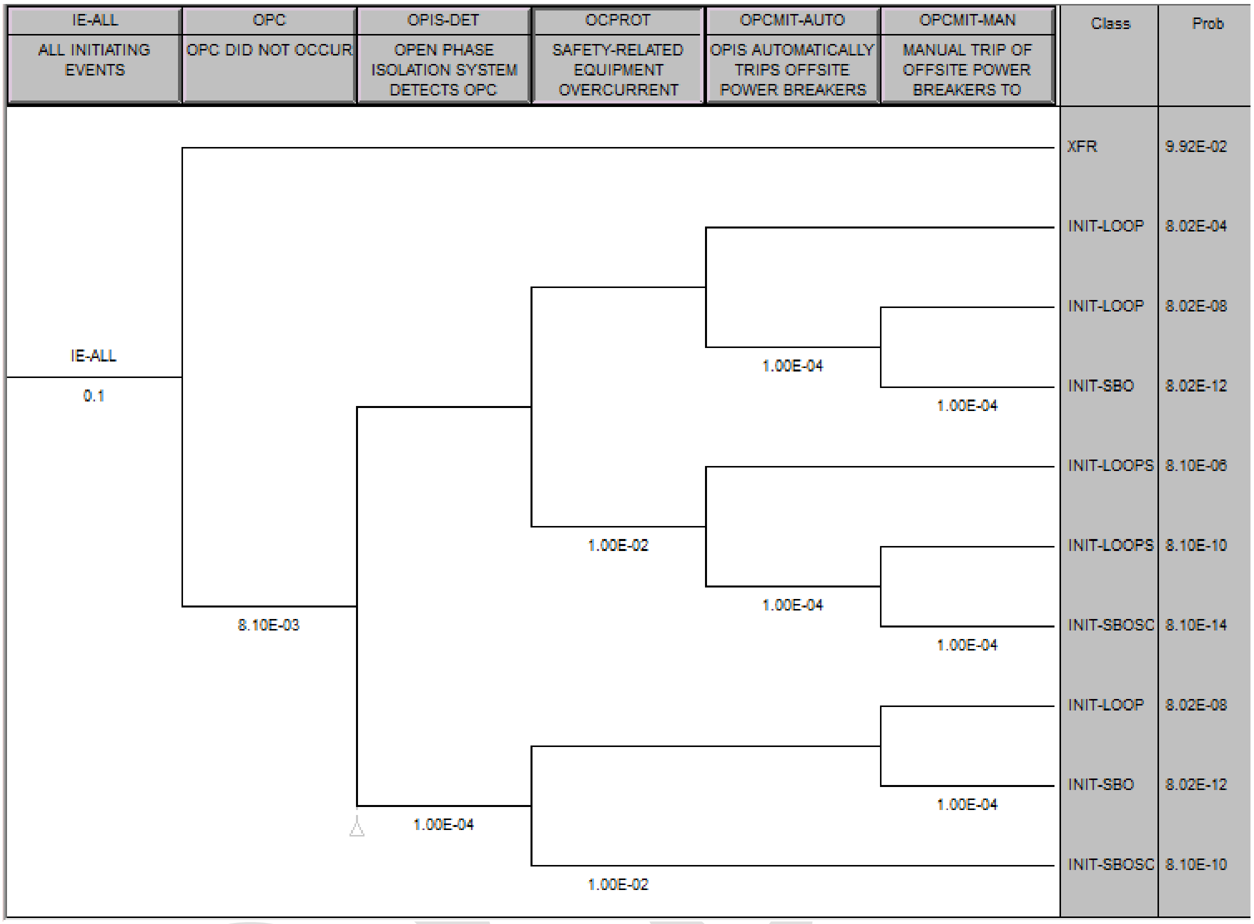

Figure 3 - Example Post-Trip OPC Model for Electrical Configurations with Both Safeguards Buses Impacted

The post-trip event tree (Figure 4) is equivalent to the initiating event tree, assuming the OPC occurs after the trip. Prior to the trip, if the OPIS alarm fails, the OPC could remain until bus transfer, and no additional cues via overcurrent relays would occur. If enough indications (such as phase voltage and/or phase current) are not available in the MCR, the condition could remain undiscovered until the initiating event occurs, and emergency bus loads begin to trip on overcurrent.

The pilot assessments [7] and [8] utilize the OPC initiating event tree and the post-trip event tree.

4.6 Open Phase Isolation System Model

The Open Phase Isolation System (OPIS) has two major functions. The function addresses the capability to detect and monitor the occurrence of an OPC upstream of the transformers that provide offsite power to the emergency safeguards buses at the plant and provide an alarm or automatic trip of circuit breakers providing power through the transformers to the emergency buses.

The automatic trip function of the OPIS could introduce a potential increase in the likelihood of loss of offsite power events due to random spurious automatic trips. The design and installation of the OPIS will have addressed random spurious trips. Depending on the plant configuration and design response to an undervoltage on the emergency buses, it is possible the automatic OPIS could result in a fast bus transfer of non-safety related buses that if successful, does not result in an automatic plant trip.

For Byron this new detection scheme monitors the current on the high side of the SATs to detect a loss of phase or low load condition. The relays are multifunction microprocessor based programmable relays. The relay compares the positive, negative, and zero sequence currents. On detection of a loss of phase upstream of the SAT, the scheme isolates the SAT via the transformer protection lockout relay. This change to add loss of phase protection functionally maintains all the existing interlock functions for the SAT 86 lockout relays.

Figure 5 shows the OPIS interface with the high side of the SATs, the comparison of positive, negative, and zero sequence currents, outputs to the SAT 86 lockout relays, and outputs to the main control room alarm and automatic trip function.

