REQUIREMENTS FOR A REAL-TIME RISK MONITORING TOOL TO REDUCE TRANSMISSION GRID–NUCLEAR PLANT VULNERABILITIES

M. D. Muhlheim,[1] L. C. Markel,[2] F. J. Rahn,[3] and B. P. Singh[4]

[1]Oak Ridge National Laboratory, Oak Ridge, TN 37831-8045
[2]Sentech, Inc., Knoxville, TN 37921
[3]Electric Power Research Institute, Palo Alto, CA 94303-0813
[4]JUPITER Corporation, Wheaton, MD 20902

ABSTRACT

ORNL, along with Sentech and the Electric Power Research Institute (EPRI), is currently developing a real-time risk monitoring tool for the U.S. Department of Energy (DOE) to help nuclear power plants (NPPs) assess the risk of loss of offsite power. These same tools will also help transmission system managers assess the adequacy of reserve margins and system conditions, provide return-to-service priorities to restore the operating margin to the system, determine which assets to protect to prevent the erosion of system margins, and highlight the shortage or inadequacy of transmission facilities. Conventional probabilistic risk assessment (PRA) techniques (e.g., fault trees and event trees) are currently incapable of modeling the transmission system because the size of the entire grid, dynamic grid topology, conditional probabilities (reflecting varying line loading levels), and common-cause threats preclude the development of a detailed, stand-alone model that can give results in real time. In addition to overcoming conventional PRA limitations, another dilemma involves identifying the undesired event(s) of interest. How do you decide where the model development begins, and how much of the grid must be modeled given that there are no clearly defined start and end points? Linking interconnected transmission line segments using a hybrid analysis tool should overcome these obstacles for conventional techniques to develop a detailed, dynamic PRA model of the entire grid. All electrical line segments (including power plants) are potential starting points; real-time conditions on the grid determine how much of the grid is to be modeled. The proposed approach enables operators to estimate the probability of localized grid disturbances and subsequent cascading instabilities that potentially affect a power plant and to estimate the probability of an NPP trip affecting the grid.

KEYWORDS

Power generation, electric transmission, reliability, nuclear power plants

INTRODUCTION

Although the grid operating standards that evolved in the past provided reasonable grid reliability, the deregulated wholesale power market has already contributed to conditions that challenge the stability of the grid. Restructuring of U.S. power systems to promote market-based dispatch was designed, in part, to increase utilization of existing assets. It has resulted in greater power transfers over longer distances. This has increased the loading of the nation's transmission system and also made local reliability more dependent on distant events. Furthermore, plant risk and grid instabilities are interrelated. The tripping of a plant can cause grid instabilities and grid instabilities can result in the tripping of a plant.

RESEARCH DESIGN AND METHODS

Overview of Method and Problem

Designing a real-time risk-monitoring tool consists of developing models (and functional specifications) to anticipate instabilities of electric transmission networks in proximity to the NPP from information obtained from wide area sensing systems. The size of the entire grid precludes the development of a stand-alone, detailed, dynamic model. Similarly, an equivalent model of the entire grid would lack the necessary local area detail to be of value. The problem is to model the grid in sufficient detail while limiting its size to a workable problem.

Information Inputs to Model

On-line contingency analyses use real-time data to assess the quality of the voltage to an NPP switchyard. NPPs and the transmission system have protective devices to prevent voltage, current, and frequency fluctuations from cascading or damaging other equipment—either on the grid or at the plant.

Will a model based upon voltage contingencies provide sufficient information for NPPs to assess their risk from grid disturbances? To answer this question, all NPP licensee event reports (LERs) that involved the high-voltage distribution systems, actuations of engineered safety features, and plant transients since 1993 were reviewed to identify those instances where a disturbance on the grid caused some action at an NPP.[a] Actions taken by the NPPs in response to grid disturbances included a plant trip or scram (54%), transferring loads to another bus and/or the emergency diesel generator (EDG) (40%), or no action taken by the plant (6%) (Table 1). Almost one-half of the time that a disturbance is large enough to affect the plant (i.e., transferring electrical loads to another bus), the plant remained at power (typically without a power reduction). This means that any real-time risk monitoring tool must be able to account for various disconnect and load transfer schemes, equipment, protection set points, etc.