Figure 6 is a trip logic diagram for the Byron OPIS. Factoring in load conditions, positive, negative, and zero sequence currents are compared to detect an OPC and actuate the alarm and the automatic trip of the 86 lockout relays associated with the SAT feeder breakers, removing the offsite power path to the emergency buses, and resulting in a valid undervoltage actuation on the emergency buses.

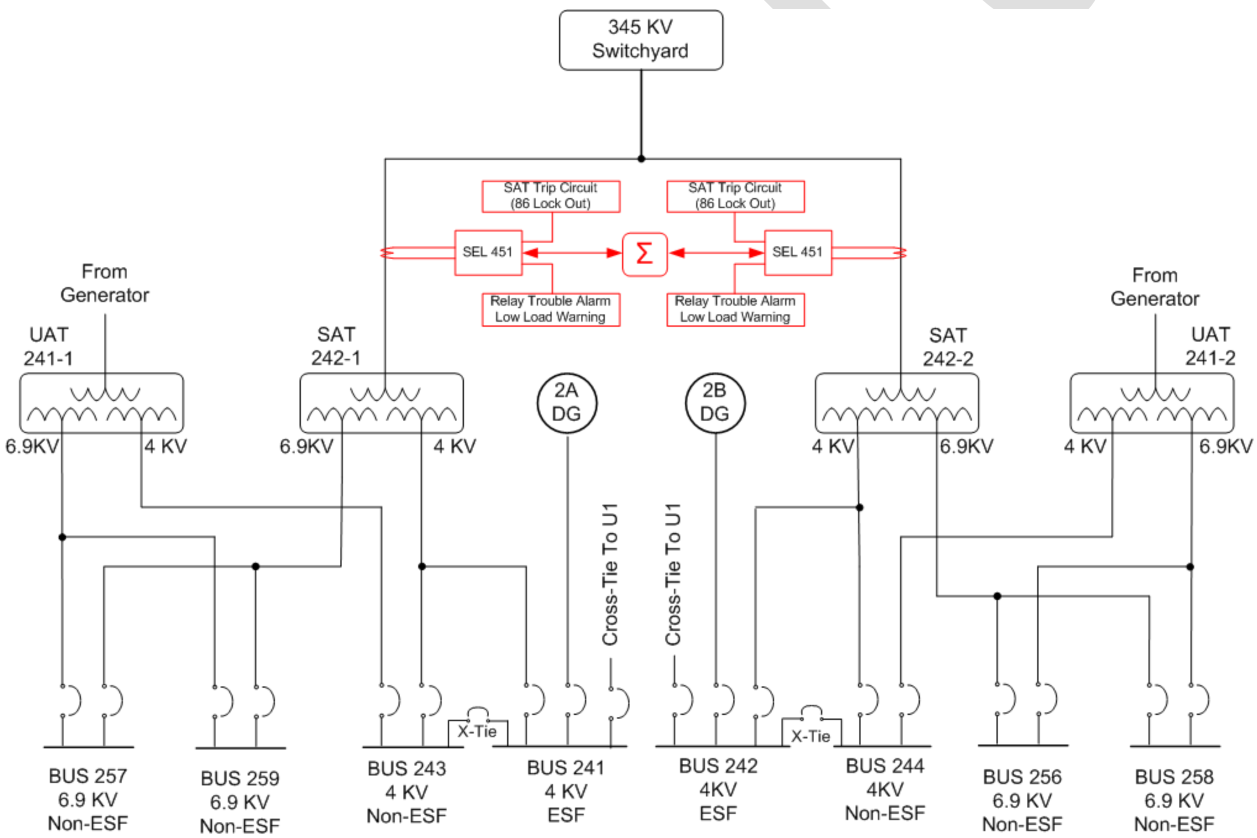

Figure 4: Example OPIS Design

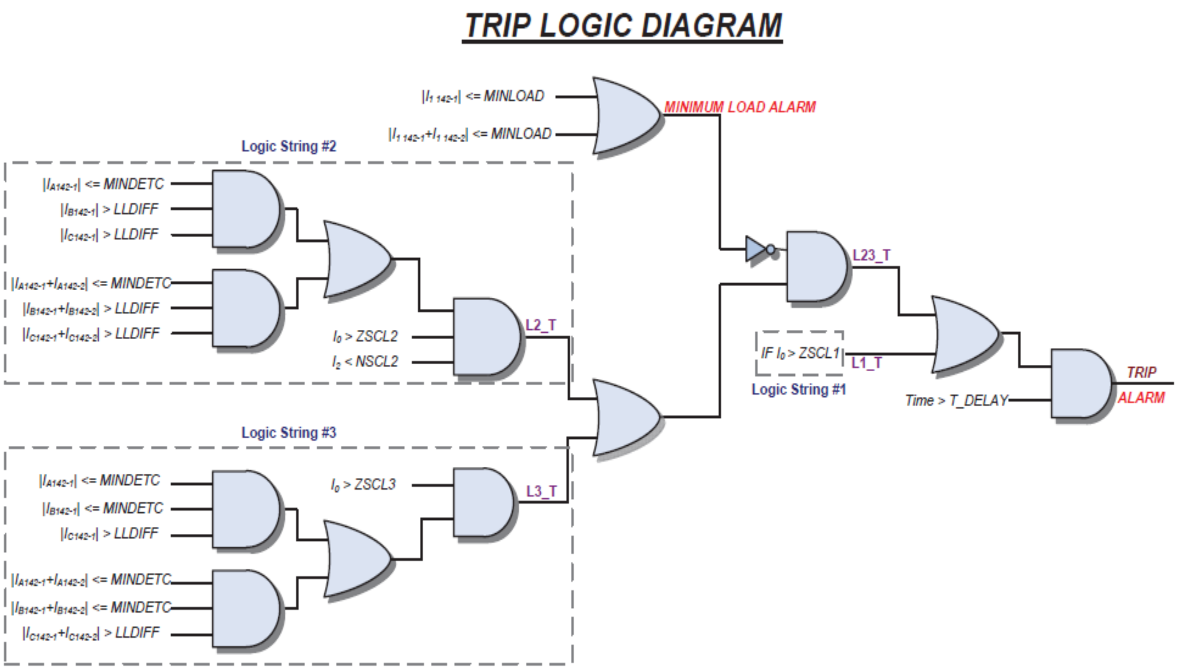

Figure 5: Example OPIS Logic

The NRC evaluation [2] assumed that the OPIS failure would closely model those of protective relays. The NRC evaluation OPIS failure rate was conservatively assumed to be 3.2 x 10^{-7} per hour, based on protective relaying failure data from IEEE-500 [9]. Assuming a one-year mission time, the post-trip failure probability for OPC was assumed to be 3 x 10^{-3}. This value can be assumed to be the upper limit for the OPIS monitoring function.

The Byron pilot OPC/OPIS risk assessment [7] quantified OPIS monitoring function failure probability of ~1.0E-04/year based on a plant-specific fault tree model. This value can be assumed to be the lower limit for the OPIS monitoring function.

OPIS reliability is a factor in the total CDF and LERF contribution from OPC events in the PRA. When analyzing the difference in risk between automatic trip function and manual alarm function, however, the OPIS failure probability does not contribute to the change in risk estimates, unless different failure probabilities are used to model failure of the trip function and failure of the alarm function. In this assessment, the failure of the OPIS is assumed to result in failure of both the trip and the alarm function, and thus, does not contribute to the change in risk estimates.

Figure 7 shows example fault tree logic that models the alarm function of the OPIS, and the operator action to trip the circuit breakers associated with offsite power supply to the emergency buses.

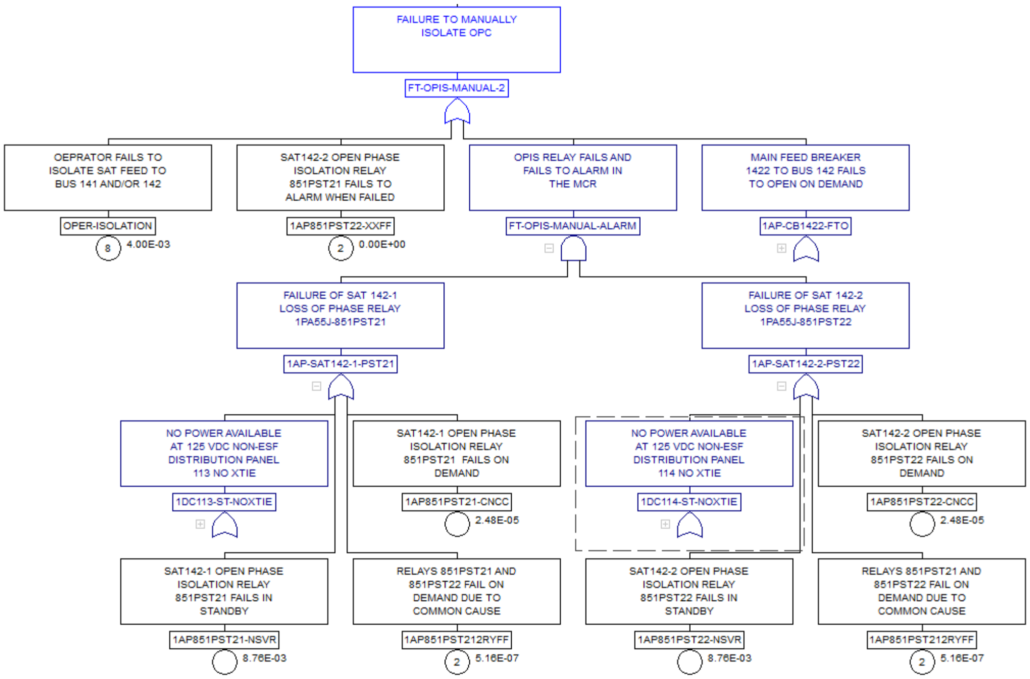

Figure 6: Example OPIS Fault Tree Model (Monitoring and Operator Action)

The determination of a plant-specific estimate of failure probability for the OPIS monitoring function will require a qualitative comparison of the plant-specific OPIS design and the OPIS design modeled in Byron pilot OPC/OPIS risk assessment. Adjustments to the Byron pilot OPC/OPIS risk assessment OPIS failure probability can be applied, as required, to quantify the plant-specific bounding OPIS failure probability. The first step involves a qualitative evaluation of the design to understand if the probability of the OPIS failure should be adjusted from the upper or lower limits provided in the previous paragraphs.

Adjustments are based on the following:

- Number of current or voltage inputs available that will detect an OPC
- Relay type/design
- Functional logic redundancy (e.g., one-out-of-two OPIS relays actuate, or two-out-of-two, etc.)

Making the general assumption that protective relays are generally similar enough to apply similar failure data, in this case, from IEEE-500 [9], the difference in OPIS failure will primarily be driven by the level of redundancy in the detection and alarm actuation scheme.

The Byron OPIS is essentially a one-out-of-two logic scheme with current detection of a common OPC upstream of the SAT, actuated by microprocessor-based relay.