Causes of plants needing to take action because of grid conditions include voltage, current, and frequency fluctuations, or no power on the line (Table 2). No power on the line could occur when, for example, a direct feed line is cut or a tower is knocked over. Thus, contingency analyses must consider not only voltage, but also current and frequency.

The next question is then, "What caused these grid conditions that affected the NPPs?" The major causes are grid perturbations (including weather-related events) and equipment failures on the grid (Table 3). In fact, disturbances resulting in a plant scram are equally divided between grid disturbances (19 events) and grid equipment weaknesses and failures (17 events). Any real-time risk monitor must be able to account for the probability of equipment's failing or being out-of-service. Equipment failures include breakers,

[a]Not included are events such as operability conditions where exceeding previously analyzed values results in the "inoperability" of the off-site power sources (e.g., "*if* this happens, then that *might* happen"). Also not included are plant-centered disturbances and LOOPs; plant-centered disturbances are those that occur inside the control area of the plant.

TABLE 1
GRID DISTURBANCE EFFECT ON NPP

Action taken by NPP	Number of occurrences	Percentage of occurrences
Scram	**36**	**54**
No scram	**30**	**46**
Loads transferred to EDG	17	26
Loads transferred to another bus	8	12
Loads transferred to EDG and another bus	1	2
No action taken	4	6

TABLE 2
GRID CONDITIONS AFFECTING NPP

Grid condition	Number of occurrences	Number of scrams
Voltage fluctuation or drop	18	8
Overcurrent	22	15
No power on line	15	4
Under frequency and undervoltage	4	3
Current imbalances	4	3
Underfrequency	1	1
Swing on load demand	2	2

circuit breakers, substation transformers, cables, capacitors, directional relays, insulators, lightning arrestors, relays, and voltage regulators.

Lightning (3), snow and ice (2), and high winds (5) were the causes of weather-related scrams. Lightning (4) and ice (3) were also the most likely causes of bus transfers because of weather (i.e., no scram). Any real-time risk model must account for weather conditions by adjusting the probability of equipment failure or loss of line segments.

How important are the lines coming into a plant's switchyard? More than 40% (15 of 36) of the scram-related events occurred because of some short-term grid disturbance (e.g., "spike") while all off-site power lines remained energized (Table 4). In fact, more than 30% (20 of 66) of *all* events generating a plant response (i.e., scram or bus transfer) occurred when all off-site lines remained energized. The loss of two to three lines, up to a LOOP, does not necessarily generate a scram signal. In fact, it is much more likely that a disturbance will lead to a trip than a LOOP (36 trips vs 5 LOOPs). Thus, the model must be able to account for degraded conditions as well as a loss of power in the line. Disconnect schemes and protective set points must also be considered.

Designers and analysts have proposed various techniques for analyzing the reliability of power systems. Proposed techniques typically involve the extension of fault tree and event tree analysis techniques. Limitations are many. Any model must be able to account for

- plant-specific conditions;
- failure probabilities of individual transmission lines and equipment;
- transmission lines and equipment out-of-service or undergoing repair;
- not only a loss of power in a transmission line segment, but degraded conditions as well;
- voltage, current, and frequency fluctuations;
- different failure rates for different conditions (e.g., weather, power flows, demand); and
- constantly changing grid conditions (i.e., the model must be dynamic and solvable in real time).

TABLE 3
INITIATING EVENTS FOR NPP ACTIONS

Initiating event	Number of occurrences	Number of scrams
Grid perturbations (excluding weather-induced)	10	9
Weather	19	10
Equipment failures (on the grid)	26	17
Human errors	6	0
Animals	3	0
Fire (and smoke)	2	0

TABLE 4
NUMBER OF POWER LINES
AFFECTED BY GRID DISTURBANCE

Number of lines without power	Number of occurrences	Number of scrams
0	20	15
1	34	13
2	5	3
3	2	1
LOOP	5	4

Dynamic PRA Model

A fault tree analysis can be used to model the probability of failure to deliver power to a point under consideration—either an NPP, a substation, or a transmission line segment. The method is versatile because it can assimilate failure rates, downtimes, repair times, and other dynamic measures of system function. It has almost everything that analysts need. However, if the failure of interest is a loss of an off-site power line to an NPP, the fault tree would grow prohibitively large before much of the grid is modeled. The grid is simply too large to model from the plant-outward approach. Any outage or stress on the grid away from the plant would be buried in the fault logic—if, in fact, the model could be made that large! Similarly, a grid-inward approach would require previously developed fault trees for every line segment and piece of equipment on the grid so that any assessment could be performed quickly. The sheer number of required fault trees precludes the development, storage, and analysis using this approach.

An event tree would start with an initiating event and have an end state of loss of power or degraded power to the plant. The functions that can prevent the initiator from evolving into a loss of power to the NPP are identified and arranged in a functionally logical, often chronological, order as event headers. Each event header represents a potential success or failure, represented as up or down branches on the tree. An event tree approach would allow the analyst to start at a stressor point, disturbance, or outage on the grid. However, the size of the grid, the number of interconnections, back-feed possibilities, and number of previously developed event trees needed to perform an analysis precludes using a conventional event tree approach.

It would be ideal to use the principles of event tree and fault tree analyses and develop a dynamic PRA model that can be used to interconnect transmission segments and equipment. An event tree model would allow the model to start at an initiating event or stressor. A fault tree model would allow the details to be incorporated. ORNL, along with Sentech and EPRI, is proposing a hybrid analysis tool that mimics the event tree for the initiators and stressors and links the segments or nodes to fault trees for the details. All segments that are electrically connected will be probabilistically connected. Unlike previously developed event trees, however, a nodal event tree is created by using the computer to link the connecting segments together. The failure probability of each transmission segment can be determined based upon actual grid conditions. For example, consider an initiating event (IE) that is the loss of line-segment 1 with line-segment 3 out-of-service (OOS) (Fig. 1). Segment 1 is connected to segments 2, 3, 4, 5, and the power plant (P). Because the loss of segment 1 cannot propagate through segment 3 (it is OOS), the development of a cascading power loss stops for this sequence. Segment 5 does not need to be considered in the analysis under these conditions. However, when segment 1 or 3 is recovered, segment 5 would then be modeled.

The cascades through segments 2, 4, and P are more complicated because there are more interconnections and the losses can propagate (Fig. 2). Segment 2 is electrically connected to segments 1, 3, 4, and P. As discussed previously, a loss of power cannot propagate through segments 1 or 3; segment 1 is the IE, and segment 3 is OOS. The loss of segment 2 could cause the plant to trip. The loss of P could then cause the loss of segment 4. Therefore, the model not only shows how a disturbance on the grid can cause a plant trip, but it then evaluates the impact of the plant trip on the grid. Rules and contingencies for linking line segments will be evaluated similarly to the examples given previously. After the computer makes all of the links and removes all of the circular logic from the model, the resulting model will only show those paths where losses could propagate. The probabilities for these losses are determined with the use of fault tree analyses.

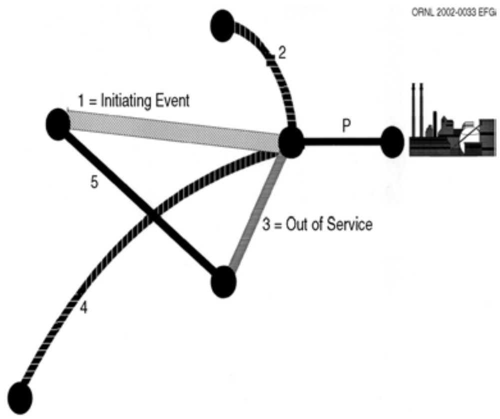

Figure 1: Electrically interconnected transmission line segments

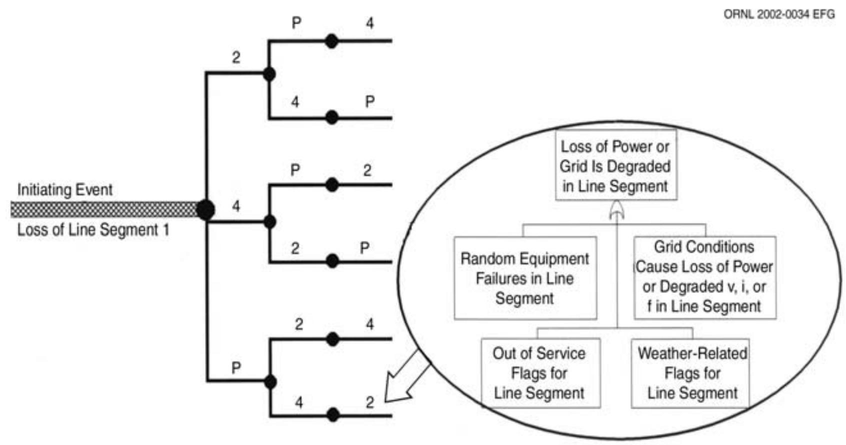

Figure 2: Risk model of electrically interconnected transmission line segments.