If the plant OPIS requires two-out-of-two logic or only has one set of components that can fail the OPIS (every individual component, such as CT or PT, relay, and/or alarm can fail the function), failure of one input can result in OPIS failure. In this condition increase the OPIS failure probability to 1E-02.

If the plant OPIS has more redundancy (multiple channels of detection and logic components would have to fail to result in no signal), decrease the failure probability to 1E-05.

An alternative, more explicit treatment is to develop an explicit model of the components in the system, based on the design. Review of the OPIS failure mode and effects analysis or other documentation associated with the design of OPIS is recommended to understand system behavior prior to developing a detailed model. Assumptions regarding the failure probability of some of the components making up the OPIS inputs (e.g., current transformers), the OPIS relay, and output actuation devices (lockout relay) may be required. For example, in the NRC analysis [2], data from IEEE-500 was assumed applicable to the OPIS. Uncertainty in the data may need to be discussed and/or characterized for impact on the overall results of the OPC/OPIS model and PRA.

As previously noted, the probability of OPIS failure is important to determining the total CDF and LERF impact, but does not impact the difference in risk between operating with automatic trip function or manual alarm function only, unless the two failure modes are modeled with different failure probabilities. In the case overall CDF and LERF are high, more detailed modeling can reduce the estimated OPIS failure probability. As an example, if the OPIS relay includes a self-alarm feature which can provide the operators indication of a fault within the OPIS that precludes proper operation, repair of the system can be initiated in a timely manner to minimize the time the OPIS is failed. The probability of OPIS reliability would depend on the mean time to repair the fault. Obtaining adequate repair parts can reduce the time to repair, which reduces the probability the OPIS is failed when concurrent with an OPC.

4.7 Human Reliability Analysis

The NRC analysis in Reference [2] assumed a conservative worst-case scenario assuming RCP seal loss of integrity and leakage starting in 13 minutes. It was therefore assumed that 13 minutes was available for the operator to mitigate the OPC.

A best-estimate HRA for an OPC event involves a realistic assessment of the failure to diagnose an OPC given several cues in the control room, and failure to perform necessary response to an OPIS alarm. Best-estimate plant response models are used to establish the time-windows for performing OPC mitigation actions. Industry is in the process of installing an OPIS, which would either alarm or alarm and automatically isolate offsite feeders to the safeguard buses upon detection of an OPC. The reliability of operator action to manually isolate the offsite feeders could be sufficient to preclude the need to arm the automatic isolation feature of the OPIS.

Upon loss of a single phase, the affected unit would be expected to experience OPIS alarm in the control room and a subsequent plant trip may occur. Based on the alarm response procedures and other confirmatory checks, the operator will open the offsite power feed breaker and cross-tie breakers to each of the associated ESF buses. From this point forward, for plants in which the OPC results in automatic or manual reactor/turbine/main generator trip, the event will resemble a LOOP event. An expected sequence of events is provided below:

- Loss of single phase condition (OPC)
- OPIS alarm in the control room and subsequent plant trip (plants that auto trip)

- Operator opens the offsite power feed breakers to affected ESF buses
- Undervoltage Relays start the DGs
- DGs are running at rated speed and voltage, and the DG feed breakers close
- Undervoltage Relays reset and the Load Sequencers start
- Operators reset lockout relays, thermal overloads, and restart pumps and Non-ESF equipment as time permits

Some sites are already utilizing the automatic trip function of the OPIS. In order to accurately model the operator response if the automatic trip function is not enabled, procedure changes may be required to achieve a level of reliability roughly equivalent or better than the reliability of the automatic trip function. One key to low probability of operator action failure is sufficient time to take action given actuation of the alarm, and sufficient time to provide for recovery if the initial operator action to open the offsite power supply breakers to the emergency bus fails. Assuming core damage timing is not driven by the immediate need to establish seal cooling or to trip the RCPs (for a PWR), greater than one hour should be available considering initial success of RCP seal integrity and secondary heat removal via AC independent AFW/EFW pumps. For a BWR, greater than one-hour timing is based on initial success of AC independent high pressure pumps. In this case, if the OPC is not initially isolated from the emergency buses, the unbalanced phase condition may result in trip of time overcurrent relays associated with 4kV bus motors, and/or 480V thermal overload relays. Trip of 4kV bus motors may provide additional cues in the MCR of the unbalanced phase condition on the emergency buses. Trip of 4kV and/or 480V motors may impact the plant response if a lockout relay is actuated or a thermal overload requires manual reset. For further discussion of the potential impact on electrical equipment exposed to the unbalanced phase condition on the emergency bus, see section 4.6.

The Byron assessment [7] , considering core damage timing (1.8 hours to core damage, one-hour conservative time window assumed) based on initial shutdown seal success, overcurrent protection success, and cues from the OPIS alarm and separate indications of the OPC, yields a mean HEP of 1.2E-03. The assessment also includes an HEP to recover loads with protective relays that require reset (4kV motor loads) in the main control room and local reset (480V thermal overloads). The HEP is 5.5E-04 for a total HEP of 1.75E-03. In the assessment, failure of either operator action is modeled to result in complete loss of the affected emergency buses. This is conservative because the number of emergency bus loads that actuate, trip, and require reset is dependent on the specific automatic or manual demands that occur during the specific sequence of events after the plant trip and the individual electrical load response to the OPC induced phase imbalance.

The LaSalle assessment [8] considered a longer time window, but 4kV and 480V resets occur outside of the main control room. The total HEP is 2.2E-03.

Given the dependence of operator actions to illustrate an equivalent mitigation response to an automatic OPIS response, the following is an example list of operator interview questions which may be required to achieve a realistic evaluation of manual action failure probabilities.

1. How is an open phase condition (OPC) detected in the control room (MCR)?

2. If detected by alarm, specify alarm number and alarm response procedure.
3. Besides alarm in the MCR, are there other indications in the MCR that could be used to confirm or diagnose the presence of an OPC (for example, phase-to-phase voltage indication)? If so, specify these other indications and their location in the MCR (front panels, or panels in the back).
4. If OPC alarm occurs, is it easily noticeable? Or would it typically occur in combination with other alarms that have higher priority?
5. Has alarm occurred spuriously and if so, how often compared to legitimate signal?
6. What are the expected actions after an OPC alarm?
7. If the OPC-affected power supply is not automatically disconnected, do the operators open the breakers manually? Is such an action in a procedure and if so which one? Is it performed from the MCR?
8. Are the operators trained on the response to an OPC? If so, how often? Does the training consider situations where automatic actions fail to occur (leading the operators to manually open the breakers of the OPC-affected power supply)?
9. Given an OPC alarm, how long would it typically take for the operators to perform each of the following actions:
    a. detect the alarm,
    b. diagnose the issue (assuming automatic trip of the OPC-affected power supply did not occur),
    c. respond and trip the OPC-affected power supply.
10. Are there JPMs for the response to an OPC?
11. How is the action executed (pushbuttons or switches in the MCR)?
12. If the OPC is alarmed and the plant has not automatically tripped, would the operators proactively trip the plant and/or the RCPs (PWR only)?

4.8 Equipment Recovery

Operating a three-phase motor with less than three phases of electrical power input to the motor (i.e., the condition induced on the emergency bus if an OPC occurs and OPIS does not automatically isolate the offsite power supply to the emergency bus) introduces electrical conditions that result in unbalanced power flow, and higher than normal current through the remaining phase(s). If a motor is initially running it may continue to run on the remaining phases. The motor time overcurrent protection may detect the higher current required through the available phase(s) as an overload and trip the circuit breaker providing power to the motor. If the time overcurrent relay actuates a lockout relay to trip the motor, it may require local, manual reset of the lockout relay in order to close the circuit breaker after a suitable three phase power supply is available on the emergency bus. The risk evaluation should account for the operator action to restore equipment, if necessary, after manual trip of the breakers that provide offsite power to the emergency bus. Similarly, 480V loads with thermal overload devices may trip and require local reset before the load can be placed back into service.

Motors that are not running and are started by manual or automatic closure of the circuit breaker will draw starting current (locked rotor current) from the power supply through the remaining phases. Starting current is several times higher than full load current with all phases available. With less than three phases, current flow through the remaining phases would be higher than if all three phases were available. In this case, the protective relaying should trip the motor circuit breaker. If the protective relaying time characteristic is based on three phase current flow, it may not actuate before current exceeds design values for the motor with less than three phases available at motor input. The risk evaluation should ensure those motors are unavailable (failed) if the overcurrent protection is inadequate to trip the motor circuit breaker, prior to exceeding design current values, or an engineering evaluation should be performed to determine if the motor is recoverable after trip of the circuit breaker. Exceeding design values does not guarantee catastrophic failure of the motors. In some cases, the motor may experience a loss of life but would still be functional for the PRA mission time.

Discussions with electrical personnel regarding the impact of motors running when an OPC occurs, the Byron and LaSalle assessments assume motors will trip on overcurrent and can be recovered, consistent with the OPC event at Byron. Motors that are demanded to start with an OPC on the bus are assumed to trip, but can be recovered after the OPC is isolated from the emergency bus.

4.9 AC Power Recovery

After an OPC, offsite AC power could be aligned from a diverse offsite source, or by repairing the supply with the OPC. AC recovery is typically modeled in response to LOOP/SBO events in the plant PRA and is provided by LOOP classifications of plant-centered, switchyard-centered, grid-related, and weather-centered [10]. AC recovery timing is modeled using lognormal distributions and a time exceedance probability curve showing the probability of recovery AC power prior to exceeding a given time. In a typical PRA, these curves are used to define probabilities of recovering AC before reaching a point in time following a LOOP initiating event representing a damage state (i.e., core damage).

In the January 30, 2012 Byron event [1], the OPC was repaired and offsite power restored 34 hours after the initial failure (Reference [1] does not indicate whether earlier restoration was possible). A similar (but not the same OPC because a ground fault also occurred) event occurred in February of 2012, which required repair of a similar component (underhung porcelain insulator) that failed in the January event, in which offsite power was restored within 4 hours via a unit emergency bus cross-tie breaker, which aligned the opposite unit SAT supply to the emergency buses. These OPC events occurred at the switchyard level at Byron. Other OPC events are possible depending on the number of operating transmission lines feeding the switchyard and the configuration of the transmission grid outside the switchyard.

Published data in References [5] and [6] does not directly distinguish between LOOPs caused by open-phase conditions and LOOPs caused by other events. For the pilot assessments [7] and [8], offsite power recovery time is based on assumption and judgment. The offsite power via the time exceedance curve that best reflects the general nature of an OPC (OPC events potentially require repair of SSCs; OPC events can occur in the transmission/distribution grid or in the switchyard) is difficult to judge without additional analysis of potential recovery times given OPC occurrence. The grid-centered curve is assumed to be applicable on the basis that it generally reflects the longest time to repair/recover LOOP events that affect the transmission system, and the events that affect the grid-related LOOP data (e.g., failed insulators, broken conductors) are also possible at the switchyard level. The grid-centered LOOP data and recovery times also reflect complex events related to grid interconnections and grid electrical protection schemes, so some of the grid-related LOOP data may not directly apply to an OPC.