Linked Fault Trees

The fault trees will evaluate the failure probability for different causes such as random equipment failures (including common-cause failures), equipment being out-of-service or undergoing repair, weather-related failures (e.g., lightning, snow, ice, wind, and heat), and grid-related failures. Although failures because of grid conditions are plant dependent, the model must account for disconnect schemes, differences of voltage, current, and frequency fluctuations that affect different NPPs, and power flows on the grid.

A key part of the project is determining the modeling required to obtain conditional probabilities using the type of sensor information and outage probabilities for line segments that EPRI has already developed. EPRI's probabilistic risk index (PRI) calculates the likelihood of violating voltage stability, voltage limits, and thermal limits for each bus in a transmission network. This methodology will be used for contingency analyses to calculate conditional probabilities of failure for interconnected line segments.

NPPs use degraded voltage relaying schemes to protect electrical equipment against sustained low voltage conditions. The fault tree evaluates the probability of the segment failing or providing voltage, current, or frequency below specified values.

The power system operator uses state estimation and on-line contingency analysis to provide a continuous assessment of current power system conditions and vulnerabilities. This analysis is automatically updated periodically (such as every 10 min) and may consider several hundred worst-case contingencies. Based upon this information, the probability of falling below (or above) plant acceptance criteria will be determined and input into the model.

Transmission outages and plant outages are automatically incorporated, and the increased risk to the adjacent transmission segments (importance) is automatically determined. Differences in philosophy of SOs, connections to different types of plants (e.g., nuclear vs other types of generators), weather, and distribution system interactions are reflected in the probability assigned to each potential outage event. The probabilistic model is dynamic because as the system is stressed, the probability of each segment's failing could be modified automatically via databases linking stress levels to probabilistic values.

The other concern is a plant trip causing instabilities on the grid. The computer code *Equipment Out Of Service* (EOOS), developed by EPRI, is the existing deterministic real-time modeling and analysis tool to evaluate changes in the plant status and to evaluate sets of critical contingencies that lead to a violation. Again, because the computer is linking the segments, the effects of a plant trip can be followed from the plant throughout the grid.

For real-time calculations, a heuristic tool for calculating conditional probabilities for different contingencies will be built for coarse bins of cases on the grid line segments. As time goes on, the grid-condition bins can be made finer; hence, the system "learns." Because this is now just looking up a probability for current grid conditions, the overall assessment of the grid and determining a probability of a contingency affecting a plant could be close to real time. All of the difficult work is performed off-line.

Output from Model

Algorithms will have to be prepared to characterize the probabilistic likelihood of moving from a stable to an unstable network configuration. The results will be presented on global/local basis with the ability to drill down to specific transmission zones. Maps and graphs will be used to help users identify bottlenecks in the system.

CONCLUSIONS

This paper describes the requirements for a real-time risk assessment tool to identify and mitigate threats to an NPP due to problems on the transmission grid. The tool is designed to provide information in both directions—to the NPP on how to harden its configuration and to the SOs on possible NPP vulnerabilities. Solutions may require SOs to increase operating reserves or to disallow proposed transactions. For example, transactions that may be acceptable from a load-flow analysis may be unacceptable from a risk standpoint because it could render the NPP more vulnerable to a disturbance.

The tool models disturbances in addition to the traditional LOOP contingency (i.e., not just "worst case" grid scenarios), as historically NPP scrams have resulted from degraded service as much as from loss of service. The tool incorporates in the risk assessment model conditions that have historically led to NPP scrams, such as local thunderstorms. Setting up this system requires detailed information from the power system and the NPP. Fortunately power systems already employ real-time data collection, state estimation, and on-line contingency analysis systems. Similar systems are available for in-plant application (e.g., EOOS). This tool specifies how the systems should work together to provide added functionality. The development of a real-time risk-monitoring tool will benefit both the power system and the NPP. It will promote safer operation of the NPP by providing more in-depth analysis of current conditions. It will simultaneously increase the performance of the NPP (and consequently the transmission system) by allowing operation over a broader range of operating conditions. Finally, it will allow both the SO and the NPP operator to take actions that increase both reliability and safety.

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