The plant-centered curve includes data reflecting failures inside the plant boundary. The data may not be most applicable to OPC events that occur in the switchyard or grid. Switchyard-centered data may be applicable, but generally results in higher probability of recovering AC power at a given time compared to grid-centered and weather-centered events, and the existing Byron event durations shows that recovery time may be generally longer than existing switchyard LOOP data (it should be noted the Byron event does not distinguish when AC could have been recovered versus actually recovered). Weather-centered events, which include widespread damage to SSCs, are judged to not be applicable to OPC which by nature is a lower damage event than those due to extreme weather.

There is uncertainty in the applicability of the AC recovery curves, which may need to be addressed and characterized.

The Byron assessment assumes AC recovery is possible regardless of whether the operators successfully trip the offsite power circuit breakers providing power to the emergency buses given an OPC or whether they fail to complete the action. If the operators succeed, plant emergency AC can be aligned, and the event progresses as a typical LOOP where AC recovery can be credited if random failure of emergency power occurs. If the operator fails, AC recovery can be credited given time available if AC independent core cooling succeeds and (for a PWR) RCP seal LOCA does not occur. In both cases, the electrical overcurrent protection associated with circuit breakers providing power to the motors on the emergency bus must succeed to prevent damage to the motors, and for the case where the operator fails to disconnect the power supply to the emergency buses, indications of the OPC independent of the OPIS alarm are required to cue recovery.

4.10 Fire and External Events

This guidance primarily addresses OPC impact to internal events risk and models. In general, fire and external event risk and models should not be significantly impacted by inclusion of an OPC. If the impact to fire and external events risk and models is small, the difference in risk between the automatic trip function and the alarm function will be very small, however, the following general considerations for OPC impact from external hazard PRAs can be applied.

Fire Events

Fire PRAs that credit offsite power supplies may have impact from incorporation of the potential for an OPC and OPIS. Spurious operation of the OPIS with automatic function enabled may result in a plant (reactor/turbine/main generator) trip, depending on the plant response to isolation of offsite power from the emergency buses. Fire damage could result in a spurious OPIS alarm, which may impact the operators in the MCR and/or result in operator action to separate the offsite power supply from the emergency buses. Spurious operation may be a risk if the plant is designed to trip on a loss of power to the emergency buses or if the same fire that actuates the OPIS also causes a plant trip and LOOP and precludes offsite power recovery within a relatively short time frame (for example, by re-closing the offsite power breaker opened by the OPIS) via other cable impacts. In this case, there is little difference in risk between operating with automatic function and manual alarm function because of the plant response to the loss of the other cables in the fire scenario.

Fires could damage electrical cabling associated with the OPIS and provide loss of OPIS automatic trip function and or alarm function, which if concurrent with an OPC during the PRA mission time, results in the OPC affecting the loads on the emergency buses (overcurrent protection and DC control power may also be affected by the fire). The probability of a post-trip (24-hour exposure) OPC is relatively small. For plants that automatically transfer emergency buses to offsite power transformers after a plant trip, an OPC could occur prior to a fire event, and if the OPIS failed and the failure was not detected, could be a latent condition that affects the emergency buses after a fire induced plant trip. Combining the likelihood of a fire with the occurrence of an OPC and failure of the OPIS makes the scenario unlikely.

<u>Seismic Events</u>

Generally, seismic PRAs assume or model a fragility of a seismic induced LOOP at a given seismic acceleration. Given the potential for widespread damage to the switchyard and/or transmission/distribution grid, and the general correlation of similar components (i.e., the individual conductors, insulators, structures associated with offsite power) it can be assumed the likelihood of an OPC without a full LOOP is small. In lower acceleration seismic events in which offsite power does to the emergency buses does not fail due to structural failure caused by the seismic event, chatter of electromechanical contacts associated with the OPIS may cause isolation of offsite power from the emergency buses via automatic trip function or if operator responds to spurious alarm by isolating offsite power. If the plant trips during this event but offsite power remains available in the switchyard, the operators could re-align the tripped breaker and recover offsite power. For plants that automatically transfer emergency buses to offsite power transformers after a plant trip, an OPC could occur prior to a seismic event, and if the OPIS failed and the failure was not detected, could be a latent condition that affects the emergency buses after a seismic induced plant trip. Combining the likelihood of a seismic event with the occurrence of an OPC and failure of the OPIS makes the scenario unlikely.

<u>High Winds Events</u>

Like seismic events, High Wind PRAs assume or model a fragility of an induced LOOP at a given wind speed. Given the potential for widespread damage to the switchyard and/or transmission/distribution grid, and the general correlation of similar components (e.g., the individual conductors, insulators, structures associated with offsite power) it can be assumed the likelihood of an OPC without a full LOOP is small.

<u>Other External Events</u>

Other external events are generally insignificant to risk and the occurrence of an OPC due to the event would depend on the likelihood of potential damage to the offsite power supply. Such damage would need to result in an OPC and not result in a full LOOP (for example, explosions near the plant could conceivably damage a single phase, but given the three phases are located together, if the event damaged one phase it would probably damage all three). Local damage to a structure or component that causes loss of one phase without the other would actuate the OPIS and the plant would respond the same as to a random OPC with no additional consequences.

4.11 Quantification and Sensitivity Analysis

Quantification of the pilot assessment PWR model (Byron [7]) and a BWR model (LaSalle [8]) was performed to estimate the change in CDF and LERF between operation with automatic trip function and alarm function. Electrical overcurrent protection was assumed successful and adequate to protect the loads affected by the OPC. AC (offsite power) recovery time was assumed similar to durations that have occurred after grid-centered LOOP events. A format for presenting the quantification results is shown in the tables below.

Plant Name/Type	Base CDF - OPC Impact not modeled (per yr.)	Base CDF - OPC Impact modeled (per yr.) Credit for both Automatic OPIS and Operator Manual Action	Base CDF - OPC Impact modeled (per yr.) Credit for Operator Manual Action Only.	Change in CDF between OPC impact with Automatic OPIS and Operator Manual Action and Operator Manual Action Only.
(PWR)				
(BWR)				

Plant Name/Type	Base LERF - OPC Impact not modeled (per yr.)	Base LERF - OPC Impact modeled (per yr.) Credit for both Automatic OPIS and Operator Manual Action	Base LERF - OPC Impact modeled (per yr.) Credit for Operator Manual Action Only.	Change in LERF between OPC impact with Automatic OPIS and Operator Manual Action and Operator Manual Action Only.
(PWR)				
(BWR)				

<u>Sensitivity Analysis</u>

Uncertainties in the overall OPC model require characterization of the impact on the change in CDF and change in LERF results. The following uncertainties are addressed via sensitivity studies:

Sensitivity Case	Method	CDF	LERF	Change in CDF	Change in LERF
OPC Occurrence Frequency/Probability	Reduce OPC frequency/probability using only events that have occurred and caused plant trip/loss of				

	emergency bus				
OPIS Failure Probability	Increase OPIS failure probability by factor of 5 to account for hardware failure probability differences				
Operator action HEP	Assume local actions required to reset loads on the 4kV and 480V buses (increase HEP to 1E-02)				
Overcurrent Success	Assume overcurrent protection fails and motors are unrecoverable with probability 1E-02				
AC Power Recovery 1	Assume AC power recovery at the 95th percentile of the grid-related curve				
AC Power Recovery 2	Assume AC power recovery at the 5th percentile of the grid-related curve				

4.12 Results Interpretation

The risk metrics quantified in this evaluation allow assessment of two impacts to the PRA. The first impact is on the base CDF and LERF itself. The second impact is the difference in risk between operating the plant with automatic OPIS function to trip the circuit breaker associated with the power supply affected by the OPC, and operating with the OPIS function to provide an alarm to cue operator manual action to trip the circuit breaker associated with the power supply affected by the OPC.

The following general conservatisms were identified during the benchmark evaluations of the difference in risk between OPIS automatic trip function mode and alarm function mode.

1. All domestic nuclear power plant OPC operating experience events used in the NRC risk evaluation are assumed applicable to all plants, and are assumed to occur in the switchyard at the most limiting location (e.g., the input to the offsite power transformer or transformers, if common physical or electrical input, that provide power to the plant emergency buses).

Including failure events where the applicable failure could not occur at a subject plant increases the change in risk between alternatives, because the difference in probability of core damage (CD) or Large Early Release (LER) given OPC is multiplied by the OPC frequency.

2. A reactor trip is assumed to occur for all OPC events. This is realistic for plants that provide offsite power to buses (emergency or balance of plant) and the OPC will propagate a phase imbalance to the bus and result in an automatic plant trip via trip of equipment protective relaying or loss of equipment function. This is conservative for plants that would not automatically trip on an OPC to the emergency buses or if the OPC does not propagate a phase imbalance to the emergency buses, though the plants would be in a technical specification LCO with eventual manual shutdown required unless alternative offsite power feed can be aligned. This increases the change in risk between alternatives because some OPC events will not cause automatic or manual shutdown prior to restoring Technical Specification operability.

3. The OPC condition is assumed to occur without a concurrent low-impedance ground fault; thus, no credit is taken for existing overcurrent or undervoltage relaying to detect the condition and isolate the OPC from the emergency buses. This increases the difference in risk between the alternatives because some OPC events would demand the existing (non-OPIS) protective relaying, equally reducing the frequency that either automatic trip function or alarm response is needed.

4. In manual alarm function mode, the OPC induced phase imbalance is assumed to result in trip of protective relaying for each load powered by the bus affected by the OPC (in automatic mode the OPIS is designed to actuate before other relays). For plants with protective relaying that requires manual reset (e.g., 480V AC Motor Control Center breakers with thermal overloads or motor circuit breaker overcurrent relaying that actuates a lockout relay) this increases the difference in risk between alternatives because it increases the probability of CD and LER given OPC occurrence, but only applies to the alarm mode.

5. Offsite power recovery is modeled using grid recovery data, as a surrogate for repairing the components that failed and caused the OPC. This is conservative because the grid centered curve represents widespread loss of power events that are more challenging than failure of conductors (bus bar connection, drop line, etc) in the operating experience data. This increases the difference in risk between the alternatives because the factor increases the probability of CD and LER equally for both alternatives, increasing the difference between the two.

6. FLEX strategies provide an alternative success path given loss of plant emergency AC buses. FLEX is not formally modeled in all plant PRAs; including FLEX would decrease the change in CDF and LERF between alternatives because it would decrease the overall probability of CD and LER given OPC induced station blackout, whether automatic trip function or alarm mode only is credited. Considering HFE dependency, it would decrease the probability of CD or LER more for automatic trip function because it does not involve operator action to isolate the OPC from the plant, unless this action and actions to deploy FLEX are completely independent.

The following general non-conservatisms were identified during the benchmark evaluations of the difference in risk between OPIS automatic trip function mode and alarm function mode.

1. All plants are assumed to be in normal electrical configuration, with more than one transmission feeder aligned to the switchyard. Time spent in unusual configurations which would propagate a

phase imbalance via an OPC in the transmission system is assumed to be small. This decreases the change in risk between alternatives because the OPC frequency would be higher if only a single transmission feeder were aligned to the switchyard, and the frequency is multiplied by the difference in probability of CD or LERF between the alternatives.

2. In manual alarm function mode, all electrical loads are assumed to be recoverable given actuation of protective relaying. Motor load overcurrent relaying that does not monitor current on all three phases to the motor are assumed to trip via increased current on the available two phases. This decreases the change in risk between alternatives because it decreases the probability of CD and LER given OPC occurrence with OPIS in alarm mode.

3. In alarm function mode for PWRs without physically independent offsite sources to the emergency buses, if RCP motors are affected by the same phase imbalance that propagates to the emergency buses, the protective relaying is assumed to trip the RCPs. If the phase imbalance is not sufficient to trip the RCPs motors, the imbalance is implied to be insufficient to cause loss of motors associated with seal cooling. The OPIS alarm response procedure will direct trip of the RCPs, and the loss of seal-cooling alarms would provide diverse alarm/indication cues to trip the RCPs. Thus, failure to trip RCPs given OPIS alarm actuation is unlikely. This decreases the change in risk between alternatives because it decreases the probability of CD and LER given OPC occurrence with OPIS in alarm mode.

Base Risk Impact

Base risk is primarily driven by the frequency of the OPC and the level of redundancy with which the OPC can be detected (the design of the OPIS) and the OPIS automatic trip function actuated (in automatic function mode). In manual alarm mode, base risk is primarily driven by the frequency of the OPC, the level of redundancy with which the OPC can be detected, and probability of operator action to isolate the OPC from the emergency buses, and recover any loads that tripped. In both modes, the plant SBO response contributes when the OPC is not isolated from the emergency buses. There is also an impact to base CDF and LERF because automatic trip function can result in a LOOP on a spurious OPIS, or the operators may trip the plant given an alarm actuation by a spurious operation of the OPIS in alarm mode, for plants that trip on a loss of offsite power to the emergency buses. Plants that do not trip automatically on a loss of offsite power to the emergency buses may eventually require manual shutdown unless the offsite power supply is re-aligned to the emergency buses or an alternate offsite power supply aligned.

Based on the results in sections 4.10 and 4.11, the change in base CDF and change in LERF results using the pilot assessments and methodology described in this document, are considered small. Small is defined as a quantitative change in CDF near 1E-06 and change in LERF near 1E-07. The application of a 1E-05 CDF “ceiling” and a quantitative result “near” 1E-06 is suggested as a risk performance measure in recognition that the existing PRA models and risk analysis methods described in this report are used to provide a measure of the change in risk that does not require detailed model development to represent the OPIS. Therefore a small difference in risk combined with the known conservative and non-conservative biases listed above is sufficient to conclude whether to enable the automatic trip function of the OPIS. The significant risk reduction from OPC events has already been addressed due to recognition of potential OPC impacts and implementation of plant changes to monitor for such events. Response to OPC events, whether manual or automatic, requires recognition of the condition to drive the response; therefore the risk difference is minimal and confirmed to be extremely small by virtue of applying the methodology described in this guidance. Lastly, improved mitigation of loss of AC power events due to plant or procedural changes at facilities since the event at Byron in 2012 also contribute to the reduction in risk from OPC.

Change in Risk Impact

Generally, the change in risk between the automatic OPIS function to trip the circuit breaker associated with the power supply affected by the OPC and the function to alarm to cue operator manual action would depend on the difference in failure probability of the OPIS in automatic mode and the difference in probability of the same OPIS hardware failing to cue an alarm plus the failure probability of the operator action to isolate the OPC and restore systems affected by the OPC that trips any protective relaying in the time the bus was exposed to the OPC. Essentially, the closer the reliability of the operator manual action gets to the reliability of the automatic function, the smaller the change in risk should become.

The difference in the probability of core damage or large early release is primarily influenced by the differences in the time the operator takes to accomplish the same action as the automatic OPIS trip. Impact on the plant emergency bus loads depends on the time the bus loads are exposed to the unbalanced phase condition. The response of the load protective relaying is dependent on the individual load and relaying, which differs depending on the electrical design of the individual load. The known existence of an OPC, and therefore the likelihood of the overcurrent condition, may still require additional scrutiny and time before recovering a critical load.

Factors that reduce the base risk due to an OPC will reduce the change in risk between operating modes by virtue of the overall risk being low and therefore the difference between smaller numbers becoming smaller. Plants with high base risk may still be able to show acceptable change in risk if the consequences to the additional time the bus loads are exposed to the OPC are small; in effect, if the protection of loads occurs and they are easily recoverable.

Regarding spurious operation, while automatic OPIS can result in a LOOP at a plant and the operator may trip the plant in response to an OPIS alarm, the alarm mode allows for confirmation of additional indications that an OPC has occurred prior to an operator taking action to trip the plant. Based on this factor, redundant and diverse OPC cues could prevent an operator from tripping the plant on a spurious OPIS alarm, whereas the automatic OPIS does not allow for confirmation of the OPC prior to actuating a trip, so spurious operation contributes more to plants operating with automatic OPIS mode enabled.

5 CONCLUSION

This document provides the guidance and framework for performing a plant-specific risk evaluation of an Open Phase Condition (OPC) at a nuclear power plant. Using the guidance, change in CDF and change in LERF results small enough (under a proposed 1E-05 CDF ceiling) to support credit for manual operator action to isolate an OPC from the plant emergency buses can be developed.

6 REFERENCES

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